Georgia-Pacific

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June 15, 2020

Dr. D Pei Wu
Air Quality Planner
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Oregon Department of Environmental Quality
700 NE Multnomah Street, Suite 600
Portland, OR 97232-4100

Re: Georgia-Pacific Consumer Operations LLC – Wauna Mill
Regional Haze Four Factor Analysis

Dear Dr. Wu:

Please find attached the Georgia-Pacific Consumer Operations LLC – Wauna Mill (GP) response to the Regional Haze Four Factor Analysis (FFA) request letter sent from the Oregon Department of Environmental Quality (Oregon DEQ) to the Wauna Mill on December 23, 2019. As found in Attachment 1 to this letter, and previously discussed with the Oregon DEQ, the Wauna Mill elected to complete this analysis in conjunction with the Northwest Pulp and Paper Association (NWPPA). As such, data is presented for all four pulp and paper mills in operation in Oregon. GP has only included the cost tables specific to the Wauna Mill in Appendix A of the report. In addition, Attachment 2 to this letter includes an FFA for the Wauna Mill's five tissue and towel paper machines. The Wauna Mill is the only pulp and paper mill in Oregon that operates tissue and towel paper machines; therefore, GP has performed an individual FFA for these units. If you have questions regarding the report, please contact Kimberly May at (503) 455-3042 or kimberly.may@gapac.com.

I, the undersigned, am the responsible official of the source for which this document is being submitted. I hereby certify, based on the information and belief formed after reasonable inquiry, that the statements made, and the data contained in this document are true, accurate, and complete.

Sincerely,

Jeremy Ness
Vice-President – Manufacturing

Attachments

CC (electronic only):
David Graiver, david.graiver@state.or.us

ATTACHMENT 1
REGIONAL HAZE RULE FOUR FACTOR ANALYSIS FOR FOUR OREGON PULP AND PAPER MILLS

REGIONAL HAZE RULE FOUR-FACTOR ANALYSIS FOR FOUR OREGON PULP AND PAPER MILLS

JUNE 2020

Submitted by:

Northwest Pulp & Paper Association

Northwest Pulp and Paper Association
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Submitted to:

DEQ

Oregon Department of Environmental Quality
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1. INTRODUCTION

The Oregon Department of Environmental Quality (DEQ) Air Quality Division is in the process of developing a State Implementation Plan (SIP) revision for the second planning period under the 1999 Regional Haze Rule (RHR) at 40 CFR Part 51, Subpart P. The RHR focuses on improving visibility in federal Class I areas by reducing emissions of visibility impairing pollutants. DEQ is required to update the SIP by July 2021 to address further controls that could be applied to reduce emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_X), and particulate matter less than 10 microns in aerodynamic diameter (PM_{10}) for the 2021-2028 period. DEQ has requested that several sources within the State submit a Four Factor Analysis (FFA) to examine the feasibility of additional emissions controls. This report provides the Northwest Pulp and Paper Association's (NWPPA's) FFA for the following mills:

- Cascade Pacific Pulp - Halsey
- Georgia-Pacific - Wauna
- Georgia-Pacific - Toledo
- International Paper - Springfield

In accordance with the August 2019 Guidance on Regional Haze State Implementation Plans for the Section Implementation Period, "there is no specified outcome or amount of emission reduction or visibility improvement that is directed as the reasonable amount of progress for any Class I area."[1] The guidance states that it may be reasonable for a state not to select an effectively controlled source for further measures and provides several examples on pages 23-25, such as sources subject to recently reviewed or promulgated federal standards, sources that combust only natural gas, and sources that are already well-controlled for SO_2 and NO_X. This report focuses

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

primarily on the significant sources of SO_2, NO_X, and PM_{10} emissions at the four NWPPA pulp and paper mills in Oregon and does not further evaluate certain well-controlled sources.

This report provides a detailed FFA for SO_2, NO_X, and PM_{10} emissions from boilers, recovery furnaces, and lime kilns located at the four mills. These source groups comprise the majority of the total SO_2, NO_X, and PM_{10} emissions at the four mills. Sections 2 through 4 provide that detailed FFA. Other sources at the mills, such as smelt dissolving tanks, paper machines, and material handling/dust sources are addressed in Section 5. If a material handling source is already controlled with a baghouse, no further controls were evaluated. Categorically insignificant activities were not evaluated. Appendix A presents the control cost calculations and Appendix B presents supporting information.

Although the FFA does not include an evaluation of visibility impacts of additional controls, the guidance indicates that states may include an analysis of visibility impacts of potential control measures as part of their determination of whether additional controls should be required for a particular source during the second implementation period. Sources such as bark and chip handling, fugitive emissions from roads, and sources with actual emissions of 5 tons per year (tpy) or less are not likely to impact visibility in Class I areas because of their emissions and dispersion characteristics. Emissions from these sources are not likely to travel much further than the facility's fenceline and Oregon air permits require management procedures to be implemented to control fugitive dust emissions.

1.1 FOUR-FACTOR ANALYSIS

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

- The cost of compliance
- Energy and non-air quality impacts of compliance
- The time necessary for compliance

- Remaining useful life of existing affected sources

NWPPA has addressed these factors for additional control options that could be applied to the most significant SO_2, NO_X, and PM_{10} emission sources at each mill using available site-specific data, capital costs of controls from U.S. EPA publications or previous analyses (either company-specific or for similar sources), and operating cost estimates using methodologies in the U.S. EPA Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual and U.S. EPA fact sheets. The mills covered in this report have not performed site-specific engineering analyses for this study, but have used readily available information to determine if additional emissions controls may be feasible and cost effective. The emissions reduction expected for each control technology evaluated was based on a typical expected control efficiency and both the unit's portion of the Plant Site Emissions Limit (PSEL) and 2017 actual emissions. Although DEQ requested that cost effectiveness be evaluated based on PSELs, evaluating cost effectiveness based on actual emissions provides a better representation of the true cost of each technology to the mills than an evaluation based on allowable emissions. A reduction in allowable emissions only represents a paper change, not a reduction in a mill's visibility impact at a Class I area. In addition, the 2017 actual emissions are expected to be more representative of what actual emissions will be during the 2021-2028 planning period than PSELs in many cases.

An interest rate of 4.75% and the typical values for equipment life shown in the OAQPS Cost Manual examples were used to calculate the capital recovery factor. A 4.75% interest rate represents the prime rate just prior to the COVID-19 pandemic (at the time of DEQ's request for the FFA) and is representative because the prime rate has varied over the past two years from the current low of 3.25% to a high of 5.5% in December 2018. Labor, fuel, and electricity costs are considered confidential business information, so typical values for the Pacific Northwest, rather than mill-specific values, were used.

1.2 SUMMARY OF SOURCES EVALUATED AND EXISTING REGULATORY REQUIREMENTS

Table 1-1 provides basic information regarding the pulp and paper mill sources that were evaluated in detail. The sources evaluated in this report are already subject to regulation under several programs aimed at reducing emissions of conventional and hazardous air pollutants (HAPs) and are already well controlled. Lime kilns, recovery furnaces, smelt dissolving tanks, and boilers are subject to National Emission Standards for Hazardous Air Pollutants (NESHAP), which require the use of Maximum Achievable Control Technology (MACT). While the MACT standards are intended to minimize HAP emissions, they also directly reduce PM_{10} emissions and promote good combustion practices.

Table 1-1
Summary of Significant Emissions Sources Evaluated

Facility	Emissions Unit Description	Year Installed	Fuels Fired	Control Technology	Major Regulatory Programs
Cascade Pacific Pulp Halsey	Recovery Furnace (RFEU)	1968	Black Liquor, Natural Gas, Oil, Propane	Electrostatic precipitator (ESP)	MACT Subpart MM
Cascade Pacific Pulp Halsey	Smelt Dissolving Tank (SDTEU)	1968	NA	Venturi scrubber	MACT Subpart MM
Cascade Pacific Pulp Halsey	Lime Kiln (LKEU)	1969	Natural Gas, No. 6 Fuel Oil, Propane (petroleum coke to be removed from permit)	Venturi scrubber	MACT Subpart MM, NO_X BACT
Cascade Pacific Pulp Halsey	No. 1 Power Boiler (PB1EU)	1968	Natural Gas, No. 6 Fuel Oil (when curtailed), Propane	Good combustion practices	MACT Subpart DDDDD
Cascade Pacific Pulp Halsey	No. 2 Power Boiler (PB2EU)	1968	Natural Gas, Propane	Good combustion practices	MACT Subpart DDDDD
Cascade Pacific Pulp Halsey	Pulp Dryer (PDEU)	1994	NA	Spray nozzles	
Georgia-Pacific Toledo	Nos. 1-3 Lime Kilns (EU1, EU2, EU3)	1957 (No. 1), 1960 (No. 2), and 1963 (No. 3)	Natural gas	Wet scrubber	MACT Subpart MM

Facility	Emissions Unit Description	Year Installed	Fuels Fired	Control Technology	Major Regulatory Programs
Georgia-Pacific Toledo	No. 4 Hog Fuel Boiler (EU4)	1963	Natural gas (hog fuel and OCC rejects are no longer burned)	Good combustion practices	MACT Subpart DDDDD
Georgia-Pacific Toledo	No. 1 Power Boiler	1957	Natural Gas (No. 6 fuel oil no longer burned)	Good combustion practices	MACT Subpart DDDDD
Georgia-Pacific Toledo	Nos. 1-2 Recovery Furnaces (EU14, EU16)	1957 (No. 1) and 1960 (No. 2)	Black liquor, natural gas	ESP	MACT Subpart MM
Georgia-Pacific Toledo	Nos. 1-2 Smelt Dissolving Tanks (EU15, EU17)	1957 (No. 1) and 1960 (No. 2)	NA	Wet scrubber	MACT Subpart MM
Georgia-Pacific Toledo	No. 3 Power Boiler (EU18)	1975	Natural gas	Good combustion practices	MACT Subpart DDDDD
Georgia-Pacific Toledo	No. 5 Power Boiler (EU22)	1995	Natural gas	Flue gas recirculation (FGR) and low-NO_X burners	MACT Subpart DDDDD
Georgia-Pacific Toledo	Nos. 1-3 Paper Machines	1957 (No. 1) 1960 (No. 2) 1973 (No. 3)	NA	Proper operation	
Georgia-Pacific Wauna	Lime Kiln (EU21)	1966	Natural gas (fuel oil is no longer burned)	Wet scrubber	MACT Subpart MM
Georgia-Pacific Wauna	Recovery Furnace (EU24)	1965	Black liquor, natural gas (fuel oil is no longer burned)	ESP	MACT Subpart MM
Georgia-Pacific Wauna	Smelt Dissolving Tank (EU25)	1966	NA	Wet scrubber	MACT Subpart MM
Georgia-Pacific Wauna	Power Boiler (EU33)	1965	Natural gas	Good combustion practices	MACT Subpart DDDDD
Georgia-Pacific Wauna	Fluid Bed Boiler (EU35)	1995	Biomass, natural gas	Limestone addition to bed, baghouse, SNCR	MACT Subpart DDDDD
Georgia-Pacific Wauna	Towel and Tissue Machines	Various	Natural gas	Rotoclone, venturi scrubbers on some non-fuel burning process vents	

Facility	Emissions Unit Description	Year Installed	Fuels Fired	Control Technology	Major Regulatory Programs
International Paper Springfield	Power Boiler (EU-150A)	1964	Natural gas (fuel oil permitted but only fired if gas curtailed)	Good combustion practices	MACT Subpart DDDDD
International Paper Springfield	Package Boiler (EU-150B)	1992	Natural gas (fuel oil permitted but only fired if gas curtailed)	Low NO_X burners and flue gas recirculation	MACT Subpart DDDDD
International Paper Springfield	No. 4 Recovery Boiler (EU-445C)	1969	Black liquor, natural gas (fuel oil permitted but not fired)	ESP	MACT Subpart MM
International Paper Springfield	No. 4 Smelt Dissolving Tank (EU-445D)	1969	NA	Wet scrubber	MACT Subpart MM
International Paper Springfield	Lime Kilns (EU-455)	1960	Natural gas, turpentine, methanol (fuel oil permitted but not fired)	ESP	MACT Subpart MM

The U.S. EPA developed the RHR to meet the Clean Air Act (CAA) requirements for the protection of visibility in 156 scenic areas across the United States. The first stage of the RHR required that certain types of existing stationary sources of air pollutants evaluate Best Available Retrofit Technology (BART). Specifically, the BART provisions required states to conduct an evaluation of existing, older stationary sources that pre-dated the 1977 CAA Amendments and, therefore, were not originally subject to the New Source Performance Standards (NSPS) at 40 CFR Part 60. The purpose of the program was to identify older emission units that contributed to haze at Class I areas that could be retrofitted with emissions control technology to reduce emissions and improve visibility in these areas. The BART requirement applied to emission units that fit all three of the following criteria:

1. The units came into existence between August 7, 1962 and August 7, 1977;
2. The units are located at facilities in one of 26 NSPS categories; and
3. The units have a total potential-to-emit (PTE) of at least 250 tpy of NO_X, SO_2, and PM_{10} from all BART-era emission units at the same facility.

MACT standards that limit visibility-impairing pollutants were determined to meet the requirements for BART unless there were new cost-effective control technologies available. Per Section IV of 40 CFR Part 51, Appendix Y, Guidelines for BART Determinations under the Regional Haze Rules: "Unless there are new technologies subsequent to the MACT standards which would lead to cost-effective increases in the level of control, [state agencies] may rely on the MACT standards for purposes of BART." Sources demonstrating compliance with MACT and BART are already well controlled. If sources are already well-controlled and not significantly contributing to visibility impacts at nearby Class I areas, further control should not be required to reduce emissions for the second planning period of the RHR.

1.3 SUMMARY OF RECENT EMISSIONS REDUCTIONS

Since 2010, the mills covered in this report have made emissions reductions for a variety of reasons. As shown in Table 1-1, each of the mills is subject to the provisions of 40 CFR Part 63, Subpart DDDDD, NESHAP for Industrial Commercial, and Institutional Boilers and Process Heaters (NESHAP DDDDD or Boiler MACT). Boilers subject to NESHAP DDDDD were required to undergo a one-time energy assessment and are required to conduct tune-ups at a frequency specified by the rule. Compliance with these standards required changes to operating practices, including the use of clean fuels for startup and a limitation on fuel oil use to periods of natural gas curtailment for boilers in the gas 1 subcategory. In addition, mills have made other improvements for operational or other site-specific reasons. Emissions reductions, fuel switches, or capital projects implemented at each mill are described in this section.

The CPP Halsey Mill installed a new air system on their recovery furnace in 2010 and rebuilt the ESP in order to reduce emissions. The Mill also no longer fires petroleum (pet) coke in the lime kiln, resulting in lower SO_2 emissions. Fuel oil is fired in the No. 1 Power Boiler only when natural gas is curtailed, resulting in lower PM_{10} and SO_2 emissions.

The GP Wauna Mill is permitted to fire fuel oil in the lime kiln and recovery furnace, but only fires natural gas as auxiliary fuel, resulting in lower PM_{10} and SO_2 emissions. The GP Toledo Mill is permitted to fire fuel oil in the No. 1 Power Boiler, but only fires natural gas, resulting in lower PM_{10} and SO_2 emissions. The GP Toledo Mill is permitted to fire hog fuel and old corrugated container (OCC) rejects in the No. 4 Power Boiler, but only fires natural gas, resulting in lower NO_X, PM_{10}, and SO_2 emissions.

The IP Springfield Mill is permitted to fire fuel oil in its lime kiln, boilers, and recovery furnace, but burns natural gas instead, resulting in lower PM_{10} and SO_2 emissions. The Mill no longer fires pet coke in the lime kiln, resulting in lower SO_2 emissions. The Mill is already subject to a Federally enforceable permit limit on SO_2 and NO_X emissions that was implemented in the 2008 Oregon Regional Haze Plan to reduce the visibility impact of the BART-eligible units (including the Power Boiler).

1.4 DOCUMENT ORGANIZATION

The document is organized as follows:

- **Section 1 – Introduction:** provides the purpose of the document and what emission units are included in the FFA.
- **Section 2 – Four-Factor Analysis for Boilers:** provides the FFA for the boilers evaluated.
- **Section 3 – Four-Factor Analysis for Recovery Furnaces:** provides the FFA for the recovery furnaces evaluated.
- **Section 4 – Four-Factor Analysis for Lime Kilns:** provides the FFA for the lime kilns evaluated.
- **Section 5 – Analysis of Other Sources:** presents an evaluation of the feasibility of additional controls on smelt dissolving tanks, paper machines, and other sources at the mills.
- **Section 6 – Summary of Findings:** presents a summary of the FFA.
- **Appendix A – Control Cost Analyses**
- **Appendix B – Supporting Information**

2. FOUR-FACTOR ANALYSIS FOR BOILERS

This section of the report presents the results of the FFA for PM_{10}, SO_2, and NO_X emitted from the industrial boilers at the four mills. To evaluate the cost of compliance portion of the FFA, NWPPA performed the following steps:

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

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

2.1 AVAILABLE CONTROL TECHNOLOGIES

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

[2] RACT/BACT/LAER Clearinghouse (RBLC). https://www.epa.gov/catc/ractbactlaer-clearinghouse-rblc-basic-information

Table 2-1
Control Technology Summary

Pollutant	Controls on Industrial Boilers
PM_{10}	ESP Fabric filter Wet scrubber
SO_2	Low-sulfur fuels Wet scrubber Dry sorbent injection (DSI)
NO_X	Good combustion practices Water/Steam injection Low-NO_X burners (LNB) Flue gas recirculation (FGR) Selective non-catalytic reduction (SNCR) Selective catalytic reduction (SCR)

Technically feasible control technologies for industrial boilers were evaluated, taking into account current air pollution controls, fuels fired, and RBLC Database information. Note that fuel switching from biomass to natural gas was not evaluated because the purpose of this analysis is not to change the operation or design of the source or to evaluate alternative energy projects. The August 20, 2019 regional haze implementation guidance indicates that states may determine it is unreasonable to consider fuel use changes because they would be too fundamental to the operation and design of a source. EPA BACT guidance states that it is not reasonable to change the design of a source, such as by requiring conversion of a coal boiler to a gas turbine.[3] It is not reasonable as part of this analysis to convert an existing biomass boiler at a forest products mill to a natural gas-fired boiler because biomass boilers at forest products mills fire the biomass residuals from the mill processes as a readily available and relatively inexpensive source of fuel.

2.1.1 Available PM_{10} Control Technologies

The potentially feasible control technologies for reducing emissions of PM_{10} from solid fuel-fired industrial boilers are discussed in detail in this section.

[3] https://www.epa.gov/sites/production/files/2015-07/documents/igccbact.pdf

Electrostatic Precipitators

ESPs are widely used for the control of PM from a variety of combustion sources. An ESP is a particulate matter control device that removes particles from a gas stream by using electrical energy to charge particles either positively or negatively. The charged particles are then attracted to collector plates carrying the opposite charge. The collected particles are periodically removed from the collector plates. There are several different designs that can achieve very high overall control efficiencies. Control efficiencies typically average over 98%, with control efficiencies almost as high for particle sizes of 1 micrometer or less. ESPs have been demonstrated in practice to have PM_{10} removal efficiencies as high as those achieved by fabric filters. Two ESP designs are common: dry electrostatic precipitators and wet electrostatic precipitators. The systems are similar except that wet electrostatic precipitators use water to flush the captured particles from the collector plates.

Fabric Filters

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

Wet Scrubbers

In wet scrubbing processes, liquid or solid particles are removed from a gas stream by transferring them to a liquid, most commonly water. A wet scrubber PM collection efficiency is directly related to the amount of energy expended in contacting the gas stream with the scrubber liquid. Wet scrubbers cannot typically achieve the levels of PM and PM_{10} reduction obtained by fabric filters and ESPs without being operated at extremely high energy input levels. In addition, wet scrubber systems often require higher levels of maintenance and generate a wastewater stream that must be treated.

2.1.2 Available SO_2 Control Technologies

Natural gas and biomass are considered low-sulfur fuels and are fired by the boilers included in this report. Natural gas-fired boilers have negligible SO_2 emissions and are not evaluated in this report for further SO_2 emissions control. The potentially feasible add-on control technologies for reducing emissions of SO_2 from other types of industrial boilers are discussed in detail in this section.

Wet Scrubbers

In a wet scrubber, a liquid is used to remove pollutants from an exhaust stream. The removal of pollutants in the gaseous stream is done by absorption. Wet scrubbing involves a mass transfer operation in which one or more soluble components of an acid gas are dissolved in a liquid that has low volatility under process conditions. For SO_2 control, the absorption process is chemical-based and uses an alkali solution (*i.e.*, sodium hydroxide, sodium carbonate, sodium bicarbonate, calcium hydroxide, etc.) as a sorbent or reagent in combination with water. Removal efficiencies are affected by the chemistry of the absorbing solution as it reacts with the pollutant. Wet scrubbers may take the form of a variety of different configurations, including packed columns, plate or tray columns, spray chambers, and venturi scrubbers.

Dry Sorbent Injection (DSI)

DSI accomplishes removal of acid gases by injecting a dry reagent (*i.e.*, lime or trona) into the flue gas stream and prior to PM air pollution control equipment. A flue gas reaction takes place between the reagent and the acid gases, producing neutral salts that must be removed by the PM air pollution control equipment located downstream. The process is totally “dry,” meaning it produces a dry disposal product and introduces the reagent as a dry powder. The benefits of this type of system include the elimination of liquid handling equipment requiring routine maintenance such as pumps, agitators, and atomizers. The drawbacks to using this type of system are the costs associated with the installation of a dry PM control device to collect the dry by-product, as well as ongoing operating costs to procure the sorbent material and dispose of additional dry waste. Dry sorbents can also prove challenging to maintain a very low moisture content and keep flowing. DSI systems are typically used to control SO_2, hydrochloric acid and other acid gases on coal-fired boilers.

2.1.3 Available NO_X Control Technologies

The potentially feasible add-on control technologies for reducing emissions of NO_X from industrial boilers are discussed in detail in this section.

Good Combustion Practices

Good combustion practices were identified in the U.S. EPA RBLC database as a control technique for industrial natural gas-fired and oil-fired boilers. Examples of good combustion practices include, but are not limited to: following manufacturer's written instructions, operating with sufficient excess air, optimum combustion temperatures, residence time, and maintaining a good mix of combustion air and fuel. The work practices required by Boiler MACT are an example of implementing good combustion practices. Through burner tune-ups and maintenance, oxygen trim controls, and burner design, the burner can be operated at the excess air level that provides efficient and complete combustion.

Water/Steam Injection

The addition of an inert diluent, such as water or steam, into the high temperature region of the boiler flame controls thermal NO_X generation by quenching peak flame temperatures, thus lowering overall NO_X levels. While atomized water or steam injection can reduce NO_X formation, flame instability, condensation problems and efficiency losses result when the water-to-fuel ratio becomes too high. This technology is most often utilized on combustion turbines, not on industrial boilers.

Low NO_X Burners (LNB)

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

Flue Gas Recirculation (FGR)

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

Selective Non-Catalytic Reduction (SNCR)

SNCR is a control technology for NO_X emissions that uses a reduction-oxidation reaction to convert NO_X into nitrogen (N_2), water (H_2O), and carbon dioxide (CO_2). SNCR involves injecting ammonia or urea into a combustion chamber or the flue gas stream, which must be between approximately 1,600 and 2,000 degrees Fahrenheit (°F) for the chemical reaction to occur. At low loads, temperatures may be below the optimum required for achieving NO_X reductions. For example, a unit that experiences load swings according to production demands has a variable temperature profile. To address this concern for a boiler, multiple levels of reagent injectors can be installed.

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

Selective Catalytic Reduction (SCR)

Although SCR was not identified in the RBLC search as a technology that is often employed on industrial boilers, it has been applied to coal-fired utility boilers. SCR is a NO_X control technology that uses a catalyst to react injected anhydrous ammonia, aqueous ammonia or urea to chemically convert NO_X into N_2 and H_2O. SCR employs a metal-based catalyst, such as vanadium or titanium, to increase the rate of the NO_X reduction reaction[4]. The flue gases flow into a reactor module containing the catalyst where the reagent selectively reacts with the NO_X. The reduction reactions used by SCR are effective only within a given temperature range where ammonia or urea is injected into the exhaust gases in a temperature range of 480°F – 800°F[5]. For an industrial boiler, this temperature range is achievable between the generating bank outlet and the air heater or economizer, but if the SCR must be placed further downstream, a duct burner is necessary to achieve the proper temperature window. At the higher end of the temperature range, with the proper amount of reducing agent and injection grid design, SCR can achieve 90 percent reduction of NO_X given the right operating conditions. However, ammonia slip can also occur, which refers to the emissions of unreacted ammonia due to the incomplete reaction of the reagent and NO_X. As discussed above, excess ammonia can result in formation of compounds that cause corrosion and impair visibility.

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[4] *Chapter 2 Selective Catalytic Reduction,* OAQPS 7th Edition (June 2019). https://www.epa.gov/sites/production/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf (Section 2.2.1).
[5] Air Pollution Control Technology Fact Sheet. EPA-452/F-03-032. https://www3.epa.gov/ttncatc1/dir1/fscr.pdf. (pg. 1).

2.2 ELIMINATION OF TECHNICALLY INFEASIBLE OPTIONS

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

PM_{10} Emissions

The Nos. 1 and 2 Power Boilers at the CPP Halsey Mill fire natural gas and have minimal PM_{10} emissions. The No. 1 Power Boiler is permitted to burn No. 6 fuel oil, but this fuel is only burned during periods of gas curtailment. The Package Boiler and the Power Boiler at the IP Springfield Mill burn natural gas, with No. 2 fuel oil as backup fuels for periods of natural gas supply interruption or natural gas curtailment. No PM_{10} controls beyond burning natural gas as the primary fuel and limiting oil firing to periods of curtailment are feasible for these boilers.

The four boilers at the GP Toledo Mill and the Power Boiler at the GP Wauna Mill burn only natural gas and have minimal PM_{10} emissions. No PM_{10} controls beyond burning natural gas are feasible for these boilers.

The GP Wauna Mill's biomass-fired Fluidized Bed Boiler is controlled by a fabric filter, is subject to a filterable PM emission limit of 0.01 grain per dry standard cubic foot (gr/dscf), and complies with both New Source Performance Standards (NSPS, Subpart Db) and Boiler MACT. Based on a review of similar units in the RBLC, this unit is already well controlled for PM_{10}.

SO_2 Emissions

Although the GP Wauna Fluidized Bed Boiler already has limestone addition to the fluidized bed, DSI in the form of trona injection prior to the fabric filter was evaluated. No further SO_2 emissions controls are feasible for the GP boilers that burn only natural gas. As indicated above, CPP and IP operate under the Boiler MACT definitions of "unit designed to burn gas 1" and "period of gas curtailment or supply interruption" at 40 CFR 63.7575.[6] No SO_2 controls beyond burning natural gas as the primary fuel and limiting fuel oil firing to periods of curtailment are feasible for these boilers.

NO_X Emissions

As discussed above, good combustion practices are already required for power boilers under Boiler MACT. Water or steam injection is not typically used on industrial boilers. Therefore, these technologies are not evaluated in this report.

Retrofit with LNB is generally feasible for gas-fired boilers and has been evaluated for those units. When retrofitting an older existing boiler with LNB, FGR may also be required to achieve the desired level of NO_X reduction. The GP Toledo No. 5 Power Boiler and IP Springfield Package Boiler already use LNB and FGR to reduce NO_X emissions. Retrofitting LNB on a small natural

[6] *Unit designed to burn gas 1 subcategory* includes any boiler or process heater that burns only natural gas, refinery gas, and/or other gas 1 fuels. Gaseous fuel boilers and process heaters that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this definition. Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply interruptions of any duration are also included in this definition.
Period of gas curtailment or supply interruption means a period of time during which the supply of gaseous fuel to an affected boiler or process heater is restricted or halted for reasons beyond the control of the facility. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas due to normal market fluctuations not during periods of supplier delivery restriction does not constitute a period of natural gas curtailment or supply interruption. On-site gaseous fuel system emergencies or equipment failures qualify as periods of supply interruption when the emergency or failure is beyond the control of the facility.

gas-fired package boiler with a single burner is fairly straightforward. However, retrofitting a larger, older boiler that has multiple burners can be more complicated, due to burner positions and the potential for overlapping flames to result in NO_X hot spots within the furnace. To achieve low NO_X concentrations, a typical retrofit of a multiple burner boiler with LNB would also include FGR, some new ductwork, and a new fan, and would likely result in a NO_X level of around 50 parts per million (ppm). A comparison of the AP-42 pre-NSPS uncontrolled and LNB/FGR emissions factors for large natural gas boilers in Table 1.4-1 shows a NO_X reduction of approximately 64%, but the actual NO_X reduction will vary based on the current emission rate of each boiler. Where current NO_X concentration data was provided, the control efficiency for LNB/FGR was calculated based on a reduction to 50 ppm. Note that the design of the CPP Halsey No. 2 Power Boiler is such that a simple burner replacement may not be feasible. The boiler's cyclopack burner is integrated into the side wall of the boiler and to change the burner, tubing and refractory would have to be reconfigured. Therefore, the cost of LNB/FGR on this boiler would likely be higher than estimated.

LNB are not feasible for GP Wauna's Fluidized Bed Boiler. The natural gas burners are only for auxiliary use and do not drive NO_X emissions from the unit. The boiler already employs SNCR to reduce NO_X emissions from the bubbling fluidized bed.

Add-on NO_X controls, such as SNCR and SCR, require a certain temperature window to be effective. These controls were developed for, and have predominantly been applied to, fossil fuel-fired utility boilers. The effectiveness of SNCR on pulp and paper mill boilers is typically on the low end of the range because they experience variable loads and the temperature profile in a pulp and paper mill boiler is not as constant as that in a base-loaded fossil fuel-fired utility boiler. Boilers at pulp and paper mills are subject to highly variable swings in steaming rate.

The variability of the SNCR temperature window is a critical issue, because of the consequences of ammonia injection outside this window. Below the temperature window, ammonia slip will occur due to incomplete reactions of the injected chemicals with the NO_X. Above the temperature window, the reducing chemicals could be combusted to form additional NO_X. Multiple injection levels must sometimes be installed to accommodate firebox temperature variability.

Additional water, power, and boiler fuel are required to operate an SNCR system because the SNCR process reduces the thermal efficiency of the boiler. The reduction reaction uses thermal energy from the boiler, which decreases the energy available for power or heat generation. As a result, additional fuel is required for the boiler to maintain the same steam output (resulting in additional emissions of other pollutants). Despite operational challenges, SNCR is considered technically feasible.

SCR uses a catalyst to reduce NO_X to nitrogen, water, and oxygen. SCR technology employs aqueous or anhydrous ammonia as a reducing agent that is injected into the gas stream near the economizer and upstream of the catalyst bed. The catalyst lowers the activation energy of the NO_X decomposition reaction. An ammonium salt intermediate is formed at the catalyst surface and subsequently decomposes to elemental nitrogen and water. This technology has been demonstrated mostly on large coal- and natural gas-fired combustion units in the utility industry. In practice, SCR systems operate at NO_X control efficiencies in the range of 70 to 90% for fossil fuel utility boilers. Operating temperatures for the SCR process range from 480 to 800°F but a temperature of at least 650°F is required to achieve the maximum control efficiency. Due to catalyst plugging problems associated with locating the catalyst at the economizer outlet of a solid fuel-fired boiler (*i.e.,* prior to the particulate control device), an SCR system on a biomass boiler would have to be installed after an existing particulate matter control device, and would require installation of a gas-fired flue gas duct burner to achieve the optimum reaction temperature (the flue gas temperature for biomass boilers is typically less than 480°F). This would incur associated fuel costs and pollution increases, assuming there is adequate space to install the SCR reactor and the size duct burner needed to raise the temperature of the exhaust gas stream to the optimum temperature of 650 °F.

The natural gas boilers evaluated in this report have air heaters and/or economizers. There is not adequate space to install an SCR reactor on these boilers prior to the air heater or economizer and the exhaust gas temperature following the air heater or economizer is typically less than 450°F. Therefore, a duct burner would be necessary for an SCR to be effective at reducing NO_X emissions from the boilers evaluated in this report. Despite the challenges of implementing SCR, it is considered technically feasible.

2.3 COST OF TECHNICALLY FEASIBLE CONTROL TECHNOLOGIES

Cost analyses were developed where add-on controls were considered technically feasible. Budgetary estimates of capital and operating costs were determined and used to estimate the annualized costs for each control technology considering existing equipment design and exhaust characteristics. A capital cost for each control measure evaluated was based on company-specific data, previously developed company project costs, or EPA cost spreadsheets. The cost effectiveness for each technically feasible control technology was calculated using the annualized capital and operating costs and the amount of pollutant expected to be removed based on the procedures presented in the latest version of the U.S. EPA OAQPS Control Cost Manual. Each boiler's assigned portion of the PSEL and a typical expected control efficiency were used as the basis for emissions reductions. The cost effectiveness based on 2017 actual emissions was also evaluated, since 2017 actual emissions are expected to be more representative of emissions during the 2021-2028 planning period than PSELs in many cases.

Technically feasible control technologies were evaluated for cost effectiveness by source as summarized in Table 2-2.

Table 2-2
Control Technologies Evaluated for Boilers

Source	Fuels Fired	Existing Control Technology			Additional Control Technology Costed		
Emissions Unit		PM_{10}	NO_X	SO_2	PM_{10}	NO_X	SO_2
CPP Halsey No. 1 Power Boiler (PB1EU)	Natural Gas/#6 Fuel Oil during curtailment only/Propane	Comply with Gas 1 definition	Good comb. practices	Comply with Gas 1 definition	NA	LNB/FGR, SNCR, SCR	NA

Source	Fuels Fired	Existing Control Technology			Additional Control Technology Costed		
Emissions Unit		PM_{10}	NO_X	SO_2	PM_{10}	NO_X	SO_2
CPP Halsey No. 2 Power Boiler (PB2EU)	Natural Gas/Propane	Clean fuel	Good comb. practices	Low-sulfur fuel	NA	LNB/FGR, SNCR, SCR	NA
GP Toledo No. 4 Hog Fuel Boiler* (EU 11)	Natural Gas	Clean fuel	Good comb. practices	Low-sulfur fuel	NA	LNB/FGR, SNCR, SCR	NA
GP Toledo No. 1 Power Boiler (EU 13)	Natural Gas	Clean fuel	Good comb. practices	Low-sulfur fuel	NA	LNB/FGR, SNCR, SCR	NA
GP Toledo No. 3 Power Boiler (EU 18)	Natural Gas	Clean fuel	Good comb. practices	Low-sulfur fuel	NA	LNB/FGR, SNCR, SCR	NA
GP Toledo No. 5 Power Boiler (EU 22)	Natural Gas	Clean fuel	LNB/ FGR	Low-sulfur fuel	NA	SNCR, SCR	NA
GP Wauna Power Boiler (EU33)	Natural Gas	Clean fuel	Good comb. practices	Low-sulfur fuel	NA	LNB/FGR, SNCR, SCR	NA
GP Wauna Fluidized Bed Boiler (EU35)	Biomass (Hog & Sludge Fuel)/ Natural Gas	Baghouse	SNCR	Low-sulfur fuel, limestone addition to bed	Polishing WESP	SCR	DSI (trona injection prior to fabric filter)
IP Springfield Power Boiler (EU-150A)	Natural Gas (No. 2 or No. 6 oil or used oil during curtailment only)	Comply with Gas 1 definition	Good comb. practices	Comply with Gas 1 definition	NA	LNB/FGR, SNCR, SCR	NA
IP Springfield Package Boiler (EU-150B)	Natural Gas (No. 2 oil or used oil during curtailment only)	Comply with Gas 1 definition	LNB/ FGR	Comply with Gas 1 definition	NA	SNCR, SCR	NA

*The GP Toledo No. 4 Hog Fuel Boiler now fires only natural gas.

Capital, operating, and total annual cost estimates for each feasible pollution control technique are presented in Appendix A. These are screening level cost estimates and are not based on detailed engineering studies of mill boilers.

Although DEQ has not indicated what additional controls they would consider cost effective, similar analyses performed by U.S. EPA and others were reviewed to get a general idea of the level above which additional controls on industrial boilers are not cost effective. As part of the 2016 CSAPR update rule[7], U.S. EPA performed an analysis to characterize whether there were non-electric generating unit (EGU) source groups with a substantial amount of available cost-effective NO_X reductions achievable by the 2017 ozone season. They evaluated control costs for non-EGU point sources with NO_X emissions greater than 25 tpy in 2017.[8] U.S. EPA did not further examine control options above $3,400 per ton. This is consistent with the range U.S. EPA analyzed for EGUs in the proposed and final CSAPR rules and is also consistent with what the U.S. EPA has identified in previous transport rules as cost-effective, including the NO_X SIP call. Notably, $3,400 per ton represents the $2,000 per ton value (in 1990 dollars) used in the NO_X SIP call, adjusted to the 2011 dollars used throughout the CSAPR update proposal. Adjustments of costs were made using the Chemical Engineering Plant Cost Index (CEPCI) annual values for 1990 and 2011.) Note that industrial boilers were among the source categories that the very conservative U.S. EPA cost analysis determined were above $3,400/ton. In addition, the Western Regional Air Partnership (WRAP) Annex to the Grand Canyon Visibility Transport Report (June 1999) indicated that control costs greater than $3,000/ton were high.[9] The costs presented in this report were developed using conservative assumptions and almost all are significantly above these thresholds.

2.3.1 Site-Specific Factors Limiting Implementation

Currently known, site-specific factors that would limit the feasibility and increase the cost of installing additional controls include space constraints. A detailed engineering study for each of

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7 81 Fed. Reg. 74504

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

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

the controls evaluated in this report would be necessary before any additional controls were determined to be feasible or cost effective.

2.3.2 PM_{10} Economic Impacts

As stated above, all of the industrial boilers evaluated in this report are already well controlled for PM_{10}. However, for purposes of this report, and because the PM_{10} PSEL for the GP Wauna Fluidized Bed Boiler is 62.4 tpy, a cursory evaluation of whether adding a polishing WESP to that unit to reduce PM_{10} emissions further would be cost effective was performed. Based on U.S. EPA's fact sheet for WESPs, in 2002 dollars, the capital cost ranges from $40 to $200 per standard cubic foot per minute (scfm) exhaust flow rate and the annual cost ranges from $12 to $46 per scfm.[10] Based on the low end of these ranges and a flow rate of 55,000 scfm, a polishing WESP would require an investment of at least $2.2 million in capital cost and $660,000 per year in annual cost. While achieving an additional 99% reduction of PM_{10} emissions from the outlet stream of an already well controlled source utilizing a baghouse is highly unlikely, even if a polishing WESP achieved a 99 percent reduction in the 62.4-tpy PM_{10} PSEL, the approximate cost would be $10,684/ton of PM_{10} removed, which is not cost effective.

2.3.3 SO_2 Economic Impacts

The capital cost for a system to inject milled trona prior to the fabric filter on the GP Wauna Fluidized Bed Boiler was estimated using an April 2017 Sargent and Lundy report prepared under a U.S. EPA contract.[11] Industry standard labor, chemical, and utility costs were used to estimate the annual cost of operating the system. The Sargent and Lundy report indicates that 90% SO_2 control can be achieved when injecting trona prior to a fabric filter. Table 2-3 summarizes the estimated capital cost, annual cost, and cost effectiveness of implementing this control technology

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[10] https://www3.epa.gov/ttn/catc/dir1/fwespwpi.pdf
[11] Sargent & Lundy LLC. 2017. *Dry Sorbent Injection for SO_2/HCl Control Cost Development Methodology.* Project 13527-001, Eastern Research Group, Inc. Chicago, IL.

for the Fluidized Bed Boiler, based on operating data and both the SO_2 PSEL and the 2017 actual emissions.

Table 2-3
Trona Injection System Cost Summary

Emissions Unit Description	Capital Cost ($)	Annual Cost ($/yr)	Cost Effectiveness of Controls ($/Ton SO_2)
Based on PSEL			
GP Wauna Fluidized Bed Boiler (EU35)	$7,517,658	$2,769,512	$111,494
Based on 2017 Actual Emissions			
GP Wauna Fluidized Bed Boiler (EU35)	$7,517,658	$2,766,700	$122,475

Installing trona injection is not considered cost effective because the estimated capital cost is more than $7 million and the cost effectiveness value is over $100,000/ton of pollutant removed.

2.3.4 NO_X Economic Impacts

LNB and FGR for Boiler NO_X Control

The capital cost of implementing LNB and FGR to reduce NO_X from each gas-fired industrial boiler without LNB is based on the document titled “Emission Control Study – Technology Cost Estimates” by BE&K Engineering for the American Forest and Paper Association (AF&PA), September 2001. Section 4.4 presents the costs associated with installing LNB, FGR, and a new fan on a 120,000 pounds of steam per hour (approximately 150 million British thermal units per hour [MMBtu/hr] heat input) natural gas-fired boiler. The direct capital cost (equipment and installation) was scaled from 2001 dollars to 2019 dollars using the CEPCI. The base capital cost was also scaled to each mill’s boiler using an engineering cost scaling factor of 0.6 and the ratio of each mill’s boiler heat input to the boiler heat input evaluated in the BE&K report. Table 2-4 summarizes the capital cost, annual cost, and cost effectiveness of implementing this control technology for the industrial boilers that do not already have LNB. The effectiveness of installing LNB and FGR on each boiler is unknown and will depend on the current NO_X emissions rate.

Where current NOx concentration data was not available, a 64% NO_X reduction was assumed based on a comparison of AP-42 natural gas boiler pre-NSPS uncontrolled and LNB/FGR emission factors. Where current NO_X concentration data were available and higher than 50 ppm, a control efficiency was calculated based on a reduction to 50 ppm.

Table 2-4
LNB and FGR Cost Summary

Emissions Unit Description	Capital Cost ($)	Annual Cost ($/yr)	Cost Effectiveness of Controls ($/Ton NO_X)
Based on PSEL			
CPP Halsey No. 1 Power Boiler (PB1EU)	$3,916,942	$975,687	$11,455
CPP Halsey No. 2 Power Boiler (PB2EU)	$3,916,942	$975,687	$20,210
GP Toledo No. 4 Hog Fuel Boiler* (EU 11)	$4,492,650	$1,135,073	$9,717
GP Toledo No. 1 Power Boiler (EU 13)	$3,411,934	$838,747	$4,769
GP Toledo No. 3 Power Boiler (EU 18)	$3,058,970	$744,700	$14,822
GP Wauna Power Boiler (EU33)	$6,578,285	$1,739,536	$4,597
IP Springfield Power Boiler (EU-150A)	$6,464,862	$1,637,176	$2,928
Based on 2017 Actual Emissions			
CPP Halsey No. 1 Power Boiler (PB1EU)	$3,916,942	$973,394	$28,623
CPP Halsey No. 2 Power Boiler (PB2EU)	$3,916,942	$881,317	$244,810
GP Toledo No. 4 Hog Fuel Boiler* (EU 11)	$4,492,650	$1,131,148	$10,042
GP Toledo No. 1 Power Boiler (EU 13)	$3,411,934	$835,843	$7,083
GP Toledo No. 3 Power Boiler (EU 18)	$3,058,970	$742,180	$21,024
GP Wauna Power Boiler (EU33)	$6,578,285	$1,566,859	$9,223
IP Springfield Power Boiler (EU-150A)	$6,464,862	$1,637,176	$18,228

*The GP Toledo No. 4 Hog Fuel Boiler now fires only natural gas.

Installing LNB/FGR is not considered cost effective for these boilers. Although the IP Springfield Power Boiler estimated cost per ton is lower than the other boilers when based on its assigned portion of the PSEL, when actual emissions are evaluated, the estimated cost is much higher and above any reasonable cost effectiveness threshold. Even when using the PSELs in the cost evaluation, the cost for all but one boiler is greater than the threshold at which the U.S. EPA determined NO_X controls for non-EGUs would be cost effective.

SNCR for Boiler NO_X Control

The cost of installing and operating an SNCR system on the natural gas-fired boilers was estimated using U.S. EPA's "Air Pollution Control Cost Estimation Spreadsheet for Selective Non-Catalytic Reduction (SNCR)" (June 2019) that reflects calculation methodologies presented in the U.S. EPA's Air Pollution Control Cost Manual, Section 4, Chapter 1. The spreadsheet estimates capital and annualized costs of installing and operating an SNCR based on site-specific data entered, such as boiler design and operating data. As the cost algorithms were developed based on project costs for large coal-fired utility boilers, they likely underestimate costs for smaller industrial boilers as costs for large utility boilers where this technology is routinely installed may not scale to smaller, variable load industrial boilers. The equipment cost was scaled to 2019 dollars using the CEPCI.

The U.S. EPA's cost manual allows a retrofit factor of greater than one where justification is provided. A retrofit factor of 1.5 was applied to account for the need to add multiple levels of injectors and perform additional tuning of the system across loads. The OAQPS Cost Manual (Section 4, Chapter 1) indicates that difficult installation conditions are often encountered for small boilers, and the boilers evaluated in this report are much smaller than coal-fired utility boilers.

SNCR control efficiencies vary widely, but urea-based systems typically achieve reductions from 37 to 60 percent on industrial boilers, according to the OAQPS Control Cost Manual. However, operating constraints on temperature, load, reaction time, and mixing often lead to less effective results when using SNCR in practice. Our analyses assume that SNCR would achieve 45% control on the boilers because pulp and paper mill boilers are subject to regular load swings. This control efficiency is supported by the range provided in the OAQPS Cost Manual and information publicly available from vendors.[12] A formal engineering analysis would be required to ultimately determine if SNCR would be effective on the boilers. This type of analysis would include obtaining temperature and flow data, developing a model of each boiler using computational fluid dynamics, determining residence time and degree of mixing, determining placement of injectors, and testing.

Table 2-5 summarizes the estimated capital cost, annual cost, and cost effectiveness of implementing this control technology on each boiler.

Table 2-5
SNCR Cost Summary

Emissions Unit Description	Capital Cost ($)	Annual Cost ($/yr)	Cost Effectiveness of Controls ($/Ton NO_X)
Based on PSEL			
CPP Halsey No. 1 Power Boiler (PB1EU)	$3,330,291	$617,700	$10,360
CPP Halsey No. 2 Power Boiler (PB2EU)	$3,333,873	$619,943	$18,344
GP Toledo No. 4 Hog Fuel Boiler* (EU 11)	$3,545,852	$649,971	$6,613
GP Toledo No. 1 Power Boiler (EU 13)	$3,005,818	$522,518	$5,191
GP Toledo No. 3 Power Boiler (EU 18)	$2,667,089	$414,919	$8,569
GP Toledo No. 5 Power Boiler (EU 22)	$3,537,101	$628,605	$15,608
GP Wauna Power Boiler (EU33)	$4,946,514	$2,359,842	$8,870
IP Springfield Power Boiler (EU-150A)	$4,912,042	$1,369,462	$3,483
IP Springfield Package Boiler (EU-150B)	$3,814,299	$743,856	$5,550
Based on 2017 Actual Emissions			
CPP Halsey No. 1 Power Boiler (PB1EU)	$3,273,971	$580,997	$24,360

[12] See for example, https://www.eescorp.com/solutions/sncr/, https://www.cecoenviro.com/selective-non-catalytic-reduction-sncr-cca-combustion-systems, https://www.ftek.com/en-US/products/productssubapc/urea-sncr

Emissions Unit Description	Capital Cost ($)	Annual Cost ($/yr)	Cost Effectiveness of Controls ($/Ton NO_X)
CPP Halsey No. 2 Power Boiler (PB2EU)	$3,225,243	$394,064	$156,375
GP Toledo No. 4 Hog Fuel Boiler* (EU 11)	$3,685,391	$723,139	$7,630
GP Toledo No. 1 Power Boiler (EU 13)	$3,013,222	$520,534	$7,706
GP Toledo No. 3 Power Boiler (EU 18)	$2,672,559	$412,543	$12,126
GP Toledo No. 5 Power Boiler (EU 22)	$3,474,043	$607,538	$35,435
GP Wauna Power Boiler (EU33)	$5,068,250	$1,597,370	$13,372
IP Springfield Power Boiler (EU-150A)	$4,283,533	$1,016,973	$16,103
IP Springfield Package Boiler (EU-150B)	$3,530,150	$345,241	$548,002

*The GP Toledo No. 4 Hog Fuel Boiler now fires only natural gas.

Installing an SNCR is not considered cost effective because the cost effectiveness values are in excess of the cost effectiveness threshold for non-EGUs used by U.S. EPA.

SCR for Boiler NO_X Control

The cost of installing and operating SCR system on each of the boilers was estimated using U.S. EPA's "Air Pollution Control Cost Estimation Spreadsheet for Selective Catalytic Reduction (SCR)" (June 2019) that reflects calculation methodologies presented in the U.S. EPA's Air Pollution Control Cost Manual, Section 4, Chapter 2. The spreadsheet estimates capital and annualized costs of installing and operating an SCR system based on site specific data entered, such as boiler design and operating data. As the cost algorithms were developed based on project costs for large coal-fired utility boilers, they likely underestimate costs for smaller industrial boilers as costs for large utility boilers where this technology is routinely installed may not scale to smaller, variable load industrial boilers.

The U.S. EPA's cost manual allows a retrofit factor of greater than one where justification is provided. A retrofit factor of 1.5 was applied since the EPA cost equations were developed based on utility boiler applications and to account for space constraints, additional ductwork, installation of a small duct burner to reheat the exhaust gas to the required temperature range, and the likelihood of needing a new ID fan to account for increased pressure drop. The equipment cost was scaled to 2019 dollars using the CEPCI. We assumed the SCR would achieve 90% control with installation of a duct burner to reheat the stack gas to 650 °F.

Table 2-6 summarizes the estimated capital cost, annual cost, and cost effectiveness of implementing this control technology on each boiler.

Table 2-6
SCR Cost Summary

Emissions Unit Description	Capital Cost ($)	Annual Cost ($/yr)	Cost Effectiveness of Controls ($/Ton NO_X)
Based on PSEL			
CPP Halsey No. 1 Power Boiler (PB1EU)	$8,239,393	$1,911,460	$16,029
CPP Halsey No. 2 Power Boiler (PB2EU)	$8,239,393	$1,916,103	$28,349
GP Toledo No. 4 Hog Fuel Boiler* (EU 11)	$9,559,027	$2,175,317	$11,067
GP Toledo No. 1 Power Boiler (EU 13)	$7,095,014	$1,736,111	$8,623
GP Toledo No. 3 Power Boiler (EU 18)	$6,303,413	$1,314,983	$13,579
GP Toledo No. 5 Power Boiler (EU 22)	$10,688,469	$2,133,579	$26,488
GP Wauna Power Boiler (EU33)	$14,448,563	$4,444,671	$8,353
GP Wauna Fluidized Bed Boiler (EU35)	$20,677,382	$3,043,381	$15,069
IP Springfield Power Boiler (EU-150A)	$14,178,873	$3,621,820	$4,606
IP Springfield Package Boiler (EU-150B)	$10,446,329	$2,130,423	$7,948
Based on 2017 Actual Emissions			
CPP Halsey No. 1 Power Boiler (PB1EU)	$8,239,393	$1,826,543	$38,292
CPP Halsey No. 2 Power Boiler (PB2EU)	$8,239,393	$1,028,580	$204,083
GP Toledo No. 4 Hog Fuel Boiler* (EU 11)	$9,559,027	$2,307,306	$12,173

Emissions Unit Description	Capital Cost ($)	Annual Cost ($/yr)	Cost Effectiveness of Controls ($/Ton NO_X)
GP Toledo No. 1 Power Boiler (EU 13)	$7,095,014	$1,713,128	$12,681
GP Toledo No. 3 Power Boiler (EU 18)	$6,303,413	$1,296,647	$19,057
GP Toledo No. 5 Power Boiler (EU 22)	$10,688,469	$2,085,037	$60,806
GP Wauna Power Boiler (EU33)	$14,448,563	$2,942,622	$12,317
GP Wauna Fluidized Bed Boiler (EU35)	$21,223,307	$3,222,435	$21,000
IP Springfield Power Boiler (EU-150A)	$14,178,873	$2,895,491	$22,924
IP Springfield Package Boiler (EU-150B)	$10,446,329	$825,603	$655,241

*The GP Toledo No. 4 Hog Fuel Boiler now fires only natural gas.

Installing an SCR system is not considered cost effective because the cost effectiveness values, even when conservatively evaluated based on each unit's assigned portion of the PSEL, are in excess of the cost effectiveness threshold for non-EGUs used by U.S. EPA. When the cost effectiveness is evaluated based on actual emissions, the cost per ton is greater than $12,000 in all cases.

2.3.5 Energy and Non-Air Related Impacts

This section describes the energy and non-air environmental impacts associated with each add-on control option evaluated for industrial boilers in this report.

Additional electricity and water would be needed to run a WESP and additional fan power may be required overcome the additional pressure drop through the WESP. Other environmental and energy impacts associated with operating a WESP include generation and disposal of solid waste and wastewater.

The environmental and energy impacts associated with SNCR include storage of additional chemicals onsite (the reagent), ammonia slip, generation and disposal of wastewater, and generation of additional emissions due to additional fuel combustion to overcome the energy penalty associated with SNCR. The environmental and energy impacts associated with SCR include the transport, handling, and use of aqueous ammonia, a corrosive hazardous material. Ammonia poses a potential exposure health and safety risk. The spent catalyst from the SCR would be required to be periodically replaced and disposed of properly, creating residual waste that would need to be landfilled or otherwise disposed. SCR systems have adverse air quality impacts due to ammonia slip, possible formation of a visible plume, oxidation of carbon monoxide to carbon dioxide, and oxidation of SO_2 to sulfur trioxide with subsequent formation of sulfuric acid mist due to ambient or stack moisture. In addition, installing an SCR system would require a duct burner to increase the temperature of the exhaust gas to the optimal range for an SCR system. The duct burner would require constant combustion of natural gas (outside of periods of natural gas curtailment or gas supply interruptions), increasing energy use and creating additional NO_X and GHG emissions.

2.4 TIME NECESSARY FOR COMPLIANCE

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

The facility would need to continue to operate as much as possible while retrofitting to meet any new requirements.

Construction would need to be staggered so only one boiler was out of service at a time. Staggering work on separate units at the same facility allows some level of continued operation. However, this staggering extends the overall compliance time. Extensive outages for retrofitting must be carefully planned. Only when all the critical prerequisites for the retrofit have been lined up (*e.g.*, the engineering is complete and the control equipment is staged for immediate installation), can an owner afford to shut down a facility's equipment to install new controls. This takes planning and coordination both within the company, with the contractors, and with customers. The process to undertake a retrofitting project is complex.

2.5 REMAINING USEFUL LIFE OF EXISTING AFFECTED SOURCES

The emissions units included in this FFA are assumed to have a remaining useful life of twenty years or more.

2.6 CONCLUSION

Based on the FFA presented above, no additional controls were determined to be cost effective for the NWPPA member mill industrial boilers.

3. FOUR-FACTOR ANALYSIS FOR RECOVERY FURNACES

This section of the report presents the results of the FFA for PM_{10}, SO_2, and NO_X emitted from recovery furnaces at the four mills. To evaluate the cost of compliance portion of the FFA, NWPPA performed the following steps:

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

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

3.1 AVAILABLE CONTROL TECHNOLOGIES

Available control options are those air pollution control technologies or techniques (including lower-emitting processes and practices) that have the potential for practical application to the emissions unit and pollutant under evaluation, with a focus on technologies that have been demonstrated to achieve the highest levels of control for the pollutant in question, regardless of the source type on which the demonstration has occurred. The scope of potentially applicable control options for recovery furnaces was determined based on a review of the RBLC database and knowledge of typical controls used on recovery furnaces in the pulp and paper industry. RBLC entries that are not representative of the type of emissions unit, or fuel being fired, were excluded from further consideration. Table 3-1 summarizes the potentially feasible control technologies for recovery furnaces, based on a review of the RBLC.

Table 3-1
Control Technology Summary

Pollutant	Controls on Recovery Furnaces
PM_{10}	ESP Wet scrubber

Pollutant	Controls on Recovery Furnaces
SO_2	Good operating practices Wet scrubber
NO_X	Proper design and operation Staged air combustion

Technically feasible control technologies for recovery furnaces were evaluated, taking into account current air pollution controls and RBLC Database information.

3.1.1 Available PM_{10} Control Technologies

The following control technologies were identified as potentially available for reducing emissions of PM_{10} from recovery furnaces.

Electrostatic Precipitators

ESPs are widely used for the control of PM from a variety of combustion sources. An ESP is a PM control device that removes particles from a gas stream by using electrical energy to charge particles either positively or negatively. The charged particles are then attracted to collector plates carrying the opposite charge. The collected particles are periodically removed from the collector plates. There are several different designs that can achieve very high overall control efficiencies. Control efficiencies typically average over 98% with control efficiencies almost as high for particle sizes of 1 micrometer or less. ESPs have been demonstrated in practice to have PM_{10} removal efficiencies as high as those achieved by fabric filters. Two ESP designs are common: dry electrostatic precipitators and wet electrostatic precipitators. The systems are similar except that wet electrostatic precipitators use water to flush the captured particles from the collector plates. All the recovery furnaces at the NWPPA Oregon mills have dry ESPs.

Wet Scrubbers

In wet scrubbing processes, liquid or solid particles are removed from a gas stream by transferring them to a liquid, most commonly water. A wet scrubber PM collection efficiency is directly related to the amount of energy expended in contacting the gas stream with the scrubber liquid. Wet scrubbers cannot typically achieve the levels of PM and PM_{10} reduction obtained by fabric filters and ESPs without being operated at extremely high energy input levels. In addition, wet scrubber systems often require higher levels of maintenance and generate a wastewater stream that must be treated.

3.1.2 Available SO_2 Control Technologies

Per NCASI Technical Bulletin 884, Section 4.11.2, most of the sulfur introduced to the recovery furnace leaves the recovery furnace in the smelt while under one percent of sulfur is released into the air. One of the primary purposes of a Kraft recovery furnace is to recover this sulfur and reuse it as fresh cooking chemical for the pulp. Factors that influence SO_2 levels include liquor sulfidity, liquor solids content, stack oxygen content, furnace load, auxiliary fuel use, and furnace design. The sodium salt fume in the upper furnace also acts to limit SO_2 emissions. A well-operated recovery furnace can have very low SO_2 emissions.

The following add-on control technologies were identified as potentially feasible for reducing emissions of SO_2 from recovery furnaces.

Wet Scrubbers

In wet scrubbing processes for gaseous control, a liquid is used to remove pollutants from an exhaust stream. The removal of pollutants in the gaseous stream is done by absorption. Wet scrubbers used for this type of pollutant control are often referred to as absorbers. Wet scrubbing involves a mass transfer operation in which one or more soluble components of an acid gas are dissolved in a liquid that has low volatility under process conditions. For SO_2 control, the absorption process is chemical-based and uses an alkali solution (*i.e.*, sodium hydroxide, sodium carbonate, sodium bicarbonate, calcium hydroxide, etc.) as a sorbent or reagent in combination with water. Removal efficiencies are affected by the chemistry of the absorbing solution as it reacts with the pollutant. Wet scrubbers may take the form of a variety of different configurations, including plate or tray columns, spray chambers, and venturi scrubbers.

3.1.3 Available NO_X Control Technologies

The National Council of Air and Stream Improvement, Inc. (NCASI) published Technical Bulletin No. 1051, "An Update to NO_X Control Limits and Technologies for Forest Products Industry Boilers, Kraft Recovery Furnaces, and Lime Kilns," in May 2019. This technical bulletin provides un update to the NCASI 2003 Special Report 03-06, where NCASI determined that staged combustion (multiple levels of combustion air) within Kraft recovery furnaces is the only technology feasible to reduce NO_X. The liquor nitrogen content is dependent on the type of wood pulped and is the dominant factor affecting the level of NO_X emissions from black liquor combustion in recovery furnaces. Pulp mill operators cannot control this factor. The May 2019 technical bulletin reviewed fundamental research for NO_X control in recovery furnaces over the past decade and concluded that staged combustion is still the only NO_X emission reduction strategy for recovery furnaces at this time.

The only NO_X minimization techniques listed in the RBLC database are good combustion practices and optimizing the staged combustion in the design of the existing furnace. No other control technologies have been demonstrated in practice for NO_X emissions from recovery furnaces at pulp and paper mills.

3.2 ELIMINATION OF TECHNICALLY INFEASIBLE OPTIONS

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

PM_{10} Emissions

All the recovery furnaces included in this FFA are equipped with dry ESPs for PM_{10} control. While fabric filters can also achieve high levels of PM_{10} control, the exhaust gas stream from a recovery furnace has a relatively high moisture content that causes the PM to be hydroscopic in nature and would cause the filter bags to blind and plug. Therefore, fabric filters are not a feasible PM_{10} control technology for recovery furnaces. Installation of a wet scrubber following the ESP was not evaluated for PM_{10} because scrubbers are not expected to further control PM_{10} that is not already controlled by the ESP. Wet scrubbers use water droplets to capture dust particles and have higher control efficiencies for larger particles[13]; therefore, scrubbers are not suited to control additional PM_{10} after an ESP.

Two additional PM_{10} control options were evaluated for each recovery furnace: (1) upgrading the existing ESP to increase PM_{10} control (the emissions reduction was calculated assuming a change from 99% to 99.5% PM_{10} control), and (2) installing a WESP following the dry ESP to achieve an estimated additional 80% reduction in controlled PM_{10} emissions. WESP operation is similar to the dry ESP except WESPs have a wet collecting surface and can collect dry and wet pollutants for additional PM_{10} control. Dry ESPs that are installed on recovery furnaces reintroduce at least a portion of the ESP ash or saltcake back into the liquor system. A WESP would not be installed to replace the dry ESP because it would prevent the saltcake from being recovered, increasing cost

[13] https://www3.epa.gov/ttn/catc/dir1/cs6ch2.pdf

to make up for the lost chemical. However, a WESP could be installed after a dry ESP to achieve additional PM_{10} control, assuming space were available.

SO_2 Emissions

The recovery furnaces in this FFA are not equipped with add-on SO_2 control technology. Although SO_2 emissions from recovery furnaces can be inherently low, addition of a wet scrubber to further reduce SO_2 emissions is considered technically feasible.

NO_X Emissions

All the recovery furnaces at the mills evaluated in this report have tertiary air (three levels of combustion air) to minimize NO_X emissions. Addition of another level of staged combustion air may require the recovery furnace to be rebuilt to lengthen the firebox and possibly require increasing the height of the recovery furnace building. This modification would require a significant construction project and would be cost prohibitive for the control of NO_x emissions. At mills where there may not be space constraints, installing the next level of air would need to be individually evaluated to determine feasibility and would not likely result in significant emissions reductions due to the existing levels of performance. An extensive air study would be required, and the cost of lost production from shutting down the recovery furnace to perform the work would need to be included in any cost estimate. It is expected that such modifications would not be cost effective, and based on a review of the emissions levels in the RBLC may not provide a significant additional reduction in NO_X emissions. Therefore, they were not evaluated in detail in this report. No additional NO_X controls for recovery furnaces are considered feasible.

3.3 COST OF TECHNICALLY FEASIBLE CONTROL TECHNOLOGIES

Cost analyses were developed where add-on controls were considered technically feasible. Budgetary estimates of capital and operating costs were determined and used to estimate the annualized costs for each control technology considering existing equipment design and exhaust characteristics. A capital cost for each control measure evaluated was based on company-specific data, previously developed industry project costs, or U.S. EPA cost spreadsheets. The cost effectiveness for each technically feasible control technology was calculated based on the annualized capital and operating costs and the amount of pollutant expected to be removed based on the procedures presented in the latest version of the U.S. EPA OAQPS Control Cost Manual and each unit's assigned portion of the PSEL. The cost effectiveness based on 2017 actual emissions was also evaluated, since 2017 actual emissions are more representative of emissions during the 2021-2028 planning period than PSELs in many cases.

Technically feasible control technologies were evaluated for cost effectiveness by source as summarized in Table 3-2.

Table 3-2
Control Technologies Evaluated for Recovery Furnaces

Source	Existing Control Technology			Additional Control Technology Costed		
Emissions Unit	PM_{10}	NO_X	SO_2	PM_{10}	NO_X	SO_2
CPP Halsey Recovery Furnace (RFEU)	ESP	Tertiary air	Proper operation	ESP Upgrade, WESP	None	Wet scrubber
GP Toledo No. 1 Recovery Furnace (EU 14)	ESP	Tertiary air	Proper operation	ESP Upgrade, WESP	None	Wet scrubber
GP Toledo No. 2 Recovery Furnace (EU 16)	ESP	Tertiary air	Proper operation	ESP Upgrade, WESP	None	Wet scrubber
GP Wauna Recovery Furnace (EU24)	ESP	Tertiary air	Proper operation	ESP Upgrade, WESP	None	Wet scrubber
IP Springfield No. 4 Recovery Furnace (EU-445C)	ESP	Tertiary air	Proper operation	ESP Upgrade, WESP	None	Wet scrubber

Capital, operating, and total annual cost estimates for each technically feasible pollution control technique are presented in Appendix A. These are screening level cost estimates and are not based on detailed engineering studies.

3.3.1 Site-Specific Factors Limiting Implementation

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

3.3.2 PM_{10} Economic Impacts

Cost estimates for upgrading recovery furnace ESPs or installing polishing WESPs are presented below. The OAQPS Cost Manual includes a statement in Section 6, Chapter 3, Paragraph 3.4.3 that for processes that can reuse the dust collected in the ESP or that can sell the dust in a local market a recovery credit should be taken. The ESP cost example under Paragraph 3.4.5.6 in the Manual includes a waste disposal cost and a remark that finding a market for the ESP dust could reduce the total annual cost. The cost estimates for upgrading an ESP and for installing a WESP in this report include neither a waste disposal cost nor a recovery credit. Mills do typically recover material collected in ESPs from recovery furnaces and lime kilns for reuse within the process. However, the amount of sulfur in the process must be managed to prevent high liquor sulfidity from causing elevated SO_2 emissions from the recovery furnace, and sometimes this is done by purging precipitator saltcake (sodium sulfate). Therefore, one cannot assume that any additional ash collected in the ESP would automatically be returned to the process. In fact, it would be more likely the case that additional ash collected from an upgraded recovery furnace ESP would be purged to the wastewater treatment system.

However, if one assumes that the reduction in PM_{10} emissions corresponds to a reduction in purchased saltcake, the recovery credit would not be significant because purchased saltcake is on the order of 11 cents per pound (*e.g.*, a 30-ton reduction in emissions would be only a $6,600 credit). Disposal costs were not included, but even if the disposal cost were $50/ton, adding this cost to the estimate would not appreciably increase the calculated cost per ton of PM_{10} removed. The amount of recovery credit for recovered saltcake and the waste disposal cost are within the margin of error of the entire estimate.

Dry ESP Upgrade for Additional PM_{10} Control

The capital cost for upgrading an ESP by adding two new parallel fields is based on the document titled "Emission Control Study – Technology Cost Estimates" by BE&K Engineering for AF&PA, September 2001. Section 10.2 presents the costs associated with upgrading an ESP on a non-direct contact evaporator (NDCE) recovery furnace burning 3.7 million pounds of black liquor solids (BLS) per day. The base equipment cost was scaled from 2001 dollars to 2019 dollars using the CEPCI. The base equipment cost was also scaled to each mill's recovery furnace using an engineering cost scaling factor of 0.6 and the ratio of each mill's recovery furnace throughput vs. the furnace throughput evaluated in the BE&K report. Operating costs were estimated using the factors in the OAQPS Cost Manual, Section 6, Chapter 3. No change in labor and maintenance cost was estimated. Additional electricity usage for the new fields was estimated by scaling the additional electricity usage stated in the BE&K report.

Table 3-3 summarizes the estimated capital cost, annual cost, and cost effectiveness of implementing this control technology, based on operating data and both PM_{10} PSEL levels assigned to each recovery furnace and 2017 actual emissions. The reduction in PM_{10} was estimated to be 50% of current levels (e.g., an increase from 99 to 99.5% PM_{10} control with the upgrade).

Table 3-3
ESP Upgrade Cost Summary

Emissions Unit Description	Capital Cost ($)	Annual Cost ($/yr)	Cost Effectiveness of Controls ($/Ton PM_{10})
Based on PSEL			
CPP Halsey Recovery Furnace (RFEU)	$11,985,809	$1,338,144	$24,919

Emissions Unit Description	Capital Cost ($)	Annual Cost ($/yr)	Cost Effectiveness of Controls ($/Ton PM_{10})
GP Toledo No. 1 Recovery Furnace (EU 14)	$8,173,024	$888,361	$61,266
GP Toledo No. 2 Recovery Furnace (EU 16)	$8,173,024	$888,361	$61,266
GP Wauna Recovery Furnace (EU24)	$14,282,074	$1,617,688	$11,156
IP Springfield No. 4 Recovery Furnace (EU-445C)	$14,006,394	$1,583,802	$21,733
Based on 2017 Actual Emissions			
CPP Halsey Recovery Furnace (RFEU)	$11,985,809	$1,333,145	$15,448
GP Toledo No. 1 Recovery Furnace (EU 14)	$8,173,024	$882,389	$66,848
GP Toledo No. 2 Recovery Furnace (EU 16)	$8,173,024	$882,389	$65,850
GP Wauna Recovery Furnace (EU24)	$14,282,074	$1,600,077	$14,136
IP Springfield No. 4 Recovery Furnace (EU-445C)	$14,006,394	$1,581,990	$26,318

Upgrading ESPs is not considered cost effective because the capital cost is more than $8 million each and the cost effectiveness values are in excess of $11,000/ton of pollutant removed. The cost of lost production during installation of the controls was not evaluated but would further demonstrate that the cost is not effective.

Wet Electrostatic Precipitator for Additional PM_{10} Control

The capital cost for a polishing WESP following each recovery furnace's ESP was estimated based on the low end of the capital cost range of $40 to $200 per scfm in the U.S. EPA WESP fact sheet.[14] The flow rate was conservatively estimated for each furnace using an NCASI-developed

[14] https://www3.epa.gov/ttn/catc/dir1/fwespwpi.pdf

average f-factor for recovery furnaces of 7,820 dscf/MMBtu, an average heat content of 6,284 Btu/pound black liquor solids, and the black liquor solids firing capacity of each furnace.[15] The BE&K report does not estimate a cost for a polishing WESP and the cost is likely less than that estimated for a new dry ESP on a recovery furnace. Operating costs were estimated using the factors in the OAQPS Cost Manual, Section 6, Chapter 3 and water and electricity use information from a Washington pulp and paper mill boiler's WESP.

Table 3-4 summarizes the capital cost, annual cost, and cost effectiveness of implementing this control technology, based on operating data and both the portion of the PM_{10} PSEL assigned to each recovery furnace and 2017 actual emissions. The cost of any ductwork or stack upgrades that may be necessary with a wet exhaust plume or the cost of lost production during installation of controls was not included.

Table 3-4
WESP Cost Summary

Emissions Unit Description	Capital Cost ($)	Annual Cost ($/yr)	Cost Effectiveness of Controls ($/Ton PM_{10})
Based on PSEL			
CPP Halsey Recovery Furnace (RFEU)	$9,698,392	$1,478,474	$17,208
GP Toledo No. 1 Recovery Furnace (EU 14)	$5,123,406	$1,729,857	$74,563
GP Toledo No. 2 Recovery Furnace (EU 16)	$5,123,406	$1,729,857	$74,563
GP Wauna Recovery Furnace (EU24)	$12,988,917	$1,878,999	$8,099
IP Springfield No. 4 Recovery Furnace (EU-445C)	$12,573,747	$2,679,387	$22,979
Based on 2017 Actual Emissions			

[15] NCASI White Paper, Developing an F-factor Calculation Tool for Black Liquor Combustion in Recovery Furnaces, March 2020.

Emissions Unit Description	Capital Cost ($)	Annual Cost ($/yr)	Cost Effectiveness of Controls ($/Ton PM_{10})
CPP Halsey Recovery Furnace (RFEU)	$9,698,392	$1,471,373	$10,716
GP Toledo No. 1 Recovery Furnace (EU 14)	$5,123,406	$1,651,639	$78,203
GP Toledo No. 2 Recovery Furnace (EU 16)	$5,123,406	$1,651,639	$77,035
GP Wauna Recovery Furnace (EU24)	$12,988,917	$1,861,413	$10,278
IP Springfield No. 4 Recovery Furnace (EU-445C)	$12,573,747	$2,669,602	$27,757

Installing a WESP is not considered cost effective because the capital cost is more than $5 million each and the cost effectiveness values are in excess of $8,000/ton of pollutant removed in all cases.

3.3.3 SO_2 Economic Impacts

Wet Scrubber for SO_2 Control

The wet scrubber capital cost is based on the document titled "Emission Control Study – Technology Cost Estimates" by BE&K Engineering for AF&PA, September 2001. Section 7.1 presents the costs associated with installing a wet scrubber for SO_2 control on an NDCE recovery furnace burning 3.7 million pounds of BLS per day. The equipment cost was updated to 2019 dollars using the CEPCI and scaled using an engineering cost scaling factor of 0.6 and the ratio of each mill's recovery furnace throughput to the throughput of the furnace evaluated in the BE&K report. Operating costs were estimated using the factors in the OAQPS Cost Manual, Section 5, Chapter 1. Table 3-5 summarizes the capital cost, annual cost, and cost effectiveness of implementing this control technology for recovery furnaces at each mill, based on operating data and both the portion of the PM_{10} PSEL assigned to each recovery furnace and 2017 actual emissions.

Table 3-5
Wet Scrubber Cost Summary

Emissions Unit Description	Capital Cost ($)	Annual Cost ($/yr)	Cost Effectiveness of Controls ($/Ton SO_2)
Based on PSEL			
CPP Halsey Recovery Furnace (RFEU)	$18,890,691	$5,106,821	$11,496
GP Toledo No. 1 Recovery Furnace (EU 14)	$12,881,407	$3,131,585	$293,165
GP Toledo No. 2 Recovery Furnace (EU 16)	$12,881,407	$3,131,585	$507,221
GP Wauna Recovery Furnace (EU24)	$22,509,808	$6,432,783	$16,220
IP Springfield No. 4 Recovery Furnace (EU-445C)	$22,075,311	$6,268,466	$76,075
Based on 2017 Actual Emissions			
CPP Halsey Recovery Furnace (RFEU)	$18,890,691	$5,025,227	$113,447
GP Toledo No. 1 Recovery Furnace (EU 14)	$12,881,407	$3,031,015	$1,066,508
GP Toledo No. 2 Recovery Furnace (EU 16)	$12,881,407	$3,031,015	$618,574
GP Wauna Recovery Furnace (EU24)	$22,509,808	$6,147,878	$21,223
IP Springfield No. 4 Recovery Furnace (EU-445C)	$22,075,311	$6,239,132	$2,323,526

Installing a wet scrubber on a recovery furnace for additional SO_2 control is not considered cost effective for any mill, especially when the cost per ton is evaluated based on actual emissions.

3.3.4 Energy and Non-Air Related Impacts

This section describes the energy and non-air environmental impacts associated with each add-on control option evaluated for recovery furnaces in this report. Additional electricity would be needed to run these additional or upgraded controls and it is likely that additional fan power would be required to overcome the additional pressure drop through a new WESP or wet scrubber. Other environmental and energy impacts associated with operating a WESP or a wet scrubber include water usage and generation and disposal of solid waste and wastewater.

3.4 TIME NECESSARY FOR COMPLIANCE

U.S. EPA allows three years plus an optional extra year for compliance with MACT standards that require facilities to install controls after the effective date of the final standard. Although our FFA shows there are no additional controls that would be feasible, if controls are ultimately required to meet RHR requirements, facilities would need at four to five years to implement them after final EPA approval of the RHR SIP. Each facility would need time to obtain corporate approvals for capital funding. The facility would have to undergo substantial re-engineering (*e.g.*, due to space constraints) to accommodate new controls. Design, procurement, installation, and shakedown of these projects would easily consume three years. The facility would need to engage engineering consultants, equipment vendors, construction contractors, financial institutions, and other critical suppliers. The facility would also need to execute air permit modifications, which are often time-consuming and have an indeterminate timeline and endpoint. Lead time would be needed to procure pollution control equipment even after it is designed and a contract is finalized, and installation of controls must be aligned with mill outage schedules that are difficult to move due to the interrelationships within corporate systems, the availability of contractors, and the like. The facility would need to continue to operate as much as possible while retrofitting to meet any new requirements.

Construction would need to be staggered so only one unit was out of service at a time. Staggering work on separate units at the same facility allows some level of continued operation. However, this staggering extends the overall compliance time. Extensive outages for retrofitting must be carefully planned. Only when all the critical prerequisites for the retrofit have been lined up (*e.g.*, the engineering is complete and the control equipment is staged for immediate installation), can an owner afford to shut down a facility’s equipment to install new controls. This takes planning and coordination both within the company, with the contractors, and with customers. The process to undertake a retrofitting project is complex.

3.5 REMAINING USEFUL LIFE OF EXISTING AFFECTED SOURCES

The recovery furnaces included in this FFA are assumed to have a remaining useful life of twenty years or more.

3.6 CONCLUSION

Based on the FFA presented above, no additional controls were determined to be cost effective for the NWPPA Oregon mill recovery furnaces.

4. FOUR-FACTOR ANALYSIS FOR LIME KILNS

This section of the report presents the results of the FFA for PM_{10}, SO_2, and NO_X emissions from lime kilns at the four NWPPA Oregon mills. To evaluate the cost of compliance portion of the FFA, NWPPA performed the following steps:

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

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

4.1 AVAILABLE CONTROL TECHNOLOGIES

Available control options are those air pollution control technologies or techniques (including lower-emitting processes and practices) that have the potential for practical application to the emissions unit and pollutant under evaluation, with a focus on technologies that have been demonstrated to achieve the highest levels of control for the pollutant in question, regardless of the source type on which the demonstration has occurred. The scope of potentially applicable control options for lime kilns was determined based on a review of the RBLC database and knowledge of typical controls used on lime kilns in the pulp and paper industry. RBLC entries that are not representative of the type of emissions unit, or fuel being fired, were excluded from further consideration. Table 4-1 summarizes the potentially feasible control technologies for lime kilns.

Table 4-1
Control Technology Summary

Pollutant	Controls on Lime Kilns
PM_{10}	ESP Wet scrubber

Pollutant	Controls on Lime Kilns
SO_2	Wet scrubber Good operating practices/ inherent control
NO_X	Proper design and operation LNB FGR SNCR SCR

Technically feasible control technologies for lime kilns were evaluated, considering current air pollution controls and RBLC Database information.

4.1.1 Available PM_{10} Control Technologies

The following control technologies were identified as potentially available for reducing emissions of PM_{10} from lime kilns.

Electrostatic Precipitators

ESPs are widely used for the control of PM from a variety of combustion sources. An ESP is a PM control device that removes particles from a gas stream by using electrical energy to charge particles either positively or negatively. The charged particles are then attracted to collector plates carrying the opposite charge. The collected particles are periodically removed from the collector plates. There are several different designs that can achieve very high overall control efficiencies. Control efficiencies typically average over 98% with control efficiencies almost as high for particle sizes of 1 micrometer or less. ESPs have been demonstrated in practice to have PM_{10} removal efficiencies as high as those achieved by fabric filters. Two ESP designs are common: dry electrostatic precipitators and wet electrostatic precipitators. The systems are similar except that wet electrostatic precipitators use water to flush the captured particles from the collector plates.

Wet Scrubbers

In wet scrubbing processes, liquid or solid particles are removed from a gas stream by transferring them to a liquid, most commonly water. A wet scrubber's PM_{10} collection efficiency is directly related to the amount of energy expended in contacting the gas stream with the scrubber liquid. Wet scrubbers cannot typically achieve the levels of PM_{10} reduction obtained by fabric filters and ESPs without being operated at extremely high energy input levels. In addition, wet scrubber systems often require higher levels of maintenance and generate a wastewater stream that must be treated.

4.1.2 Available SO_2 Control Technologies

The purpose of a lime kiln is to calcine lime mud ($CaCO_3$) to produce lime product (CaO). Typically, SO_2 that might be generated through combustion of fuel or pulp mill non-condensable gases (NCGs) in a lime kiln is absorbed by the calcium in the lime, which results in low emissions. The following add-on control technologies were identified as potentially feasible for reducing emissions of SO_2 from lime kilns.

Wet Scrubbers

In wet scrubbing processes for gaseous control, a liquid is used to remove pollutants from an exhaust stream. The removal of pollutants in the gaseous stream is done by absorption. Wet scrubbers used for this type of pollutant control are often referred to as absorbers. Wet scrubbing involves a mass transfer operation in which one or more soluble components of an acid gas are dissolved in a liquid that has low volatility under process conditions. For SO_2 control, the absorption process is chemical-based and uses an alkali solution (*i.e.*, sodium hydroxide, sodium carbonate, sodium bicarbonate, calcium hydroxide, etc.) as a sorbent or reagent in combination with water. Removal efficiencies are affected by the chemistry of the absorbing solution as it reacts with the pollutant. Wet scrubbers may take the form of a variety of different configurations including plate or tray columns, spray chambers, and venturi scrubbers.

4.1.3 Available NO_X Control Technologies

Based on a review of NCASI Technical Bulletins 847 ("Factors Affecting NO_X Generation from Burning Stripper Off-Gases in Power Boilers and Lime Kilns"), 855 ("Factors Affecting NO_X Emissions from Lime Kilns"), and 884 ("Compilation of Criteria Air Pollutant Emissions Data for Sources at Pulp and Paper Mills Including Boilers"), the two primary factors that affect NO_X emissions in lime kilns burning natural gas are the dry end lime temperature and the combustion of NCGs and/or stripper off gases (SOGs). Thermal NO_X is the primary NO_X formation mechanism in a natural gas-fired kiln and the ammonia present in SOGs will also contribute to NO_X formation.

The following add-on control technologies were identified as potentially feasible for reducing emissions of NO_X from lime kilns.

Low NO_X Burners (LNB)

The use of LNB is a front-end control technology for limiting NO_X emissions. An LNB is designed to control fuel and air mixing by staging the air or fuel in multiple zones and thus limit peak flame temperatures in the burners. NO_X reduction is accomplished in an LNB by using techniques such as recycling internal gas, staging the combustion air, or injecting natural gas. These techniques would create burner temperatures that are below the peak NO_X formation temperature range, thus limiting NO_X formation. LNB burner conversion capability may also be complicated by a unit's age, configuration, and fire-box dimensions (if the kiln has a separate fuel combustion chamber, which pulp and paper lime kilns do not).

Flue Gas Recirculation (FGR)

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

Selective Non-Catalytic Reduction (SNCR)

SNCR is a control technology for NO_X emissions that uses a reduction-oxidation reaction to convert NO_X into N_2, H_2O, and CO_2. SNCR involves injecting ammonia or urea into a combustion chamber or the flue gas stream, which must have a temperature between approximately 1,600 and 2,000°F for the chemical reaction to occur.

Selective Catalytic Reduction (SCR)

Although SCR was not identified in the RBLC search as a technology employed on lime kilns it has been applied to other types of industrial calciners and kilns. SCR is a NO_X control technology that uses a catalyst to react injected anhydrous ammonia, aqueous ammonia or urea to chemically convert NO_X into N_2 and H_2O. SCR employs a metal-based catalyst, such as vanadium or titanium, to increase the rate of the NO_X reduction reaction[16]. The flue gases flow into a reactor module containing the catalyst where the reagent selectively reacts with the NO_X. The reduction reactions used by SCR are effective only within a given temperature range where ammonia or urea is injected into the exhaust gases in a temperature range of 480°F – 800°F[17]. Under optimum temperatures, amount of reducing agent and injection grid design, SCR can achieve 90 percent reduction of NO_X. However, ammonia slip can also occur, which refers to the emissions of unreacted ammonia due to the incomplete reaction of the reagent and NO_X. Excess ammonia can result in formation of compounds that cause corrosion and impair visibility.

[16] *Chapter 2 Selective Catalytic Reduction,* OAQPS 7th Edition (June 2019). https://www.epa.gov/sites/production/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf (Section 2.2.1).
[17] Air Pollution Control Technology Fact Sheet. EPA-452/F-03-032. https://www3.epa.gov/ttncatc1/dir1/fscr.pdf. (pg. 1).

4.2 ELIMINATION OF TECHNICALLY INFEASIBLE OPTIONS

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

PM_{10} Emissions

Three of the mills (CPP Halsey, GP Toledo, and GP Wauna) utilize wet scrubbers for PM control on their lime kilns. An ESP prior to the wet scrubber would provide additional PM_{10} control and is considered technically feasible. The IP Springfield Mill uses a dry ESP for control of PM emissions from their lime kiln. An ESP upgrade for additional PM_{10} control is considered technically feasible.

SO_2 Emissions

The lime kilns provide inherent control of SO_2 through absorption of sulfur by the calcium in the kiln. All the mills fire natural gas as the primary fuel in their lime kilns, which minimizes SO_2 emissions, particularly during startup and shutdown. Three of the four lime kilns at the NWPPA Oregon mills are equipped with wet scrubbers, primarily for reduction of PM and TRS emissions. Actual lime kiln SO_2 emissions at the GP Toledo mill are less than 1 tpy and the portion of the SO_2 PSEL assigned to the lime kilns at GP Wauna and GP Toledo is less than 5 tpy, so no additional SO_2 controls are necessary for these kilns.

The CPP Halsey lime kiln's portion of the SO_2 PSEL is 68.4 tpy, but 65.7 tpy of the PSEL is from combustion of pulp mill NCG that contain sulfur compounds. The kiln's venturi scrubber is designed for PM control and has a very short residence time. No caustic is added to this scrubber and the short residence time would preclude achieving significant additional SO_2 control if a caustic solution were used. Although the kiln is the backup control device for NCG combustion, addition of a packed bed scrubber to further reduce SO_2 emissions from this kiln was evaluated (rather than replacing the venturi scrubber with a caustic wet scrubber and potentially decreasing the PM_{10} control efficiency). Addition of a wet scrubber with caustic addition (following the ESP) for additional SO_2 control was evaluated for the IP Springfield lime kilns (which also burn pulp mill NCG).

NO_X Emissions

The primary NO_X formation mechanism in a lime kiln is thermal NO_X. Because the calcination reaction requires a certain temperature and residence time within the kiln, combustion temperature cannot be reduced without changing the size of the kiln. Therefore, technologies that involve injecting cooler exhaust gas or water into the kiln are not feasible. Natural gas-fired kilns and calciners in other industries primarily use LNB to reduce NO_X emissions. It is uncertain whether a burner replacement would achieve lower NO_X emissions from pulp and paper mill lime kilns while still maintaining the required temperature for calcination. Although cement kilns and calciners used in other industries have employed SNCR and SCR, the pulp and paper mill lime kilns are different because they are not equipped with a pre-calciner, pre-heater, or a separate fuel combustion chamber into which a reagent could be injected (or flue gas recirculated) for NO_X control. The temperature within the kiln is not in the SNCR effective range because of the calcination temperature. Even if it were, injecting ammonia or urea into a rotating lime kiln would be difficult to achieve and would affect product quality.

While it might be possible to add SCR on the back end of a lime kiln exhaust system, it would need to be installed after existing PM control equipment to ensure the integrity of the catalyst. Location at the tail end of the pollution control train would require re-heating of the gases to create an ideal SCR temperature zone (480°F – 800°F[18]) as well, thereby increasing operating cost, energy use, and product of combustion emissions. No operator of a pulp and paper mill lime kiln has found SCR to be feasible. Because pulp and paper mill lime kiln exhaust gas temperatures are well below the effective SCR and SNCR operating temperatures and due to design differences from other types of kilns and calciners that have employed NO_X control technologies, FGR, SNCR, and SCR are not technically feasible for pulp and paper mill lime kilns.

4.3 COST OF TECHNICALLY FEASIBLE CONTROL TECHNOLOGIES

Cost analyses were developed where add-on controls were considered technically feasible. Budgetary estimates of capital and operating costs were determined and used to estimate the annualized costs for each control technology considering existing equipment design and exhaust characteristics. A capital cost for each control measure evaluated was based on company-specific data, previously developed company project costs, or U.S. EPA cost spreadsheets. The cost effectiveness for each technically feasible control technology was calculated based on the annualized capital and operating costs and the amount of pollutant expected to be removed based on the procedures presented in the latest version of the U.S. EPA OAQPS Control Cost Manual. Emissions reductions were evaluated based on each unit's assigned portion of the PSEL and also based on 2017 actual emissions, which are more representative of emissions during the 2021-2028 planning period than PSELs in many cases.

Technically feasible control technologies were evaluated for cost effectiveness by source as summarized in Table 4-2.

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[18] Air Pollution Control Technology Fact Sheet. EPA-452/F-03-032. https://www3.epa.gov/ttncatc1/dir1/fscr.pdf. (pg. 1).

Table 4-2
Control Technologies Evaluated for Lime Kilns

Emissions Unit	Existing Control Technology			Additional Control Technology Costed		
	PM_{10}	NO_X	SO_2	PM_{10}	NO_X	SO_2
CPP Halsey Lime Kiln (LKEU)	Venturi scrubber	Good combustion practices, NO_X BACT	Inherent process control	ESP	None	Packed bed scrubber
GP Toledo No. 1 Lime Kiln (EU1)	Wet scrubber	Good combustion practices	Inherent process control	ESP	None	None
GP Toledo No. 2 Lime Kiln (EU2)	Wet scrubber	Good combustion practices	Inherent process control	ESP	None	None
GP Toledo No. 3 Lime Kiln (EU3)	Wet scrubber	Good combustion practices	Inherent process control	ESP	None	None
GP Wauna Lime Kiln (EU21)	Wet scrubber	Good combustion practices	Wet scrubber	ESP	None	None
IP Springfield Lime Kilns (EU-455)	ESP	Good combustion practices	Inherent process control	ESP upgrade	None	Wet scrubber

Capital, operating, and total annual cost estimates for each feasible pollution control technique are presented in Appendix A. These are screening level cost estimates and are not based on detailed engineering studies.

4.3.1 Site Specific Factors Limiting Implementation

Currently known, site-specific factors that would limit the feasibility and increase the cost of installing additional controls include space constraints at the lime kiln locations to add an additional control device. A detailed engineering study for each of the controls evaluated in this report would be necessary before any additional controls were determined to be feasible.

4.3.2 PM_{10} Economic Impacts

Installation of an ESP prior to a Wet Scrubber

The estimated capital cost for installing a dry ESP is based on the "Emission Control Study – Technology Cost Estimates" by BE&K Engineering for AF&PA, September 2001. Section 10.5 presents the costs associated with installing an ESP on a lime kiln processing 240 tons of calcium oxide (CaO) per day. The base equipment cost was scaled from 2001 dollars to 2019 dollars using the CEPCI. The base equipment cost was also scaled to each mill's kiln using an engineering cost scaling factor of 0.6 and the ratio of each mill's kiln throughput to the kiln throughput evaluated in the BE&K report. Operating costs were estimated using the factors in the OAQPS Cost Manual, Section 6, Chapter 3. An additional 90% reduction in emissions of PM_{10} is estimated to result from installing an ESP prior to each kiln's wet scrubber.

Table 2-3 summarizes the estimated capital cost, annual cost, and cost effectiveness of implementing this control technology, based on both each kiln's portion of the PM_{10} PSEL and 2017 actual emissions. Note that the cost of lost production during installation of the controls was not evaluated but would further demonstrate that the cost is not effective.

Table 4-3
Lime Kiln ESP Cost Summary

Emissions Unit Description	Capital Cost ($)	Annual Cost ($/yr)	Cost Effectiveness of Controls ($/Ton PM_{10})
Based on PSEL			
CPP Halsey Lime Kiln (LKEU)	$7,149,088	$1,103,358	$47,152
GP Toledo Nos. 1-3 Lime Kilns (EU1, 2, 3)	$10,030,211	$1,548,526	$16,110
GP Wauna Lime Kiln (EU21)	$8,529,788	$1,314,369	$45,496
Based on 2017 Actual Emissions			
CPP Halsey Lime Kiln (LKEU)	$7,149,088	$1,099,183	$43,309
GP Toledo Nos. 1-3 Lime Kilns (EU1, 2, 3)	$10,030,211	$1,536,218	$24,280

Emissions Unit Description	Capital Cost ($)	Annual Cost ($/yr)	Cost Effectiveness of Controls ($/Ton PM_{10})
GP Wauna Lime Kiln (EU21)	$8,529,788	$1,299,455	$16,537

Installing an ESP on the lime kilns that are currently equipped with wet scrubbers is not considered cost effective because the capital cost is more than $7 million each and the cost effectiveness values are in excess of $16,000/ton of pollutant removed.

ESP Upgrade

The estimated capital cost for upgrading a dry ESP is based on the "Emission Control Study – Technology Cost Estimates" by BE&K Engineering for AF&PA, September 2001. Section 10.6 presents the costs associated with upgrading an ESP on a lime kiln processing 240 tons of CaO per day. The base equipment cost to add a single electric field was scaled from 2001 dollars to 2019 dollars using the CEPCI. The base equipment cost was also scaled for IP's kiln using an engineering cost scaling factor of 0.6 and the ratio of the kiln throughput to the kiln throughput evaluated in the BE&K report. Operating costs were estimated using the factors in the OAQPS Cost Manual, Section 6, Chapter 3. An additional 50% reduction in emissions of PM_{10} is estimated to result from upgrading the ESP (*e.g.*, an improvement from 99% PM_{10} control to 99.5% control).

Table 2-4 summarizes the estimated capital cost, annual cost, and cost effectiveness of implementing this control technology. Note that the cost of lost production during installation of the controls was not evaluated but would further demonstrate that the cost is not effective.

Table 4-4
Lime Kiln ESP Upgrade Cost Summary

Emissions Unit Description	Capital Cost ($)	Annual Cost ($/yr)	Cost Effectiveness of Controls ($/Ton PM_{10})
Based on PSEL			
IP Springfield Lime Kilns (EU455)	$3,615,422	$413,302	$43,323
Based on 2017 Actual Emissions			
IP Springfield Lime Kilns (EU455)	$3,615,422	$412,976	$52,475

The ESP upgrade is not considered cost effective because the capital cost is more than $3 million and the cost effectiveness is in excess of $40,000/ton of pollutant removed.

4.3.3 SO_2 Economic Impacts

The U.S. EPA's fact sheet on packed bed scrubbers[19] was used to develop a rough estimate of capital and annual costs for a packed bed scrubber on the CPP Halsey lime kiln. The fact sheet indicates that capital cost ranges from $11 to $55 per scfm and annual cost ranges from $17 to $78 per scfm. The flow rate from the CPP Halsey lime kiln is approximately 25,000 scfm. Using the low end of the cost ranges in the fact sheet results in a capital cost estimate of $275,000 and an annual cost estimate of $425,000 per year. Assuming the packed bed scrubber would achieve 98 percent control of the lime kiln's portion of the SO_2 PSEL of 68.4 tpy, the cost effectiveness is at least $6,340. Installing a packed bed scrubber after the venturi scrubber to achieve additional SO_2 control from periodic NCG combustion in the CPP Halsey lime kiln is not cost effective.

The wet scrubber capital cost for the IP Springfield lime kilns was estimated by scaling the recovery furnace wet scrubber cost in the BE&K report using an engineering cost scaling factor of 0.6 and the ratio of the estimated kiln exhaust flow rate to the estimated exhaust flow rate of the

[19] https://www3.epa.gov/ttncatc1/cica/files/fpack.pdf

furnace evaluated in the BE&K report. Operating costs were estimated using the factors in the OAQPS Cost Manual, Section 5, Chapter 1. Table 2-5 summarizes the estimated capital cost, annual cost, and cost effectiveness of implementing this control technology.

Table 4-5
Wet Scrubber Cost Summary

Emissions Unit Description	Capital Cost ($)	Annual Cost ($/yr)	Cost Effectiveness of Controls ($/Ton SO_2)
Based on PSEL			
IP Springfield Lime Kilns (EU-455)	$10,783,348	$2,514,180	$16,895
Based on 2017 Actual Emissions			
IP Springfield Lime Kilns (EU455)	$10,783,348	$2,508,122	$52,124

Installing a wet scrubber on the IP lime kilns is not considered cost effective as the capital cost is over $10 million and the cost effectiveness is in excess of $16,000/ton of pollutant removed.

4.3.4 Energy and Non-Air Related Impacts

This section describes the energy and non-air environmental impacts associated with each add-on control option evaluated in this report.

Additional electricity would be needed to run a new ESP or wet scrubber and it is likely that additional fan power would be required to overcome the additional pressure drop through the additional control device. Other environmental and energy impacts associated with operating a wet scrubber include water usage and generation and disposal of wastewater.

4.4 TIME NECESSARY FOR COMPLIANCE

U.S. EPA allows three years plus an optional extra year for compliance with MACT standards that require facilities to install controls after the effective date of the final standard. Although our FFA shows there are no additional controls that would be feasible, if controls are ultimately required to meet RHR requirements, facilities would need at four to five years to implement them after final EPA approval of the RHR SIP. Each facility would have to undergo substantial re-engineering (*e.g.*, due to space constraints) to accommodate new controls. Design, procurement, installation, and shakedown of these projects would easily consume three years. The facility would need to engage engineering consultants, equipment vendors, construction contractors, financial institutions, and other critical suppliers. The facility would also need to execute air permit modifications, which are often time-consuming and have an indeterminate timeline and endpoint. Lead time would be needed to procure pollution control equipment even after it is designed and a contract is finalized, and installation of controls must be aligned with mill outage schedules that are difficult to move due to the interrelationships within corporate systems, the availability of contractors, and the like. The facility would need to continue to operate as much as possible while retrofitting to meet any new requirements.

Construction would need to be staggered so only one unit was out of service at a time. Staggering work on separate units at the same facility allows some level of continued operation. However, this staggering extends the overall compliance time. Extensive outages for retrofitting must be carefully planned. Only when all the critical prerequisites for the retrofit have been lined up (*e.g.*, the engineering is complete and the control equipment is staged for immediate installation), can an owner afford to shut down a facility's equipment to install new controls. This takes planning and coordination both within the company, with the contractors, and with customers. The process to undertake a retrofitting project is complex.

4.5 REMAINING USEFUL LIFE OF EXISTING AFFECTED SOURCES

The emissions units included in this FFA are assumed to have a remaining useful life of twenty years or more.

4.6 CONCLUSION

Based on the FFA presented above, no additional controls were determined to be cost effective for lime kilns at NWPPA member mills.

5. EVALUATION OF ADDITIONAL SOURCES

The boilers, recovery furnaces, and lime kilns evaluated in Sections 2 through 4 make up the vast majority of the actual PM_{10}, NO_X, and SO_2 emissions from the four mills addressed in this report. However, this section also evaluates whether additional emissions controls are feasible for the remaining significant sources of PM_{10}, NO_X, and SO_2 emissions at the mills.

Lime slakers emit small amounts of PM_{10} and are already controlled with wet scrubbers. There are no further controls to evaluate.

Each mill has paved and unpaved roads with the potential to emit some fugitive PM_{10}. Paved roads are swept, unpaved roads may be watered as needed, and a low facility-wide speed limit reduces the potential for emissions of road dust. Each mill's Title V permit requires fugitive emissions to be minimized to prevent offsite deposition. Fugitive emissions from paved and unpaved roads are a small portion of a site's actual PM_{10} emissions and are not likely to affect visibility in a Class I area, as any road dust emissions are not likely to travel much further than the facility boundary. No further controls are feasible or warranted for purposes of the regional haze SIP.

The following sections evaluate whether further controls are feasible for:

- Smelt Dissolving Tanks
- Paper Machines and Pulp Dryers
- Material Handling

5.1 SMELT DISSOLVING TANKS

All smelt dissolving tanks covered by this report are controlled with wet scrubbers and are subject to a MACT standard at 40 CFR Part 63, Subpart MM that limits PM emissions. The U.S. EPA declined to increase the stringency of either the MACT or the NSPS PM limit for smelt dissolving tanks when it recently reviewed both standards, based primarily on high cost of additional control. Smelt dissolving tank emissions of NO_X and SO_2 are based on NCASI emissions data that ranges from non-detect to low, and these emissions are likely a result of either carryover from the recovery furnace or smelt/water interactions. The NO_X and SO_2 emissions are not significant enough to warrant controls and the PM emissions already meet MACT based on use of a wet scrubber. However, for completeness, a cost evaluation for PM_{10} was performed.

The cost of installing a replacement wet scrubber to improve PM_{10} control was evaluated. The equipment cost is based on the document titled "Emission Control Study – Technology Cost Estimates" by BE&K Engineering for AF&PA, September 2001. Section 10.4 presents the costs associated with replacing the wet scrubber on a smelt dissolving tank serving a recovery furnace burning 3.7 million pounds of BLS per day. The base equipment cost was scaled from 2001 dollars to 2019 dollars using the CEPCI. The base equipment cost was also scaled to each mill's smelt dissolving tank using an engineering cost scaling factor of 0.6 and the ratio of each mill's recovery furnace throughput to the furnace throughput evaluated in the BE&K report. Operating costs were estimated using the factors in the OAQPS Cost Manual, Section 6, Chapter 2. No increase in labor and maintenance cost was estimated. The cost effectiveness was estimated based on a 50% reduction in each smelt dissolving tank's assigned portion of the PM_{10} PSEL, which is the approximate difference between the new and existing source MACT PM limits for smelt dissolving tanks. The cost effectiveness based on a reduction in 2017 actual emissions was also evaluated, since 2017 actual emissions are more representative of emissions during the 2021-2028 planning period than PSELs in many cases.

Table 5-1 summarizes the estimated capital cost, annual cost, and cost effectiveness of implementing this control technology.

Table 5-1
Scrubber Upgrade Cost Summary

Emissions Unit Description	Capital Cost ($)	Annual Cost ($/yr)	Cost Effectiveness of Controls ($/Ton PM_{10})
Based on PSEL			
CPP Halsey Smelt Dissolving Tank (SDTEU)	$2,154,144	$410,489	$33,647
GP Toledo No. 1 Smelt Dissolving Tank (EU 15)	$1,468,893	$261,432	$23,985
GP Toledo No. 2 Smelt Dissolving Tank (EU 17)	$1,468,893	$261,432	$34,858
GP Wauna Smelt Dissolving Tank (EU25)	$2,566,839	$506,897	$13,410
IP Springfield Smelt Dissolving Tank (EU-445D)	$2,517,292	$444,727	$20,978
Based on 2017 Actual Emissions			
CPP Halsey Smelt Dissolving Tank (SDTEU)	$2,154,144	$406,974	$37,858
GP Toledo No. 1 Smelt Dissolving Tank (EU 15)	$1,468,893	$256,855	$27,037
GP Toledo No. 2 Smelt Dissolving Tank (EU 17)	$1,468,893	$257,370	$39,293
GP Wauna Smelt Dissolving Tank (EU25)	$2,566,839	$493,399	$17,117
IP Springfield Smelt Dissolving Tank (EU-445D)	$2,517,292	$441,113	$25,228

Replacing a wet scrubber on a smelt dissolving tank with a more efficient scrubber is not considered cost effective because the cost effectiveness is in excess of $13,000/ton of pollutant removed.

5.2 PAPER MACHINES AND PULP DRYERS

Paper machines and pulp dryers consist of the wet end and the dry end and the combined equipment can be the length of a football field and have many different exhaust points through roof vents or building exhausts. On the wet end, pulp is combined with additives and diluted with water at the head box, applied to the former or wire, where it forms a sheet as the water drains, and then travels to the press and dryer sections (dry end) to remove the remaining water. The paper machines at GP Toledo and IP Springfield and the pulp dryer at CPP Halsey are steam heated and do not have emissions of NO_X or SO_2.

Concentrations of PM are very low in each paper machine vent, as discussed in NCASI Technical Bulletin No. 942, "Measurement of PM, PM_{10}, $PM_{2.5}$ and CPM Emissions from Paper Machine Sources," November 2007 (updated February 2017). PM emissions include both filterable (FPM) and CPM, with the FPM coming primarily from the pulp fibers and the CPM resulting from organics. Limited NCASI test data indicate that the FPM concentrations for paper machine vents average less than 0.0004 gr/dscf at each vent (not including tissue machine vents). There are no known control technologies that would remove particulate matter at such a low concentration. It is expected that pulp dryer vent concentrations would be similarly low or lower because the sheet of pulp is thicker and typically has a higher moisture content than paper. BACT analyses for paper machines and pulp dryers routinely indicate that add-on controls are not feasible.

GP Wauna's towel and tissue machines include fuel burning sources and wet controls to limit PM_{10} emissions. Tissue machines are configured differently than traditional paper machines and pulp dryers and their PM emissions are higher in most cases. GP Wauna has performed an evaluation of whether additional controls are feasible and is submitting the evaluation as an attachment to their cover letter transmitting this report.

5.3 PM_{10} EMISSIONS FROM MATERIAL HANDLING SOURCES

Table 5-2 shows the material handling type sources that emit PM_{10} at each mill. The current PM_{10} control technique, assigned portion of the PM_{10} PSEL, and additional control evaluated are shown.

Note that IP Springfield has eliminated the New Fiber Line emission unit (EU-402), which had a PM_{10} PSEL of 427 tpy, so this unit is not evaluated here.

If a material handling source is already controlled with a baghouse, no additional controls were evaluated. If emissions of PM_{10} from a source are 5 tpy or less, no further controls would be cost effective. For example, assuming based on a U.S. EPA fabric filter fact sheet[20], that the annual cost of a fabric filter is $10/scfm and if the flow rate from a currently uncontrolled source is only 10,000 scfm, the cost to apply a fabric filter to any source that emits 5 tpy or less of PM_{10} is at least $20,000/ton of PM_{10} reduced, which is not cost effective.

Data on PM_{10} emissions from sources such as chip and bark handling are fairly limited and have historically been calculated using very conservative agency emissions estimation techniques such as AP-42 equations for drop points and wind erosion that were developed using characteristics of other materials such as sand, aggregate, and coal, which have moisture contents much lower and silt contents much higher than chips and bark. NCASI developed Special Report 15-01, "Estimating the Potential for $PM_{2.5}$ Emissions from Wood and Bark Handling," in 2015. The study determined that PM_{10} fractions were less than 1.5 pounds of PM_{10} per million pounds of bark or chips and less than 3 percent of total suspended PM. Potential filterable PM_{10} emission factors developed as a result of the NCASI study are much lower than emission factors historically used, so actual PM_{10} emissions from chip and wood handling are likely much lower than PSEL emissions.

[20] https://www3.epa.gov/ttn/catc/dir1/ff-revar.pdf

Table 5-2
Material Handling Sources

Emissions Unit Description	PM_{10} Control Technique	PM_{10} PSEL, tpy	Additional PM_{10} Control Evaluated
CPP Halsey Lime Storage (LSTEU) Reburned Lime Storage Purchased Lime Storage Reburned Lime Conveyor Reburned Lime Crusher	Baghouses on reburned and purchased lime storage Reburned lime conveyor is enclosed	2.5	None, already well controlled.
CPP Halsey New Chip Handling (NCHEU) Pre-steamer surge bins Shavings shredder	Surge bins – none Shredder – enclosure	7.6	At a flow rate of 18,544 acfm total from the three surge bins, no further control would be cost effective (>$20,000/ton).
CPP Halsey Old Chip Handling (OCHEU) Two blow lines with cyclones to surge bins to feed digesters	None	19.1	At a flow rate of 19,328 acfm total from both cyclones, a baghouse would not be cost effective at >$10,000/ton.
CPP Halsey Storage Piles (SPEU)	Management of fugitive emissions	2.4	No additional control would be cost effective.
CPP Halsey Fiber Receiving (FREU)	Baghouse on sawdust truck dump	3.5	None, already well controlled.
GP Toledo Hardwood Transfer Cyclone (EU 118)	None	49.2 (based on factors in AQ-EF02 and AQ-EF03 forms)	At an estimated flow rate of 25,000 acfm, a baghouse would not be cost effective at >$5,000/ton. Actual emissions are approximately half the PSEL, which would increase the cost to about $10,000/ton.
GP Toledo Wood Storage Piles (EU 132)	Management of fugitive emissions	1.7	No additional control would be cost effective.
GP Toledo Advanced Material Recycling System (EU 144, 145)	None	5.6	At a flow rate of 30,000 scfm, a baghouse would not be cost effective at >$50,000/ton.
GP Wauna Limestone Silo, Limestone Daybin, Ash Silo Transfer Receiver, Ash Silo Bin, Sand Silo (EU37a)	Baghouses	2.8	None, already well controlled.
GP Wauna Converting (EU37b)	Scrubbers and baghouse	26.5	None, already well controlled.
GP Wauna Chip and Bark Storage Piles (EU44)	Management of fugitive emissions	5.7	No additional control would be cost effective.

Emissions Unit Description	PM_{10} Control Technique	PM_{10} PSEL, tpy	Additional PM_{10} Control Evaluated
GP Wauna Fugitive Chip Unloading (EU47)	Management of fugitive emissions	1.8	No additional control would be cost effective.
GP Wauna Chip Screen Room (EU50)	None	7.5	At a flow rate of 28,630 scfm, a baghouse would not be cost effective at >$30,000/ton.
GP Wauna Chip Storage Silo (EU51)	None	36.4	At a flow rate of 138,356 scfm, a baghouse would not be cost effective at >$30,000/ton.
GP Wauna Kraft Mill Cyclone (EU52)	None	1.9	At a flow rate of 7329 scfm, a baghouse would not be cost effective at >$40,000/ton.
GP Wauna Chip Mill (EU55)	Enclosures, management of fugitive emissions	1.8	No additional control would be cost effective.
IP Springfield Chip Handling (EU-310)	Management of fugitive emissions	1.11	No additional control would be cost effective.
IP Springfield Chip Storage (EU-320)	Management of fugitive emissions	0.8	No additional control would be cost effective.
IP Springfield Fines Storage (EU-330)	Management of fugitive emissions	0.5	No additional control would be cost effective.

6. SUMMARY OF FINDINGS

The emission sources at the NWPPA Oregon pulp and paper mills evaluated in this report are already well-controlled and are subject to various stringent emission limits. However, in response to a request from DEQ, the mills worked together with NWPPA to evaluate whether additional emissions controls for SO_2, NO_X, and PM_{10} are feasible for significant emissions units.

As part of the FFA, the following information was reviewed: site-specific emissions and controls information, industry- and site-specific cost data, publicly-available cost data, previous similar control evaluations, the U.S. EPA RBLC database, and U.S. EPA's OAQPS Control Cost Manual. The best information available in the time allotted to perform the analyses was used.

Our review of the best available information indicates that additional emissions controls for SO_2, NO_X, and PM_{10} are either not feasible or not cost effective. Any determination that additional controls are feasible would need to be justified based on a more detailed evaluation that fully considers site-specific factors. In addition, it is important to note the following points:

- Pulp and paper mill significant emissions units are already well controlled.
- The recovery furnaces, smelt dissolving tanks, and lime kilns included in the FFA are subject to recently reviewed MACT emission limits that directly limit emissions of PM_{10}.
- The boilers included in the FFA are subject to Boiler MACT emission limits and work practices that became effective in 2013 with a 2016 compliance date. The required tune ups serve to ensure good combustion practices (indirectly limiting emissions of all pollutants) and the rule allows gas 1 subcategory boilers to burn fuel oil only during periods of gas curtailment or gas supply interruption, serving to limit PM_{10} and SO_2 emissions from fuel oil.
- U.S. EPA will continue the required process to evaluate PM and acid gas control technology improvements for the industrial boiler source category with its upcoming periodic technology review for NESHAP Subpart DDDDD sources.

- U.S. EPA determined in its CSAPR rulemaking that additional NO_X controls on non-EGU combustion units are not cost effective.

APPENDIX A - CONTROL COST ESTIMATES

Table A-1

GP Wauna Fluidized Bed Boiler

Capital and Annual Costs Associated with Trona Injection

Variable	Designation	Units	Value	Calculation
Unit Size	A	MW	18	200 MMBtu/hr, assumes 30% efficiency to convert to equivalent MW output
Retrofit Factor	B	-	1	
Gross Heat Rate	C	Btu/kWh	37,944	Assumes 30% efficiency
SO_2 Rate (uncontrolled)	D	lb/MMBtu	0.1	Based on 50 ppm permit limit
Type of Coal	E	-		
Particulate Capture	F	-	Fabric filter	
Sorbent	G	-	Milled Trona	
Removal Target	H	%	90	Per the Sargent and Lundy document, 90% reduction can be achieved using milled trona with a fabric filter.
Heat Input	J	Btu/hr	2.00E+08	200 MMBtu/hr
NSR	K	-	2.61	Milled Trona w/ FF = 0.208e^(0.0281*H)
Sorbent Feed Rate	M	ton/hr	0.21	Trona = (1.2011*10^-06)*K*A*C*D
Estimated HCl Removal	V	%	98.85	Milled or Unmilled Trona w/ FF = 84.598*H^0.0346
Sorbent Waste Rate	N	ton/hr	0.17	Trona = (0.7387+0.00185*H/K)*M
Fly Ash Waste Rate	P	ton/hr	2.90	Ash in Bark = 0.05; Boiler Ash Removal = 0.2; HHV = 4600 (A*C)*Ash*(1-Boiler Ash Removal)/(2*HHV)
Aux Power	Q	%	0.24	Milled Trona M*20/A
Sorbent Cost	R	$/ton	170	Default value in report
Waste Disposal Cost	S	$/ton	50	Default value for disposal with fly ash
Aux Power Cost	T	$/kWh	0.06	Default value in report
Operating Labor Rate	U	$/hr	31	Typical labor cost

SO_2 Control Efficiency:	90%
PSEL, tpy	27.6
Controlled SO_2 Emissions:	24.8

Capital Costs					
Direct Costs					
BM (Base Module) scaled to 2019 dollars		$	$	5,966,395	Milled Trona if(M>25, 820000*B*M, 8300000*B*(M^0.284))
Indirect Costs					
Engineering & Construction Management	A1	$	$	596,640	10% BM
Labor adjustment	A2	$	$	298,320	5% BM
Contractor profit and fees	A3	$	$	298,320	5% BM
Capital, engineering and construction cost subtotal	CECC	$	$	7,159,674	BM+A1+A2+A3
Owner costs including all "home office" costs	B1	$	$	357,984	5% CEC
Total project cost w/out AFUDC	TPC	$	$	7,517,658	B1+CEC
AFUDC (0 for <1 year engineering and construction cycle)	B2	$		0	0% of (CECC+B1)
Total Capital Investment	**TCI**	**$**	**$**	**7,517,658**	CECC+B1+B2

Annualized Costs					
Fixed O&M Cost					
Additional operating labor costs	FOMO	$	$	128,960	(2 additional operator)*2080*U
Additional maintenance material and labor costs	FOMM	$	$	59,664	BM*0.01/B
Additional administrative labor costs	FOMA	$	$	4,585	0.03*(FOMO+0.4*FOMM)
Total Fixed O&M Costs	**FOM**	**$**	**$**	**193,209**	FOMO+FOMM+FOMA
Variable O&M Cost					
Cost for Sorbent	VOMR	$	$	311,053	M*R
Cost for waste disposal that includes both sorbent & fly ash waste not removed prior to sorbent injection	VOMW	$	$	1,342,986	(N+P)*S
Additional auxiliary power required	VOMP	$	$	31,042	Q*T*10*ton SO_2
Total Variable O&M Cost	**VOM**	**$**	**$**	**1,685,081**	VOMR+VOMW+VOMP
Indirect Annual Costs					
General and Administrative	2%	of TCI	$	150,353	
Property Tax	1%	of TCI	$	75,177	
Insurance	1%	of TCI	$	75,177	
Capital Recovery	7.86%	x TCI	$	590,516	
Total Indirect Annual Costs			**$**	**891,222**	
Life of the Control:		20 years		4.75%	interest
Total Annual Costs			**$**	**2,769,512**	
Total Annual Costs/SO_2 Emissions			**$**	**111,494**	

[(a)]Cost information based on the April 2017 "Dry Sorbent Injection for SO_2/HCl Control Cost Development Methodology" study by Sargent & Lundy for a milled Trona system. 2016 costs scaled to 2019 costs using the CEPCI.

Table A-1a
GP Wauna Fluidized Bed Boiler
Capital and Annual Costs Associated with Trona Injection

Variable	Designation	Units	Value	Calculation
Unit Size	A	MW	18	200 MMBtu/hr, assumes 30% efficiency to convert to equivalent MW output
Retrofit Factor	B	-	1	
Gross Heat Rate	C	Btu/kWh	37,944	Assumes 30% efficiency
SO_2 Rate (uncontrolled)	D	lb/MMBtu	0.1	Based on 50 ppm permit limit
Type of Coal	E	-		
Particulate Capture	F	-	Fabric filter	
Sorbent	G	-	Milled Trona	
Removal Target	H	%	90	Per the Sargent and Lundy document, 90% reduction can be achieved using milled trona with a fabric filter.
Heat Input	J	Btu/hr	2.00E+08	200 MMBtu/hr
NSR	K	-	2.61	Milled Trona w/ FF = 0.208e^(0.0281*H)
Sorbent Feed Rate	M	ton/hr	0.21	Trona = (1.2011*10^-06)*K*A*C*D
Estimated HCl Removal	V	%	98.85	Milled or Unmilled Trona w/ FF = 84.598*H^0.0346
Sorbent Waste Rate	N	ton/hr	0.17	Trona = (0.7387+0.00185*H/K)*M
Fly Ash Waste Rate	P	ton/hr	2.90	Ash in Bark = 0.05; Boiler Ash Removal = 0.2; HHV = 4600 (A*C)*Ash*(1-Boiler Ash Removal)/(2*HHV)
Aux Power	Q	%	0.24	Milled Trona M*20/A
Sorbent Cost	R	$/ton	170	Default value in report
Waste Disposal Cost	S	$/ton	50	Default value for disposal with fly ash
Aux Power Cost	T	$/kWh	0.06	Default value in report
Operating Labor Rate	U	$/hr	31	Typical labor cost

SO_2 Control Efficiency:	90%
2017 Actual Emissions, tpy	25.1
Controlled SO_2 Emissions:	22.6

Capital Costs				
Direct Costs				
BM (Base Module) scaled to 2019 dollars		$	$ 5,966,395	Milled Trona if(M>25, 820000*B*M, 8300000*B*(M^0.284))
Indirect Costs				
Engineering & Construction Management	A1	$	$ 596,640	10% BM
Labor adjustment	A2	$	$ 298,320	5% BM
Contractor profit and fees	A3	$	$ 298,320	5% BM
Capital, engineering and construction cost subtotal	CECC	$	$ 7,159,674	BM+A1+A2+A3
Owner costs including all "home office" costs	B1	$	$ 357,984	5% CEC
Total project cost w/out AFUDC	TPC	$	$ 7,517,658	B1+CEC
AFUDC (0 for <1 year engineering and construction cycle)	B2	$	0	0% of (CECC+B1)
Total Capital Investment	**TCI**	**$**	**$ 7,517,658**	CECC+B1+B2

Annualized Costs					
Fixed O&M Cost					
Additional operating labor costs	FOMO	$	$	128,960	(2 additional operator)*2080*U
Additional maintenance material and labor costs	FOMM	$	$	59,664	BM*0.01/B
Additional administrative labor costs	FOMA	$	$	4,585	0.03*(FOMO+0.4*FOMM)
Total Fixed O&M Costs	**FOM**	**$**	**$**	**193,209**	FOMO+FOMM+FOMA
Variable O&M Cost					
Cost for Sorbent	VOMR	$	$	311,053	M*R
Cost for waste disposal that includes both sorbent & fly ash waste not removed prior to sorbent injection	VOMW	$	$	1,342,986	(N+P)*S
Additional auxiliary power required	VOMP	$	$	28,230	Q*T*10*ton SO_2
Total Variable O&M Cost	**VOM**	**$**	**$**	**1,682,270**	VOMR+VOMW+VOMP
Indirect Annual Costs					
General and Administrative	2%	of TCI	$	150,353	
Property Tax	1%	of TCI	$	75,177	
Insurance	1%	of TCI	$	75,177	
Capital Recovery	7.86%	x TCI	$	590,516	
Total Indirect Annual Costs			**$**	**891,222**	
Life of the Control:		20 years		4.75%	interest
Total Annual Costs			**$**	**2,766,700**	
Total Annual Costs/SO_2 Emissions			**$**	**122,475**	

[(a)]Cost information based on the April 2017 "Dry Sorbent Injection for SO_2/HCl Control Cost Development Methodology" study by Sargent & Lundy for a milled Trona system. 2016 costs scaled to 2019 costs using the CEPCI.

Table A-7
Low NOx Burner/FGR Retrofit - GP Wauna Power Boiler

CAPITAL COSTS				
	COST ITEM	FACTOR		COST ($)
Costs to Purchase and Install Equipment				
(a)	LNB and FGR Retrofit cost for 120kpph/150 MMBtu/hr boiler adjusted for 560 MMBtu/hr boiler and 2019 dollars			***$4,099,131***
(b)	Instrumentation	0.10 × A		***$409,913***
(b)	Sales Tax	0.03 × A		***$122,974***
(b)	Freight	0.05 × A		***$204,957***
	Total Purchased Equipment Cost, B =	B		***$4,836,975***
	Total Direct Cost:		***TDC***	***$4,836,975***
Indirect Capital Costs				
(c)	Engineering	0.10 × B		***$483,697***
(c)	Contingencies	0.20 × B		***$967,395***
(c)	General Facilities	0.05 × B		***$241,849***
(b)	Testing	0.01 × B		***$48,370***
	Total Indirect Cost:		***TIC***	***$1,741,311***
	Total Capital Investment:		***TCI***	***$6,578,285***

ANNUALIZED COSTS				
	COST ITEM	COST FACTOR	UNIT COST	COST ($)
Annual Operating Costs - Direct Annual Costs				
(d)	Maintenance Costs	2.75% of TCI		***$180,903***
Utilities				
(a)	Electricity	657 kW	$0.060 per kWh	***$345,354***
	Total Direct Annual Costs:		***DAC***	***$526,257***
Annual Operating Costs - Indirect Annual Costs				
(b)	Overhead	60% of sum of operating & maintenance costs		***$108,542***
(b)	Administrative Charges	2% of TCI		***$131,566***
(b)	Property Taxes	1% of TCI		***$65,783***
(b)	Insurance	1% of TCI		***$65,783***
	Total Indirect Annual Costs:		***IDAC***	***$371,673***
	Total Annual Costs:		***TAC***	***$897,930***
Cost Effectiveness				
(b)	Expected lifetime of equipment, years	10		
(b)	Interest rate, %/yr	4.75%		
(b)	Capital recovery factor	0.128		
(b)	Total Capital Investment Cost	$6,578,285		
	Annualized Capital Investment Cost:			***$841,606***
	Total Annualized Cost:			***$1,739,536***
(e)	NO_X Reduction	64%		
(f)	Pre-retrofit NO_X	591.2 tons NO_X/yr		
	Post-retrofit NO_X using LNB	212.83 tons NO_X/yr		
	NO_X Removed	378.4 tons NO_X/yr		
	Annual Cost/Ton Removed:			***$4,597***

(a) Cost information obtained from Section 4.4 in document titled "Emission Control Study - Technology Cost Estimates" by BE&K Engineering for AF&PA, September 2001. The labor and equipment cost of installing LNB, FGR, new fan on a gas-fired boiler was scaled based on boiler capacity. The cost was adjusted from 2001 dollars to 2019 dollars using the Chemical Engineering Plant Cost Index (CEPCI). Electricity requirement ratioed based on boiler size.

(b) Cost information estimated using the U.S. EPA Air Pollution Control Cost Manual (6th edition) published in January 2002 by the OAQPS (Section 3.2, Chapter 2, "Thermal and Catalytic Incinerators"). The website for the manual is available at http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf.

(c) Indirect capital cost factors (i.e., engineering and office fees, contingencies, and general facilities) based on guidance from "Methods for Evaluating the Costs of Utility NO_X Control Technologies," Loan K. Tran and H. Christopher Frey, June 1996.

(d) Maintenance costs were estimated based on the U.S. EPA OAQPS Alternative Control Techniques Document - NO_X Emissions from Process Heaters (Revised), Document No. EPA-453/R-93-034 (September 1993).

(e) Control efficiency based on comparison of uncontrolled and controlled AP-42 factors.

(f) PSEL

Table A-7a

Low NOx Burner/FGR Retrofit - GP Wauna Power Boiler

CAPITAL COSTS				
	COST ITEM	**FACTOR**		**COST ($)**
Costs to Purchase and Install Equipment				
(a)	LNB and FGR Retrofit cost for 120kpph/150 MMBtu/hr boiler adjusted for 560 MMBtu/hr boiler and 2019 dollars			***$4,099,131***
(b)	Instrumentation	0.10 × A		***$409,913***
(b)	Sales Tax	0.03 × A		***$122,974***
(b)	Freight	0.05 × A		***$204,957***
	Total Purchased Equipment Cost, B =	B		***$4,836,975***
	Total Direct Cost:		***TDC***	***$4,836,975***
Indirect Capital Costs				
(c)	Engineering	0.10 × B		***$483,697***
(c)	Contingencies	0.20 × B		***$967,395***
(c)	General Facilities	0.05 × B		***$241,849***
(b)	Testing	0.01 × B		***$48,370***
	Total Indirect Cost:		***TIC***	***$1,741,311***
	Total Capital Investment:		***TCI***	***$6,578,285***

ANNUALIZED COSTS				
	COST ITEM	**COST FACTOR**	**UNIT COST**	**COST ($)**
Annual Operating Costs - Direct Annual Costs				
(d)	Maintenance Costs	2.75% of TCI		***$180,903***
Utilities				
(a)	Electricity	657 kW	$0.060 per kWh	***$172,677***
	Total Direct Annual Costs:		***DAC***	***$353,580***
Annual Operating Costs - Indirect Annual Costs				
(b)	Overhead	60% of sum of operating & maintenance costs		***$108,542***
(b)	Administrative Charges	2% of TCI		***$131,566***
(b)	Property Taxes	1% of TCI		***$65,783***
(b)	Insurance	1% of TCI		***$65,783***
	Total Indirect Annual Costs:		***IDAC***	***$371,673***
	Total Annual Costs:		***TAC***	***$725,253***
Cost Effectiveness				
(b)	Expected lifetime of equipment, years	10		
(b)	Interest rate, %/yr	4.75%		
(b)	Capital recovery factor	0.128		
(b)	Total Capital Investment Cost	$6,578,285		
	Annualized Capital Investment Cost:			***$841,606***
	Total Annualized Cost:			***$1,566,859***
(e)	NO_X Reduction	64%		
(f)	Pre-retrofit NO_X	265.5 tons NO_X/yr		
	Post-retrofit NO_X using LNB	95.57 tons NO_X/yr		
	NO_X Removed	169.9 tons NO_X/yr		
	Annual Cost/Ton Removed:			***$9,223***

(a) Cost information obtained from Section 4.4 in document titled "Emission Control Study - Technology Cost Estimates" by BE&K Engineering for AF&PA, September 2001. The labor and equipment cost of installing LNB, FGR, new fan on a gas-fired boiler was scaled based on boiler capacity. The cost was adjusted from 2001 dollars to 2019 dollars using the Chemical Engineering Plant Cost Index (CEPCI). Electricity requirement ratioed based on boiler size.

(b) Cost information estimated using the U.S. EPA Air Pollution Control Cost Manual (6th edition) published in January 2002 by the OAQPS (Section 3.2, Chapter 2, "Thermal and Catalytic Incinerators"). The website for the manual is available at http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf.

(c) Indirect capital cost factors (i.e., engineering and office fees, contingencies, and general facilities) based on guidance from "Methods for Evaluating the Costs of Utility NO_X Control Technologies," Loan K. Tran and H. Christopher Frey, June 1996.

(d) Maintenance costs were estimated based on the U.S. EPA OAQPS Alternative Control Techniques Document - NO_X Emissions from Process Heaters (Revised), Document No. EPA-453/R-93-034 (September 1993).

(e) Control efficiency based on comparison of uncontrolled and controlled AP-42 factors.

(f) 2017 Actual Emissions

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

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

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.5

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

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 560 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,050 Btu/scf

What is the estimated actual annual fuel consumption? 3,360,897,773 scf/Year

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) 8.2 MMBtu/MW

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

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

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): percent by weight

Not applicable to units buring fuel oil or natural gas

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

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

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

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	365	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.341	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.187	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	1.82	

Plant Elevation	20	Feet above sea level

Concentration of reagent as stored (C_{stored})	29	Percent
Density of reagent as stored (ρ_{stored})	56	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years

Densities of typical SNCR reagents:		
50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Select the reagent used: Ammonia

(The Wauna FBB uses ammonia in its SNCR system)

Enter the cost data for the proposed SNCR:

Desired dollar-year	2019			
CEPCI for 2019	607.5	Enter the CEPCI value for 2019	541.7	2016 CEPCI
Annual Interest Rate (i)	4.75	Percent		
Fuel ($Cost_{fuel}$)	5.00	$/MMBtu		
Reagent ($Cost_{reag}$)	3.53	$/gallon for a 29 percent solution of ammonia		
Water ($Cost_{water}$)	0.0042	$/gallon*		
Electricity ($Cost_{elect}$)	0.0676	$/kWh*		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		$/ton		

CEPCI = Chemical Engineering Plant Cost Index

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

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

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon of 29% Ammonia	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	Representative Pacific NW Mill cost for aqueous ammonia. 0.47/lb * 56 lb/ft3 * 0.134 ft3/gal = $3.53/gal
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Fuel Cost ($/MMBtu)	2.87	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	EIA.gov Oregon representative industrial natural gas price of $5/MMBtu used.
Ash Disposal Cost ($/ton)	-	Not applicable	Not Applicable
Percent sulfur content for Coal (% weight)	-	Not applicable	Not Applicable
Percent ash content for Coal (% weight)	-	Not applicable	Not Applicable
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	1028 is basis of PSEL calcs
Interest Rate (%)	5.5	Default bank prime rate	4.75 used, pre-COVID prime rate

SNCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	560	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	4,672,000,000	scf/Year	
Actual Annual fuel consumption (Mactual) =		3,360,897,773	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.72	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	8760	hours	Based on 8760 (PTE)
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	45	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	85.83	lb/hour	
Total NO_x removed per year =	$(NOx_{in}$ x EF x Q_B x $t_{op})/2000$ =	266.04	tons/year	Based on PSEL of 591.2
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)			Not applicable; factor applies only to coal-fired boilers
SO_2 Emission rate =	$(\%S/100)x(64/32)*(1x10^6)/HHV$ =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at 20 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

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

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in}$ x Q_B x NSR x $MW_R)/(MW_{NOx}$ x SR) = (whre SR = 1 for NH_3; 2 for Urea)	129	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	444	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	59.3	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	20,000	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

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

Parameter	Equation	Calculated Value	Units	
Electricity Usage: Electricity Consumption (P) =	(0.47 x NOx_{in} x NSR x Q_B)/NPHR =	19.9	kW/hour	
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	101	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	1.04	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x $1x10^6$)/HHV =	0.0	lb/hour	Not applicable - Ash disposal cost applies only to coal-fired boilers

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

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

For Fuel Oil and Natural Gas-Fired Boilers:

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

Capital costs for the SNCR ($SNCR_{cost}$) =	$1,341,019 in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0 in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$2,463,992 in 2019 dollars
Total Capital Investment (TCI) =	$4,946,514 in 2019 dollars

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

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

SNCR Capital Costs ($SNCR_{cost}$) =	$1,341,019 in 2019 dollars

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

For Coal-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2019 dollars

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

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320,000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213,000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320,000 \times (0.1 \times Q_B)^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213,000 \times (Q_B/NPHR)^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$2,463,992 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,968,820	in 2019 dollars
Indirect Annual Costs (IDAC) =	$391,022	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$2,359,842	in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$74,198	in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$1,833,407	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$11,814	in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$3,695	in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$45,707	in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0	in 2019 dollars
Direct Annual Cost =		$1,968,820	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$2,226	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$388,796	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$391,022	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$2,359,842	per year in 2019 dollars
NOx Removed =	266	tons/year
Cost Effectiveness =	$8,870	per ton of NOx removed in 2019 dollars

Table A-15a - SNCR for GP Wauna Power Boiler

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

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

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.5

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

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 560 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,050 Btu/scf

What is the estimated actual annual fuel consumption? 1,087,930,476 scf/Year

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) 8.2 MMBtu/MW

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

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

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): percent by weight

Not applicable to units buring fuel oil or natural gas

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

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

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

Table A-15a - SNCR for GP Wauna Power Boiler

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	183	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.465	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.256	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	1.58	
Concentration of reagent as stored (C_{stored})	29	Percent
Density of reagent as stored (ρ_{stored})	56	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years
Select the reagent used	Ammonia	

(The Wauna FBB uses ammonia in its SNCR system)

Plant Elevation	20	Feet above sea level

Densities of typical SNCR reagents:

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

Enter the cost data for the proposed SNCR:

Desired dollar-year	2019			
CEPCI for 2019	607.5	Enter the CEPCI value for 2019	541.7	2016 CEPCI
Annual Interest Rate (i)	4.75	Percent		
Fuel ($Cost_{fuel}$)	5.00	$/MMBtu		
Reagent ($Cost_{reag}$)	3.53	$/gallon for a 29 percent solution of ammonia		
Water ($Cost_{water}$)	0.0042	$/gallon*		
Electricity ($Cost_{elect}$)	0.0676	$/kWh*		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		$/ton		

CEPCI = Chemical Engineering Plant Cost Index

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

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

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Table A-15a - SNCR for GP Wauna Power Boiler

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon of 29% Ammonia	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	Representative Pacific NW Mill cost for aqueous ammonia. 0.47/lb * 56 lb/ft3 * 0.134 ft3/gal = $3.53/gal
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Fuel Cost ($/MMBtu)	2.87	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	EIA.gov Oregon representative industrial natural gas price of $5/MMBtu used.
Ash Disposal Cost ($/ton)	-	Not applicable	Not Applicable
Percent sulfur content for Coal (% weight)	-	Not applicable	Not Applicable
Percent ash content for Coal (% weight)	-	Not applicable	Not Applicable
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	1028 is basis of PSEL calcs
Interest Rate (%)	5.5	Default bank prime rate	4.75 used, pre-COVID prime rate

SNCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	560	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	4,672,000,000	scf/Year	
Actual Annual fuel consumption (Mactual) =		1,087,930,476	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.12	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	4392	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	45	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	117.12	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	119.46	tons/year	Based on 2017 Actual Emissions
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)			Not applicable; factor applies only to coal-fired boilers
SO_2 Emission rate =	(%S/100)x(64/32)*($1x10^6$)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at 20 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

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

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x NSR x MW_R)/(MW_{NOx} x SR) = (whre SR = 1 for NH_3; 2 for Urea)	152	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/C_{sol} =	524	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	70.0	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	23,600	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

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

Parameter	Equation	Calculated Value	Units	
Electricity Usage: Electricity Consumption (P) =	(0.47 x NOx_{in} x NSR x Q_B)/NPHR =	23.5	kW/hour	
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	119	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	1.23	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x $1x10^6$)/HHV =	0.0	lb/hour	Not applicable - Ash disposal cost applies only to coal-fired boilers

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

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

For Fuel Oil and Natural Gas-Fired Boilers:

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

Capital costs for the SNCR ($SNCR_{cost}$) =	$1,341,019	in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$2,557,635	in 2019 dollars
Total Capital Investment (TCI) =	$5,068,250	in 2019 dollars

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

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

SNCR Capital Costs ($SNCR_{cost}$) =	$1,341,019	in 2019 dollars

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

For Coal-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

Air Pre-Heater Costs (APH_{cost}) =	$0	in 2019 dollars

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

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$2,557,635	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,196,724	in 2019 dollars
Indirect Annual Costs (IDAC) =	$400,645	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$1,597,370	in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$76,024	in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$1,084,491	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$6,988	in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$2,186	in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$27,036	in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0	in 2019 dollars
Direct Annual Cost =		$1,196,724	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$2,281	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$398,364	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$400,645	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,597,370	per year in 2019 dollars
NOx Removed =	119	tons/year
Cost Effectiveness =	$13,372	per ton of NOx removed in 2019 dollars

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

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

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

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

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	560	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,050	Btu/scf
What is the estimated actual annual fuel consumption?	3,306,483,238	scf/Year
Enter the net plant heat input rate (NPHR)	8.2	MMBtu/MW

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

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

Plant Elevation	20	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

Not applicable to units buring fuel oil or natural gas

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

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

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

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

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.341	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.034	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	25	Years*

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

Gas temperature at the SCR inlet (T)	650	^{o}F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	431	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:		
50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2019		
CEPCI for 2019	607.5	Enter the CEPCI value for 2019 — 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	4.75	Percent	
Reagent ($Cost_{reag}$)	3.53	$/gallon for 29% ammonia	
Electricity ($Cost_{elect}$)	0.0676	$/kWh	* $0.0676/kWh is a default value for electrity cost. User should enter actual value, if known.
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	Representative Pacific NW Mill cost for aqueous ammonia. 0.47/lb * 56 lb/ft3 * 0.134 ft3/gal = $3.53/gal
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Representative Industrial Natural Gas Price in Oregon	$ 5.00	Per EIA.gov, Oregon natural gas industrial price is around $5/MMBtu	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	1050 used in PSEL calcs
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	4.75 used, 2019 prime rate

SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	560	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	4,672,000,000	scf/Year	
Actual Annual fuel consumption (Mactual) =		3,306,483,238	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.708	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8760	hours	Based on 8760 (PTE)
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	90.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	171.66	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	532.08	tons/year	Based on PSEL of 591.2
NO_x removal factor (NRF) =	EF/80 =	1.13		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	230,957	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	95.32	/hour	
Residence Time	$1/V_{space}$	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	$(\%S/100)x(64/32)*1x10^6)/HHV$ =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at sea level (P) =	2116 x $[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.50		

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

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}/(t_{SCR}$ x 24 hours) rounded to the nearest integer	0.3180	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	2,422.86	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	241	ft^2
Height of each catalyst layer (H_{layer}) =	$(Vol_{catalyst}/(R_{layer}$ x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	277	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	16.6	feet
Reactor height =	$(R_{layer}$ + R_{empty}) x (7ft + h_{layer}) + 9ft	54	feet

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times EF \times SRF \times MW_R)/MW_{NOx}$ =	67	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	230	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	31	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	10,400	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i(1+i)^n/(1+i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0692

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(CoalF \times HRF)^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	287.95	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86,380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62,680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7,850 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5,700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7,640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$14,448,563	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$3,441,336	in 2019 dollars
Indirect Annual Costs (IDAC) =	$1,003,335	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$4,444,671	in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =		$72,243	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =		$950,277	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =		$170,517	in 2019 dollars
Annual Catalyst Replacement Cost =			$58,299	in 2019 dollars
Natural gas for duct burner to reheat stack gas, based on MMBtu/hr of:		50	$2,190,000	in 2019 dollars
	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF			
Direct Annual Cost =			$3,441,336	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,495	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$999,841	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,003,335	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$4,444,671	per year in 2019 dollars
NOx Removed =	532	tons/year
Cost Effectiveness =	$8,353	per ton of NOx removed in 2019 dollars

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

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

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

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

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	560	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,050	Btu/scf
What is the estimated actual annual fuel consumption?	1,087,930,476	scf/Year
Enter the net plant heat input rate (NPHR)	8.2	MMBtu/MW

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

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

Plant Elevation	20	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

Not applicable to units buring fuel oil or natural gas

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

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

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

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

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Table A-24a - SCR for GP Wauna Power Boiler

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	183	days
Number of days the boiler operates (t_{plant})	183	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.465	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.046	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	25	Years*

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

Gas temperature at the SCR inlet (T)	650	^{o}F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	431	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:		
50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2019		
CEPCI for 2019	607.5	Enter the CEPCI value for 2019 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	4.75	Percent	
Reagent ($Cost_{reag}$)	3.53	$/gallon for 29% ammonia	
Electricity ($Cost_{elect}$)	0.0676	$/kWh	* $0.0676/kWh is a default value for electrity cost. User should enter actual value, if known.
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

Table A-24a - SCR for GP Wauna Power Boiler

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	Representative Pacific NW Mill cost for aqueous ammonia. 0.47/lb * 56 lb/ft3 * 0.134 ft3/gal = $3.53/gal
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Representative Industrial Natural Gas Price in Oregon	$ 5.00	Per EIA.gov, Oregon natural gas industrial price is around $5/MMBtu	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	1050 used in PSEL calcs
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	4.75 used, 2019 prime rate

SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	560	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	4,672,000,000	scf/Year	
Actual Annual fuel consumption (Mactual) =		1,087,930,476	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.233	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	4392	hours	Based on 2017 Operating Hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	90.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	234.24	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	238.91	tons/year	Based on 2017 Annual Emissions
NO_x removal factor (NRF) =	EF/80 =	1.13		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	230,957	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	91.53	/hour	
Residence Time	$1/V_{space}$	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	$(\%S/100)x(64/32)*1x10^6)/HHV$ =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at sea level (P) =	2116 x $[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.50		

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

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.1819	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	2,523.22	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	241	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	277	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	16.6	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	55	feet

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	91	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	314	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	42	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	14,100	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0692

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	287.95	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$14,448,563	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,940,597	in 2019 dollars
Indirect Annual Costs (IDAC) =	$1,002,025	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$2,942,622	in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =		$72,243	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =		$650,133	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =		$85,492	in 2019 dollars
Annual Catalyst Replacement Cost =			$34,729	in 2019 dollars
Natural gas for duct burner to reheat stack gas, based on MMBtu/hr of:		50	$1,098,000	in 2019 dollars
	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF			
Direct Annual Cost =			$1,940,597	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,185	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$999,841	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,002,025	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$2,942,622	per year in 2019 dollars
NOx Removed =	239	tons/year
Cost Effectiveness =	$12,317	per ton of NOx removed in 2019 dollars

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

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

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

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

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 240 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 4,500 Btu/lb

What is the estimated actual annual fuel consumption? 389,333,333 lbs/year

Enter the net plant heat input rate (NPHR) 10 MMBtu/MW

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

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

Plant Elevation 20 Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned: Bituminous

Enter the sulfur content (%S) = 0.07 percent by weight

For units burning coal blends:

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

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

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

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

- (●) Method 1
- ( ) Method 2
- ( ) Not applicable

Enter the following design parameters for the proposed SCR:

Table A-25 - SCR for GP Wauna Fluid Bed Boiler

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.256	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.026	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	25	Years*

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

Gas temperature at the SCR inlet (T)	650	^{o}F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	484	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:		
50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2019			
CEPCI for 2019	607.5	Enter the CEPCI value for 2019 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	4.75	Percent	
Reagent ($Cost_{reag}$)	3.53	$/gallon for 29% ammonia	
Electricity ($Cost_{elect}$)	0.0676	$/kWh	* $0.0676/kWh is a default value for electrity cost. User should enter actual value, if known.
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	Representative Pacific NW Mill cost for aqueous ammonia. 0.47/lb * 56 lb/ft3 * 0.134 ft3/gal = $3.53/gal
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Representative Industrial Natural Gas Price in Oregon	$ 5.00	Per EIA.gov, Oregon natural gas industrial price is around $5/MMBtu	
Percent sulfur content for Coal (% weight)	1.84	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	11,841	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	4.75% pre-COVID rate used

SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	240	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	467,200,000	lbs/year	
Actual Annual fuel consumption (Mactual) =		389,333,333	lbs/year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.00		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.833	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8760	hours	Based on 8760 (PTE)
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	90.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	55.33	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	201.96	tons/year	Based on PSEL of 224.4 tpy
NO_x removal factor (NRF) =	EF/80 =	1.13		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	111,153	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	109.79	/hour	
Residence Time	$1/V_{space}$	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =	< 3	lbs/MMBtu	
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.50		

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

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3180	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	1,012.46	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	116	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	133	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	11.5	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	53	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	22	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	74	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	10	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	3,400	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0692

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(CoalF \times HRF)^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	134.40	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

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

Capital costs for the SCR (SCR_{cost}) =	$9,937,228	in 2019 dollars
Reagent Preparation Cost (RPC) =	$2,587,623	in 2019 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2019 dollars
Balance of Plant Costs (BPC) =	$3,380,828	in 2019 dollars
Total Capital Investment (TCI) =	$20,677,382	in 2019 dollars

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

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

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

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

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

SCR Capital Costs (SCR_{cost}) =	$9,937,228 in 2019 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

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

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

$$RPC = 564{,}000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =	$2,587,623 in 2019 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

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

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

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

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2019 dollars

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

Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

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

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

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

Balance of Plant Costs (BOP_{cost}) =	$3,380,828 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,608,638	in 2019 dollars
Indirect Annual Costs (IDAC) =	$1,434,743	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$3,043,381	in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =		$103,387	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =		$306,300	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =		$79,588	in 2019 dollars
Annual Catalyst Replacement Cost =			$24,362	in 2019 dollars
Natural gas for duct burner to reheat stack gas, based on MMBtu/hr of:		25	$1,095,000	in 2019 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.				
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF		* Calculation Method 1 selected.	
Method 2 (for coal-fired industrial boilers):	(Q_B/NPHR) x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x ($CC_{replace}$) x 35.3			
Direct Annual Cost =			$1,608,638	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,869	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,430,875	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,434,743	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$3,043,381	per year in 2019 dollars
NOx Removed =	202	tons/year
Cost Effectiveness =	$15,069	per ton of NOx removed in 2019 dollars

Table A-25a - SCR for GP Wauna Fluid Bed Boiler

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

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

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

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

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	240	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	4,500	Btu/lb
What is the estimated actual annual fuel consumption?	162,094,000	lbs/year
Enter the net plant heat input rate (NPHR)	10	MMBtu/MW

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

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

Plant Elevation	20	Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned: Bituminous

Enter the sulfur content (%S) = 0.07 percent by weight

For units burning coal blends:

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

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

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

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

- (●) Method 1
- ( ) Method 2
- ( ) Not applicable

Enter the following design parameters for the proposed SCR:

Table A-25a - SCR for GP Wauna Fluid Bed Boiler

Number of days the SCR operates (t_{SCR})	341	days
Number of days the boiler operates (t_{plant})	341	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.467	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.047	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	25	Years*

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

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	484	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:		
50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Select the reagent used	Ammonia

Table A-25a - SCR for GP Wauna Fluid Bed Boiler

Enter the cost data for the proposed SCR:

Desired dollar-year	2019			
CEPCI for 2019	607.5	Enter the CEPCI value for 2019 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index	
Annual Interest Rate (i)	4.75	Percent		
Reagent ($Cost_{reag}$)	3.53	$/gallon for 29% ammonia		
Electricity ($Cost_{elect}$)	0.0676	$/kWh	* $0.0676/kWh is a default value for electrity cost. User should enter actual value, if known.	
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.	
Operator Labor Rate	60.00	$/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.	
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.	

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

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Table A-25a - SCR for GP Wauna Fluid Bed Boiler

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	Representative Pacific NW Mill cost for aqueous ammonia. 0.47/lb * 56 lb/ft3 * 0.134 ft3/gal = $3.53/gal
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Representative Industrial Natural Gas Price in Oregon	$ 5.00	Per EIA.gov, Oregon natural gas industrial price is around $5/MMBtu	
Percent sulfur content for Coal (% weight)	1.84	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	11,841	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	4.75% pre-COVID rate used

SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	240	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	467,200,000	lbs/year	
Actual Annual fuel consumption (Mactual) =		162,094,000	lbs/year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.00		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.347	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8175	hours	Based on 2017 Operating Hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	90.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	100.98	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	153.45	tons/year	Based on 2017 Annual Emissions
NO_x removal factor (NRF) =	EF/80 =	1.13		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	111,153	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	102.36	/hour	
Residence Time	$1/V_{space}$	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	$(\%S/100)x(64/32)*1x10^6)/HHV$ =	< 3	lbs/MMBtu	
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at sea level (P) =	$2116 \times [(59-(0.00356xh)+459.7)/518.6]^{5.256} \times (1/144)$* =	14.7	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.50		

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

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3180	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	1,085.90	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	116	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	133	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	11.5	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	54	feet

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	39	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	135	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	18	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	6,100	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0692

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	134.40	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

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

Capital costs for the SCR (SCR_{cost}) =	$9,937,228	in 2019 dollars
Reagent Preparation Cost (RPC) =	$3,007,565	in 2019 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2019 dollars
Balance of Plant Costs (BPC) =	$3,380,828	in 2019 dollars
Total Capital Investment (TCI) =	$21,223,307	in 2019 dollars

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

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

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

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

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

SCR Capital Costs (SCR_{cost}) =	$9,937,228 in 2019 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

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

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

$$RPC = 564{,}000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =	$3,007,565 in 2019 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

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

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

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

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2019 dollars

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

Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

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

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

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

Balance of Plant Costs (BOP_{cost}) =	$3,380,828 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,750,054	in 2019 dollars
Indirect Annual Costs (IDAC) =	$1,472,381	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$3,222,435	in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =		$106,117	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =		$521,660	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =		$74,273	in 2019 dollars
Annual Catalyst Replacement Cost =			$26,129	in 2019 dollars
Natural gas for duct burner to reheat stack gas, based on MMBtu/hr of:		25	$1,021,875	in 2019 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.				
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF		* Calculation Method 1 selected.	
Method 2 (for coal-fired industrial boilers):	(Q_B/NPHR) x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x ($CC_{replace}$) x 35.3			
Direct Annual Cost =			$1,750,054	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,729	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,468,653	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,472,381	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$3,222,435	per year in 2019 dollars
NOx Removed =	153	tons/year
Cost Effectiveness =	$21,000	per ton of NOx removed in 2019 dollars

Table A-31

Georgia-Pacific Consumer Products LP - Wauna

Capital and Annual Costs Associated with ESP Upgrade for Recovery Furnace

CAPITAL COSTS[a]

		COST ITEM	COST FACTOR	COST ($)
		Direct Costs		
		Purchased Equipment Costs		
(a)	***A***	ESP		$5,501,569
(b)		Instrumentation	0.10 A	$550,157
(b)		Sales Tax	0.03 A	$165,047
(b)		Freight	0.05 A	$275,078
	B	***Total Purchased Equipment Cost***		***$6,491,852***
		Direct Installation Costs		
(b)		Foundations and Supports[c]	0.04 B	$0
(b)		Handling and Erection	0.50 B	$3,245,926
(b)		Electrical	0.08 B	$519,348
(b)		Piping	0.01 B	$64,919
(b)		Insulation	0.02 B	$129,837
(b)		Painting	0.02 B	$129,837
		Direct Installation Cost		***$4,089,867***
		Total Direct Costs		***$10,581,719***
		Indirect Costs		
(b)		Engineering	0.20 B	$1,298,370
(b)		Construction Management	0.20 B	$1,298,370
(b)		Contractor fees	0.10 B	$649,185
(b)		Start-up	0.01 B	$64,919
(b)		Performance test	0.01 B	$64,919
(b)		Model Study	0.02 B	$129,837
(b)		Contingencies	0.03 B	$194,756
		Total Indirect Costs		***$3,700,356***
		Total Capital Investment (TCI)[a]		***$14,282,074***

ANNUALIZED COSTS

	COST ITEM	COST FACTOR		RATE	COST ($)
	Direct Annual Costs				
	Operating Labor[c]				
(b)	Operator		hours/shift	$31.00 per hour[d]	$0
(b)	Supervisor		of operator labor		$0
(b)	Coordinator		of operator labor		$0
	Maintenance[c]				
(b)	Maintenance labor		hours/shift	$34.00 per hour[d]	$0
(b)	Maintenance materials		of purchased equipment costs		$0
	Utilities[e]				
	Electricity	400	kW	$0.060 per kWh[b]	$210,183
	Total Direct Annual Costs				***$210,183***
	Indirect Annual Costs				
(c)	Overhead	60%	Labor and Material Costs		$0
(c)	General and administrative	2%	of TCI		$0
(b)	Property taxes	1%	of TCI		$142,821
(b)	Insurance	1%	of TCI		$142,821
(b)	Capital recovery	0.079	x TCI		$1,121,864
	Life of the control:		20 years at	4.75% interest	
	Total Indirect Annual Costs				***$1,407,505***
	Total Annual Costs				***$1,617,688***
	Cost Effectiveness ($/ton)				
	PM_{10} Control Efficiency[f]:	99.5%			
	PM_{10} Emissions[g]:	290	tpy	Total Annual Costs/Controlled PM_{10} Emissions:	
	Controlled PM_{10} Emissions[h]:	145.0	tons of additional PM_{10} removed annually		***$11,156***

[a] ESP upgrade capital cost based on Section 10.2 in document titled "Emission Control Study - Technology Cost Estimates" by BE&K Engineering for AF&PA, September 2001. The equipment cost of rebuilding an ESP on an NDCE Recovery Furnace was scaled based on furnace BLS throughput capacity. The cost was adjusted from 2001 dollars to 2019 dollars using the Chemical Engineering Plant Cost Index (CEPCI).

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

[c] Costs associated with these parameters are zero because ESP system is already installed on the source. This cost analysis represents an upgrade to the existing ESP System.

[d] Nominal Pacific NW pulp and paper mill rates.

[e] The electricity requirement for new equipment is based on the BE&K document cited in footnote (a) and scaled based on the furnace size.

[f] Control efficiency from upgrading a dry ESP is assumed to be 99.5% based on a U.S. EPA Air Pollution Control Technology Fact Sheet for a dry ESP and engineering judgment. Controlled emissions takes into account control from existing ESP.

[g] PM10 PSEL

[h] Controlled PM_{10} emissions are estimated by calculating uncontrolled PSEL emissions assuming a 99% control efficiency, controlling emissions by 99.5%, and taking the difference between the PSEL emissions vs. the emissions post upgrade.

Table A-31a

Georgia-Pacific Consumer Products LP - Wauna

Capital and Annual Costs Associated with ESP Upgrade for Recovery Furnace

CAPITAL COSTS[a]					ANNUALIZED COSTS					
	COST ITEM		COST FACTOR	COST ($)		COST ITEM	COST FACTOR		RATE	COST ($)
	Direct Costs					***Direct Annual Costs***				
	Purchased Equipment Costs					***Operating Labor*** [c]				
(a)	***A***	ESP		$5,501,569	(b)	Operator		hours/shift	$31.00 per hour[d]	$0
(b)		Instrumentation	0.10 A	$550,157	(b)	Supervisor		of operator labor		$0
(b)		Sales Tax	0.03 A	$165,047	(b)	Coordinator		of operator labor		$0
(b)		Freight	0.05 A	$275,078		***Maintenance*** [c]				
	B	***Total Purchased Equipment Cost***		***$6,491,852***	(b)	Maintenance labor		hours/shift	$34.00 per hour[d]	$0
					(b)	Maintenance materials		of purchased equipment costs		$0
	Direct Installation Costs					***Utilities*** [e]				
(b)		Foundations and Supports[c]	0.04 B	$0		Electricity	400	kW	$0.060 per kWh[b]	$192,572
(b)		Handling and Erection	0.50 B	$3,245,926						
(b)		Electrical	0.08 B	$519,348		***Total Direct Annual Costs***				***$192,572***
(b)		Piping	0.01 B	$64,919						
(b)		Insulation	0.02 B	$129,837						
(b)		Painting	0.02 B	$129,837		***Indirect Annual Costs***				
		Direct Installation Cost		***$4,089,867***	(c)	Overhead	60%	Labor and Material Costs		$0
	Total Direct Costs			***$10,581,719***	(c)	General and administrative	2%	of TCI		$0
					(b)	Property taxes	1%	of TCI		$142,821
	Indirect Costs				(b)	Insurance	1%	of TCI		$142,821
(b)		Engineering	0.20 B	$1,298,370	(b)	Capital recovery	0.079	x TCI		$1,121,864
(b)		Construction Management	0.20 B	$1,298,370		Life of the control:		20 years at	4.75% interest	
(b)		Contractor fees	0.10 B	$649,185						
(b)		Start-up	0.01 B	$64,919		***Total Indirect Annual Costs***				***$1,407,505***
(b)		Performance test	0.01 B	$64,919						
(b)		Model Study	0.02 B	$129,837		***Total Annual Costs***				***$1,600,077***
(b)		Contingencies	0.03 B	$194,756						
	Total Indirect Costs			***$3,700,356***		***Cost Effectiveness ($/ton)***				
						PM_{10} Control Efficiency[f]:	99.5%			
	Total Capital Investment (TCI) [a]			***$14,282,074***		PM_{10} Emissions[g]:	226.4	tpy	Total Annual Costs/Controlled PM_{10} Emissions:	
						Controlled PM_{10} Emissions [h]:	113.2	tons of additional PM_{10} removed annually		***$14,136***

[a] ESP upgrade capital cost based on Section 10.2 in document titled "Emission Control Study - Technology Cost Estimates" by BE&K Engineering for AF&PA, September 2001. The equipment cost of rebuilding an ESP on an NDCE Recovery Furnace was scaled based on furnace BLS throughput capacity. The cost was adjusted from 2001 dollars to 2019 dollars using the Chemical Engineering Plant Cost Index (CEPCI).

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

[c] Costs associated with these parameters are zero because ESP system is already installed on the source. This cost analysis represents an upgrade to the existing ESP System.

[d] Nominal Pacific NW pulp and paper mill rates.

[e] The electricity requirement for new equipment is based on the BE&K document cited in footnote (a) and scaled based on the furnace size.

[f] Control efficiency from upgrading a dry ESP is assumed to be 99.5% based on a U.S. EPA Air Pollution Control Technology Fact Sheet for a dry ESP and engineering judgment. Controlled emissions takes into account control from existing ESP.

[g] PM10 2017 Actual Emissions

[h] Controlled PM_{10} emissions are estimated by calculating uncontrolled PSEL emissions assuming a 99% control efficiency, controlling emissions by 99.5%, and taking the difference between the PSEL emissions vs. the emissions post upgrade.

Table A-36
Georgia-Pacific - Wauna
Capital and Annual Costs Associated with WESP for Recovery Furnace

CAPITAL COSTS

		COST ITEM	COST FACTOR	COST ($)
Direct Costs				
	Purchased Equipment Costs			
(a)	*A*	WESP		$4,914,088
(b)		Instrumentation and controls	0.10 A	$491,409
(b)		Sales Tax	0.03 A	$147,423
(b)		Freight	0.05 A	$245,704
	B	***Total Purchased Equipment Cost***		***$5,798,624***
	Direct Installation Costs			
(b)		Foundations and Supports	0.04 B	$231,945
(b)		Handling and Erection	0.50 B	$2,899,312
(b)		Electrical	0.08 B	$463,890
(b)		Piping	0.01 B	$57,986
(b)		Insulation for Ductwork	0.02 B	$115,972
(b)		Painting	0.02 B	$115,972
		Direct Installation Cost		***$3,885,078***
	Total Direct Costs			***$9,683,702***
Indirect Costs				
(b)		Engineering	0.20 B	$1,159,725
(b)		Construction and Field Expenses	0.20 B	$1,159,725
(b)		Contractor fees	0.10 B	$579,862
(b)		Start-up	0.01 B	$57,986
(b)		Performance test	0.01 B	$57,986
(b)		Model Study	0.02 B	$115,972
(b)		Contingencies	0.03 B	$173,959
	Total Indirect Costs			***$3,305,216***
Total Capital Investment (TCI)				***$12,988,917***

ANNUALIZED COSTS

	COST ITEM	COST FACTOR		RATE		COST ($)
Direct Annual Costs						
	Operating Labor					
(b)	Operator[c]	1	hours/shift	$29.06	per hour[d]	$31,821
(b)	Supervisor	15%	of operator labor			$4,773.11
(b)	Coordinator	33%	of operator labor			$10,500.83
	Maintenance					
(b)	Maintenance labor[c]	0.5	hours/shift	$24.82	per hour[d]	$13,589
(b)	Maintenance materials	1%	of purchased equipment costs			$57,986
	Utilities [c)(e]					
	Electricity	215	kW	$0.060	per kWh	$112,785
	Water	10,000	gal/day	$0.01	per gal	$36,500
	Total Direct Annual Costs					***$267,955***
Indirect Annual Costs						
(b)	Overhead	60%	Labor and Material Costs			$71,201.89
(b)	General and administrative	2%	of TCI			$259,778
(b)	Property taxes	1%	of TCI			$129,889
(b)	Insurance	1%	of TCI			$129,889
(b)	Capital recovery	0.079	x TCI			$1,020,286
	Life of the control:		20 years at	4.75%	interest	
	Total Indirect Annual Costs					***$1,611,044***
Total Annual Costs						***$1,878,999***
Cost Effectiveness ($/ton)						
	PM_{10} Control Efficiency[f]:	80%				
	2017 PM_{10} Emissions[g]:	290	tpy		Total Annual Costs/Controlled PM_{10} Emissions:	
	Controlled PM_{10} Emissions:	232	tons of PM_{10} removed annually			***$8,099***

[a] Wet electrostatic precipitator (WESP) capital cost based on $40/scfm, the low end of the range in EPA's WESP fact sheet.
[b] Cost information estimated based on the U.S. EPA OAQPS Control Cost Manual, Section 6, Chapter 3, September 1999 except labor hours based on Section 6, Chapter 2.
[c] Based on 8760 operating hours.
[d] Nominal Pacific NW pulp and paper mill rates.
[e] Based on Washington pulp and paper mill boiler WESP electricity and water usage.
[f] Assumes installation of a WESP after the existing control equipment will achieve an additional 80% reduction in PM_{10} emissions.
[g] PSEL

Table A-36a

Georgia-Pacific - Wauna

Capital and Annual Costs Associated with WESP for Recovery Furnace

CAPITAL COSTS

		COST ITEM	COST FACTOR	COST ($)
Direct Costs				
	Purchased Equipment Costs			
(a)	*A*	WESP		$4,914,088
(b)		Instrumentation and controls	0.10 A	$491,409
(b)		Sales Tax	0.03 A	$147,423
(b)		Freight	0.05 A	$245,704
	B	***Total Purchased Equipment Cost***		***$5,798,624***
	Direct Installation Costs			
(b)		Foundations and Supports	0.04 B	$231,945
(b)		Handling and Erection	0.50 B	$2,899,312
(b)		Electrical	0.08 B	$463,890
(b)		Piping	0.01 B	$57,986
(b)		Insulation for Ductwork	0.02 B	$115,972
(b)		Painting	0.02 B	$115,972
		Direct Installation Cost		***$3,885,078***
	Total Direct Costs			***$9,683,702***
Indirect Costs				
(b)		Engineering	0.20 B	$1,159,725
(b)		Construction and Field Expenses	0.20 B	$1,159,725
(b)		Contractor fees	0.10 B	$579,862
(b)		Start-up	0.01 B	$57,986
(b)		Performance test	0.01 B	$57,986
(b)		Model Study	0.02 B	$115,972
(b)		Contingencies	0.03 B	$173,959
	Total Indirect Costs			***$3,305,216***
Total Capital Investment (TCI)				***$12,988,917***

ANNUALIZED COSTS

	COST ITEM	COST FACTOR		RATE		COST ($)
Direct Annual Costs						
	Operating Labor					
(b)	Operator[c]	1	hours/shift	$29.06	per hour[d]	$29,154
(b)	Supervisor	15%	of operator labor			$4,373.17
(b)	Coordinator	33%	of operator labor			$9,620.97
	Maintenance					
(b)	Maintenance labor[c]	0.5	hours/shift	$24.82	per hour[d]	$12,450
(b)	Maintenance materials	1%	of purchased equipment costs			$57,986
	Utilities [c][e]					
	Electricity	215	kW	$0.060	per kWh	$103,335
	Water	10,000	gal/day	$0.01	per gal	$36,500
	Total Direct Annual Costs					***$253,420***
Indirect Annual Costs						
(b)	Overhead	60%	Labor and Material Costs			$68,151.09
(b)	General and administrative	2%	of TCI			$259,778
(b)	Property taxes	1%	of TCI			$129,889
(b)	Insurance	1%	of TCI			$129,889
(b)	Capital recovery	0.079	x TCI			$1,020,286
	Life of the control:	20	years at	4.75%	interest	
	Total Indirect Annual Costs					***$1,607,993***
Total Annual Costs						***$1,861,413***
Cost Effectiveness ($/ton)						
	PM_{10} Control Efficiency[f]:	80%				
	2017 PM_{10} Emissions[g]:	226.4	tpy		Total Annual Costs/Controlled PM_{10} Emissions:	
	Controlled PM_{10} Emissions:	181.1	tons of PM_{10} removed annually			***$10,278***

[a] Wet electrostatic precipitator (WESP) capital cost based on $40/scfm, the low end of the range in EPA's WESP fact sheet.

[b] Cost information estimated based on the U.S. EPA OAQPS Control Cost Manual, Section 6, Chapter 3, September 1999 except labor hours based on Section 6, Chapter 2.

[c] Based on 8026 operating hours.

[d] Nominal Pacific NW pulp and paper mill rates.

[e] Based on Washington pulp and paper mill boiler WESP electricity and water usage.

[f] Assumes installation of a WESP after the existing control equipment will achieve an additional 80% reduction in PM_{10} emissions.

[g] 2017 Actual Emissions

Table A-41

Georgia-Pacific - Wauna

Capital and Annual Costs Associated with Wet Scrubbing for Recovery Furnace

CAPITAL COSTS[a]

		COST ITEM	COST FACTOR		COST ($)
		Direct Costs			
		Purchased Equipment Costs			
(a)	***A***	Equipment Costs			***$8,670,958***
(b)		Instrumentation	0.10	A	$867,096
(b)		Sales Tax	0.03	A	$260,129
(b)		Freight	0.05	A	$433,548
	B	***Total Purchased Equipment Cost***			***$10,231,731***
		Direct Installation Costs			
(b)		Foundations and Supports	0.12	B	$1,227,808
(b)		Handling and erection	0.40	B	$4,092,692
(b)		Electrical	0.01	B	$102,317
(b)		Piping	0.30	B	$3,069,519
(b)		Insulation for ductwork	0.01	B	$102,317
(b)		Painting	0.01	B	$102,317
		Direct Installation Cost			***$8,696,971***
		Total Direct Costs			***$18,928,702***
		Indirect Costs			
(b)		Engineering	0.10	B	$1,023,173
(b)		Construction Management	0.10	B	$1,023,173
(b)		Contractor fees	0.10	B	$1,023,173
(b)		Start-up	0.01	B	$102,317
(b)		Performance test	0.01	B	$102,317
(b)		Contingencies	0.03	B	$306,952
		Total Indirect Costs			***$3,581,106***
		Total Capital Investment (TCI)			***$22,509,808***

ANNUALIZED COSTS

	COST ITEM	COST FACTOR		RATE		COST ($)
	Direct Annual Costs					
	Operating Labor					
(b)	Operator[c]	0.5	hours/shift	$31.00	per hour[d]	$16,973
(b)	Supervisor	15%	of operator labor			$2,546
	Maintenance					
(b)	Maintenance labor[c]	0.5	hours/shift	$34.00	per hour[d]	$18,615
(b)	Maintenance materials	100%	of maintenance labor			$18,615
	Utilities[e]					
	Electricity	1,587	kW	$0.060	per kWh[b]	$834,085
	Chemicals	1,110	lb/hr NaOH	$0.25	per lb NaOH[d]	$2,431,068
	Fresh water usage	144	gpm	$0.20	per 1000 gallon[b]	$15,137
	Wastewater disposal	14.59	gpm	$3.80	per 1000 gallon[b]	$29,149
	Total Direct Annual Costs					***$3,366,187***
	Indirect Annual Costs					
	Overhead	60%	Labor and Material Costs			$34,049
	General and administrative	2%	of TCI			$450,196
	Property taxes	1%	of TCI			$225,098
	Insurance	1%	of TCI			$225,098
	Capital recovery	0.095	x TCI			$2,132,155
	Life of the control:		15 years at	4.75%	interest	
	Total Indirect Annual Costs					***$3,066,596***
	Total Annual Costs					***$6,432,783***
	Cost Effectiveness ($/ton)					
	SO_2 Control Efficiency[f]:	98%				
	SO_2 Emissions[g]:	404.7	tpy	Total Annual Costs/Controlled SO_2 Emissions:		
	Controlled SO_2 Emissions:	396.6	tons of SO_2 removed annually			***$16,220***

[a] Wet scrubber capital cost based on Section 7.1 in document titled "Emission Control Study - Technology Cost Estimates" by BE&K Engineering for AF&PA, September 2001. The cost of a wet scrubber on an NDCE Recovery Furnace was scaled based on furnace BLS throughput capacity. The cost was adjusted from 2001 dollars to 2018 dollars using the Chemical Engineering Plant Cost Index (CEPCI).

[b] Cost information estimated based on the U.S. EPA OAQPS Control Cost Manual, Section 5, Chapter 1, December 1995.

[c] Based on 8760 operating hours.

[d] Nominal Pacific NW pulp and paper mill rates.

[e] Utility cost represents the electrical, chemical, and water consumption, and wastewater disposal of a wet scrubber system, based on the BE&K document cited in footnote (a) and scaled based on the furnace size.

[f] Control efficiency of SO_2 emissions from installing a wet scrubber is assumed to be 98 percent based on U.S. EPA OAQPS Control Cost Manual, Section 5, Chapter 1, December 1995 and engineering judgment.

[g] PSEL

Table A-41a

Georgia-Pacific - Wauna

Capital and Annual Costs Associated with Wet Scrubbing for Recovery Furnace

CAPITAL COSTS[(a)]

		COST ITEM	COST FACTOR	COST ($)
		Direct Costs		
		Purchased Equipment Costs		
(a)	***A***	Equipment Costs		***$8,670,958***
(b)		Instrumentation	0.10 A	$867,096
(b)		Sales Tax	0.03 A	$260,129
(b)		Freight	0.05 A	$433,548
	B	***Total Purchased Equipment Cost***		***$10,231,731***
		Direct Installation Costs		
(b)		Foundations and Supports	0.12 B	$1,227,808
(b)		Handling and erection	0.40 B	$4,092,692
(b)		Electrical	0.01 B	$102,317
(b)		Piping	0.30 B	$3,069,519
(b)		Insulation for ductwork	0.01 B	$102,317
(b)		Painting	0.01 B	$102,317
		Direct Installation Cost		***$8,696,971***
		Total Direct Costs		***$18,928,702***
		Indirect Costs		
(b)		Engineering	0.10 B	$1,023,173
(b)		Construction Management	0.10 B	$1,023,173
(b)		Contractor fees	0.10 B	$1,023,173
(b)		Start-up	0.01 B	$102,317
(b)		Performance test	0.01 B	$102,317
(b)		Contingencies	0.03 B	$306,952
		Total Indirect Costs		***$3,581,106***
		Total Capital Investment (TCI)		***$22,509,808***

ANNUALIZED COSTS

	COST ITEM	COST FACTOR		RATE		COST ($)
	Direct Annual Costs					
	Operating Labor					
(b)	Operator[(c)]	0.5	hours/shift	$31.00	per hour[(d)]	$15,550
(b)	Supervisor	15%	of operator labor			$2,333
	Maintenance					
(b)	Maintenance labor[(c)]	0.5	hours/shift	$34.00	per hour[(d)]	$17,055
(b)	Maintenance materials	100%	of maintenance labor			$17,055
	Utilities[(e)]					
	Electricity	1,587	kW	$0.060	per kWh[(b)]	$764,197
	Chemicals	1,110	lb/hr NaOH	$0.25	per lb NaOH[(d)]	$2,227,369
	Fresh water usage	144	gpm	$0.20	per 1000 gallon[(b)]	$13,869
	Wastewater disposal	14.59	gpm	$3.80	per 1000 gallon[(b)]	$26,707
	Total Direct Annual Costs					***$3,084,135***
	Indirect Annual Costs					
	Overhead	60%	Labor and Material Costs			$31,196
	General and administrative	2%	of TCI			$450,196
	Property taxes	1%	of TCI			$225,098
	Insurance	1%	of TCI			$225,098
	Capital recovery	0.095	x TCI			$2,132,155
	Life of the control:	15	years at	4.75%	interest	
	Total Indirect Annual Costs					***$3,063,743***
	Total Annual Costs					***$6,147,878***
	Cost Effectiveness ($/ton)					
	SO_2 Control Efficiency[(f)]:	98%				
	SO_2 Emissions[(g)]:	295.6	tpy	Total Annual Costs/Controlled SO_2 Emissions:		
	Controlled SO_2 Emissions:	289.7	tons of SO_2 removed annually			***$21,223***

[(a)] Wet scrubber capital cost based on Section 7.1 in document titled "Emission Control Study - Technology Cost Estimates" by BE&K Engineering for AF&PA, September 2001. The cost of a wet scrubber on an NDCE Recovery Furnace was scaled based on furnace BLS throughput capacity. The cost was adjusted from 2001 dollars to 2018 dollars using the Chemical Engineering Plant Cost Index (CEPCI).

[(b)] Cost information estimated based on the U.S. EPA OAQPS Control Cost Manual, Section 5, Chapter 1, December 1995.

[(c)] Based on 8026 operating hours.

[(d)] Nominal Pacific NW pulp and paper mill rates.

[(e)] Utility cost represents the electrical, chemical, and water consumption, and wastewater disposal of a wet scrubber system, based on the BE&K document cited in footnote (a) and scaled based on the furnace size.

[(f)] Control efficiency of SO_2 emissions from installing a wet scrubber is assumed to be 98 percent based on U.S. EPA OAQPS Control Cost Manual, Section 5, Chapter 1, December 1995 and engineering judgment.

[(g)] 2017 Actual Emissions

Table A-45

GP Wauna

Capital and Annual Costs Associated with New ESP for Lime Kiln

CAPITAL COSTS[a]

	COST ITEM	COST FACTOR	COST ($)
	Direct Costs		
	Purchased Equipment Costs		
(a)	***A*** ESP		$3,227,069
(b)	Instrumentation	0.10 A	$322,707
(b)	Sales Tax	0.03 A	$96,812
(b)	Freight	0.05 A	$161,353
	B Total Purchased Equipment Cost		***$3,807,941***
	Direct Installation Costs		
(b)	Foundations and Supports	0.04 B	$152,318
(b)	Handling and Erection	0.50 B	$1,903,970
(b)	Electrical	0.08 B	$304,635
(b)	Piping	0.01 B	$38,079
(b)	Insulation	0.02 B	$76,159
(b)	Painting	0.02 B	$76,159
	Direct Installation Cost		***$2,551,320***
	Total Direct Costs		***$6,359,261***
	Indirect Costs		
(b)	Engineering	0.20 B	$761,588
(b)	Construction Management	0.20 B	$761,588
(b)	Contractor fees	0.10 B	$380,794
(b)	Start-up	0.01 B	$38,079
(b)	Performance test	0.01 B	$38,079
(b)	Model Study	0.02 B	$76,159
(b)	Contingencies	0.03 B	$114,238
	Total Indirect Costs		***$2,170,526***
	Total Capital Investment (TCI)[a]		***$8,529,788***

ANNUALIZED COSTS

	COST ITEM	COST FACTOR	RATE	COST ($)
	Direct Annual Costs			
	Operating Labor			
(b)	Operator	1 hours/shift	$31.00 per hour[d]	$33,945
(b)	Supervisor	15% of operator labor		$5,092
(b)	Coordinator	33% of operator labor		$11,202
	Maintenance			
(b)	Maintenance labor	0.25 hours/shift	$34.00 per hour[d]	$9,308
(b)	Maintenance materials	1% of purchased equipment costs		$38,079
	Utilities			
	Electricity	280 kW	$0.060 per kWh[b]	$146,958
	Total Direct Annual Costs			***$244,583***
	Indirect Annual Costs			
(b)	Overhead	60% Labor and Material Costs		$58,575
(b)	General and administrative	2% of TCI		$170,596
(b)	Property taxes	1% of TCI		$85,298
(b)	Insurance	1% of TCI		$85,298
(b)	Capital recovery	0.079 x TCI		$670,019
	Life of the control:	20 years at	4.75% interest	
	Total Indirect Annual Costs			***$1,069,786***
	Total Annual Costs			***$1,314,369***
	Cost Effectiveness ($/ton)			
	PM_{10} Control Improvement[f]:	90.0%		
	PM_{10} Emissions[g]:	32.1 tpy	Total Annual Costs/Controlled PM_{10} Emissions:	
	Reduction in PM_{10} Emissions[h]:	28.9 tpy		***$45,496***

[a] ESP upgrade capital cost based on Section 10.5 in document titled "Emission Control Study - Technology Cost Estimates" by BE&K Engineering for AF&PA, September 2001. The equipment cost of installing an ESP on a lime kiln was scaled based on kiln throughput capacity. The cost was adjusted from 2001 dollars to 2019 dollars using the Chemical Engineering Plant Cost Index (CEPCI).

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

[c] Reserved

[d] Nominal Pacific NW pulp and paper mill rates.

[e] The electricity requirement for new equipment is based on the BE&K document cited in footnote (a) and scaled based on the exhaust flow rate.

[f] Estimated additional reduction in emissions already controlled by wet scrubber.

[g] PM10 PSEL

[h] The reduction in PM10 emissions is estimated assuming the ESP will provide an additional 90% PM10 control.

Table A-45a

GP Wauna

Capital and Annual Costs Associated with New ESP for Lime Kiln

CAPITAL COSTS[a]					ANNUALIZED COSTS				
	COST ITEM	COST FACTOR	COST ($)		COST ITEM	COST FACTOR		RATE	COST ($)
	Direct Costs				***Direct Annual Costs***				
	Purchased Equipment Costs				***Operating Labor***				
(a)	***A*** ESP		$3,227,069	(b)	Operator	1	hours/shift	$31.00 per hour[d]	$33,945
(b)	Instrumentation	0.10 A	$322,707	(b)	Supervisor	15%	of operator labor		$5,092
(b)	Sales Tax	0.03 A	$96,812	(b)	Coordinator	33%	of operator labor		$11,202
(b)	Freight	0.05 A	$161,353		***Maintenance***				
	B Total Purchased Equipment Cost		***$3,807,941***	(b)	Maintenance labor	0.25	hours/shift	$34.00 per hour[d]	$9,308
				(b)	Maintenance materials	1%	of purchased equipment costs		$38,079
	Direct Installation Costs				***Utilities***				
(b)	Foundations and Supports	0.04 B	$152,318		Electricity	280	kW	$0.060 per kWh[b]	$132,044
(b)	Handling and Erection	0.50 B	$1,903,970						
(b)	Electrical	0.08 B	$304,635		***Total Direct Annual Costs***				***$229,669***
(b)	Piping	0.01 B	$38,079						
(b)	Insulation	0.02 B	$76,159						
(b)	Painting	0.02 B	$76,159		***Indirect Annual Costs***				
	Direct Installation Cost		***$2,551,320***	(b)	Overhead	60%	Labor and Material Costs		$58,575
	Total Direct Costs		***$6,359,261***	(b)	General and administrative	2%	of TCI		$170,596
				(b)	Property taxes	1%	of TCI		$85,298
	Indirect Costs			(b)	Insurance	1%	of TCI		$85,298
(b)	Engineering	0.20 B	$761,588	(b)	Capital recovery	0.079	x TCI		$670,019
(b)	Construction Management	0.20 B	$761,588		Life of the control:		20 years at	4.75% interest	
(b)	Contractor fees	0.10 B	$380,794						
(b)	Start-up	0.01 B	$38,079		***Total Indirect Annual Costs***				***$1,069,786***
(b)	Performance test	0.01 B	$38,079						
(b)	Model Study	0.02 B	$76,159		***Total Annual Costs***				***$1,299,455***
(b)	Contingencies	0.03 B	$114,238						
	Total Indirect Costs		***$2,170,526***		***Cost Effectiveness ($/ton)***				
					PM_{10} Control Improvement[f]:	90.0%			
	Total Capital Investment (TCI) [a]		***$8,529,788***		PM_{10} Emissions[g]:	87.3	tpy	Total Annual Costs/Controlled PM_{10} Emissions:	
					Reduction in PM_{10} Emissions [h]:	78.6	tpy		***$16,537***

[a] ESP upgrade capital cost based on Section 10.5 in document titled "Emission Control Study - Technology Cost Estimates" by BE&K Engineering for AF&PA, September 2001. The equipment cost of installing an ESP on a lime kiln was scaled based on kiln throughput capacity. The cost was adjusted from 2001 dollars to 2019 dollars using the Chemical Engineering Plant Cost Index (CEPCI).

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

[c] Reserved

[d] Nominal Pacific NW pulp and paper mill rates.

[e] The electricity requirement for new equipment is based on the BE&K document cited in footnote (a) and scaled based on the exhaust flow rate.

[f] Estimated additional reduction in emissions already controlled by wet scrubber.

[g] PM10 2017 Actual Emissions

[h] The reduction in PM10 emissions is estimated assuming the ESP will provide an additional 90% PM10 control.

Table A-51

Georgia-Pacific - Wauna

Capital and Annual Costs Associated with Replacing the Smelt Dissolving Tank Wet Scrubber

CAPITAL COSTS[a]

		COST ITEM	COST FACTOR	COST ($)
Direct Costs				
		Purchased Equipment Costs		
(a)	***A***	Equipment Costs		***$988,767***
(b)		Instrumentation	0.10 A	$98,877
(b)		Sales Tax	0.03 A	$29,663
(b)		Freight	0.05 A	$49,438
	B	***Total Purchased Equipment Cost***		***$1,166,745***
		Direct Installation Costs		
(b)		Foundations and Supports	0.12 B	$140,009
(b)		Handling and erection	0.40 B	$466,698
(b)		Electrical	0.01 B	$11,667
(b)		Piping	0.30 B	$350,023
(b)		Insulation for ductwork	0.01 B	$11,667
(b)		Painting	0.01 B	$11,667
		Direct Installation Cost		***$991,733***
	Total Direct Costs			***$2,158,478***
Indirect Costs				
(b)		Engineering	0.10 B	$116,674
(b)		Construction Management	0.10 B	$116,674
(b)		Contractor fees	0.10 B	$116,674
(b)		Start-up	0.01 B	$11,667
(b)		Performance test	0.01 B	$11,667
(b)		Contingencies	0.03 B	$35,002
	Total Indirect Costs			***$408,361***
Total Capital Investment (TCI)				***$2,566,839***

ANNUALIZED COSTS

	COST ITEM	COST FACTOR		RATE		COST ($)
Direct Annual Costs						
	Operating Labor					
(b)	Operator[c]		hours/shift	$31.00	per hour[d]	$0
(b)	Supervisor	15%	of operator labor			$0
	Maintenance					
(b)	Maintenance labor[c]		hours/shift	$34.00	per hour[d]	$0
(b)	Maintenance materials	100%	of maintenance labor			$0
	Utilities[e]					
	Electricity	306	kW	$0.060	per kWh[b]	$161,089
	Total Direct Annual Costs					***$161,089***
Indirect Annual Costs						
	Overhead	60%	Labor and Material Costs			$0
	General and administrative	2%	of TCI			$51,337
	Property taxes	1%	of TCI			$25,668
	Insurance	1%	of TCI			$25,668
	Capital recovery	0.095	x TCI			$243,134
	Life of the control:		15 years at	4.75%	interest	
	Total Indirect Annual Costs					***$345,807***
Total Annual Costs						***$506,897***
Cost Effectiveness ($/ton)						
	Additional PM10 Control Efficiency[f]:	50%				
	PM10 Emissions[g]:	75.6	tpy	Total Annual Costs/Controlled PM10 Emissions:		
	Reduced PM10 Emissions:	37.8	tons of additional PM10 removed annually			***$13,410***

[a] Wet scrubber capital cost based on Section 10.4 in document titled "Emission Control Study - Technology Cost Estimates" by BE&K Engineering for AF&PA, September 2001. The cost of a wet scrubber on a smelt tank was scaled based on BLS throughput capacity. The cost was adjusted from 2001 dollars to 2019 dollars using the Chemical Engineering Plant Cost Index (CEPCI).

[b] Cost information estimated based on the U.S. EPA OAQPS Control Cost Manual, Section 5, Chapter 1, December 1995.

[c] Based on 8760 operating hours.

[d] Nominal Pacific NW pulp and paper mill rates.

[e] Utility cost represents the electrical consumption of the new wet scrubber system, based on the BE&K document cited in footnote (a) and scaled based on the furnace size. No change is estimated for water usage and wastewater disposal.

[f] Control efficiency improvement from replacing the wet scrubber is assumed to be 50% (the approximate difference between the MACT limit and the NSPS limit).

[g] PSEL

Table A-51a

Georgia-Pacific - Wauna

Capital and Annual Costs Associated with Replacing the Smelt Dissolving Tank Wet Scrubber

CAPITAL COSTS[(a)]

	COST ITEM	COST FACTOR	COST ($)
	Direct Costs		
	Purchased Equipment Costs		
(a)	***A*** Equipment Costs		***$988,767***
(b)	Instrumentation	0.10 A	$98,877
(b)	Sales Tax	0.03 A	$29,663
(b)	Freight	0.05 A	$49,438
	B Total Purchased Equipment Cost		***$1,166,745***
	Direct Installation Costs		
(b)	Foundations and Supports	0.12 B	$140,009
(b)	Handling and erection	0.40 B	$466,698
(b)	Electrical	0.01 B	$11,667
(b)	Piping	0.30 B	$350,023
(b)	Insulation for ductwork	0.01 B	$11,667
(b)	Painting	0.01 B	$11,667
	Direct Installation Cost		***$991,733***
	Total Direct Costs		***$2,158,478***
	Indirect Costs		
(b)	Engineering	0.10 B	$116,674
(b)	Construction Management	0.10 B	$116,674
(b)	Contractor fees	0.10 B	$116,674
(b)	Start-up	0.01 B	$11,667
(b)	Performance test	0.01 B	$11,667
(b)	Contingencies	0.03 B	$35,002
	Total Indirect Costs		***$408,361***
	Total Capital Investment (TCI)		***$2,566,839***

ANNUALIZED COSTS

	COST ITEM	COST FACTOR		RATE		COST ($)
	Direct Annual Costs					
	Operating Labor					
(b)	Operator[(c)]		hours/shift	$31.00	per hour[(d)]	$0
(b)	Supervisor	15%	of operator labor			$0
	Maintenance					
(b)	Maintenance labor[(c)]		hours/shift	$34.00	per hour[(d)]	$0
(b)	Maintenance materials	100%	of maintenance labor			$0
	Utilities [(e)]					
	Electricity	306	kW	$0.060	per kWh[(b)]	$147,592
	Total Direct Annual Costs					***$147,592***
	Indirect Annual Costs					
	Overhead	60%	Labor and Material Costs			$0
	General and administrative	2%	of TCI			$51,337
	Property taxes	1%	of TCI			$25,668
	Insurance	1%	of TCI			$25,668
	Capital recovery	0.095	x TCI			$243,134
	Life of the control:	15	years at	4.75%	interest	
	Total Indirect Annual Costs					***$345,807***
	Total Annual Costs					***$493,399***
	Cost Effectiveness ($/ton)					
	Additional PM10 Control Efficiency[(f)]:	50%				
	PM10 Emissions[(g)]:	57.7	tpy		Total Annual Costs/Controlled PM10 Emissions:	
	Reduced PM10 Emissions:	28.8	tons of additional PM10 removed annually			***$17,117***

[(a)] Wet scrubber capital cost based on Section 10.4 in document titled "Emission Control Study - Technology Cost Estimates" by BE&K Engineering for AF&PA, September 2001. The cost of a wet scrubber on a smelt tank was scaled based on BLS throughput capacity. The cost was adjusted from 2001 dollars to 2019 dollars using the Chemical Engineering Plant Cost Index (CEPCI).

[(b)] Cost information estimated based on the U.S. EPA OAQPS Control Cost Manual, Section 5, Chapter 1, December 1995.

[(c)] Based on 8026 operating hours.

[(d)] Nominal Pacific NW pulp and paper mill rates.

[(e)] Utility cost represents the electrical consumption of the new wet scrubber system, based on the BE&K document cited in footnote (a) and scaled based on the furnace size. No change is estimated for water usage and wastewater disposal.

[(f)] Control efficiency improvement from replacing the wet scrubber is assumed to be 50% (the approximate difference between the MACT limit and the NSPS limit).

[(g)] 2017 Actual Emissions

APPENDIX B -
SUPPORTING INFORMATION

IPM Model – Updates to Cost and Performance for APC Technologies

Dry Sorbent Injection for SO_2/HCl Control Cost Development Methodology

Final

April 2017

Project 13527-001

Eastern Research Group, Inc.

Prepared by

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LEGAL NOTICE

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DSI Cost Methodology

Purpose of Cost Algorithms for the IPM Model

The primary purpose of the cost algorithms is to provide generic order-of-magnitude costs for various air quality control technologies that can be applied to the electric power generating industry on a system-wide basis, not on an individual unit basis. Cost algorithms developed for the IPM model are based primarily on a statistical evaluation of cost data available from various industry publications as well as Sargent & Lundy's proprietary database and do not take into consideration site-specific cost issues. By necessity, the cost algorithms were designed to require minimal site-specific information and were based only on a limited number of inputs such as unit size, gross heat rate, baseline emissions, removal efficiency, fuel type, and a subjective retrofit factor.

The outputs from these equations represent the "average" costs associated with the "average" project scope for the subset of data utilized in preparing the equations. The IPM cost equations do not account for site-specific factors that can significantly affect costs, such as flue gas volume and temperature, and do not address regional labor productivity, local workforce characteristics, local unemployment and labor availability, project complexity, local climate, and working conditions. In addition, the indirect capital costs included in the IPM cost equations do not account for all project-related indirect costs, such as project contingency, that a facility would incur to install a retrofit control.

Technology Description

Dry sorbent injection (DSI) is a viable technology for moderate SO_2/HCl reduction on coal-fired boilers. Demonstrations and utility testing have shown SO_2/HCl removals greater than 80% for systems using sodium-based sorbents. The most commonly used sodium-based sorbent is Trona. However, if the goal is only HCl removal, the amount of sorbent injection will be significantly lower. In this case, Trona may still be the most commonly used reagent, but hydrated lime also has been employed in some situations. Because of Trona's high reactivity with SO_2, when this sorbent is used, significant SO_2 removal must occur before high levels of HCl removal can be achieved. Studies show, however, that hydrated lime is quite effective for HCl removal because the need for simultaneous SO_2 removal is much reduced. In either case, actual testing must be carried out before the permanent DSI system for SO_2 or HCl removal is designed.

The level of removal for Trona can vary from 0 to 90% depending on the Normalized Stoichiometric Ratio (NSR) and particulate capture device. NSR is defined as follows:

$$\frac{\left(\frac{\text{(moles of Na injected)}}{(\text{moles of } SO_2 \text{ in flue gas})}\right)}{\text{(theoretical moles of Na required)}}$$

DSI Cost Methodology

The required injection rate for alkali sorbents can vary depending on the required removal efficiency, NSR, and particulate capture device. The costs for an SO_2 mitigation system are primarily dependent on sorbent feed rate. This rate is a function of NSR and the required SO_2 removal (the latter is set by the utility and is not a function of unit size). Therefore, the required SO_2 removal is determined by the user-specified SO_2 emission limit, and the cost estimation is based on sorbent feed rate and not unit size. Because HCl concentrations are low compared with SO_2 concentrations, any unused reagent for SO_2 removal is assumed to be used for HCl removal, resulting in a very small change in the NSR used for SO_2 removal when HCl removal is the main goal.

The sorbent solids can be collected in either an ESP or a baghouse. Baghouses generally achieve greater SO_2 removal efficiencies than ESPs because the presence of filter cake on the bags allows for a longer reaction time between the sorbent solids and the flue gas. Thus, for a given Trona removal efficiency, the NSR is reduced when a baghouse is used for particulate capture.

The dry-sorbent capture ability is also a function of particle surface area. To increase the particle surface area, the sorbent must be injected into a relatively hot flue gas. Heating the solids produces micropores on the particle surface, which greatly improve the sulfur capture ability. For Trona, the sorbent should be injected into flue gas at temperatures above 275°F to maximize the micropore structure. However, if the flue gas is too hot (greater than 800°F), the solids may sinter, reducing their surface area and thus lowering the SO_2 removal efficiency of the sorbent.

Another way to increase surface area is to mechanically reduce the particle size by grinding the sorbent. Typically, Trona is delivered unmilled. The ore is ground such that the unmilled product has an average particle size of approximately 30 μm. Commercial testing has shown that the reactivity of the Trona can be increased when the sorbent is ground to produce particles smaller than 30 μm. In the cost estimation methodology, the Trona is assumed to be delivered in the unmilled state only. To mill the Trona, in-line mills are continuously used during the Trona injection process. Therefore, the delivered cost of Trona will not change; only the reactivity of the sorbent and amount used change when Trona is milled.

Ultimately, the NSR required for a given removal is a function of Trona particle size and particulate capture equipment. In the cost program, the user can choose either as-delivered Trona (approximately 30 μm average size) or in-line milled Trona (approximately 15 μm average size) for injection. The average Trona particle size and the type of particulate removal equipment both contribute to the predicted Trona feed rate.

DSI Cost Methodology

Establishment of the Cost Basis

For wet or dry FGD systems, sulfur removal is generally specified at the maximum achievable level. With those systems, costs are primarily a function of plant size and target sulfur removal rate. However, DSI systems are quite different. The major cost for the DSI system is the sorbent itself. The sorbent feed rate is a function of sulfur generation rate, particulate collection device, and removal efficiency. To account for all of the variables, the capital cost was established based on a sorbent feed rate, which is calculated from user input variables. Cost data for several DSI systems were reviewed and a relationship was developed for the capital costs of the system on a sorbent feed-rate basis.

Methodology

Inputs

Several input variables are required in order to predict future retrofit costs. The sulfur feed rate and NSR are the major variables for the cost estimate. The NSR is a function of the following:

- Removal efficiency,
- Sorbent particle size, and
- Particulate capture device.

A retrofit factor that equates to difficulty in construction of the system must be defined. The gross unit size and gross heat rate will factor into the amount of sulfur generated.

Based on commercial testing, removal efficiencies with DSI are limited by the particulate capture device employed. Trona, when captured in an ESP, typically removes 40 to 50% of SO_2 without an increase in particulate emissions, whereas hydrated lime may remove an even lower percentage of SO_2. A baghouse used with sodium-based sorbents generally achieves a higher SO_2 removal efficiency (70 to 90%) than that of an ESP. DSI technology, however, should not be applied to fuels with sulfur content greater than 2 lb SO_2/MMBtu.

Units with a baghouse and limited NO_X control that target a high SO_2 removal efficiency with sodium sorbents may experience a brown plume resulting from the conversion of NO to NO_2. The formation of NO_2 would then have to be addressed by adding an adsorbent, such as activated carbon, into the flue gas. However, many coal-fired units control NO_X to a sufficiently low level that a brown plume should not be an issue with sodium-based DSI. Therefore, this algorithm does not incorporate any additional costs to control NO_2.

DSI Cost Methodology

The equations provided in the cost methodology spreadsheet allow the user to input the required removal efficiency, within the limits of the technology. To simplify the correlation between efficiency and technology, SO_2 removal should be set at 50% with an ESP and 70% with a baghouse. The simplified sorbent NSR would then be calculated as follows:

For an ESP at the target 50% removal —
Unmilled Trona NSR = 2.00
Milled Trona NSR = 1.40

For a baghouse at the target 70% removal —
Unmilled Trona NSR = 1.90
Milled Trona NSR = 1.50

The algorithm identifies the maximum expected HCl removal based on SO_2 removal. The HCl removal should be limited to achieve 0.002 lb HCl/MBtu to meet the Mercury Air Toxics (MATS) regulation. The hydrated lime algorithm should be used only for the HCl removal requirement. For hydrated lime injection systems, the SO_2 removal should be limited to 20% to achieve maximum HCl removal.

The correlation could be further simplified by assuming that only milled Trona is used. The current trend in the industry is to use in-line milling of the Trona to improve its utilization. For a minor increase in capital, milling can greatly reduce the variable operating expenses, thus it is recommended that only milled Trona be considered in the simplified algorithm.

Outputs

Total Project Costs (TPC)

First, the base installed cost for the complete DSI system is calculated (BM). The base installed cost includes the following:

- All equipment,
- Installation.
- Buildings,
- Foundations,
- Electrical, and
- Average retrofit difficulty.

The base module cost is adjusted by the selection of in-line milling equipment. The base installed cost is then increased by the following:

DSI Cost Methodology

- Engineering and construction management costs at 10% of the BM cost;
- Labor adjustment for 6 x 10-hour shift premium, per diem, etc., at 5% of the BM cost; and
- Contractor profit and fees at 5% of the BM cost.

A capital, engineering, and construction cost subtotal (CECC) is established as the sum of the BM and the additional engineering and construction fees.

Additional costs and financing expenditures for the project are computed based on the CECC. Financing and additional project costs include the following:

- Owner's home office costs (owner's engineering, management, and procurement) are added at 5% of the CECC.
- Allowance for Funds Used During Construction (AFUDC) is added at 0% of the CECC and owner's costs because these projects are expected to be completed in less than a year.

The total project cost is based on a multiple lump-sum contract approach. Should a turnkey engineering procurement construction (EPC) contract be executed, the total project cost could be 10 to 15% higher than what is currently estimated.

Escalation is not included in the estimate. The total project cost (TPC) is the sum of the CECC and the additional costs and financing expenditures.

Fixed O&M (FOM)

The fixed operating and maintenance (O&M) cost is a function of the additional operations staff (FOMO), maintenance labor and materials (FOMM), and administrative labor (FOMA) associated with the DSI installation. The FOM is the sum of the FOMO, FOMM, and FOMA.

The following factors and assumptions underlie calculations of the FOM:

- All of the FOM costs are tabulated on a per-kilowatt-year (kW-yr) basis.
- In general, 2 additional operators are required for a DSI system. The FOMO is based on the number of additional operations staff required.
- The fixed maintenance materials and labor is a direct function of the process capital cost (BM).
- The administrative labor is a function of the FOMO and FOMM.

DSI Cost Methodology

Variable O&M (VOM)

Variable O&M is a function of the following:

- Reagent use and unit costs,
- Waste production and unit disposal costs, and
- Additional power required and unit power cost.

The following factors and assumptions underlie calculations of the VOM:

- All of the VOM costs are tabulated on a per megawatt-hour (MWh) basis.
- The additional power required includes increased fan power to account for the added DSI system and, as applicable, air blowers and transport-air drying equipment for the SO_2 mitigation system.
- The additional power is reported as a percentage of the total unit gross production. In addition, a cost associated with the additional power requirements can be included in the total variable costs.
- The reagent usage is a function of NSR and the required SO_2 removal. The estimated NSR is a function of the removal efficiency required. The basis for total reagent rate purity is 95% for hydrated lime and 98% for Trona.
- The waste-generation rate, which is based on the reaction of Trona or hydrated lime with SO_2, is a function of the sorbent feed rate. The waste-generation rate is also adjusted for excess sorbent fed. The reaction products in the waste for hydrated lime and Trona mainly contain $CaSO_4$ and Na_2SO_4 and unreacted dry sorbent such as $Ca(OH)_2$ and Na_2CO_3, respectively.
- The user can remove fly ash disposal volume from the waste disposal cost to reflect the situation where the unit has separate particulate capture devices for fly ash and dry sorbent.
- If Trona is the selected sorbent, the fly ash captured with this sodium sorbent in the same particulate control device must be landfilled. Typical ash content for each fuel is used to calculate a total fly ash production rate. The fly ash production is added to the sorbent waste to account for a total waste stream in the O&M analysis.

DSI Cost Methodology

Input options are provided for the user to adjust the variable O&M costs per unit. Average default values are included in the base estimate. The variable O&M costs per unit options are as follows:

- Reagent cost in $/ton.
- Waste disposal costs in $/ton that should vary with the type of waste being disposed.
- Auxiliary power cost in $/kWh; no noticeable escalation has been observed for auxiliary power cost since 2012.
- Operating labor rate (including all benefits) in $/hr.

The variables that contribute to the overall VOM are:

VOMR = Variable O&M costs for reagent

VOMW = Variable O&M costs for waste disposal

VOMP = Variable O&M costs for additional auxiliary power

The total VOM is the sum of VOMR, VOMW, and VOMP. The additional auxiliary power requirement is also reported as a percentage of the total gross power of the unit. Table 1 contains an example of the complete capital and O&M cost estimate worksheet for a DSI installation with milled Trona injection ahead of an ESP. Table 2 contains an example of the complete capital and O&M cost estimate worksheet for a DSI installation with milled Trona injection ahead of a baghouse. Table 3 contains an example of the complete capital and O&M cost estimate worksheet for a DSI installation with unmilled Trona injection ahead of an ESP. Table 4 contains an example of the complete capital and O&M cost estimate worksheet for a DSI installation with unmilled Trona ahead of a baghouse. Table 5 contains an example of the complete capital and O&M cost estimate worksheet for a DSI installation with hydrated lime injection ahead of an ESP. Table 6 contains an example of the complete capital and O&M cost estimate worksheet for a DSI installation with hydrated lime ahead of a baghouse.

DSI Cost Methodology

Table 1. Example of a Complete Cost Estimate for a Milled Trona DSI System with an ESP

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input
Type of Coal	E		Bituminous	<--- User Input
Particulate Capture	F		ESP	<--- User Input
Sorbent	G		Milled Trona	<--- User Input
Removal Target	H	(%)	50	Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with an BGH = 80% Milled Trona with an BGH = 90% Hydrated Lime with an ESP = 30% Hydrated Lime with a BGH = 50%
Heat Input	J	(Btu/hr)	4.75E+09	A*C*1000
NSR	K		1.43	Unmilled Trona with an ESP = if (H<40,0.0350*H,0.352e^(0.0345*H)) Milled Trona with an ESP = if (H<40,0.0270*H,0.353e^(0.0280*H)) Unmilled Trona with a BGH = if (H<40,0.0215*H,0.295e^(0.0267*H)) Milled Trona with a BGH = if (H<40,0.0160*H,0.208e^(0.0281*H)) Hydrated Lime with an ESP = 0.504*H^0.3905 Hydrated Lime with a BGH = 0.0087*H+0.6505
Sorbent Feed Rate	M	(ton/hr)	16.33	Trona = (1.2011 x 10^-06)*K*A*C*D Hydrated Lime = (6.0055 x 10^-07)*K*A*C*D
Estimated HCl Removal	V	(%)	93	Milled or Unmilled Trona with an ESP = 60.86*H^0.1081, or 0.002 lb/MBtu Milled or Unmilled Trona with a BGH =84.598*H^0.0346 or 0.002 lb/MBtu Hydrated Lime with an ESP = 54.92*H^0.197 or 0.002 lb/MBtu Hydrated Lime with a BGH = 0.0085*H+99.12 or 0.002 lb/MBtu
Sorbent Waste Rate	N	(ton/hr)	13.12	Trona = (0.7387 + 0.00185*H/K)*M Lime = (1.00 + 0.00777*H/K)*M Waste product adjusted for a maximum inert content of 5% for Trona and 2% for Hydrated Lime.
Fly Ash Waste Rate Include in VOM? ☑	P	(ton/hr)	20.73	(A*C)*Ash in Coal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2; HHV = 11000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2; HHV = 8400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal
Aux Power **Include in VOM?** ☑	**Q**	**(%)**	**0.65**	=if Milled Trona M*20/A else M*18/A
Sorbent Cost	R	($/ton)	170	<--- User Input (Trona = $170, Hydrated Lime = $150)
Waste Disposal Cost	S	($/ton)	50	<--- User Input (Disposal cost with fly ash = $50. Without fly ash, the sorbent waste alone will be more dificult to dispose = $100)
Aux Power Cost	T	($/kWh)	0.06	<--- User Input
Operating Labor Rate	U	($/hr)	60	<--- User Input (Labor cost including all benefits)

Costs are all based on 2016 dollars

		Example	Comments
Capital Cost Calculation			
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty			
BM ($) = Unmilled Trona or Hydrated Lime if (M>25 then (745,000*B*M) else 7,500,000*B*(M^0.284) Milled Trona if (M>25 then (820,000*B*M) else 8,300,000*B*(M^0.284)	$	18,348,000	Base module for unmilled sorbent includes all equipment from unloading to injection, including dehumification system
BM ($/KW) =		37	Base module cost per kW
Total Project Cost			
A1 = 10% of BM	$	1,835,000	Engineering and Construction Management costs
A2 = 5% of BM	$	917,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc...
A3 = 5% of BM	$	917,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3	**$**	**22,017,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) - Excludes Owner's Costs =		**44**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC	$	1,101,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1	**$**	**23,118,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =		**46**	Total project cost per kW without AFUDC
B2 = 0% of (CECC + B1)	$	-	AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2	**$**	**23,118,000**	Total project cost
TPC ($/kW) =		**46**	Total project cost per kW
Fixed O&M Cost			
FOMO ($/kW yr) = (2 additional operator)*2080*U/(A*1000)	$	0.50	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.01/(B*A*1000)	$	0.37	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.02	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**$**	**0.89**	Total Fixed O&M costs
Variable O&M Cost			
VOMR ($/MWh) = M*R/A	$	5.55	Variable O&M costs for sorbent
VOMW ($/MWh) = (N+P)*S/A	$	3.39	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not removed prior to the sorbent injection
VOMP ($/MWh) =Q*T*10	$	0.39	Variable O&M costs for additional auxiliary power required (Refer to Aux Power % above)
VOM ($/MWh) = VOMR + VOMW + VOMP	**$**	**9.33**	

DSI Cost Methodology

Table 2. Example of a Complete Cost Estimate for a Milled Trona DSI System with a Baghouse

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input
Type of Coal	E		Bituminous	<--- User Input
Particulate Capture	F		Baghouse	<--- User Input
Sorbent	G		Milled Trona	<--- User Input
Removal Target	H	(%)	50	Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with an BGH = 80% Milled Trona with an BGH = 90% Hydrated Lime with an ESP = 30% Hydrated Lime with a BGH = 50%
Heat Input	J	(Btu/hr)	4.75E+09	A*C*1000
NSR	K		0.85	Unmilled Trona with an ESP = if (H<40,0.0350*H,0.352e^(0.0345*H)) Milled Trona with an ESP = if (H<40,0.0270*H,0.353e^(0.0280*H)) Unmilled Trona with a BGH = if (H<40,0.0215*H,0.295e^(0.0267*H)) Milled Trona with a BGH = if (H<40,0.0160*H,0.208e^(0.0281*H)) Hydrated Lime with an ESP = 0.504*H^0.3905 Hydrated Lime with a BGH = 0.0087*H+0.6505
Sorbent Feed Rate	M	(ton/hr)	9.67	Trona = (1.2011 x 10^-06)*K*A*C*D Hydrated Lime = (6.0055 x 10^-07)*K*A*C*D
Estimated HCl Removal	V	(%)	97	Milled or Unmilled Trona with an ESP = 60.86*H^0.1081, or 0.002 lb/MBtu Milled or Unmilled Trona with a BGH =84.598*H^0.0346 or 0.002 lb/MBtu Hydrated Lime with an ESP = 54.92*H^0.197 or 0.002 lb/MBtu Hydrated Lime with a BGH = 0.0085*H+99.12 or 0.002 lb/MBtu
Sorbent Waste Rate	N	(ton/hr)	8.20	Trona = (0.7387 + 0.00185*H/K)*M Lime = (1.00 + 0.00777*H/K)*M Waste product adjusted for a maximum inert content of 5% for Trona and 2% for Hydrated Lime.
Fly Ash Waste Rate Include in VOM? ☑	P	(ton/hr)	20.73	(A*C)*Ash in Coal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2; HHV = 11000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2; HHV = 8400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal
Aux Power **Include in VOM?** ☑	**Q**	**(%)**	**0.39**	=if Milled Trona M*20/A else M*18/A
Sorbent Cost	R	($/ton)	170	<--- User Input (Trona = $170, Hydrated Lime = $150)
Waste Disposal Cost	S	($/ton)	50	<--- User Input (Disposal cost with fly ash = $50. Without fly ash, the sorbent waste alone will be more dificult to dispose = $100)
Aux Power Cost	T	($/kWh)	0.06	<--- User Input
Operating Labor Rate	U	($/hr)	60	<--- User Input (Labor cost including all benefits)

Costs are all based on 2016 dollars

Capital Cost Calculation		Example	Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty			
BM ($) = Unmilled Trona or Hydrated Lime if (M>25 then (745,000*B*M) else 7,500,000*B*(M^0.284) Milled Trona if (M>25 then (820,000*B*M) else 8,300,000*B*(M^0.284)	$	15,812,000	Base module for unmilled sorbent includes all equipment from unloading to injection, including dehumidification system
BM ($/KW) =		32	Base module cost per kW
Total Project Cost			
A1 = 10% of BM	$	1,581,000	Engineering and Construction Management costs
A2 = 5% of BM	$	791,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 5% of BM	$	791,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3	**$**	**18,975,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) - Excludes Owner's Costs =		**38**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC	$	949,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1	**$**	**19,924,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =		**40**	Total project cost per kW without AFUDC
B2 = 0% of (CECC + B1)	$	-	AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2	**$**	**19,924,000**	Total project cost
TPC ($/kW) =		**40**	Total project cost per kW
Fixed O&M Cost			
FOMO ($/kW yr) = (2 additional operator)*2080*U/(A*1000)	$	0.50	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.01/(B*A*1000)	$	0.32	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.02	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**$**	**0.83**	Total Fixed O&M costs
Variable O&M Cost			
VOMR ($/MWh) = M*R/A	$	3.29	Variable O&M costs for sorbent
VOMW ($/MWh) = (N+P)*S/A	$	2.89	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not removed prior to the sorbent injection
VOMP ($/MWh) =Q*T*10	$	0.23	Variable O&M costs for additional auxiliary power required (Refer to Aux Power % above)
VOM ($/MWh) = VOMR + VOMW + VOMP	**$**	**6.41**	

DSI Cost Methodology

Table 3. Example of a Complete Cost Estimate for an Unmilled Trona DSI System with an ESP

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	500	<-- User Input
Retrofit Factor	B		1	<-- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<-- User Input
SO2 Rate	D	(lb/MMBtu)	2	<-- User Input
Type of Coal	E		Bituminous	<-- User Input
Particulate Capture	F		ESP	<-- User Input
Sorbent	G		Unmilled Trona	<-- User Input
Removal Target	H	(%)	50	Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with an BGH = 80% Milled Trona with an BGH = 90% Hydrated Lime with an ESP = 30% Hydrated Lime with a BGH = 50%
Heat Input	J	(Btu/hr)	4.75E+09	A*C*1000
NSR	K		1.98	Unmilled Trona with an ESP = if (H<40,0.0350*H,0.352e^(0.0345*H)) Milled Trona with an ESP = if (H<40,0.0270*H,0.353e^(0.0280*H)) Unmilled Trona with a BGH = if (H<40,0.0215*H,0.295e^(0.0267*H)) Milled Trona with a BGH = if (H<40,0.0160*H,0.208e^(0.0281*H)) Hydrated Lime with an ESP = 0.504*H^0.3905 Hydrated Lime with a BGH = 0.0087*H+0.6505
Sorbent Feed Rate	M	(ton/hr)	22.54	Trona = (1.2011 x 10^-06)*K*A*C*D Hydrated Lime = (6.0055 x 10^-07)*K*A*C*D
Estimated HCl Removal	V	(%)	93	Milled or Unmilled Trona with an ESP = 60.86*H^0.1081, or 0.002 lb/MBtu Milled or Unmilled Trona with a BGH =84.598*H^0.0346 or 0.002 lb/MBtu Hydrated Lime with an ESP = 54.92*H^0.197 or 0.002 lb/MBtu Hydrated Lime with a BGH = 0.0085*H+99.12 or 0.002 lb/MBtu
Sorbent Waste Rate	N	(ton/hr)	17.71	Trona = (0.7387 + 0.00185*H/K)*M Lime = (1.00 + 0.00777*H/K)*M Waste product adjusted for a maximum inert content of 5% for Trona and 2% for Hydrated Lime.
Fly Ash Waste Rate Include in VOM? ☑	P	(ton/hr)	20.73	(A*C)*Ash in Coal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2; HHV = 11000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2; HHV = 8400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal
Aux Power Include in VOM? ☑	**Q**	**(%)**	**0.81**	=if Milled Trona M*20/A else M*18/A
Sorbent Cost	R	($/ton)	225	<-- User Input (Trona = $170, Hydrated Lime = $150)
Waste Disposal Cost	S	($/ton)	50	<-- User Input (Disposal cost with fly ash = $50. Without fly ash, the sorbent waste alone will be more dificult to dispose = $100)
Aux Power Cost	T	($/kWh)	0.06	<-- User Input
Operating Labor Rate	U	($/hr)	60	<-- User Input (Labor cost including all benefits)

Costs are all based on 2016 dollars

Capital Cost Calculation		Example	Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty			
BM ($) = Unmilled Trona or Hydrated Lime if (M>25 then (745,000*B*M) else 7,500,000*B*(M^0.284) Milled Trona if (M>25 then (820,000*B*M) else 8,300,000*B*(M^0.284)	$	18,168,000	Base module for unmilled sorbent includes all equipment from unloading to injection, including dehumidification system
BM ($/KW) =		36	Base module cost per kW
Total Project Cost			
A1 = 10% of BM	$	1,817,000	Engineering and Construction Management costs
A2 = 5% of BM	$	908,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc...
A3 = 5% of BM	$	908,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3	**$**	**21,801,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) - Excludes Owner's Costs =		**44**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC	$	1,090,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1	**$**	**22,891,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =		**46**	Total project cost per kW without AFUDC
B2 = 0% of (CECC + B1)	$	-	AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2	**$**	**22,891,000**	Total project cost
TPC ($/kW) =		**46**	Total project cost per kW
Fixed O&M Cost			
FOMO ($/kW yr) = (2 additional operator)*2080*U/(A*1000)	$	0.50	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.01/(B*A*1000)	$	0.36	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.02	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**$**	**0.88**	Total Fixed O&M costs
Variable O&M Cost			
VOMR ($/MWh) = M*R/A	$	10.14	Variable O&M costs for sorbent
VOMW ($/MWh) = (N+P)*S/A	$	3.84	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not removed prior to the sorbent injection
VOMP ($/MWh) =Q*T*10	$	0.49	Variable O&M costs for additional auxiliary power required (Refer to Aux Power % above)
VOM ($/MWh) = VOMR + VOMW + VOMP	**$**	**14.47**	

DSI Cost Methodology

Table 4. Example of a Complete Cost Estimate for an Unmilled Trona DSI System with a Baghouse

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input
Type of Coal	E		Bituminous	<--- User Input
Particulate Capture	F		Baghouse	<--- User Input
Sorbent	G		Unmilled Trona	<--- User Input
Removal Target	H	(%)	50	Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with an BGH = 80% Milled Trona with an BGH = 90% Hydrated Lime with an ESP = 30% Hydrated Lime with a BGH = 50%
Heat Input	J	(Btu/hr)	4.75E+09	A*C*1000
NSR	K		1.12	Unmilled Trona with an ESP = if (H<40,0.0350*H,0.352e^(0.0345*H)) Milled Trona with an ESP = if (H<40,0.0270*H,0.353e^(0.0280*H)) Unmilled Trona with a BGH = if (H<40,0.0215*H,0.295e^(0.0267*H)) Milled Trona with a BGH = if (H<40,0.0160*H,0.208e^(0.0281*H)) Hydrated Lime with an ESP = 0.504*H^0.3905 Hydrated Lime with a BGH = 0.0087*H+0.6505
Sorbent Feed Rate	M	(ton/hr)	12.79	Trona = (1.2011 x 10^-06)*K*A*C*D Hydrated Lime = (6.0055 x 10^-07)*K*A*C*D
Estimated HCl Removal	V	(%)	97	Milled or Unmilled Trona with an ESP = 60.86*H^0.1081, or 0.002 lb/MBtu Milled or Unmilled Trona with a BGH =84.598*H^0.0346 or 0.002 lb/MBtu Hydrated Lime with an ESP = 54.92*H^0.197 or 0.002 lb/MBtu Hydrated Lime with a BGH = 0.0085*H+99.12 or 0.002 lb/MBtu
Sorbent Waste Rate	N	(ton/hr)	10.50	Trona = (0.7387 + 0.00185*H/K)*M Lime = (1.00 + 0.00777*H/K)*M Waste product adjusted for a maximum inert content of 5% for Trona and 2% for Hydrated Lime.
Fly Ash Waste Rate Include in VOM? ☑	P	(ton/hr)	20.73	(A*C)*Ash in Coal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2; HHV = 11000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2; HHV = 8400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal
Aux Power **Include in VOM?** ☑	**Q**	**(%)**	**0.46**	=if Milled Trona M*20/A else M*18/A
Sorbent Cost	R	($/ton)	225	<--- User Input (Trona = $170, Hydrated Lime = $150)
Waste Disposal Cost	S	($/ton)	50	<--- User Input (Disposal cost with fly ash = $50. Without fly ash, the sorbent waste alone will be more dificult to dispose = $100)
Aux Power Cost	T	($/kWh)	0.06	<--- User Input
Operating Labor Rate	U	($/hr)	60	<--- User Input (Labor cost including all benefits)

Costs are all based on 2016 dollars

Capital Cost Calculation		Example	Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty			
BM ($) = Unmilled Trona or Hydrated Lime if (M>25 then (745,000*B*M) else 7,500,000*B*(M^0.284) Milled Trona if (M>25 then (820,000*B*M) else 8,300,000*B*(M^0.284)	$	15,468,000	Base module for unmilled sorbent includes all equipment from unloading to injection, including dehumification system
BM ($/KW) =		31	Base module cost per kW
Total Project Cost			
A1 = 10% of BM	$	1,547,000	Engineering and Construction Management costs
A2 = 5% of BM	$	773,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc...
A3 = 5% of BM	$	773,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3	**$**	**18,561,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) - Excludes Owner's Costs =		**37**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC	$	928,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1	**$**	**19,489,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =		**39**	Total project cost per kW without AFUDC
B2 = 0% of (CECC + B1)	$	-	AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2	**$**	**19,489,000**	Total project cost
TPC ($/kW) =		**39**	Total project cost per kW
Fixed O&M Cost			
FOMO ($/kW yr) = (2 additional operator)*2080*U/(A*1000)	$	0.50	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.01/(B*A*1000)	$	0.31	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.02	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**$**	**0.83**	Total Fixed O&M costs
Variable O&M Cost			
VOMR ($/MWh) = M*R/A	$	5.76	Variable O&M costs for sorbent
VOMW ($/MWh) = (N+P)*S/A	$	3.12	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not removed prior to the sorbent injection
VOMP ($/MWh) =Q*T*10	$	0.28	Variable O&M costs for additional auxiliary power required (Refer to Aux Power % above)
VOM ($/MWh) = VOMR + VOMW + VOMP	**$**	**9.16**	

DSI Cost Methodology

Table 5. Example of a Complete Cost Estimate for a Hydrated Lime DSI System with an ESP

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input
Type of Coal	E		Bituminous	<--- User Input
Particulate Capture	F		ESP	<--- User Input
Sorbent	G		Hydrated Lime	<--- User Input
Removal Target	H	(%)	30	Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with an BGH = 80% Milled Trona with an BGH = 90% Hydrated Lime with an ESP = 30% Hydrated Lime with a BGH = 50%
Heat Input	J	(Btu/hr)	4.75E+09	A*C*1000
NSR	K		1.90	Unmilled Trona with an ESP = if (H<40,0.0350*H,0.352e^(0.0345*H)) Milled Trona with an ESP = if (H<40,0.0270*H,0.353e^(0.0280*H)) Unmilled Trona with a BGH = if (H<40,0.0215*H,0.295e^(0.0267*H)) Milled Trona with a BGH = if (H<40,0.0160*H,0.208e^(0.0281*H)) Hydrated Lime with an ESP = 0.504*H^0.3905 Hydrated Lime with a BGH = 0.0087*H+0.6505
Sorbent Feed Rate	M	(ton/hr)	10.85	Trona = (1.2011 x 10^-06)*K*A*C*D Hydrated Lime = (6.0055 x 10^-07)*K*A*C*D
Estimated HCl Removal	V	(%)	95	Milled or Unmilled Trona with an ESP = 60.86*H^0.1081, or 0.002 lb/MBtu Milled or Unmilled Trona with a BGH =84.598*H^0.0346 or 0.002 lb/MBtu Hydrated Lime with an ESP = 54.92*H^0.197 or 0.002 lb/MBtu Hydrated Lime with a BGH = 0.0085*H+99.12 or 0.002 lb/MBtu
Sorbent Waste Rate	N	(ton/hr)	12.18	Trona = (0.7387 + 0.00185*H/K)*M Lime = (1.00 + 0.00777*H/K)*M Waste product adjusted for a maximum inert content of 5% for Trona and 2% for Hydrated Lime.
Fly Ash Waste Rate Include in VOM? ☑	P	(ton/hr)	20.73	(A*C)*Ash in Coal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2; HHV = 11000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2; HHV = 8400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal
Aux Power **Include in VOM?** ☑	**Q**	**(%)**	**0.39**	=if Milled Trona M*20/A else M*18/A
Sorbent Cost	R	($/ton)	150	<--- User Input (Trona = $170, Hydrated Lime = $150)
Waste Disposal Cost	S	($/ton)	50	<--- User Input (Disposal cost with fly ash = $50. Without fly ash, the sorbent waste alone will be more dificult to dispose = $100)
Aux Power Cost	T	($/kWh)	0.06	<--- User Input
Operating Labor Rate	U	($/hr)	60	<--- User Input (Labor cost including all benefits)

Costs are all based on 2016 dollars

		Example	Comments
Capital Cost Calculation			
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty			
BM ($) = Unmilled Trona or Hydrated Lime if (M>25 then (745,000*B*M) else 7,500,000*B*(M^0.284) Milled Trona if (M>25 then (820,000*B*M) else 8,300,000*B*(M^0.284)	$	14,762,000	Base module for unmilled sorbent includes all equipment from unloading to injection, including dehumidification system
BM ($/KW) =		30	Base module cost per kW
Total Project Cost			
A1 = 10% of BM	$	1,476,000	Engineering and Construction Management costs
A2 = 5% of BM	$	738,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc...
A3 = 5% of BM	$	738,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3	**$**	**17,714,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) - Excludes Owner's Costs =		**35**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC	$	886,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1	**$**	**18,600,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =		**37**	Total project cost per kW without AFUDC
B2 = 0% of (CECC + B1)	$	-	AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2	**$**	**18,600,000**	Total project cost
TPC ($/kW) =		**37**	Total project cost per kW
Fixed O&M Cost			
FOMO ($/kW yr) = (2 additional operator)*2080*U/(A*1000)	$	0.50	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.01/(B*A*1000)	$	0.30	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.02	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**$**	**0.81**	Total Fixed O&M costs
Variable O&M Cost			
VOMR ($/MWh) = M*R/A	$	3.26	Variable O&M costs for sorbent
VOMW ($/MWh) = (N+P)*S/A	$	3.29	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not removed prior to the sorbent injection
VOMP ($/MWh) =Q*T*10	$	0.23	Variable O&M costs for additional auxiliary power required (Refer to Aux Power % above)
VOM ($/MWh) = VOMR + VOMW + VOMP	**$**	**6.78**	

DSI Cost Methodology

Table 6. Example of a Complete Cost Estimate for a Hydrated Lime DSI System with a Baghouse

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input
Type of Coal	E		Bituminous	<--- User Input
Particulate Capture	F		Baghouse	<--- User Input
Sorbent	G		Hydrated Lime	<--- User Input
Removal Target	H	(%)	50	Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with an BGH = 80% Milled Trona with an BGH = 90% Hydrated Lime with an ESP = 30% Hydrated Lime with a BGH = 50%
Heat Input	J	(Btu/hr)	4.75E+09	A*C*1000
NSR	K		1.09	Unmilled Trona with an ESP = if (H<40,0.0350*H,0.352e^(0.0345*H)) Milled Trona with an ESP = if (H<40,0.0270*H,0.353e^(0.0280*H)) Unmilled Trona with a BGH = if (H<40,0.0215*H,0.295e^(0.0267*H)) Milled Trona with a BGH = if (H<40,0.0160*H,0.208e^(0.0281*H)) Hydrated Lime with an ESP = 0.504*H^0.3905 Hydrated Lime with a BGH = 0.0087*H+0.6505
Sorbent Feed Rate	M	(ton/hr)	6.19	Trona = (1.2011 x 10^-06)*K*A*C*D Hydrated Lime = (6.0055 x 10^-07)*K*A*C*D
Estimated HCl Removal	V	(%)	99	Milled or Unmilled Trona with an ESP = 60.86*H^0.1081, or 0.002 lb/MBtu Milled or Unmilled Trona with a BGH =84.598*H^0.0346 or 0.002 lb/MBtu Hydrated Lime with an ESP = 54.92*H^0.197 or 0.002 lb/MBtu Hydrated Lime with a BGH = 0.0085*H+99.12 or 0.002 lb/MBtu
Sorbent Waste Rate	N	(ton/hr)	8.41	Trona = (0.7387 + 0.00185*H/K)*M Lime = (1.00 + 0.00777*H/K)*M Waste product adjusted for a maximum inert content of 5% for Trona and 2% for Hydrated Lime.
Fly Ash Waste Rate Include in VOM? ☑	P	(ton/hr)	20.73	(A*C)*Ash in Coal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2; HHV = 11000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2; HHV = 8400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal
Aux Power **Include in VOM?** ☑	**Q**	**(%)**	**0.22**	=if Milled Trona M*20/A else M*18/A
Sorbent Cost	R	($/ton)	150	<--- User Input (Trona = $170, Hydrated Lime = $150)
Waste Disposal Cost	S	($/ton)	50	<--- User Input (Disposal cost with fly ash = $50. Without fly ash, the sorbent waste alone will be more dificult to dispose = $100)
Aux Power Cost	T	($/kWh)	0.06	<--- User Input
Operating Labor Rate	U	($/hr)	60	<--- User Input (Labor cost including all benefits)

Costs are all based on 2016 dollars

Capital Cost Calculation		Example	Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty			
BM ($) = Unmilled Trona or Hydrated Lime if (M>25 then (745,000*B*M) else 7,500,000*B*(M^0.284) Milled Trona if (M>25 then (820,000*B*M) else 8,300,000*B*(M^0.284)	$	12,588,000	Base module for unmilled sorbent includes all equipment from unloading to injection, including dehumification system
BM ($/KW) =		25	Base module cost per kW
Total Project Cost			
A1 = 10% of BM	$	1,259,000	Engineering and Construction Management costs
A2 = 5% of BM	$	629,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 5% of BM	$	629,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3	**$**	**15,105,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) - Excludes Owner's Costs =		**30**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC	$	755,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1	**$**	**15,860,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =		**32**	Total project cost per kW without AFUDC
B2 = 0% of (CECC + B1)	$	-	AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2	**$**	**15,860,000**	Total project cost
TPC ($/kW) =		**32**	Total project cost per kW
Fixed O&M Cost			
FOMO ($/kW yr) = (2 additional operator)*2080*U/(A*1000)	$	0.50	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.01/(B*A*1000)	$	0.25	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.02	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**$**	**0.77**	Total Fixed O&M costs
Variable O&M Cost			
VOMR ($/MWh) = M*R/A	$	1.86	Variable O&M costs for sorbent
VOMW ($/MWh) = (N+P)*S/A	$	2.91	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not removed prior to the sorbent injection
VOMP ($/MWh) =Q*T*10	$	0.13	Variable O&M costs for additional auxiliary power required (Refer to Aux Power % above)
VOM ($/MWh) = VOMR + VOMW + VOMP	**$**	**4.91**	

AF&PA®

Emission Control Study – Technology Cost Estimates

American Forest & Paper Association
Washington, D.C.

BE&K Engineering
Birmingham, Alabama
September 2001
Contract 50-01-0089

Table of Contents

1. Results

See "AF&PA Emission Control Summary Sheet" Excel Spreadsheet

2. Capital Cost Estimate Basis

The capital cost estimate is based upon similar projects that have been done within the last 10 years. The costs were escalated to 2001 dollars, where necessary. The capital cost estimates were divided into labor, materials, subcontracts, and equipment. The 0.6 power conversion [Cost of Project A x (AF&PA rate / Project A)$^{0.6}$] rate was used to adjust the estimated costs to the AF&PA sizing criteria for each control technology.

For some of the selected technologies – Mercury removal, VOC removal on paper machines, use of SCR on a non-gas fired combustion unit, use of SNCR on recovery furnace, and black liquor gasification - Research & Development costs were factored in. The R&D costs were assumed to be 0.5 to 1.5% of the direct costs – labor, materials, subcontract, and equipment.

The labor cost includes the labor rate and construction indirects (i.e., equipment rental, small tool rentals, payroll, temporary facilities, home office and field office expenses, and profit). The material cost represents the cost for the materials of construction such as concrete, pipe, electrical conduit, steel, etc. The subcontract cost represents the cost for the specialty items such as siding, piping, field-erected tanks, cooling towers, etc. The equipment cost includes the cost for the control equipment, motors, instrumentation, etc.

The major process equipment was based on quotes, recent projects, and similar projects. The labor work-hours and materials of construction were based on historical data and similar projects. The basis for all construction costs is for the Southeastern United States.

The engineering cost was based upon 15% of the total direct costs (i.e., sum of labor, materials, subcontract, and equipment costs). The contingency was based upon 20% of the total direct costs. The owner's cost (i.e., corporate and mill engineering, training, builder's risk insurance, checkout and start-up, etc.) was based upon 5% of the total direct costs. The construction management cost was base upon 5% of the total direct costs.

Although process or equipment downtime was considered for inclusion in the analysis, it was discarded as being of minimal impact. A net downtime analysis was conducted which initially assumed that the majority of the work would be done during scheduled downtime. Then the net downtime was computed which was the number of additional days past the scheduled downtime, which would be required to complete the work. With the exception of the conversion from a DCE to NDCE recovery furnace, the net downtime was between three and 5 days. Therefore, since process or equipment downtime is very mill specific, no inclusion was made for this short duration downtime. Appendix 18.2 contains BE&K's estimate of net downtime for each technology considered.

The capital cost estimate does not include the following:

- ✓ Local, state, and federal permitting costs
- ✓ Sales tax (varies by both company directives, and by state)
- ✓ Extraordinary workman's compensation costs (beyond scope of this study)
- ✓ Spares
- ✓ Cost of capital

3. Operating Cost Estimate Basis

The annual operating costs were divided into the following categories: materials, chemicals, maintenance, energy, manpower, testing, and water wastewater, utilities, and fuel cost.

The materials category included the cost for, fabric filter media, SCR media, etc. The chemical category provides an estimate of the type and amount of chemical used for the pollution control technology. The maintenance category includes the estimated maintenance labor and maintenance material costs. The energy category was based upon the estimated installed horsepower utilizing a typical usage factor. The manpower category is an estimate of fraction of time existing operators would need to spend in operating the control equipment. No additional personnel were added for any of the technologies. However, the time spent by mill technology operating the new technologies was estimated. The testing category is an estimate of annual fees for testing. The water & wastewater category is an estimate of the additional water and subsequent wastewater costs for the given technology. The utility category includes the cost of the additional steam and compressed air used for a given technology. For the technology case where fuel switching was employed, the fuel usage category contains the differential cost for either switching to low-sulfur oil or to natural gas.

4. NO_x Control Good Technology Limit

4.1. NDCE Kraft Recovery Furnace

4.1.1. Description

Combustion controls for recovery furnaces utilizing addition of a quartenary air system yielding a NO_x level in the stack gases of 80 ppm @ 8% oxygen. Equipment sized for a NDCE recovery furnace burning 3.7 x 10^6 (Mm) lb BLS per day.

4.1.2. Major Equipment

- ✓ Quartenary air fan
- ✓ Dampers
- ✓ Flow meters
- ✓ New CEMS

4.1.3. Basis for Estimate

Southeast Kraft mill recovery furnace firing 2.6 x 10^6-lb black liquor solids per day. Project was estimated in 1999.

4.1.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power."
- ✓ Costs were escalated to 2001 dollars

4.1.5. Operating Cost Estimate Assumptions

- ✓ Maintenance & materials – 1% of TIC
- ✓ Power75 kw
- ✓ Power usage factor: 70%
- ✓ Workhours: 0.75 hours /day
- ✓ Testing: $5,000 per year

4.2. Lime Kiln – Route SOGs to new Thermal Oxidizer

4.2.1. Description

For those systems where the SOGs are incinerated in the limekiln, the SOGs will be rerouted to a new thermal oxidizer equipped with Low NO_x controls and a caustic scrubber. The system is sized for a limekiln producing 240 tpd CaO.

4.2.2. Major Equipment

- ✓ Thermal oxidizer
- ✓ Caustic scrubber

4.2.3. Basis for Estimate

Southeastern Kraft mill which routed its NCGs to a thermal oxidizer. System was sized for 20,000 ACFM. The project was estimated in 1999.

4.2.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power."
- ✓ Costs were escalated to 2001 dollars

4.2.5. Operating Cost Estimate Assumptions

- ✓ Caustic: 0 gpm (assumed that all the caustic-sulfur solution would be reclaimed)
- ✓ Maintenance labor & materials: 3.5% of TIC
- ✓ Power: 75 kw
- ✓ Power usage factor: 70%
- ✓ Workhours: 3 hours per day
- ✓ Testing: $5,000 per year
- ✓ Water: 35 gpm

4.3. Coal or Coal / Wood Boiler

4.3.1. Description

Installation of Low NO_x burners on a coal-fired boiler producing 300,000 lb/hr of steam. The maximum NO_x emission rate is 0.3 lb/Mm Btu

4.3.2. Major Equipment

- ✓ Low NO_x burner assemblies
- ✓ Replace forced draft fan
- ✓ New CEMS

4.3.3. Basis for Estimate

Southeastern Kraft mill with 400,000 lb/hr steam coal / wood boiler. The project was estimated in 1999.

4.3.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power."
- ✓ Costs were escalated to 2001 dollars

4.3.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials : 2% of TIC
- ✓ Power: 243 kw
- ✓ Power usage factor: 70%
- ✓ Workhours: 1.5 hours per day
- ✓ Testing: $5,000 per year.

4.4. Gas Boiler

4.4.1. Description

Low NO_x burners and flue gas recirculation for a natural gas-fired boiler producing 120,000 lb/hr of steam. The maximum NO_x emission rate is 0.05 lb/Mmbtu as a 30-day average.

4.4.2. Major Equipment

- ✓ Low NO_x burner assemblies
- ✓ Replace forced draft fan
- ✓ New CEMS
- ✓ Flue gas recirculation fan

4.4.3. Basis for Estimate

Southeastern Kraft mill with a multi-fuel boiler producing 420,000 lb/hr of steam. The project was estimated in 1999.

4.4.4. Capital Cost Estimate Assumption

- ✓ Costs were factored using the "0.6 power."
- ✓ Costs were escalated to 2001 dollars

4.4.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials : 3% of TIC
- ✓ Power: 176 kw
- ✓ Power usage factor: 70%
- ✓ Workhours: 1.5 hours per day
- ✓ Testing: $5,000 per year.

4.5. Gas Turbine – Water Injection

4.5.1. Description

Installation of water injection system for NO_x emission control to reduce the NO_x emissions to 25 ppm @ 15% oxygen for a 30-day average. The system was sized for a 30 MW gas turbine.

4.5.2. Major Equipment

- ✓ High pressure water pump
- ✓ Water injection system

4.5.3. Basis for Estimate

Budget quotation from Alpha Power Systems for a Swirlflash technology system for NO_x reduction. The project costs are in 2001 dollars.

4.5.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power.

4.5.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials : 2% of TIC
- ✓ Power: 2 kw

- ✓ Power usage factor: 70%
- ✓ Workhours: 1.5 hours per day
- ✓ Testing: $5,000 per year.
- ✓ Water: 10 gpm

4.6. Gas Turbine – Steam Injection

4.6.1. Description

Installation of steam injection system for NO_x emission control to reduce the NO_x emissions to 25 ppm @ 15% oxygen for a 30-day average. The system was sized for a 30 MW gas turbine.

4.6.2. Major Equipment

- ✓ High pressure water pump
- ✓ Water injection system

4.6.3. Basis for Estimate

Budget quotation from Alpha Power Systems for a Swirlflash technology system for NO_x reduction. The project costs are in 2001 dollars.

4.6.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power."

4.6.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials : 2% of TIC
- ✓ Power: 2 kw
- ✓ Power usage factor: 70%
- ✓ Workhours: 1.5 hours per day
- ✓ Testing: $5,000 per year.
- ✓ Water: 4.76 gpm
- ✓ Steam: 2381 lb/hr

4.7. Oil Boiler

4.7.1. Description

Low NO_x burners for oil-fired boiler producing 135,000 lb/hr of steam. The maximum NO_x emission rate is 0.2 lb/Mm Btu as a 30-day average.

4.7.2. Major Equipment

- ✓ Low NO_x burner assemblies
- ✓ Replace forced draft fan
- ✓ New CEMS

4.7.3. Basis for Estimate

Southeastern Kraft mill with a multi-fuel boiler producing 420,000 lb/hr of steam. The project was estimated in 1999.

4.7.4. Capital Cost Estimate Assumption

- ✓ Costs were factored using the "0.6 power."
- ✓ Costs were escalated to 2001 dollars

4.7.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3% of TIC
- ✓ Power: 151 kw
- ✓ Power usage factor: 70%
- ✓ Workhours: 1.5 hours per day
- ✓ Testing: $5,000 per year

4.8. Wood Boiler

4.8.1. Description

Upgrade combustion controls and FD fan. The NO_x emissions will be reduced from 0.33 lb/Mm Btu to 0.25 lb/Mm Btu for a 3-hour limit.

4.8.2. Major Equipment

- ✓ Upgrade FD fan
- ✓ Replace combustion dampers and controls

- ✓ New tertiary air nozzles
- ✓ New cameras
- ✓ New CEM
- ✓ Upgrade DCS controls

4.8.3. Basis for Estimate

Northern Kraft mill with a coal fired 120,000-lb/hr boiler. The project was estimated in 1999.

4.8.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power."
- ✓ Costs were escalated to 2001 dollars

4.8.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3% of TIC
- ✓ Power: 298 kw
- ✓ Power usage factor: 70%
- ✓ Workhours: 1.5 hours per day
- ✓ Testing: $5,000

5. NO_x Control Best Technology Limit

5.1. Technical Feasibility of SNCR and SCR Technologies

There are no SNCR units known to be operating for NO_x control in a recovery boiler. While SNCR was attempted on one recovery furnace in Sweden for a short period, the unit no longer operates and the technology is not considered to be proven. The major concern with SNCR is the ability to add urea in the correct flue temperature window to ensure effectiveness and minimal slip (i.e., urea/ammonia carryover with the flue gas). Recovery boilers are operated over a wide range of conditions, which affect both the amount of urea added and the location of the addition. Other concerns include safety (i.e., risk of urea solution reaching the floor and causing a smelt-water explosion), and maintenance of equipment (i.e., atomizing nozzles) in a highly corrosive environment.

There are financial incentives to reduce NO_x emissions in Sweden and therefore, it would be expected that either SCR or SNCR would be used extensively if they were cost-effective. Currently only combustion controls are used to reduce NO_x.

The SCR technology presents unique problems with respect to potential poisoning of the catalyst from the alkali dust from the recovery boiler. To minimize this the SCR would need to be place downstream of the ESP, which means that the flue gas must be reheated before application of the SCR. This adds unnecessary cost – both capital and operating.

5.2. NDCE Kraft Recovery - SNCR Technology

5.2.1. Description

Selective non-catalytic reduction system for NO_x control to achieve a maximum emission of 40 ppm @ 8% oxygen or achieve a 50% reduction using a 30-day average. The system is sized for a NDCE recovery furnace burning 3.7-Mm lb BLS per day.

5.2.2. Major Equipment

- ✓ Urea storage
- ✓ Metering pump
- ✓ Urea injection system

5.2.3. Basis for Estimate

A Scandinavian recovery furnace firing at a 3.5-Mm lb BLS/day rate. The project was estimated in 1990. The inlet concentration was assumed 60 ppm with an outlet concentration of 24 ppm.

5.2.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power."
- ✓ Costs were escalated to 2001 dollars
- ✓ R&D cost: 1.0% of total direct costs (i.e., labor, materials, subcontract, and equipment)

5.2.5. Operating Cost Estimate Assumptions

- ✓ Urea: 256 TPY
- ✓ Maintenance labor & materials: 3.5% of TIC
- ✓ Power: 16 kw
- ✓ Power usage factor: 70%
- ✓ Workhours: 3 hours per day
- ✓ Testing: $5,000 per year
- ✓ Water: 3 gpm

5.3. NDCE Kraft Recovery – SCR Technology

5.3.1. Description

Installation of a SCR NO_x control system in a NDCE recovery furnace burning 3.7 x 10^6 (Mm) lb BLS per day. The target is 40 ppm @ 8% oxygen or 50% reduction) for a 30-day average.

5.3.2. Major Equipment

- ✓ SCR reactor
- ✓ Duct burner
- ✓ CEM

5.3.3. Basis for Estimate

Northern Kraft mill with a coal fired 120,000-lb/hr boiler. The project was estimated in 1999. The inlet NO_x is estimated to be 92 ppm and the outlet NO_x is estimated to be 18 ppm.

5.3.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power."
- ✓ Costs were escalated to 2001 dollars

- ✓ R&D cost: 1.5% of total direct costs (i.e., labor, materials, subcontract, and equipment)

5.3.5. Operating Cost Estimate Assumptions

- ✓ Materials – catalyst: 1072 ft^3 per yr.
- ✓ Chemicals – urea: 377 tons per year
- ✓ Maintenance: 2% of TIC
- ✓ Power: 547 kw
- ✓ Power usage factor: 70%
- ✓ Workhours: 28.6 hr per day
- ✓ Testing: $5,000 per year
- ✓ Water: 7 gpm
- ✓ Steam: 1,830 lb/hr
- ✓ Compressed air: 39 cfm

5.4. DCE Kraft Recovery – SNCR Technology

5.4.1. Description

Selective non-catalytic reduction system for NO_x control to achieve 50% reduction of the NO_x. The system is sized for a DCE recovery furnace burning 1.7-Mm lb BLS/day.

5.4.2. Major Equipment

- ✓ Urea storage
- ✓ Metering pump
- ✓ Urea injection system

5.4.3. Basis for Estimate

A Scandinavian recovery furnace firing at a 3.5-Mm lb BLS/day rate. The project was estimated in 1990. The inlet concentration was assumed 60 ppm with an outlet concentration of 30 ppm.

5.4.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power."
- ✓ Costs were escalated to 2001 dollars
- ✓ R&D cost: 1.0% of total direct costs (i.e., labor, materials, subcontract, and equipment)

5.4.5. Operating Cost Estimate Assumptions

- ✓ Urea: 118 TPY
- ✓ Maintenance labor & materials: 3.5% of TIC
- ✓ Power: 16 kw
- ✓ Power usage factor: 70%
- ✓ Workhours: 3 hours per day
- ✓ Testing: $5,000 per year
- ✓ Water: 3 gpm

5.5. DCE Kraft Recovery – SCR Technology

5.5.1. Description

Installation of a SCR NO_x control system in a DCE recovery furnace burning 1.7 x 10^6 (Mm) lb BLS per day. The target is 40 ppm @ 8% oxygen or 50% reduction) for a 30-day average.

5.5.2. Major Equipment

- ✓ SCR reactor
- ✓ Duct burner
- ✓ CEM

5.5.3. Basis for Estimate

Northern Kraft mill with a coal fired 120,000-lb/hr boiler. The project was estimated in 1999. The inlet NO_x is estimated to be 67 ppm and the outlet NO_x is estimated to be 13 ppm.

5.5.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power."
- ✓ Costs were escalated to 2001 dollars

- ✓ R&D cost: 1.5% of total direct costs (i.e., labor, materials, subcontract, and equipment)

5.5.5. Operating Cost Estimate Assumptions

- ✓ Materials – catalyst: 697 ft^3 per yr.
- ✓ Chemicals – urea: 245 tons per year
- ✓ Maintenance: 2% of TIC
- ✓ Power: 355 kw
- ✓ Power usage factor: 70%
- ✓ Workhours: 28.6 hr per day
- ✓ Testing: $5,000 per year
- ✓ Water: 4 gpm
- ✓ Steam: 1,190 lb/hr
- ✓ Compressed air: 26 cfm

5.6. Lime Kiln – Low-NO_x burners, & SCR

5.6.1. Description

Install Low NO_x burners and SCR systems in lime kiln, which produces 240 tpd CaO. SCR can be applied at the limekiln provided the flue gas temperature is controlled and the dust is removed prior to application.

5.6.2. Major Equipment

- ✓ SCR reactor
- ✓ Low NO_x burners
- ✓ Upgrade to forced draft fan
- ✓ ID fan

5.6.3. Basis for Estimate

Northern Kraft mill with a coal fired 120,000-lb/hr boiler. The project was estimated in 1999.

5.6.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power."
- ✓ Costs were escalated to 2001 dollars
- ✓ R&D cost: 1.5% of total direct costs (i.e., labor, materials, subcontract, and equipment)

5.6.5. Operating Cost Estimate Assumptions

- ✓ Materials – catalyst: 323 ft^3 per yr.
- ✓ Chemicals – urea: 113.5 tons per year
- ✓ Maintenance: 2% of TIC
- ✓ Power: 165 kw
- ✓ Power usage factor: 70%
- ✓ Workhours: 28.6 hr per day
- ✓ Testing: $5,000 per year
- ✓ Water: 1.97 gpm
- ✓ Steam: 552 lb/hr
- ✓ Compressed air: 12 cfm

5.7. Coal or Coal / Wood Boiler – SCR

5.7.1. Description

Installation of a SCR system on a coal or coal/wood boiler producing 300,000 lb/hr of steam. The maximum NO_x emission rate is 0.17 lb/Mm Btu for a 30-day average.

5.7.2. Major Equipment

- ✓ SCR reactor
- ✓ Low NO_x burners
- ✓ Upgrade to forced draft fan
- ✓ ID fan

5.7.3. Basis for Estimate

Northern Kraft mill with a coal fired 120,000-lb/hr boiler. The project was estimated in 1999.

5.7.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power."
- ✓ Costs were escalated to 2001 dollars
- ✓ R&D cost: 0.5% of total direct costs (i.e., labor, materials, subcontract, and equipment)

5.7.5. Operating Cost Estimate Assumptions

- ✓ Materials – catalyst: 1219 ft^3 per yr.
- ✓ Chemicals – urea: 428 tons per year
- ✓ Maintenance: 2% of TIC
- ✓ Power: 622 kw
- ✓ Power usage factor: 70%
- ✓ Workhours: 28.6 hr per day
- ✓ Testing: $5,000 per year
- ✓ Water: 7.43 gpm
- ✓ Steam: 2082 lb/hr
- ✓ Compressed air: 45 cfm

5.8. Coal or Coal / Wood Boiler – Switch to Natural Gas

5.8.1. Description

Switch from coal to natural gas for a coal or coal/wood boiler producing 300,000 lb/hr of steam.

5.8.2. Major Equipment

- ✓ New burners
- ✓ Natural gas reducing station

5.8.3. Basis for Estimate

Southeastern Kraft mill which switched from coal to natural gas for a boiler producing 420,000 lb/hr of steam. The project was estimated in 1999.

5.8.4. Capital Cost Estimate Assumptions

- ✓ Natural gas delivered at 700 psig to property line of plant.
- ✓ Costs were factored using the "0.6 power."
- ✓ Costs were escalated to 2001 dollars

5.8.5. Operating Cost Estimate Assumptions

- ✓ Maintenance: 1% of TIC
- ✓ Power: N/A
- ✓ Workhours: 1.5 hr per day
- ✓ Testing: $5,000 per year

5.9. Gas Boiler

5.9.1. Description

Installation of SCR on natural gas-fired boiler producing 120,000 lb/hr of steam. The maximum NO_x emission rate is 0.015 lb/Mm Btu utilizing a 30-day average.

5.9.2. Major Equipment

- ✓ SCR reactor
- ✓ Low NO_x burners
- ✓ Upgrade to forced draft fan
- ✓ ID fan

5.9.3. Basis for Estimate

Northern Kraft mill with a coal fired 120,000-lb/hr boiler. The project was estimated in 1999.

5.9.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power."
- ✓ Costs were escalated to 2001 dollars

5.9.5. Operating Cost Estimate Assumptions

- ✓ Materials – catalyst: 464 ft^3 per yr. @ \$350 per ft^3
- ✓ Chemicals – urea: 163 tons per year
- ✓ Maintenance: 2% of TIC
- ✓ Power: 237 kw
- ✓ Power usage factor: 70%
- ✓ Workhours: 28.6 hr per day
- ✓ Testing: \$5,000 per year
- ✓ Water: 2.83 gpm
- ✓ Steam: 793 lb/hr
- ✓ Compressed air: 17 cfm

5.10. Gas Turbine

5.10.1. Description

Installation of SCR system for a 30-MW natural gas turbine yielding an emission level of 5 ppm @15% oxygen for a 30-day average representing a 95% NO_x reduction.

5.10.2. Major Equipment

- ✓ SCR reactor
- ✓ Low NO_x burners
- ✓ Upgrade to forced draft fan
- ✓ ID fan

5.10.3. Basis for Estimate

Northern Kraft mill with a coal fired 120,000-lb/hr boiler. The project was estimated in 1999.

5.10.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power."
- ✓ Costs were escalated to 2001 dollars

5.10.5. Operating Cost Estimate Assumptions

- ✓ Materials – catalyst: 298 ft^3 per yr. @ \$350 per ft^3
- ✓ Chemicals – urea: 105 tons per year
- ✓ Maintenance: 2% of TIC
- ✓ Power: 418 kw
- ✓ Power usage factor: 70%
- ✓ Workhours: 3 hr per day
- ✓ Testing: \$5,000 per year
- ✓ Water: 5 gpm
- ✓ Steam: 1400 lb/hr
- ✓ Compressed air: 30 cfm

5.11. Oil Boiler

5.11.1. Description

Installation of SCR system on oil-fired boiler producing 135,000 lb/hr of steam. The maximum NO_x emission rate is 0.04 lb/Mmbtu for a 30-day average or a 90% reduction.

5.11.2. Major Equipment

- ✓ SCR reactor
- ✓ Low NO_x burners
- ✓ Upgrade to forced draft fan
- ✓ ID fan

5.11.3. Basis for Estimate

Northern Kraft mill with a coal fired 120,000-lb/hr boiler. The project was estimated in 1999.

5.11.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the “0.6 power.”
- ✓ Costs were escalated to 2001 dollars

- ✓ R&D cost: 0.5% of total direct costs (i.e., labor, materials, subcontract, and equipment)

5.11.5. Operating Cost Estimate Assumptions

- ✓ Materials – catalyst: 679 ft^3 per yr. @ $350 per ft^3
- ✓ Chemicals – urea: 238 tons per year
- ✓ Maintenance: 2% of TIC
- ✓ Power: 346 kw
- ✓ Power usage factor: 70%
- ✓ Workhours: 28.6 hr per day
- ✓ Testing: $5,000 per year
- ✓ Water: 4.14 gpm
- ✓ Steam: 1159 lb/hr
- ✓ Compressed air: 25 cfm

5.12. Wood Boiler - SNCR

5.12.1. Description

Installation of SNCR system on a wood boiler producing 300,000 lb/hr of steam. The maximum NO_x emission rate is 0.20 lb/ Mmbtu and represents a 40% reduction.

5.12.2. Major Equipment

- ✓ Urea storage and metering system
- ✓ Urea Injectors
- ✓ Boiler Modifications
- ✓ Control Enhancements

5.12.3. Basis for Estimate

An Atlantic states Kraft mill with a multi-fuel boiler producing 400,000 lb/hr of steam.

5.12.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power."
- ✓ Costs were escalated to 2001 dollars

5.12.5. Operating Cost Estimate Assumptions

- ✓ Chemical – urea 165 tons per year
- ✓ Maintenance labor & materials: 3.5% of TIC
- ✓ Power: 13 kw
- ✓ Power usage factor: 80%
- ✓ Workhours: 3 hours per day
- ✓ Water: 3 gpm

5.13. Wood Boiler – SCR (technical feasibility)

5.13.1. Description

Installation of a SCR system on a wood-fired boiler capable of producing 300,000 lb/hr of steam. The maximum NO_x emission rate is 0.025 lb/Mmbtu with a 85% reduction anticipated. The SCR is feasible provided the temperature of the flue gas is controlled.

5.13.2. Major Equipment

- ✓ SCR reactor
- ✓ Low NO_x burners
- ✓ Upgrade to forced draft fan
- ✓ ID fan

5.13.3. Basis for Estimate

Northern Kraft mill with a coal fired 120,000-lb/hr boiler. The project was estimated in 1999.

5.13.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power."
- ✓ Costs were escalated to 2001 dollars

- ✓ R&D cost: 0.5% of total direct costs (i.e., labor, materials, subcontract, and equipment)

5.13.5. Operating Cost Estimate Assumptions

- ✓ Materials – catalyst: 821 ft^3 per yr. @ $350 per ft^3
- ✓ Chemicals – urea: 287 tons per year
- ✓ Maintenance: 2% of TIC
- ✓ Power: 420 kw
- ✓ Power usage factor: 75%
- ✓ Workhours: 28.6 hr per day
- ✓ Testing: $5,000 per year
- ✓ Water: 5 gpm
- ✓ Steam: 1403 lb/hr
- ✓ Compressed air: 30 cfm

6. SO_2 Reduction – Good Technology Limits

6.1. NDCE Recovery Boiler

6.1.1. Description

Installation of a chemical scrubber to achieve sulfur dioxide (SO_2) level in stack gas of 50 ppm @ 8% oxygen. The system is sized for a NDCE recovery furnace burning 3.7-Mm lb BLS per day.

6.1.2. Major Equipment

- ✓ Scrubber tower
- ✓ Booster fan
- ✓ Recirculation pump
- ✓ Caustic pump

6.1.3. Basis for Estimate

Southeast Kraft mill recovery furnace firing 2.5 x 10^6-lb black liquor solids per day. Project was estimated in 1998.

6.1.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the “0.6 power.”
- ✓ Costs were escalated to 2001 dollars

6.1.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3.5% of TIC
- ✓ Power: 1631 kw
- ✓ Power usage factor: 70%
- ✓ Chemical: 1.3 gpm 50% caustic soda
- ✓ Water: 148 gpm
- ✓ Wastewater: 15 gpm
- ✓ Workhours: 3 hours per day
- ✓ Testing: $5,000 per year

6.2. DCE Kraft Recovery Furnace

6.2.1. Description

Installation of a chemical scrubber to achieve sulfur dioxide (SO_2) level in stack gas of 50 ppm @ 8% oxygen. The system is sized for a DCE recovery furnace burning 1.7-Mm lb BLS per day.

6.2.2. Major Equipment

- ✓ Scrubber tower
- ✓ Booster fan
- ✓ Recirculation pump
- ✓ Oxidizer blower
- ✓ Caustic pump

6.2.3. Basis for Estimate

Southeast Kraft mill recovery furnace firing 2.5 x 10^6 lb black liquor solids per day. Project was estimated in 1998.

6.2.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the “0.6 power.”
- ✓ Costs were escalated to 2001 dollars

6.2.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3.5% of TIC
- ✓ Power: 1023 kw
- ✓ Power usage factor: 70%
- ✓ Chemical: 0.82 gpm 50% caustic soda
- ✓ Water: 68 gpm
- ✓ Wastewater: 6.8 gpm
- ✓ Workhours: 3 hours per day
- ✓ Testing: $5,000 per year

6.3. Coal or Coal / Wood Boiler

6.3.1. Description

Installation of a caustic scrubber for a coal or coal / wood boiler producing 300,000 lb/hour of steam. The SO_2 level would be reduced by 50% producing a maximum emission of 0.6 lb / Mm Btu.

6.3.2. Major Equipment

- ✓ Scrubber tower
- ✓ Recirculation pump
- ✓ Booster fan
- ✓ Caustic feed system

6.3.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler producing 600,000 lb/hour of steam. The project was estimated in 1992.

6.3.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power."
- ✓ Costs were escalated to 2001 dollars

6.3.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3.5% of TIC
- ✓ Power: 1142 kw
- ✓ Power usage factor: 70%
- ✓ Chemical: 0.6 gpm 50% caustic soda
- ✓ Water: 143 gpm
- ✓ Wastewater: 14 gpm
- ✓ Workhours: 3 hours per day
- ✓ Testing: $5,000 per year

6.4. Oil Boiler

6.4.1. Description

Installation of caustic scrubber on a oil-fired boiler producing 135,000 lb/hr of steam. The SO_2 emission will be reduced by 50% with a maximum emission rate of 0.4 lb/Mm Btu for a 30-day average.

6.4.2. Major Equipment

- ✓ Scrubber tower
- ✓ Booster fan
- ✓ Caustic feed system

6.4.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler producing 600,000 lb/hour of steam. The project was estimated in 1992.

6.4.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power."
- ✓ Costs were escalated to 2001 dollars

6.4.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3.0% of TIC
- ✓ Power: 555 kw
- ✓ Power usage factor: 70%
- ✓ Chemical: 0.26 gpm 50% caustic soda
- ✓ Water: 42.9 gpm
- ✓ Wastewater: 4.3 gpm
- ✓ Workhours: 3 hours per day
- ✓ Testing: $5,000 per year

7. SO_2 Reduction – Best Technology Limits

7.1. NDCE Recovery Boiler

7.1.1. Description

Installation of a caustic scrubber to achieve sulfur dioxide (SO_2) level in stack gas of 10 ppm @ 8% oxygen. The system is sized for a NDCE recovery furnace burning 3.7 Mm lb BLS per day.

7.1.2. Major Equipment

- ✓ Scrubber tower
- ✓ Booster fan
- ✓ Recirculation pump
- ✓ Caustic pump

7.1.3. Basis for Estimate

Southeast Kraft mill recovery furnace firing 2.5 x 10^6 lb black liquor solids per day. Project was estimated in 1998.

7.1.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the “0.6 power.”
- ✓ Costs were escalated to 2001 dollars

7.1.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3.5% of TIC
- ✓ Power: 1631 kw
- ✓ Power usage factor: 80%
- ✓ Chemical: 1.5 gpm 50% caustic soda
- ✓ Water: 148 gpm
- ✓ Wastewater: 15 gpm
- ✓ Work hours: 3 hours / day
- ✓ Testing: $5,000 per year

7.2. DCE Kraft Recovery Furnace

7.2.1. Description

Installation of a caustic scrubber to achieve sulfur dioxide (SO_2) level in stack gas of 10 ppm @ 8% oxygen. The system is sized for a DCE recovery furnace burning 1.7 Mm lb BLS per day.

7.2.2. Major Equipment

- ✓ Scrubber tower
- ✓ Booster fan
- ✓ Recirculation pump
- ✓ Oxidizer blower
- ✓ Caustic pump

7.2.3. Basis for Estimate

Southeast Kraft mill recovery furnace firing 2.5 x 10^6 lb black liquor solids per day. Project was estimated in 1998.

7.2.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power."
- ✓ Costs were escalated to 2001 dollars

7.2.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3.5% of TIC
- ✓ Power: 1023 kw
- ✓ Power usage factor: 80%
- ✓ Chemical: 0.94 gpm 50% caustic soda
- ✓ Water: 68 gpm
- ✓ Wastewater: 6.8 gpm
- ✓ Work hours: 3 hours / day
- ✓ Testing: $5,000 per year

7.3. Coal or Coal / Wood Boiler

7.3.1. Description

Installation of a caustic scrubber for a coal or coal / wood boiler producing 300,000 lb/hour of steam. The SO_2 level would be reduced by 90% producing a maximum emission of 0.17 lb / Mm Btu for a 30-day average.

7.3.2. Major Equipment

- ✓ Scrubber tower
- ✓ Booster fan
- ✓ Caustic feed system

7.3.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler producing 600,000 lb/hour of steam. The project was estimated in 1992.

7.3.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the “0.6 power.”
- ✓ Costs were escalated to 2001 dollars

7.3.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3.5% of TIC
- ✓ Power: 1523 kw
- ✓ Power usage factor: 80%
- ✓ Chemical: 1.1 gpm 50% caustic soda
- ✓ Water: 143 gpm
- ✓ Wastewater: 14 gpm
- ✓ Workhours: 3 hours per day
- ✓ Testing: $5,000 per year

7.4. Oil Boiler

7.4.1. Description

Installation of caustic scrubber on a oil-fired boiler producing 135,000 lb/hr of steam. The SO_2 emission will be reduced by 90% with a maximum emission rate of 0.08 lb/Mm Btu for a 30-day average.

7.4.2. Major Equipment

- ✓ Scrubber tower
- ✓ Booster fan
- ✓ Caustic feed system

7.4.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler producing 600,000 lb/hour of steam. The project was estimated in 1992.

7.4.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power."
- ✓ Costs were escalated to 2001 dollars

7.4.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3.0% of TIC
- ✓ Power: 740 kw
- ✓ Power usage factor: 80%
- ✓ Chemical: 0.34 gpm 50% caustic soda
- ✓ Water: 42.9 gpm
- ✓ Wastewater: 4.3 gpm
- ✓ Workhours: 3 hours per day
- ✓ Testing: $5,000 per year

8. Mercury Removal – Best Technology Limit

8.1. Coal or Coal / Wood Boiler

8.1.1. Description

Installation of a spray dryer absorber fabric filter dry scrubbing system with carbon injection for a coal or coal/wood-fired boiler producing 300,000 lb/hr of steam. The Hg emission level is anticipated to be lowered from 16 lb/10^{12} Btu to 8 lb/10^{12} Btu, representing a 50% reduction.

8.1.2. Major Equipment

- ✓ Fabric filter modules
- ✓ Lime storage and metering system
- ✓ Activated carbon storage and metering system
- ✓ Blower
- ✓ Atomizing air compressor
- ✓ Fabric filter scrubbing system

8.1.3. Basis for Estimate

A budget quotation from WAPC for a spray dryer absorber fabric filter dry scrubbing system with carbon injection for a coal-fired boiler.

8.1.4. Capital Cost Estimate Assumptions

- ✓ R&D cost: 1.5% of total direct costs (i.e., labor, materials, subcontract, and equipment)

8.1.5. Operating Cost Estimate Assumptions

- ✓ Chemicals – activated carbon: 0.08 tons per day
- ✓ Maintenance labor & materials: 5% of TIC
- ✓ Chemicals – pebble lime: 3750 lb/hr
- ✓ Power: 327 kw
- ✓ Power usage factor: 75%
- ✓ Workhours: 3 hours per day

- ✓ Testing: $5,000 per year
- ✓ Water: 64 gpm
- ✓ Wastewater: 20 gpm
- ✓ Incremental waste disposal: 15,780 tpy of carbon and lime

8.2. Wood Boiler

8.2.1. Description

Installation of a spray dryer absorber fabric filter dry scrubbing system with carbon injection for a wood-fired boiler producing 300,000 lb/hr of steam. The Hg emission level is anticipated to be lowered from 0.572 lb/10^{12} Btu to 0.286 lb/10^{12} Btu, representing a 50% reduction.

8.2.2. Major Equipment

- ✓ Fabric filter modules
- ✓ Lime storage and metering system
- ✓ Activated carbon storage and metering system
- ✓ Blower
- ✓ Atomizing air compressor
- ✓ Fabric filter scrubbing system

8.2.3. Basis for Estimate

A budget quotation from WAPC for a spray dryer absorber fabric filter dry scrubbing system with carbon injection for a wood fired boiler.

8.2.4. Capital Cost Estimate Assumptions

- ✓ R&D cost: 1.5% of total direct costs (i.e., labor, materials, subcontract, and equipment)

8.2.5. Operating Cost Estimate Assumptions

- ✓ Chemicals – activated carbon: 7.923 lb per day
- ✓ Maintenance labor & materials: 5% of TIC
- ✓ Chemicals – pebble lime: 375 lb/hr
- ✓ Power: 262 kw

- ✓ Power usage factor: 70%
- ✓ Workhours: 3 hours per day
- ✓ Testing: $5,000 per year
- ✓ Water: 90 gpm
- ✓ Wastewater: 28 gpm
- ✓ Incremental waste disposal: 1,576 tpy of carbon and lime

9. Particulate Matter – Good Technology Limits

9.1. NDCE Kraft Recovery Boiler – New Precipitator

9.1.1. Description

Installation of an electrostatic precipitator capable of achieving 0.044 gr/dscf @ 8% oxygen of particulate matter. The system is sized for a NDCE recovery furnace firing 3.7 Mm lb BLS per day

9.1.2. Major Equipment

- ✓ New electrostatic precipitator
- ✓ New concrete stack acid-brick lined
- ✓ Modification to existing ID fan
- ✓ Conveyors
- ✓ Dampers

9.1.3. Basis for Estimate

Southeast Kraft mill with a recovery boiler firing 2.15 x 10^6 lb black liquor solids per day. Project estimated in 2000.

9.1.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP at 3.7 x 10^6 lb black liquor solids per day.
- ✓ Costs escalated to 2001

9.1.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3.5% of TIC cost
- ✓ Power – 2023 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 3 hours per day
- ✓ Testing - $5,000 per year

9.2. NDCE Kraft Recovery Boiler – Rebuilt Precipitator

9.2.1. Description

ESP upgrade by addition of two parallel fields so that system is capable of achieving 0.044 gr/dscf @ 8% oxygen of particulate matter. The system is sized for a NDCE recovery furnace firing 3.7 Mm lb BLS per day

9.2.2. Major Equipment

- ✓ Modification to existing ESP
- ✓ Modifications to ash handling system

9.2.3. Basis for Estimate

Southeast Kraft mill with a recovery boiler firing 2.70 x 10^6 lb black liquor solids per day. Project estimated in 1999.

9.2.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP at 3.7 x 10^6 lb black liquor solids per day.
- ✓ Costs escalated to 2001

9.2.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 2% of TIC cost
- ✓ Power –377 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 1.5 hours per day
- ✓ Testing - $5,000 per year

9.3. DCE Kraft Recovery Boiler

9.3.1. Description

Installation of a electrostatic precipitator capable of achieving 0.044 gr/SDCF @ 8% oxygen of particulate matter. The system is sized for a DCE recovery furnace firing 1.7 Mm lb BLS per day.

9.3.2. Major Equipment

- ✓ New electrostatic precipitator
- ✓ New concrete stack acid-brick lined
- ✓ Modification to existing ID fan

- ✓ Conveyors
- ✓ Dampers

9.3.3. Basis for Estimate

Southeast Kraft mill with a recovery boiler firing 2.15 x 10^6 lb black liquor solids per day. Project estimated in 2000.

9.3.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP at 1.7 x 10^6 lb black liquor solids per day.
- ✓ Costs escalated to 2001

9.3.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3.5% of TIC cost
- ✓ Power – 1268 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 3 hours per day
- ✓ Testing - $5,000 per year

9.4. Smelt Dissolving Tank

9.4.1. Description

Installation of a scrubber on a smelt dissolving tank capable of achieving a particulate matter emission rate of 0.2 lb/ton BLS. The system is sized for a recovery furnace firing 3.7 Mm lb BLS per day.

9.4.2. Major Equipment

- ✓ New scrubber
- ✓ Fan
- ✓ Recirculation pump

9.4.3. Basis for Estimate

Atlantic states Kraft mill with a recovery furnace firing 2 Mm lb BLS per day. The project was estimated in 1997.

9.4.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for a smelt-dissolving tank scrubber at a recovery furnace firing rate of 3.7 x 10^6 lb black liquor solids per day. Costs escalated to 2001

9.4.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 2% of TIC cost
- ✓ Power – 287 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 1.5 hours per day
- ✓ Testing - $5,000 per year

9.5. Lime Kiln

9.5.1. Description

Installation of an electrostatic precipitator on a lime kiln processing 240 TPD of CaO. The emission rate for particulate matter is 0.064 gr/DSCF @ 10% oxygen.

9.5.2. Major Equipment

- ✓ New ESP
- ✓ Penthouse blower
- ✓ Hopper with screw conveyor
- ✓ Bucket elevator
- ✓ ID fan
- ✓ New stack

9.5.3. Basis for Estimate

Southeastern Kraft mill with a lime kiln capable of processing 540 TPD of CaO. The project was estimated in 2001.

9.5.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a lime kiln processing 240 tpd of CaO.

9.5.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3% of TIC cost

- ✓ Power 187 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 2.25 hours per day
- ✓ Testing - $5,000 per year

9.6. Coal Boiler

9.6.1. Description

Installation of electrostatic precipitator in a coal boiler producing 300,000 lb/hr of steam. The particulate emission rate is 0.065 lb / Mm Btu.

9.6.2. Major Equipment

- ✓ ID fan modification
- ✓ ESP
- ✓ Conveyors
- ✓ Penthouse blower

9.6.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler capable of producing 600,000 lb/hr of steam. The project was estimated in 1992.

9.6.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a boiler producing 300,000 lb/hr of steam.
- ✓ Costs escalated to 2001

9.6.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3% of TIC cost
- ✓ Power – 1331 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 3 hours per day
- ✓ Testing - $5,000 per year
- ✓ Incremental waste disposal: 39 tpy of ash

9.7. Coal / Wood Boiler

9.7.1. Description

Installation of electrostatic precipitator in a coal or coal / wood boiler producing 300,000 lb/hr of steam. The particulate emission rate is 0.065 lb / Mm Btu.

9.7.2. Major Equipment

- ✓ ID fan modification
- ✓ ESP
- ✓ Conveyors
- ✓ Penthouse blower

9.7.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler capable of producing 600,000 lb/hr of steam. The project was estimated in 1992.

9.7.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a boiler producing 300,000 lb/hr of steam.
- ✓ Costs escalated to 2001

9.7.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3% of TIC cost
- ✓ Power – 1331 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 3 hours per day
- ✓ Testing - $5,000 per year
- ✓ Incremental waste disposal: 94 tpy of ash

9.8. Oil Boiler

9.8.1. Description

The switch to low-sulfur fuel oil to achieve lower particulate matter emission rates from a oil-fired boiler capable of producing 135,000 lb/hr of steam.

9.8.2. Major Equipment

- ✓ Oil gun nozzles
- ✓ Flow meters

9.8.3. Basis for Estimate

Southeastern Kraft mill which switched from No. 6 to No. 2 fuel oil in a oil-fired boiler producing 135,000 lb/hour of steam. The project was estimated in 1999.

9.8.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a boiler producing 135,000 lb/hr of steam.
- ✓ Costs escalated to 2001

9.8.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3% of TIC cost
- ✓ Power – not applicable
- ✓ Workhours – not applicable
- ✓ Testing - $5,000 per year
- ✓ Fuel costs: $2.86 million per year

9.9. Wood Boiler

9.9.1. Description

Removal of existing scrubber and installation of electrostatic precipitator in a wood boiler producing 300,000 lb/hr of steam. The particulate emission rate is 0.065 lb / Mm Btu.

9.9.2. Major Equipment

- ✓ ID fan modification
- ✓ ESP
- ✓ Conveyors
- ✓ Penthouse blower

9.9.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler capable of producing 600,000 lb/hr of steam. The project was estimated in 1992.

9.9.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a boiler producing 300,000 lb/hr of steam.
- ✓ Costs escalated to 2001

9.9.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3.5% of TIC cost
- ✓ Power – 911 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 3 hours per day
- ✓ Testing - $5,000 per year
- ✓ Water – (200) gpm savings from elimination of scrubber
- ✓ Wastewater – (20) gpm savings from elimination of scrubber
- ✓ Incremental waste disposal: 551 tpy of ash

10. Particulate Matter – Best Technology Limit

10.1. NDCE Kraft Recovery Boiler – New Precipitator

10.1.1. Description

Installation of an electrostatic precipitator capable of achieving 0.015 gr/dscf @ 8% oxygen. The system would be installed in a recovery furnace burning 3.7 Mm lb BLS per day.

10.1.2. Major Equipment

- ✓ New electrostatic precipitator
- ✓ New concrete stack acid-brick lined
- ✓ Modification to existing ID fan
- ✓ Conveyors
- ✓ Dampers

10.1.3. Basis for Estimate

Southeast Kraft mill with a recovery boiler firing 2.15 x 10^6 lb black liquor solids per day. Project estimated in 2000.

10.1.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP at 3.7 x 10^6 lb black liquor solids per day.
- ✓ Costs escalated to 2001

10.1.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3.5% of TIC cost
- ✓ Power – 2528 kw
- ✓ Power usage factor: 80%
- ✓ Workhours – 3 hours per day
- ✓ Testing - $5,000 per year

10.2. NDCE Kraft Recovery Boiler – Rebuilt Precipitator

10.2.1. Description

ESP upgrade by addition of two parallel fields so that system is capable of achieving 0.015 gr/dscf @ 8% oxygen of particulate matter. The system is sized for a NDCE recovery furnace firing 3.7 Mm lb BLS per day

10.2.2. Major Equipment

- ✓ Modification to existing ESP
- ✓ Modifications to ash handling system

10.2.3. Basis for Estimate

Southeast Kraft mill with a recovery boiler firing 2.70 x 10^6 lb black liquor solids per day. Project estimated in 1999.

10.2.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP at 3.7 x 10^6 lb black liquor solids per day.
- ✓ Costs escalated to 2001

10.2.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 2% of TIC cost
- ✓ Power –411 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 1.5 hours per day
- ✓ Testing - $5,000 per year

10.3. DCE Kraft Recovery Boiler

10.3.1. Description

Installation of a electrostatic precipitator capable of achieving 0.015 gr/SDCF @ 8% oxygen of particulate matter. The system is sized for a DCE recovery furnace firing 1.7 Mm lb BLS per day.

10.3.2. Major Equipment

- ✓ New electrostatic precipitator
- ✓ New concrete stack acid-brick lined
- ✓ Modification to existing ID fan

- ✓ Conveyors
- ✓ Dampers

10.3.3. Basis for Estimate

Southeast Kraft mill with a recovery boiler firing 2.15 x 10^6 lb black liquor solids per day. Project estimated in 2000.

10.3.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP at 1.7 x 10^6 lb black liquor solids per day.
- ✓ Costs escalated to 2001

10.3.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3.5% of TIC cost
- ✓ Power – 1585 kw
- ✓ Power usage factor: 80%
- ✓ Workhours – 3 hours per day
- ✓ Testing - $5,000 per year

10.4. Smelt Dissolving Tank

10.4.1. Description

Installation of a scrubber on a smelt dissolving tank capable of achieving a particulate matter emission rate of 0.12 lb/ton BLS. The system is sized for a recovery furnace firing 3.7 Mm lb BLS per day.

10.4.2. Major Equipment

- ✓ New scrubber
- ✓ Fan
- ✓ Recirculation pump

10.4.3. Basis for Estimate

Atlantic states Kraft mill with a recovery furnace firing 2 Mm lb BLS per day. The project was estimated in 1997.

10.4.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for a smelt-dissolving tank scrubber at a recovery furnace firing rate of 3.7 x 10^6 lb black liquor solids per day.
- ✓ Costs escalated to 2001

10.4.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 2% of TIC cost
- ✓ Power – 315 kw
- ✓ Power usage factor: 80%
- ✓ Workhours – 1.5 hours per day
- ✓ Testing - $5,000 per year

10.5. Lime Kiln – New ESP

10.5.1. Description

Installation of an electrostatic precipitator on a lime kiln processing 240 TPD of CaO. The emission rate for particulate matter is 0.01 gr/DSCF @ 10% oxygen.

10.5.2. Major Equipment

- ✓ New ESP
- ✓ Penthouse blower
- ✓ Hopper with screw conveyor
- ✓ Bucket elevator
- ✓ ID fan
- ✓ New stack

10.5.3. Basis for Estimate

Southeastern Kraft mill with a lime kiln capable of processing 540 TPD of CaO. The project was estimated in 2001.

10.5.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a lime kiln processing 240 TPD of CaO.

10.5.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3% of TIC cost
- ✓ Power – 233 kw
- ✓ Power usage factor: 80%
- ✓ Workhours – 2.25 hours per day
- ✓ Testing - $5,000 per year

10.6. Lime Kiln – Upgraded ESP

10.6.1. Description

Addition of a single electric field to an existing electrostatic precipitator on a lime kiln processing 240 TPD of CaO. The emission rate for particulate matter is 0.01 gr/DSCF @ 10% oxygen.

10.6.2. Major Equipment

- ✓ Modifications to existing ESP
- ✓ Ductwork modifications

10.6.3. Basis for Estimate

Southeastern Kraft mill with a lime kiln capable of processing 540 TPD of CaO. The project was estimated in 2001.

10.6.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a lime kiln processing 240 TPD of CaO

10.6.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 1% of TIC cost
- ✓ Power – 100 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 1.5 hours per day
- ✓ Testing - $5,000 per year

10.7. Coal Boiler – New ESP

10.7.1. Description

Installation of electrostatic precipitator in a coal boiler producing 300,000 lb/hr of steam. The particulate emission rate is 0.04 lb / Mm Btu.

10.7.2. Major Equipment

- ✓ ID fan modification
- ✓ ESP
- ✓ Conveyors
- ✓ Penthouse blower

10.7.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler capable of producing 600,000 lb/hr of steam. The project was estimated in 1992.

10.7.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a boiler producing 300,000 lb/hr of steam.
- ✓ Costs escalated to 2001

10.7.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3% of TIC cost
- ✓ Power – 1664 kw
- ✓ Power usage factor: 80%
- ✓ Workhours – 3 hours per day
- ✓ Testing - $5,000 per year
- ✓ Incremental waste disposal: 77 tpy of ash

10.8. Coal Boiler – Rebuild Existing ESP

10.8.1. Description

Addition of a single electric field in two chambers to an electrostatic precipitator in a coal boiler producing 300,000 lb/hr of steam. The particulate emission rate is 0.04 lb / Mm Btu.

10.8.2. Major Equipment

- ✓ Modifications to existing ESP
- ✓ Ductwork modifications

10.8.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler capable of producing 600,000 lb/hr of steam. The project was estimated in 1992.

10.8.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a boiler producing 300,000 lb/hr of steam.
- ✓ Costs escalated to 2001

10.8.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 1% of TIC cost
- ✓ Power – 550 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 3 hours per day
- ✓ Testing - $5,000 per year
- ✓ Incremental waste disposal: 38 tpy of ash

10.9. Coal / Wood Boiler - New

10.9.1. Description

Installation of electrostatic precipitator in a coal or coal / wood boiler producing 300,000 lb/hr of steam. The particulate emission rate is 0.04 lb / Mm Btu.

10.9.2. Major Equipment

- ✓ ID fan modification
- ✓ ESP
- ✓ Conveyors
- ✓ Penthouse blower

10.9.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler capable of producing 600,000 lb/hr of steam. The project was estimated in 1992.

10.9.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a boiler producing 300,000 lb/hr of steam.
- ✓ Costs escalated to 2001

10.9.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3% of TIC cost
- ✓ Power 1331 kw
- ✓ Power usage factor: 80%
- ✓ Workhours – 3 hours per day
- ✓ Testing - $5,000 per year
- ✓ Incremental waste disposal: 137 tpy of ash

10.10. Coal / Wood Boiler – Rebuild Existing ESP

10.10.1. Description

Addition of single electric field in two chambers to an existing electrostatic precipitator in a coal or coal / wood boiler producing 300,000 lb/hr of steam. The particulate emission rate is 0.04 lb / Mm Btu.

10.10.2. Major Equipment

- ✓ Modifications to existing ESP
- ✓ Ductwork modifications

10.10.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler capable of producing 600,000 lb/hr of steam. The project was estimated in 1992.

10.10.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a boiler producing 300,000 lb/hr of steam.
- ✓ Costs escalated to 2001

10.10.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 1% of TIC cost
- ✓ Power 500 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 3 hours per day
- ✓ Testing - $5,000 per year
- ✓ Incremental waste disposal: 43 tpy of ash

10.11. Oil Boiler

10.11.1. Description

Installation of electrostatic precipitator in a oil-fired boiler producing 135,000 lb/hr of steam. The particulate emission rate is 0.02 lb / Mm Btu.

10.11.2. Major Equipment

- ✓ ID fan modification
- ✓ ESP
- ✓ Conveyors
- ✓ Penthouse blower

10.11.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler capable of producing 600,000 lb/hr of steam. The project was estimated in 1992.

10.11.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a boiler producing 135,000 lb/hr of steam.
- ✓ Costs escalated to 2001

10.11.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3% of TIC cost
- ✓ Power – 1098 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 3 hours per day

- ✓ Testing - $5,000 per year
- ✓ Incremental waste disposal: 99 tpy of ash

10.12. Wood Boiler

10.12.1. Description

Installation of an electrostatic precipitator in wood boiler producing 300,000 lb/hr of steam. The particulate emission rate is 0.04 lb / Mm Btu.

10.12.2. Major Equipment

- ✓ ID fan modification
- ✓ ESP
- ✓ Conveyors
- ✓ Penthouse blower

10.12.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler capable of producing 600,000 lb/hr of steam. The project was estimated in 1992.

10.12.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a boiler producing 300,000 lb/hr of steam.
- ✓ Costs escalated to 2001

10.12.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3.5% of TIC cost
- ✓ Power – 1978 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 3 hours per day
- ✓ Testing - $5,000 per year
- ✓ Incremental waste disposal: 599 tpy of ash

10.13. Wood Boiler – upgrade existing ESP

10.13.1. Description

Upgrade of existing electrostatic precipitator in a wood boiler producing 300,000 lb/hr of steam. The particulate emission rate is moved from 0.1 to 0.04 lb / Mm Btu.

10.13.2. Major Equipment

- ✓ ID fan modification
- ✓ ESP
- ✓ Conveyors
- ✓ Penthouse blower

10.13.3. Basis for Estimate

Southeastern Kraft mill boiler ESP rebuild for a boiler capable of producing 310,000 lb/hr of steam. The project was estimated in 1996.

10.13.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a boiler producing 300,000 lb/hr of steam.
- ✓ Costs escalated to 2001

10.13.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3.5% of TIC cost
- ✓ Power – 250 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 3 hours per day
- ✓ Testing - $5,000 per year
- ✓ Incremental waste disposal: 116 tpy of ash

11. Carbon Monoxide – Best Technology Limit

11.1. Coal or Coal / Wood Boiler

11.1.1. Description

Installation of combustion control modifications on a coal-fired boiler producing 300,000 lb/hr of steam. The carbon monoxide (CO) emission rate is anticipated to be 200 or less ppm for a 24-hour average.

11.1.2. Major Equipment

- ✓ Replace forced draft fan
- ✓ Repairs to windbox
- ✓ Replace combustion air dampers
- ✓ New set of tertiary air nozzles
- ✓ New furnace cameras
- ✓ New CEM
- ✓ DCS control upgrade

11.1.3. Basis for Estimate

Southeastern Kraft mill which installed combustion controls on a wood-fired boiler producing 350,000 lb/hr of steam. The project was estimated in 2000.

11.1.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a boiler producing 300,000 lb/hr of steam.
- ✓ Costs escalated to 2001

11.1.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3% of TIC cost
- ✓ Power – 298 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 1.5 hours per day
- ✓ Testing - $5,000 per year

11.2. Wood Boiler

11.2.1. Description

Installation of combustion control modifications on a wood-fired boiler producing 300,000 lb/hr of steam. The carbon monoxide (CO) emission rate is anticipated to be 200 or less ppm for a 24-hour average.

11.2.2. Major Equipment

- ✓ Replace forced draft fan
- ✓ Repairs to windbox
- ✓ Replace combustion air dampers
- ✓ New set of tertiary air nozzles
- ✓ New furnace cameras
- ✓ New CEM
- ✓ DCS control upgrade

11.2.3. Basis for Estimate

Southeastern Kraft mill which installed combustion controls on a wood-fired boiler producing 350,000 lb/hr of steam. The project was estimated in 2000.

11.2.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a boiler producing 300,000 lb/hr of steam.
- ✓ Costs escalated to 2001

11.2.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3% of TIC cost
- ✓ Power – 298 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 1.5 hours per day
- ✓ Testing - $5,000 per year

12. HCl – Good Technology Limit

12.1. Coal Boiler

12.1.1. Description

Installation of caustic scrubber to remove HCl to the level of 0.048 lb/Mm Btu from a coal-fired boiler producing 300,000 lb/hr of steam. Assumes inlet HCl concentration of 0.064 lb/Mm Btu.

12.1.2. Major Equipment

- ✓ Scrubber tower
- ✓ Recirculation pump
- ✓ Booster fan
- ✓ Caustic feed system

12.1.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler producing 600,000 lb/hour of steam. The project was estimated in 1992.

12.1.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power."
- ✓ Costs were escalated to 2001 dollars

12.1.5. Operating Cost Estimate Assumptions

- ✓ Chloride content of coal is 800 ppm which equates to 23 lb/hr of HCl
- ✓ Maintenance labor & materials: 5% of TIC
- ✓ Power: 811 kw
- ✓ Power usage factor: 70%
- ✓ Chemical: 8 lb/hr caustic soda
- ✓ Testing: $5,000 per year
- ✓ Water: 64 gpm
- ✓ Wastewater: 20 gpm
- ✓ Workhours: 3 hours per day

13. HCl – Best Technology Limit

13.1. Coal Boiler

13.1.1. Description

Installation of caustic scrubber to remove HCl to the level of 0.015 lb/Mm Btu from a coal-fired boiler producing 300,000 lb/hr of steam. Assumes inlet HCl concentration of 0.064 lb/Mm Btu.

13.1.2. Major Equipment

- ✓ Scrubber tower
- ✓ Recirculation pump
- ✓ Booster fan
- ✓ Caustic feed system

13.1.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler producing 600,000 lb/hour of steam. The project was estimated in 1992.

13.1.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power."
- ✓ Costs were escalated to 2001 dollars

13.1.5. Operating Cost Estimate Assumptions

- ✓ Chloride content of coal is 800 ppm which equates to 23 lb/hr of HCl
- ✓ Maintenance labor & materials: 5% of TIC
- ✓ Power: 811 kw
- ✓ Power usage factor: 80%
- ✓ Chemical: 25 lb/hr caustic soda
- ✓ Testing: $5,000 per year
- ✓ Water: 64 gpm
- ✓ Wastewater: 20 gpm
- ✓ Workhours: 3 hours per day

14. VOC – Good Technology Limit

14.1. DCE Kraft Recovery Furnace

14.1.1. Description

Collection of black liquor oxidation system vent gases from a DCE recovery furnace burning 1.7 Mm lb BLS per day. The vent gases would be incinerated in an existing multi-fuel boiler.

14.1.2. Major Equipment

- ✓ Vent fan
- ✓ Condensate pump

14.1.3. Basis for Estimate

Rust MACT Cost Analysis report for a DCE recovery furnace burning 1.5 Mm lb BLS per day. The work was done in October 1993.

14.1.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power."
- ✓ Costs were escalated to 2001 dollars
- ✓ Rust estimate was escalated and included as a TIC only.
- ✓ No additional indirect costs were applied to the Rust estimate.

14.1.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3% of TIC
- ✓ Power: 151 kw
- ✓ Power usage factor: 70%
- ✓ Testing: $5,000 per year
- ✓ Steam: 500 lb/hr
- ✓ Workhours: 3 hours per day

14.2. Paper Machines

14.2.1. Description

Based upon NCASI studies ("Volatile Organic Emissions from Pulp & Paper Sources Part VII - Pulp Dryers & Paper Machines at Integrated Chemical Pulp Mills. Tech Bulletin No.681 Oct 1994 NCASI) the paper machines utilizing unbleached pulps had the highest non-additive VOC emission rates. The machines utilizing bleached pulps had very low VOC emissions.

The source of the VOC was from the fluid contained in the unbleached pulp. If the consistency of the unbleached pulp is raised to 30+% (from a nominal 12%) prior to discharge to either the high density storage or to the paper machines, then the VOC contained in the fluid will be reduced by more than two-thirds.

To increase the consistency to 30+%, a screw press would be installed ahead of the high density storage for the unbleached Kraft, semi-chemical (or NSSC), and mechanical pulp mills. The re-dilution water to be used after the screw press would be paper machine whitewater. In the case of the unbleached Kraft mill and semi-chemical mill, the filtrate from the press would be sent to the spent pulping liquor system.

The system was sized for a 1000 ton per day paper machine.

14.2.2. Major Equipment

- ✓ Two screw presses
- ✓ Pressate (filtrate) tank
- ✓ Thick stock pump

14.2.3. Basis for Estimate

Estimate for 1000 tons per day screw press system based upon a quotation from Kvaerner Pulping. The estimate is in 2001 dollars.

14.2.4. Capital Cost Estimate Assumptions

- ✓ None

14.2.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3% of TIC
- ✓ Power: 861 kw
- ✓ Power usage factor: 70%
- ✓ Testing: $5,000 per year

- ✓ Workhours: 1.5 hours per day
- ✓ A COD reduction will result from utilizing the screw press, which can result in enhanced runnability, improved sheet quality, and reduced chemical costs. However, these potential savings are very paper machine specific and were deemed beyond the scope of this study.

14.3. Mechanical Pulping - TMP

14.3.1. Description

Installation of a heat recovery system on TMP systems which will produce clean steam, a NCG vent, and dirty condensates. The system is designed to condense the VOCs to <0.5 lb C / ODTP.

14.3.2. Major Equipment

- ✓ Reboiler
- ✓ Vent condenser / feed water heater
- ✓ Boiler feed water heater
- ✓ Atmospheric start-up scrubber with silencer

14.3.3. Basis for Estimate

Estimate for 500 tpd TMP heat recovery system based upon quotation from Andritz-Ahlstrom for a 500 ADTPD TMP heat recovery system. The quotation was in 2001 dollars.

14.3.4. Capital Cost Estimate Assumptions

- ✓ None

14.3.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3% of TIC
- ✓ Power: 165 kw
- ✓ Power usage factor: 70%
- ✓ Testing: $5,000
- ✓ Workhours: 1.5 hours per day
- ✓ Water: 192 gpm
- ✓ Wastewater: 194
- ✓ Steam: (94,255 lb/hr) (This is projected amount of steam to be recovered.)

14.4. Mechanical Pulping – Pressure Groundwood

14.4.1. Description

Installation of a heat recovery system on pressure groundwood systems which will produce clean steam, a NCG vent, and dirty condensates. The system is designed to condense the VOCs to <0.5 lb C / ODTP.

14.4.2. Major Equipment

- ✓ Reboiler
- ✓ Vent condenser / feed water heater
- ✓ Boiler feed water heater
- ✓ Atmospheric start-up scrubber with silencer

14.4.3. Basis for Estimate

Estimate for 500-tpd-pressure groundwood heat recovery system based upon quotation from Andritz-Ahlstrom for a 500 ADTPD TMP heat recovery system. The quotation was in 2001 dollars.

14.4.4. Capital Cost Estimate Assumptions

- ✓ None

14.4.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3% of TIC
- ✓ Power: 165 kw
- ✓ Power usage factor: 70%
- ✓ Testing: $5,000 per year
- ✓ Workhours: 1.5 hours per day
- ✓ Water: 192 gpm
- ✓ Wastewater: 39
- ✓ Steam: (18,851 lb/hr) (This is projected amount of steam to be recovered and assumes that the heat recovery would be 20% of that for a comparable TMP plant.)

15. VOC – Best Technology Limit

15.1. NDCE Kraft Recovery Furnace

15.1.1. Description

Conversion of wet bottom ESP to a dry bottom ESP for a NDCE recovery furnace burning 3.7 Mm lb BLS per day. 99.8% particulate collection efficiency was assumed.

15.1.2. Major Equipment

- ✓ New dry bottom hopper
- ✓ Ash mix tank
- ✓ Conveyors

15.1.3. Basis for Estimate

Rust MACT Cost Analysis report for a NDCE recovery furnace burning 1.5-Mm lb BLS per day. The work was done in October 1993.

15.1.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power."
- ✓ Costs were escalated to 2001 dollars
- ✓ Rust estimate was escalated and included as a TIC only.
- ✓ No additional indirect costs were applied to the Rust estimate.

15.1.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 2% of TIC
- ✓ Power: 15 kw
- ✓ Power usage factor: 70%
- ✓ Testing: $5,000 per year
- ✓ Workhours: 1.5 hours per day

15.2. DCE Kraft Recovery Furnace

15.2.1. Description

Conversion of DCE recovery furnace burning 1.7 Mm lb BLS per day to a NDCE type.

15.2.2. Major Equipment

- ✓ New economizer
- ✓ New spent pulping liquor concentrator
- ✓ Additional soot blowers
- ✓ Ash mix tank
- ✓ CEMS

15.2.3. Basis for Estimate

Rust MACT Cost Analysis report for a DCE recovery furnace burning 1.5-Mm lb BLS per day. The work was done in October 1993.

15.2.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power."
- ✓ Costs were escalated to 2001 dollars
- ✓ Rust estimate was escalated and included as a TIC only.
- ✓ No additional indirect costs were applied to the Rust estimate.
- ✓

15.2.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3% of TIC
- ✓ Power: 450 kw
- ✓ Power usage factor: 70%
- ✓ Testing: $5,000 per year
- ✓ Steam: (26,984 lb/hr) (steam savings)
- ✓ Workhours: 3 hours per day

15.3. Paper Machines – Wet End

15.3.1. Description

Collection of wet end exhaust gases from a 1000 TPD paper machine and incineration in a regenerative thermal oxidizer (RTO).

15.3.2. Major Equipment

- ✓ Combustion blower
- ✓ Seal fan
- ✓ Main fan
- ✓ Regenerative thermal oxidizer
- ✓ 100' stack with testing platform
- ✓ 316L stainless steel duct

15.3.3. Basis for Estimate

Northern pulp mill with dryer equipped with a collection system and RTO unit. The mill is designed to produce 415 ODTPD of deink pulp. The project was estimated in 2000.

15.3.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power."
- ✓ R&D costs: 1.5% of total direct costs (i.e., labor, materials, subcontract, and equipment)

15.3.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3% of TIC
- ✓ Power: 310 kw
- ✓ Power usage factor: 70%
- ✓ Testing: $5,000 per year
- ✓ Natural gas: 4.71 Mmbtu/hr
- ✓ Workhours: 1.5 hours per day

15.4. Paper Machines – Dry End

15.4.1. Description

Collection of dry-end exhaust gases from a 1000 TPD paper machine and incineration in a RTO.

15.4.2. Major Equipment

15.4.3. Major Equipment

- ✓ Combustion blower
- ✓ Seal fan
- ✓ Main fan
- ✓ Regenerative thermal oxidizer
- ✓ 100' stack with testing platform
- ✓ 316L stainless steel duct

15.4.4. Basis for Estimate

Northern pulp mill with dryer equipped with a collection system and RTO unit. The mill is designed to produce 415 ODTPD of deink pulp. The project was estimated in 2000.

15.4.5. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power."
- ✓ R&D costs: 1.5% of total direct costs (i.e., labor, materials, subcontract, and equipment)

15.4.6. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3% of TIC
- ✓ Power: 380 kw
- ✓ Power usage factor: 70%
- ✓ Testing: $5,000 per year
- ✓ Natural gas: 8.1 MmBtu/hr
- ✓ Workhours: 1.5 hours per day

15.5. Mechanical Pulping – TMP with Existing Heat Recovery System

15.5.1. Description

Collection and incineration of the NCGs from a TMP heat recovery system. The system was sized for a 500 ADTPD mechanical pulp mill.

15.5.2. Major Equipment

- ✓ Duct work
- ✓ Combustion blower
- ✓ Thermal oxidizer

15.5.3. Basis for Estimate

Southeastern Kraft mill which routed its NCGs to a thermal oxidizer. System was sized for 20,000 ACFM. The project was estimated in 1999.

15.5.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the “0.6 power.”
- ✓ Costs were escalated to 2001 dollars

15.5.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3.5% of TIC
- ✓ Power: 22 kw
- ✓ Power usage factor: 70%
- ✓ Workhours: 2.25 hours per day
- ✓ Testing: $5,000 per year
- ✓ Water: 10gpm
- ✓ Wastewater: 10 gpm

15.6. Mechanical Pulping – TMP Without Existing Heat Recovery System

15.6.1. Description

Installation of a heat recovery system on mechanical pulping systems which will produce clean steam, a NCG vent, and dirty condensates. Then collection and incineration of the NCGs. The system was sized for a 500 ADTPD TMP mill.

15.6.2. Major Equipment

- ✓ Reboiler
- ✓ Vent condenser / feed water heater
- ✓ Boiler feed water heater
- ✓ Atmospheric start-up scrubber with silencer
- ✓ Duct work
- ✓ Combustion blower
- ✓ Thermal oxidizer

15.6.3. Basis for Estimate

Estimate for 500 tpd TMP heat recovery system based upon quotation from Andritz-Ahlstrom for a 500 ADTPD TMP heat recovery system. The quotation was in 2001 dollars.

For NCG collection and incineration, Southeastern Kraft mill which routed its NCGs to a thermal oxidizer. System was sized for 20,000 ACFM. The project was estimated in 1999.

15.6.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power."
- ✓ Costs were escalated to 2001 dollars

15.6.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3.5% of TIC
- ✓ Power: 187 kw
- ✓ Power usage factor: 70%
- ✓ Workhours: 2.25 hours per day
- ✓ Testing: $5,000 per year
- ✓ Water: 202gpm
- ✓ Wastewater: 204 gpm
- ✓ Steam: (94,255 lb/hr) (This is projected amount of steam to be recovered)

15.7. Mechanical Pulping – Pressurized Groundwood Without Existing Heat Recovery System

15.7.1. Description

Installation of a heat recovery system on pressurized groundwood pulping systems which will produce clean steam, a NCG vent, and dirty condensates. Then collection and incineration of the NCGs. The system was sized for a 500 ADTPD pressurized groundwood mill.

15.7.2. Major Equipment

- ✓ Reboiler
- ✓ Vent condenser / feed water heater
- ✓ Boiler feed water heater
- ✓ Atmospheric start-up scrubber with silencer
- ✓ Duct work
- ✓ Combustion blower
- ✓ Thermal oxidizer

15.7.3. Basis for Estimate

Estimate for 500 tpd pressurized groundwood heat recovery system based upon quotation from Andritz-Ahlstrom for a 500 ADTPD TMP heat recovery system. The quotation was in 2001 dollars.

For NCG collection and incineration, Southeastern Kraft mill which routed its NCGs to a thermal oxidizer. System was sized for 20,000 ACFM. The project was estimated in 1999.

15.7.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power."
- ✓ Costs were escalated to 2001 dollars

15.7.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3.5% of TIC
- ✓ Power: 198 kw
- ✓ Power usage factor: 70%

- ✓ Workhours: 2.25 hours per day
- ✓ Testing: $5,000 per year
- ✓ Water: 202gpm
- ✓ Wastewater: 49 gpm
- ✓ Steam: (18,851 lb/hr) (This is projected amount of steam to be recovered and assumes that the heat recovery would be 20% of that for a comparable TMP plant.)

15.8. Mechanical Pulping – Atmospheric Groundwood

15.8.1. Description

Collection and incineration of the NCGs from a atmospheric groundwood system. The system was sized for a 500 ADTPD mechanical pulp mill. The estimated emission was 20,000 ACFM.

15.8.2. Major Equipment

- ✓ Hoods
- ✓ Duct work
- ✓ Combustion blower
- ✓ Thermal oxidizer

15.8.3. Basis for Estimate

Southeastern Kraft mill which routed its NCGs to a thermal oxidizer. System was sized for 20,000 ACFM. The project was estimated in 1999.

15.8.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the “0.6 power.”
- ✓ Costs were escalated to 2001 dollars

15.8.5. Operating Cost Estimate Assumptions

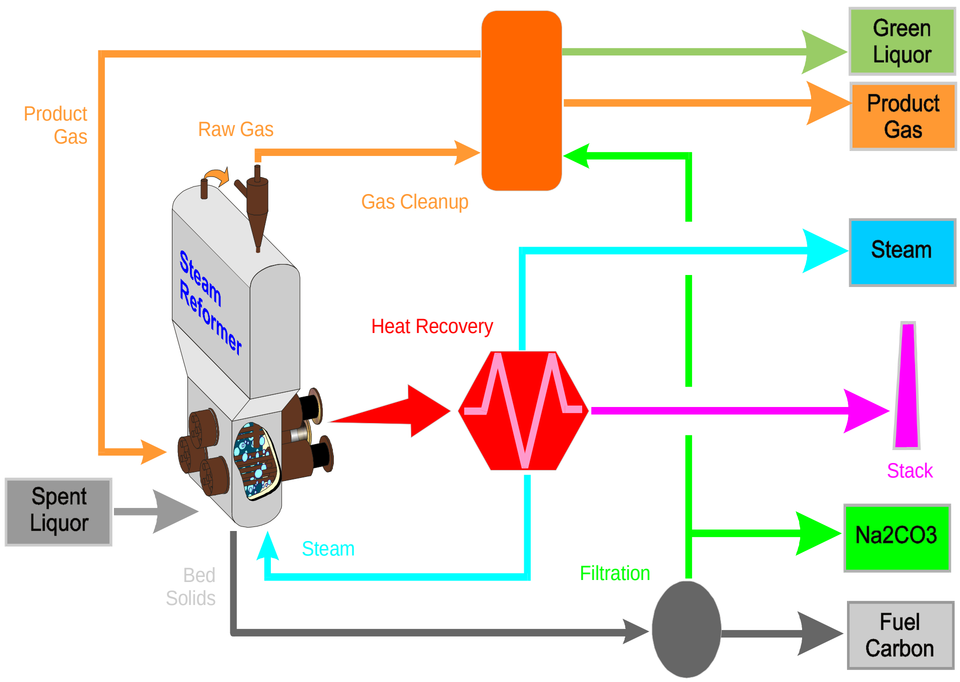
- ✓ Maintenance labor & materials: 3.5% of TIC
- ✓ Power: 22 kw
- ✓ Power usage factor: 70%
- ✓ Workhours: 2.25 hours per day

- ✓ Testing: $5,000 per year
- ✓ Water: 10gpm
- ✓ Wastewater: 10 gpm

16. Gasification

16.1. Description of Technology

For this study, chemical recovery via gasification is based on the PulseEnhanced™ Steam Reformation technology developed by MTCI/ThermoChem, which is designed to process spent liquor and recover its chemical and energy value. A simplified diagram of the technology is shown below.



The recovery of chemicals and energy from spent liquor is effected by an indirectly heated steam-reforming process which results in the generation of a hydrogen-rich, medium-Btu product gas and bed solids, a dry alkali, which flow from the bottom of the reformer. Neither direct combustion nor alkali salt smelt formation occurs in this steam-reforming process.

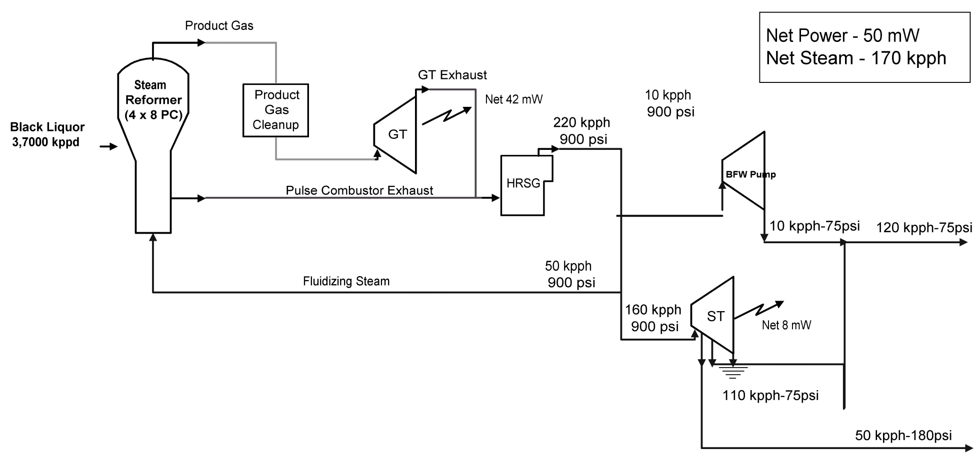
Dissolving, washing, and filtering the bed solids produce a "clear" alkali carbonate solution. The filter cake contains any unreacted carbon as well as insoluble non-process elements such as calcium and silicon. The carbon cake can be used as an activated charcoal for color or odor removal, mixed on the fuel pile for the powerhouse, or discarded as a "dregs" waste.

The product gas is cleaned, compressed, and then sent to the pulse heaters to provide the indirect heat in the reformer and to a combustion turbine to produce electricity. The combustion turbine exhaust is combined with the pulse heater exhaust and then sent to a heat recovery steam generator. The resulting high-pressure steam is then sent to an extraction/condensing steam turbine where addition electricity is produced and lower pressure steam is made available to the mill. A process flow diagram showing the complete system is shown on the following page.

AF&PA/BE&K

Black Liquor Gasification Combined Cycle System
Block Flow diagram

Project 12104
23 June, 2001



The scope developed assumes that the mill can supply concentrated black liquor (80% solids). Since the costs for doing this can vary widely between mills and modern recovery boilers would require a similar concentration, these costs have been omitted from this study.

We recognize that the steam produced by this system is probably not sufficient for a typical Kraft mill. The additional steam requirements will either need to be provided by a biomass gasifier or boiler or a power boiler. These additional systems offer the opportunity for further power generation as well as steam production. This too is site specific and not included in this study.

16.2. Major Equipment

The major subsystems include liquor injection, steam reformer, gas cleanup, combustion turbine, heat recovery and steam generation, steam turbine, bed solids dissolution, sodium carbonate solution filter, and bed solids storage.

16.2.1. Black Liquor Supply and Steam Reformer

High solids black liquor is supplied to the reformer via a recirculation line feeding multiple steam jacketed injectors. Four reformers each containing 8-pulse heaters are required for this size plant. Each steam reformer is a carbon steel; fabricated vessel lined with refractory. The upper region of the vessel is expanded to reduce gas velocity, permitting entrained particles to disengage and fall back to the fluid bed. Internal stainless cyclones, mounted from the roof of the reformer, provide primary dust collection and a second set of external cyclones further captures fines. The reformer is fluidized with superheated steam using stainless fluidizer headers that are located just above the refractory floor. Bed drains penetrate the refractory floor for removal of bed solids via lock hoppers during normal operation.

Pulsed jet heater modules (fired heat exchangers) are used to indirectly heat the reformer. Pulsed heater modules are cantilever-mounted in the reformer utilizing a flange located on the front of the vessel. Each module extends through the reformer with it resonance tubes in contact with the fluid bed particles inside the vessel.

16.2.2. Product Gas Cleanup

Cyclone-cleaned product gas exits the reformer and enters a product gas heat recovery steam generator (HRSG) which cools the gas prior to entering a venturi separator, which further cools the gas and washes out any solids carryover. A packed gas cooler follows the venturi separator. Once the gas is cooled, it enters the H2S absorber (green liquor column). The absorber is a carbon steel cylinder with two packed stages.

16.2.3. Product Gas Combustion

The clean/cool product gas is sent to the pulse heaters and to a compressor, which then feeds a combustion turbine. The CT generates 50mW of net power.

16.2.4. Heat Recovery and Steam Generation

Steam is generated in both the product gas HRSG and the waste heat boiler. The product gas HRSG consists of a vertical shell and tube generating section and an external steam drum. The product gas HRSG also serves as a source of cooling water for the pulsed heaters.

The waste heat boiler is a two-drum, bottom-supported boiler. Hot flue gas from the pulse heaters and the combustion turbine flows into the HRSG to produce 220-pph 900psi/900F steam.

16.2.5. Steam Turbine

Steam from the waste heat boiler is sent to an extraction condensing steam turbine, which will extract the energy in the high-pressure steam to generate a net 8 mw of power. The resulting lower pressure steam is then piped to the mill steam distribution system.

16.2.6. Solids Dissolution

The solids from each reformer flows through refractory-lined lock hoppers into dissolving tanks. The dissolving tank is carbon steel, insulated tank outfitted with a side-entry agitator, and sized to provide additional retention time to effect dissolution of the soluble sodium carbonate.

16.2.7. Sodium Carbonate Filter

The function of the filter system is to filter the dissolving tank solution to produce a clear sodium carbonate liquor; free of suspended solids such as unreacted organic carbon and non-process elements.

16.2.8. Media Storage Bin

The media bin is an insulated carbon steel vessel (mass flow design) with a capacity sufficient to hold the inventory of several reformers during repair and maintenance.

16.3. Basis for Estimate

Our database of studies, extending over the last 5 years for systems ranging from 250,000 lb/day to 1,000,000 lb/day black liquor solids, was used to create a base for the capital cost estimate.

16.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power."
- ✓ Costs were escalated to 2001 dollars
- ✓ Engineering was assumed to 8% vs. the standard 15% because of the high cost of the equipment and the fact that there is little integration to existing plant
- ✓ R&D expenses of 1.5% of the direct costs were assumed.
- ✓ Equipment foundations on spread footings
- ✓ No allowance for disposal of any potential contaminated soils

- ✓ Except for the purchase of one spare pulsed heater unit, no standalone spares are included. Installed spares are listed as equipment.
- ✓ No demolition costs
- ✓ Pricing was obtained for major equipment. Some prices were not competitively bid and no negotiations were undertaken to firm or clarify process scope.

16.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3% of TIC cost
- ✓ Utilities: 0.1% of TIC cost
- ✓ Power
  - ♦ New loads: 11,600 kw
  - ♦ Credit for shutdown of existing recovery boiler: (3700) kw
  - ♦ Revenue – sale of power: 50,000 kw
- ✓ Dregs disposal: 1.9 tons per hour
- ✓ Waste water treatment: 650 gpm
- ✓ Steam (revenue): (170,000) lb/hr

16.6. Impact on Emissions

Emissions estimates prepared in earlier studies were scaled up for the 3.7 million-lb/day gasifier and then compared to equivalent data for a similarly sized recovery boiler. The emissions are shown in the tables and chart below.

Black Liquor Gasification Emission Estimates

	Black Liquor Reformer Pulse Combustion Exhaust	Combustion Turbine Exhaust	Total
	(lb/hr)	(lb/hr)	(lb/hr)
Particulate matter	2.9	5.7	8.5
Nitrous oxides (NO_x)	18.7	46.1	64.7
Carbon monoxide (CO)	11.4	56.1	67.5
Sulfur dioxide (SO_2)	70.0	81.0	151.0
Volatile organic (as carbon)	0.4	0.0	0.4
as Methanol	2.8	0.0	2.8
TRS (as H_2S)	0.0	0.0	0.0

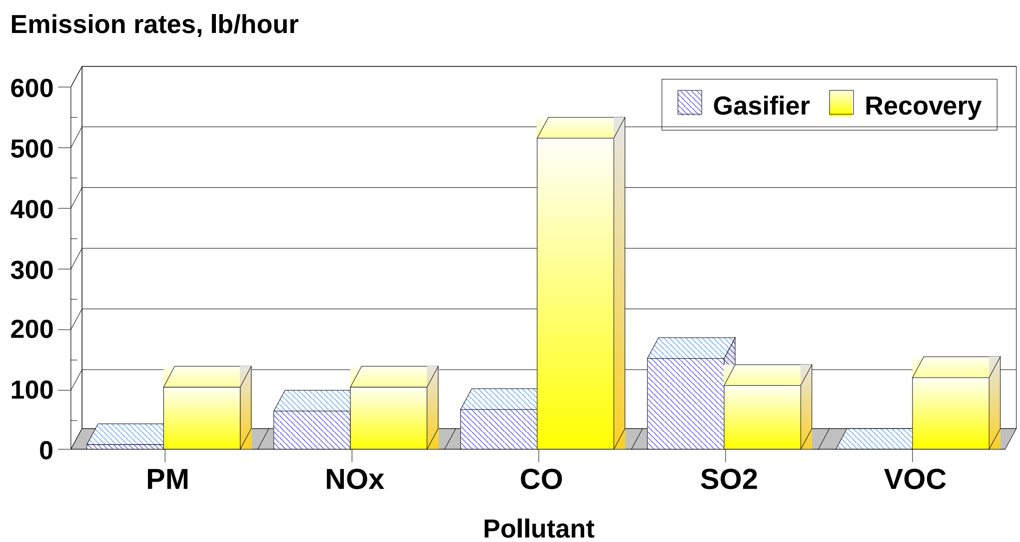
Recovery Boiler & Smelt Dissolver Emission Estimates

	Recovery Boiler Exhaust	Smelt Dissolving Exhaust	Total
	lb/hr	lb/hr	lb/hr
Particulate matter	93.9	9.4	103.3
Nitrous oxides (NO_x)	89.2	16.1	105.3
Carbon monoxide (CO)	516.5	0.3	516.8
Sulfur dioxide (SO_2)	98.7	9.4	108.1
Volatile organic (as carbon)	37.6	7.5	45.1
as Methanol	100.2	20.0	120.2
TRS (as H_2S)	4.7	2.5	7.2

Additionally for carbon dioxide the black liquor gasification emission rate is estimated to be 240,400 lb/hr for a 4 Mm lb BLS/day unit, while a comparable Tomilson unit would discharge 318,600 lb/hour.

The following illustrates the differences between a black liquor gasification unit and a Tomilson recovery system:

Estimated Emission Rates - Gasifier vs. Recovery Furnace



Emission estimates based on 3.7 Mmlb BLS/day firing rate.

17. Industry – Wide Control Cost Estimates

17.1. General Assumptions

The following are the general assumptions:

17.1.1. Capital Costs

- ✓ The individual mill cost estimates are based upon using the 0.6 power rule [Project A cost x (AF&PA firing rate / Project A firing rate)$^{0.6}$] to factor the control technology estimates
- ✓ The boiler emission rates are compared with pollutant limits to determine relative compliance. If the mill discharge level is less than 90% of the pollutant limit, then no control technology will be installed.
- ✓ The base labor is $58.62 per hour and was determined from:

Area	Rate, $/hour	Comment
Base rate	$17.50	
Benefits	$3.25	18.55% of base rate
Fringes	$2.01	11.50% of base rate
Workman's compensation insurance	$2.13	Varies by craft from 6 to 30% of base rate
Indirects	$27.00	Includes home office expenses, field supervision, temporary facilities, tools/ consumables, construction equipment, permits/miscellaneous, and contractor's fee
Premium mark-up	$2.07	
Per diem	$4.66	Includes direct and indirect
Total	**$58.62**	

- ✓ The labor costs portion of the TIC were adjusted for each mill utilizing the BE&K labor rates by region. See Appendix 18.1 for a listing of the factors by state.
- ✓ The material and subcontract costs were adjusted for each mill utilizing the MEANS database factors averaged for each state. See Appendix 18.1 for a listing of the factors by state.
- ✓ Research & Development expenses were assumed for the SCR-non-natural gas, mercury removal, and paper machine VOC removal – best technology applications. They ranged from 0.5 to 1.5% of the sum of the labor, material, subcontract, and equipment direct costs.
- ✓ The BE&K project costs were escalated according to the following:

Period	Escalation rate
1994 to 1995	2.50%
1995 to 1996	3.30%
1996 to 1997	1.70%
1997 to 1998	1.60%
1998 to 1999	2.70%
1999 to 2000	3.40%

17.1.2. Annual Operating and Maintenance Costs

- ✓ The maintenance labor and material annual costs were reported as a percentage of the TIC. The typical range was between 1% and 5% of the total TIC.
- ✓ The operating costs for the mills were proportionately factored for each of the areas (excluding testing and workhours) from the design case.
- ✓ 355 operating days per year were assumed for the equipment.
- ✓ The materials category such as fabric filter or SCR catalyst was reported in terms of 2001 dollars.
- ✓ The wastewater category reported the usage in gallons per year based upon the estimated flow; gpm/feed rate x feed rate x 1440 min/day x 365 dy/yr. The water usage used the same formula but with only 350 dy/yr.

- ✓ The steam and compressed air usage was calculated by multiplying the usage per feed rate x feed rate per day x 350 dy/yr.
- ✓ The estimated cost for process water was $0.58 per thousand gallons.
- ✓ The estimated cost for wastewater treatment was $0.41 per thousand gallons.
- ✓ The estimated cost for caustic soda was $0.17 per lb.
- ✓ The estimated cost for urea was $225 per ton
- ✓ The estimated cost for activated carbon is $0.58 per lb
- ✓ The estimated cost for pebble lime is $56.50 per ton
- ✓ The differential price between No. 2 and No. 6 fuel oil is $0.84 per Mmbtu (assumes a cost of $4.32 /Mmbtu for No. 6 fuel oil and $5.16 / MmBtu for No. 2 fuel oil)
- ✓ The energy usage was first calculated in kWh/year and is based upon the estimated connected kilowatts x 24/hr/day times 350 days times usage factor (typically 70 to 80%).
- ✓ The price of electricity was assumed to $0.05/kwhr and was multiplied by the kWh/year.
- ✓ The price of steam was assumed to be $0.00500 per lb of steam and was multiplied by the steam usage in lb/hr per year. For any recovered steam, a recovered steam factor times the price of steam was used to determine the value of the steam.
- ✓ The price of compressed air was assume to be $0.00010 per cfm and was multiplied by the compressed air usage in cfm/year.
- ✓ The utilities category totals the costs for compressed air, water, wastewater, steam, and solid waste disposal.
- ✓ The price of natural gas was assumed to be $4.00 per Mmbtu.
- ✓ The landfill cost for hauling and disposal was assumed to be $25 per ton of solid waste.
- ✓ An annual testing cost of $5,000 was assumed for each technology applied and was assumed constant independent of the size of the facility.
- ✓ The workhours were reported in $ /year based upon hours / day x 350 operating days/year x the hourly rate. The hourly rate was obtained from AF&PA Labor

Database with 91% of member contracts entered (missing about 20); the average hourly rate for year 2000 was $18.14. This data only includes hourly employees. An additional 40% was added to the figure to account for benefits to yield a rate of $25.40. The workhour dollars were not factored, but were assumed to be constant no matter what the size of the facility.

- ✓ The NCASI database for recovery furnaces, limekilns, and power boilers was used. This included equipment information, combustion firing rates and types, and pulping information.
- ✓ NCASI provided the mill code for the BE&K supplied paper machine and mechanical pulping information.

17.2. CO_2 Emission Assumptions

- ✓ The CO_2 emissions were calculated by multiplying the 1995 NCASI fossil fuel usage from the power boilers, recovery furnaces, and lime kilns times the CO_2 factors times 99% (assuming a 99% burn factor). This was the recommended calculation technique from the DOE Emission of Greenhouse Gases in the United States report.
- ✓ The CO_2 emission factors are:

Distillate Oil (No.2)	21.945	Tons / MmBtu
Residual Oil (No.6)	23.639	Tons / MmBtu
Coal Industrial (other)	28.193	Tons / MmBtu
Natural gas	15.917	Tons / MmBtu
Petroleum Coke*	30.635	Tons / MmBtu

* Petroleum Coke was assumed to have a heat content of 15,000 Btu/lb

17.3. Recovery Furnace Assumptions

The following are the assumptions:

17.3.1. General Assumptions

- ✓ NDCE recovery furnace firing 3.7 Mm lb BLS/day is assumed to have an air flow of 27,500 lb/min, NO_x Control Technology.
- ✓ For the cases where the design heat load (i.e., Mm Btu/hr) is not known, it was calculated from the design BLS firing rate, utilizing a heat content of 5900 Btu/lb.

17.3.2. NO_x Control Technology

- ✓ The limits were converted to a lb/Mm Btu basis that equates to.

NDCE at 80 ppm	0.1415 lb / Mm Btu
NDCE at 40 ppm	0.0726 lb / Mm Btu
DCE at 30 ppm	0.0544 lb / Mm Btu

- ✓ The annual NO_x emission rates from the NCASI database were converted to lb/Mm Btu and compared with 80% of the above limits. The NO_x limits are based upon 30-day averages and it was assumed that to comply with the 30-day average limits the annual average would be approximately 80% of the 30-day limits.
- ✓ For the case of the good technology, if a given furnace did not meet the adjusted limit, then its emission rate was assumed to average the adjusted limit (i.e., 80% of the 30-day average limits) after treatment. The adjustment of 80% represents a compliance safety margin.
- ✓ If no emission rates were indicated for 1995, then no treatment estimate was made for that furnace.
- ✓ For the case of the best technology, if a given furnace did not meet the adjusted limit, then its emission rate was assumed to be reduced by 50% after treatment

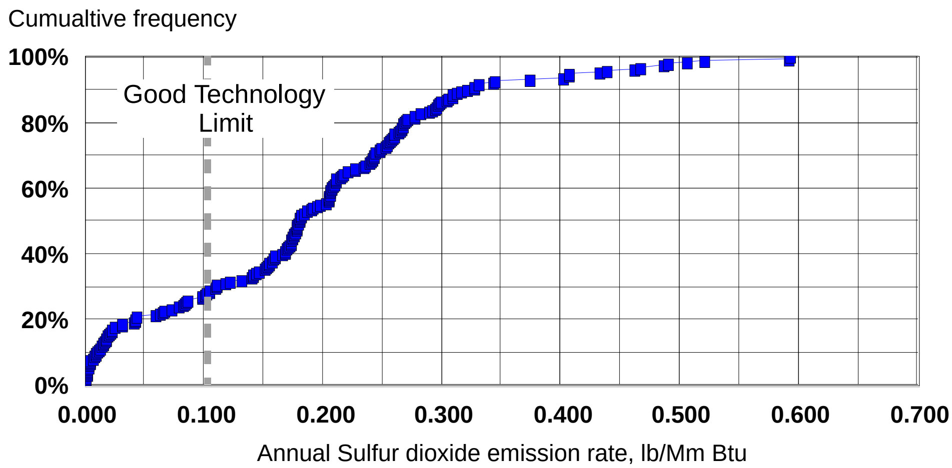
17.3.3. SO_2 Control Technology

- ✓ The limits were converted to a lb/Mm Btu basis that equates to.

NDCE at 50 ppm	0.12 Lb / MmBtu
NDCE at 10 ppm	0.0.024 Lb / MmBtu
DCE at 50 ppm	0.0.12 Lb / MmBtu
DCE at 10 ppm	0.0.024 Lb / MmBtu

- ✓ The annual SO_2 emission rates from the NCASI database were converted to lb/Mm Btu basis and compared with 80% of the above limits. The SO_2 limits are based upon 30-day averages and it was assumed that to comply with the 30-day average limits the annual average would be approximately 80% of the 30-day limits.
- ✓ The following illustrates the cumulative distribution for the recovery furnace SO_2 emission rates from the 1995 NCASI database:

Recovery Furnace SO2 Emission Distribution



Basis: 1995 NCASI emission data base
Good technology limit is based upon 30-day average time 0.8

- ✓ For recovery furnaces with up to four-times the adjusted SO_2 limit (i.e., 0.3628 lb/Mm Btu), combustion control modifications (**<u>these are the same as what was estimated for good controls for</u>** **<u>NO_x</u>**) would be implemented. For recovery furnaces with SO_2 limits greater than 0.3628 lb/Mm Btu, a new scrubber would be installed. In either case, the controlled emission rate would be equivalent to an annual average of 40 ppm (i.e., 50 ppm x 80%).
- ✓ If no emissions were indicated for 1995, then no treatment estimate was made for the furnace.
- ✓ For both technologies, if a given furnace did not meet the adjusted limit, then its emission rate was assumed to average the adjusted limit. The adjustment of 80% represents a compliance safety margin.

17.3.4. PM Control Technology

- ✓ Any recovery furnace ESP built or rebuilt after 1990 but before 1998 was assumed capable of meeting the good PM technology limit.

- ✓ Any recovery furnace ESP built after 1990 but before 1998 will be upgraded with additional fields for best PM technology limits.
- ✓ Any NDCE recovery furnace ESP built or rebuilt before 1980 will be upgraded with additional field for the good PM technology limit and be replaced for the best PM technology limit.
- ✓ Any NDCE recovery furnace ESP built or rebuilt after 1980 will meet the good technology limits.
- ✓ Any non-NDCE recovery furnace ESP or scrubber built before 1990 will be replaced with a new ESP for either good or best PM technology.
- ✓ Any recovery furnace ESP built or rebuilt after 1998 was assumed to comply with the best PM technology limit.

17.3.5. VOC Control Technology

- ✓ Good VOC technology limit consists of collecting and incinerating the BLO vent gas from any non-NDCE recovery furnace.
- ✓ Best VOC technology consists of converting any NDCE recovery furnace ESPs from wet to dry bottom and converting any non-NDCE to a NDCE recovery furnace

17.3.6. Smelt Dissolving Tank Scrubber - PM Technology

- ✓ Number of smelt dissolving tank was determined based upon the manufacturer. Combustion Engineering furnaces with greater than a 3.5 Mm lb BLS/ day firing rates are assumed to have two smelt dissolving tanks and the other manufacturer's have one smelt dissolving tank. For the case of the two smelt dissolving tank scrubbers, the initial scrubber was factored based on half the black liquor-firing rate and then multiplied by two.
- ✓ Any recovery furnace built before 1976 will require a new smelt dissolving tank scrubber.
- ✓ Any recovery furnace built or rebuilt after 1976 but before 1990 was assumed to meet the good PM technology limit
- ✓ Any recovery furnace built or rebuilt after 1990 was assumed to meet the best PM technology limit

17.4. Lime Kiln Assumptions

The following are the assumptions:

17.4.1. PM Control Technology

- ✓ Any lime kiln built after 1976 and equipped with a wet scrubber or those kiln equipped with an ESP installed prior to 1990 was assumed to meet the good PM technology limit.
- ✓ Any limekiln equipped with an ESP installed prior to 1990 was assumed upgradable to meet the best PM technology limit.
- ✓ Any lime kiln equipped with an ESP installed after 1990 was assumed to meet the best PM technology limit

17.4.2. NO_x Control Technology

- ✓ If the annual NCASI-estimated NO_x levels are less than 20 TPY, no controls will be added. This level represents approximately 10% of the limekilns from the NCASI database.
- ✓ If no emissions where indicated for 1995, then no treatment estimate was made for the kiln.
- ✓ If the mill burns the NCGs primarily in the limekiln, then it was assumed that if there is a stripper present the stripper off-gases (SOGs) are burned in the limekiln.
- ✓ The NO_x level in the limekiln if NCGs are being burned will decrease by 30% if the SOGs are burned in a thermal oxidizer. The thermal oxidizer would be equipped with staged combustion to control the NO_x levels.
- ✓ The NO_x level in the limekiln will decrease by 60% with the incorporation of SCR and low-NO_x burners. If a good technology fix was required, the best technology was additive: the 60% reduction was compounded on the 30% reduction for a total of a 72% reduction [(1-0.3) x (1-0.6)].

17.5. Boiler and Turbine Assumptions

- ✓ 350 operating days per year were assumed.
- ✓ If the Btu/hr capacity of the boiler was not provided, then the steam output was multiplied by the assumed heating value for the steam of 1200 Btu/lb.
- ✓ If only the fuel combusted in 1995 was known,

- ✓ The fuel usage for each boiler from the NCASI database was multiplied by the following heating values:

Coal	25,000	MmBtu/1000 ton
Residual Oil (No.6)	5,920	MmBtu/1000 bbl
Distillate Oil (No.2)	5,376	MmBtu/1000 bbl
Natural gas	950	MmBtu/MmCF
Wood	9,000	MmBtu/1000 ton
Sludge	10,000	MmBtu/1000 ton

- ✓ If the design information for the boiler – either steam or Btu were not provided, then the sizing was based upon the 1995 NCASI fuel usage (if given) and Btu estimate. The steam output was calculated from the Btu estimate and the boiler efficiency, which was assumed 85% for everything, except for wood-fired boilers, which was assumed to have a 65% efficiency.
- ✓ The boiler design figure was compared with the predicted steam (i.e., based upon 1995 reported fuel usages) and which ever was higher was used to compute the capital costs for the control technologies. The operating costs were based upon the predicted steam usage.
- ✓ The best estimate SO_2, and NO_x yearly emission rates were converted to pounds and divided by Btus to determine a lb/MmBtu emission rate.
- ✓ The SO_2 and NO_x emission rates were then multiplied by 80% and compared with the technology limits. The technology limits are based upon 30-day averages and it was assumed that to comply with the 30-day average limits the annual average would be approximately 80% of the 30-day limits.
- ✓ For the case of the good technology, if a given furnace did not meet the adjusted limit, then its emission rate was assumed to average the adjusted limit after treatment (i.e., 80% of the 30-day average limits).
- ✓ For the case of SO_2 control technology, no control costs were assumed for any boiler designated as a wood or gas boiler, regardless of the emission level.
- ✓ NCASI has listed 1225 boilers or turbines, and had fuel consumption information on 1074 of them. Control technology estimates for boilers were only made if fuel consumption information was provided.

17.6. Coal Boiler Assumptions

17.6.1. General

- ✓ If more than 80% of the gross Btu's originated from coal, then the boiler was assumed a coal boiler.

17.6.2. NO_x Limits

- ✓ Any coal boilers after 1990 are assumed to have low NO_x burners and are assumed to meet the 0.3 lb/10^6 Btu, 30-day average.
- ✓ If the coal boilers were converted to natural gas with low NO_x-burners, then the emission rates were assumed to be 0.0490 and 0.1373 lb / 10^6 Btu for boilers less than and greater than 100 million Btu/hr, respectively.

17.6.3. SO_2 Limits

- ✓ Application of scrubbers to coal boilers will yield 50% reduction at good technology and 90% reduction at best technology.

17.6.4. Hg limits

- ✓ The uncontrolled limits were obtained by multiplying the MmBtu/year for 1995 by 16 lb/10^{12} Btu that is the AP-42 emission factor.
- ✓ The removal rate for the carbon injection and fabric filter approach was assumed 50%.

17.6.5. PM limits

- ✓ Any coal boiler with an ESP built or rebuilt after 1980 is assumed able to meet the good technology limit. If the ESP was built or rebuilt before 1980, the ESP's would be upgraded by adding a single field. If the year the ESP was constructed or rebuilt was not in the NCASI database, then the ESP was assumed to have been built or rebuilt before 1980. Any coal boiler constructed after 1990 is assumed to meet the good technology limit.
- ✓ Any coal boiler with an ESP built or rebuilt after 1980 can be upgraded to by adding a single field in two chambers to meet the best technology limit. A new ESP will be priced out for an ESP built or rebuilt before 1980.
- ✓ Any coal boiler constructed or an ESP built or rebuilt after 1998 is assumed to meet the best technology limit.

17.6.6. CO limits

- ✓ Any coal boiler constructed after 1990 is assumed to be able to meet the best technology limit of 200 ppm (24-hour average).

17.6.7. HCl limits

- ✓ Use same criteria as for SO_2 limits – if a scrubber was required for SO2, then it was assumed a scrubber would be required for HCl control. This applied to both good and best control technologies.
- ✓ If SO_2 control is installed there will be no need to install HCl controls as well; the chemical addition rate for SO_2 is greater than what is required to remove the HCl present.

17.7. Coal / Wood Boiler Assumptions

17.7.1. General Assumptions

- ✓ At least 20% of the Btus had to come from coal or wood provided both were used within the boiler.

17.7.2. NO_x Limits

- ✓ Any coal boilers after 1990 were assumed to have low NO_x burners and were assumed to meet the 0.3 lb/10^6 Btu, 30-day average
- ✓ For the case of the good or best technology, if a given boiler did not meet the adjusted limit, then its emission rate was assumed to average the adjusted limit (i.e., 80% of the 30-day average limits) after treatment

17.7.3. SO_2 Limits

- ✓ Application of scrubbers to coal/wood boilers will yield 50% reduction at good technology and 90% reduction at best technology.

17.7.4. Hg limits

- ✓ The uncontrolled limits were obtained by multiplying the MmBtu/year for 1995 by 16 lb/10^{12} Btu for coal and by 0.572 lb/10^{12} Btu for wood. Both are based upon the AP-42 emission factor with the wood corrected for the difference in heavy metals between coal and wood.
- ✓ The removal rate for the carbon injection and fabric filter approach was assumed 50%.

17.7.5. PM limits

- ✓ Any coal/wood boiler with an ESP built or rebuilt after 1980 is assumed able to meet the good technology limit. If the ESP was built or rebuilt before 1980, the ESP's would be upgraded by adding a single field in two chambers. If the year the ESP was constructed or rebuilt was not in the NCASI database, then the ESP was assumed to have been built or rebuilt before 1980.

- ✓ Any coal/wood boiler constructed after 1990 is assumed to meet the good technology limit.
- ✓ Any coal /wood boiler with an ESP built or rebuilt after 1980 can be upgraded to by adding a single field in two chambers to meet the best technology limit. A new ESP will be priced out for an ESP built or rebuilt before 1980.
- ✓ Any coal/wood boiler constructed or an ESP built or rebuilt after 1998 is assumed to meet the best technology limit.

17.7.6. CO limits

- ✓ Any coal / wood boiler will require controls to meet the best technology limit of 200 ppm (24-hour average)

17.8. Gas Boiler Assumptions

17.8.1. General Assumptions

- ✓ A minimum of 90% of the Btu's had to come from natural gas, in order for the boiler to be considered a gas boiler.

17.8.2. NO_x Limits

- ✓ Any gas boilers after 1990 are assumed to have low-NO_x burners and are assumed to meet the 0.05 lb/10^6 Btu, 30-day average
- ✓ For the case of the good or best technology, if a given boiler did not meet the adjusted limit, then its emission rate was assumed to average the adjusted limit (i.e., 80% of the 30-day average limits) after treatment

17.9. Gas Turbine Assumptions

17.9.1. NO_x Limits

- ✓ Any gas turbines after 1995 are assumed to have water or steam injection to control to the good technology limit of 25 ppm @ 15% oxygen.
- ✓ For the case of the good or best technology, if a given turbine did not meet the adjusted limit, then its emission rate was assumed to average the adjusted limit (i.e., 80% of the 30-day average limits) after treatment

17.10. Oil Boiler Assumptions

17.10.1. General Assumptions

- ✓ If both oil and gas are burned, then if more than 15% of the Btu's originates from oil, the boiler was considered an oil boiler.

- ✓ If oil and wood or coal was burned, then at least 85% of the Btu had to originate from oil for the boiler to be considered an oil boiler.

17.10.2. NO_x Limits

- ✓ Any oil boilers after 1990 are assumed to have low-NO_x burners and are assumed to meet the 0.2 lb/10^6 Btu, 30-day average
- ✓ For the case of the good or best technology, if a given boiler did not meet the adjusted limit, then its emission rate was assumed to average the adjusted limit (i.e., 80% of the 30-day average limits) after treatment

17.10.3. SO_2 Limits

- ✓ Application of scrubbers to oil boilers will yield 50% reduction at good technology and 90% reduction at best technology.

17.10.4.PM limits

- ✓ Any oil boiler with an ESP is assumed able to meet the good technology limit.
- ✓ Any oil boiler constructed after 1990 is assumed to meet the good technology limit.
- ✓ Any oil boiler burning distillate oil is assumed to meet the good technology limit.
- ✓ Any oil boiler with an ESP can be upgraded to by adding a single field in two chambers to meet the best technology limit.
- ✓ Any oil boiler constructed after 1998 is assumed to meet the best technology limit.

17.11. Wood-Fired Boiler Assumptions

17.11.1. General Assumptions

- ✓ Any boiler where at least 80% of the Btu originate from wood, then the boiler is considered a wood-fired boiler.

17.11.2. NO_x Limits

- ✓ Any wood boiler after 1990 are assumed to have combustion controls and are assumed to meet the 0.25 lb/10^6 Btu, 30-day average
- ✓ For the case of the good or best technology, if a given boiler did not meet the adjusted limit, then its emission rate was assumed to average the adjusted limit after treatment (i.e., 80% of the 30-day average limits).

17.11.3. Hg limits

- ✓ The uncontrolled limits were obtained by multiplying the MmBtu/year for 1995 by 0.572 lb/10^{12} Btu for wood. This is based upon the AP-42 emission factor for coal corrected for the difference in heavy metals between coal and wood.
- ✓ The removal rate for the carbon injection and fabric filter approach was assumed 50%.

17.11.4. PM limits

- ✓ Any wood boiler with an ESP built or rebuilt after 1980 is assumed able to meet the good technology limit. If the ESP was built or rebuilt before 1980, the ESP's would be upgraded by adding a single field in two chambers. If the year the ESP was constructed or rebuilt was not in the NCASI database, then the ESP was assumed to have been built or rebuilt before 1980.
- ✓ Any wood boiler constructed after 1990 is assumed to meet the good technology limit.
- ✓ Any wood boiler with an ESP built or rebuilt after 1980 can be upgraded to by adding a single field in two chambers to meet the best technology limit. A new ESP will be priced out for an ESP built or rebuilt before 1980.
- ✓ Any wood boiler constructed or an ESP built or rebuilt after 1998 is assumed to meet the best technology limit.

17.11.5.CO limits

- ✓ Any wood boiler will require cotnrols to meet the best technology limit of 200 ppm (24-hour average)

17.12. Paper Machine Assumptions

- ✓ Fisher Database statistics were used.
- ✓ Minimum machine size capacity of 50 tons per day was used as the cut-off.
- ✓ Only paper machines with unbleached Kraft, semi-chemical, NSSC, and mechanical pulp furnishes were considered for the good technology limits. Unbleached recycle fiber furnishes were considered for the best technology limits.
- ✓ Each mechanical pulp line was treated separately for the good technology limit.
- ✓ The good technology was sized based upon the pulp mill production. A minimum of 200 tons per day was used as the cut-off for the pulp mill production for everything but mechanical pulping, which was set at 100 tons per day.

- ✓ The best technology was sized based upon the paper machine capacity. If only a portion of a paper machine's furnish was one of the above fiber furnishes, then the paper machine was treated.
- ✓ The untreated emission rate for the unbleached paper machines was assumed to be 0.47 lb C / ODTP. (Basis: NCASI Tech Bulletin No. 681)
- ✓ The emission reduction for the good technology was assumed 67%.
- ✓ The emission reduction for the best technology was assumed 99%.

17.13. Mechanical Pulping

- ✓ Fisher Database statistics were used
- ✓ Minimum production level of 18,000 tons per year was used as the cut-off.
- ✓ Any TMP line constructed after 1989 is assumed to meet the good technology limits. Heat recovery was applied to all pressure groundwood mills regardless of age.
- ✓ Heat recovery was not applied to any atmospheric groundwood pulping lines.
- ✓ Any TMP pulping line constructed after 1998 is assumed to meet the best technology limits.

18. Appendix

18.1. MEANS and BE&K Labor Rate Factors by State

The following presents the state factors for the RS Means Open Shop Building Construction Cost Data 17th edition location factors for materials and subcontracting (or total) and the BE&K construction labor factors:

	Materials Factor	Subcontracting Factor	BE&K Construction Labor Factor
Alabama	0.967	0.823	1.000
Alaska	1.354	1.254	0.959
Arizona	0.989	0.876	0.975
Arkansas	0.957	0.778	0.970
California	1.076	1.119	0.983
Colorado	1.019	0.937	0.974
Connecticut	1.028	1.054	0.979
Delaware	0.992	1.009	0.968
Florida	0.987	0.841	0.992
Georgia	0.967	0.840	0.979
Idaho	1.021	0.938	0.960
Illinois	0.970	1.041	0.997
Indiana	0.975	0.957	0.958
Iowa	0.996	0.918	0.995
Kansas	0.966	0.864	0.961
Kentucky	0.955	0.895	0.992
Louisiana	0.989	0.824	0.990
Maine	0.996	0.824	1.003
Massachusetts	0.997	1.043	0.975
Maryland	0.937	0.884	0.973

	Materials Factor	Subcontracting Factor	BE&K Construction Labor Factor
Michigan	0.970	0.948	0.973
Minnesota	0.984	1.073	0.983
Mississippi	0.985	0.739	0.977
Missouri	0.962	0.950	0.987
Montana	0.995	0.938	0.977
Nebraska	0.978	0.828	0.962
Nevada	1.020	0.993	0.967
New Hampshire	0.983	0.913	0.982
New Jersey	1.028	1.125	0.965
New Mexico	1.006	0.912	0.972
New York	0.968	0.945	0.977
North Carolina	0.959	0.734	0.982
North Dakota	1.008	0.849	0.939
Ohio	0.967	0.944	0.954
Oklahoma	0.971	0.789	0.990
Oregon	1.044	1.060	0.967
Pennsylvania	0.975	0.982	0.982
Rhode Island	1.001	1.040	0.980
South Carolina	0.954	0.726	0.970
South Dakota	0.989	0.778	0.970
Tennessee	0.968	0.803	0.998
Texas	0.965	0.807	0.991
Utah	1.018	0.899	0.951
Vermont	1.010	0.855	0.973
Virginia	0.972	0.838	0.966
Washington	1.062	1.016	0.964
West Virginia	0.970	0.937	1.005

	Materials Factor	Subcontracting Factor	BE&K Construction Labor Factor
Wisconsin	0.984	0.959	0.979
Wyoming	1.003	0.826	0.939

18.2. Net Downtime

Although mill or process downtime costs were not included in the analysis, an estimate was made of the net downtime. Since the work would be done during scheduled downtime, the net downtime is the additional time required above the typical scheduled downtime. The following is BE&K's estimate for net downtime:

Good / Best Technology	Pollutant	Equipment	Net Downtime, days
Good	PM	NDCE Kraft Recovery Furnace	3
Best	PM	NDCE Kraft Recovery Furnace	3
Good	SO2	NDCE Kraft Recovery Furnace	3
Best	SO2	NDCE Kraft Recovery Furnace	3
Good	NOx	NDCE Kraft Recovery Furnace	3
Best	NOx	NDCE Kraft Recovery Furnace	3
Best	VOC	NDCE Kraft Recovery Furnace	3
Good	PM	DCE Kraft Recovery Furnace	3
Best	PM	DCE Kraft Recovery Furnace	3
Good	SO2	DCE Kraft Recovery Furnace	3
Best	SO2	DCE Kraft Recovery Furnace	3
Best	NOx	DCE Kraft Recovery Furnace	3
Good	VOC	DCE Kraft Recovery Furnace	4
Best	VOC	DCE Kraft Recovery Furnace	20
Good	PM	Smelt Dissolving tank	3
Best	PM	Smelt Dissolving tank	3
Good	PM	Lime Kilns	3
Best	PM	Lime Kilns	3
Best	NOx	Lime Kilns	3
Best	NOx	Lime Kilns	5
Good	PM	Coal Boiler	3
Best	PM	Coal Boiler	3

Good / Best Technology	Pollutant	Equipment	Net Downtime, days
Good	HCl	Coal Boiler	3
Best	HCl	Coal Boiler	3
Good	PM	Coal/Wood Boiler (50/50)	3
Best	PM	Coal/Wood Boiler (50/50)	3
Good	SO2	Coal or Coal/Wood boiler (50/50)	3
Best	SO2	Coal or Coal/Wood boiler (50/50)	3
Good	NOx	Coal or Coal/Wood boiler (50/50)	3
Best	NOx	Coal or Coal/Wood boiler (50/50)	5
Best	NOx	Coal or Coal/Wood boiler (50/50)	3
Best	Hg	Coal or Coal/Wood boiler (50/50)	5
Best	CO	Coal or Coal/Wood boiler (50/50)	3
Good	NOx	Gas boiler	3
Best	NOx	Gas boiler	5
Good	NOx	Gas turbine	5
Good	NOx	Gas turbine	5
Best	NOx	Gas turbine	5
Good	PM	Oil boiler	3
Best	PM	Oil boiler	3
Good	SO2	Oil boiler	3
Best	SO2	Oil boiler	3
Good	NOx	Oil boiler	3
Best	NOx	Oil boiler	5
Good	PM	Wood boiler	5
Best	PM	Wood boiler	3
Best	PM	Wood boiler	5
Good	NOx	Wood boiler	3
Best	NOx	Wood boiler	3

Good / Best Technology	Pollutant	Equipment	Net Downtime, days
Best	NOx	Wood boiler	5
Best	Hg	Wood boiler	5
Best	CO	Wood boiler	3
Good	VOC	Paper machines	3
Best	VOC	Paper machines	3
Best	VOC	Paper machines	3
Good	VOC	Mechanical pulping	3
Best	VOC	Mechanical pulping	3
Best	Various	Recovery Furnace	NA
Best	PM	NDCE Kraft Recovery Furnace	3
Good	PM	NDCE Kraft Recovery Furnace	3
Best	PM	Lime Kilns	3
Best	PM	Coal Boiler	3
Best	PM	Coal/Wood Boiler (50/50)	3
Best	NOx	NDCE Kraft Recovery Furnace	5
Best	NOx	DCE Kraft Recovery Furnace	5
Best	VOC	Mechanical Pulp	3

															15%		20%	5%	5%		Annual Operating and Maintenance Costs and Assumptions						
No.	Good / Best	Pollutant	Equipment	Size	Technology limit	R&D % of Labor + Mat + Sub + equip	R&D	Labor hours	Labor $/hr	Labor	Materials	Subcontracts	Equipment	Total Directs Costs	Engineering	Subtotal	Contingency of direct costs + engineering	Owner's Cost % of direct costs	Construction Management % of direct costs	Total	Size of base unit	Feed rate	Materials Consumables (fabric filters, SCR media, etc.) at design	Chemical for design rate	Units	Type of chemical	Chemical (2) for design rate
1	Good	PM	NDCE Kraft Recovery Furnace	3.7x 106 lb BLS/day	ESP - 0.044 gr/dscf @ 8% Oxygen	0.0%	$ -	74,844	$ 58.62	$ 4,387,355	$ 1,834,000	$ 10,009,900	$ 1,054,500	$ 17,285,755	$ 2,592,863	$ 19,878,619	$ 3,975,724	$ 864,288	$ 864,288	$ 25,582,918	2.15	Mmlb BLS/day	$ -	-	NA	NA	-
2	Best	PM	NDCE Kraft Recovery Furnace	3.7x 106 lb BLS/day	ESP - 0.015 gr/dscf @ 8% Oxygen	0.0%	$ -	74,844	$ 58.62	$ 4,387,355	$ 1,834,000	$ 12,261,000	$ 1,319,600	$ 19,801,955	$ 2,970,293	$ 22,772,249	$ 4,554,450	$ 990,098	$ 990,098	$ 29,306,894	2.15	Mmlb BLS/day	$ -	-	NA	NA	-
3	Good	SO2	NDCE Kraft Recovery Furnace	3.7x 106 lb BLS/day	Scrubber - 50 ppm@ 8% Oxygen, 30-day average	0.0%	$ -	50,443	$ 58.62	$ 2,956,969	$ 861,100	$ 1,274,100	$ 3,586,000	$ 8,678,169	$ 1,301,725	$ 9,979,894	$ 1,995,979	$ 433,908	$ 433,908	$ 12,843,690	2.50	Mmlb BLS/day	$ -	1.33	gpm	50% NaOH	-
4	Best	SO2	NDCE Kraft Recovery Furnace	3.7x 106 lb BLS/day	Scrubber - 10 ppm @ 8% Oxygen, 30-day average	0.0%	$ -	50,443	$ 58.62	$ 2,956,969	$ 861,100	$ 1,274,100	$ 3,586,000	$ 8,678,169	$ 1,301,725	$ 9,979,894	$ 1,995,979	$ 433,908	$ 433,908	$ 12,843,690	2.50	Mmlb BLS/day	$ -	1.53	gpm	50% NaOH	-
5	Good	NOx	NDCE Kraft Recovery Furnace	3.7x 106 lb BLS/day	Combustion control - 80 ppm@ 8% Oxygen, 30-day average	0.0%	$ -	1,713	$ 58.62	$ 100,416	$ 28,800	$ 14,000	$ 278,500	$ 421,716	$ 63,257	$ 484,973	$ 96,995	$ 21,086	$ 21,086	$ 624,140	2.60	Mmlb BLS/day	$ -	-	NA	NA	-
6	Best	NOx	NDCE Kraft Recovery Furnace	3.7x 106 lb BLS/day	SNCR - 40 ppm@ 8% Oxygen (50% reduction, 30-day average)	1.0%	$ 34,210	-	$ 58.62	$ -	$ -	$ 3,421,000	$ -	$ 3,455,210	$ 518,282	$ 3,973,492	$ 794,698	$ 172,761	$ 172,761	$ 5,113,711	3.50	Mmlb BLS/day	$ -	256.00	tpy	urea	-
7	Best	VOC	NDCE Kraft Recovery Furnace	3.7x 106 lb BLS/day	Replace wet bottom with dry bottom, no limit	0.0%	$ -	-	$ 58.62	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,266,300	1.50	Mmlb BLS/day	$ -	-	NA	NA	-
8	Good	PM	DCE Kraft Recovery Furnace	1.7x 106 lb BLS/day	ESP - 0.044 gr/dscf @ 8% Oxygen	0.0%	$ -	46,755	$ 58.62	$ 2,740,778	$ 1,152,300	$ 6,273,200	$ 665,300	$ 10,831,578	$ 1,624,737	$ 12,456,315	$ 2,491,263	$ 541,579	$ 541,579	$ 16,030,736	2.15	Mmlb BLS/day	$ -	-	NA	NA	-
9	Best	PM	DCE Kraft Recovery Furnace	1.7x 106 lb BLS/day	ESP - 0.015 gr/dscf @ 8% Oxygen	0.0%	$ -	46,755	$ 58.62	$ 2,740,778	$ 1,152,300	$ 7,702,300	$ 829,000	$ 12,424,378	$ 1,863,657	$ 14,288,035	$ 2,857,607	$ 621,219	$ 621,219	$ 18,388,080	2.15	Mmlb BLS/day	$ -	-	NA	NA	-
10	Good	SO2	DCE Kraft Recovery Furnace	1.7x 106 lb BLS/day	Scrubber - 50 ppm @ 8% Oxygen, 30-day average	0.0%	$ -	31,777	$ 58.62	$ 1,862,768	$ 542,800	$ 802,900	$ 2,203,800	$ 5,412,268	$ 811,840	$ 6,224,108	$ 1,244,822	$ 270,613	$ 270,613	$ 8,010,156	2.50	Mmlb BLS/day	$ -	0.82	gpm	50% NaOH	-
11	Best	SO2	DCE Kraft Recovery Furnace	1.7x 106 lb BLS/day	Scrubber - 10 ppm @ 8% Oxygen, 30-day average	0.0%	$ -	31,777	$ 58.62	$ 1,862,768	$ 542,800	$ 802,900	$ 2,203,800	$ 5,412,268	$ 811,840	$ 6,224,108	$ 1,244,822	$ 270,613	$ 270,613	$ 8,010,156	2.50	Mmlb BLS/day	$ -	0.94	gpm	50% NaOH	-
12	Best	NOx	DCE Kraft Recovery Furnace	1.7x 106 lb BLS/day	SNCR - 50% reduction (30ppm @ 8% Oxygen)	1.0%	$ 16,020	-	$ 58.62	$ -	$ -	$ 1,602,000	$ -	$ 1,618,020	$ 242,703	$ 1,860,723	$ 372,145	$ 80,901	$ 80,901	$ 2,394,670	3.50	Mmlb BLS/day	$ -	117.69	tpy	urea	-
13	Good	VOC	DCE Kraft Recovery Furnace	1.7x 106 lb BLS/day	BLO vent gas collection & incineration	0.0%	$ -	-	$ 58.62	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,554,700	1.50	Mmlb BLS/day	$ -	-	NA	NA	-
14	Best	VOC	DCE Kraft Recovery Furnace	1.7x 106 lb BLS/day	Conversion to NDCE	0.0%	$ -	-	$ 58.62	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 19,664,100	1.50	Mmlb BLS/day	$ -	-	NA	NA	-
15	Good	PM	Smelt Dissolving tank	3.7x 106 lb BLS/day	0.2 lb/ton BLS	0.0%	$ -	16,177	$ 58.62	$ 948,296	$ 244,900	$ 13,500	$ 342,400	$ 1,549,096	$ 232,364	$ 1,781,460	$ 356,292	$ 77,455	$ 77,455	$ 2,292,662	2	Mmlb BLS/day	$ -	-	NA	NA	-
16	Best	PM	Smelt Dissolving tank	3.7x 106 lb BLS/day	0.12 lb/ton BLS	0.0%	$ -	16,177	$ 58.62	$ 948,296	$ 244,900	$ 13,500	$ 394,000	$ 1,600,696	$ 240,104	$ 1,840,800	$ 368,160	$ 80,035	$ 80,035	$ 2,369,030	2	Mmlb BLS/day	$ -	-	NA	NA	-
17	Good	PM	Lime Kilns	240 tons CaO/day	0.064 gr/dscf @ 10% oxy	0.0%	$ -	6,529	$ 58.62	$ 382,730	$ 70,700	$ 425,600	$ 1,022,900	$ 1,901,930	$ 285,289	$ 2,187,219	$ 437,444	$ 95,096	$ 95,096	$ 2,814,856	540	TPD CaO	$ -	-	NA	NA	-
18	Best	PM	Lime Kilns	240 tons CaO/day	0.01 gr/dscf @ 10%oxy	0.0%	$ -	6,633	$ 58.62	$ 388,826	$ 70,700	$ 526,600	$ 1,280,200	$ 2,266,326	$ 339,949	$ 2,606,275	$ 521,255	$ 113,316	$ 113,316	$ 3,354,163	540	TPD CaO	$ -	-	NA	NA	-
19	Best	NOx	Lime Kilns	240 tons CaO/day	Route stripper off-gas to new thermal oxidizer	0.0%	$ -	10,126	$ 58.62	$ 593,586	$ 272,500	$ 233,600	$ 870,100	$ 1,969,786	$ 295,468	$ 2,265,254	$ 453,051	$ 98,489	$ 98,489	$ 2,915,283	20,000	ACFM	$ -	-	gpm	Net reclaim for NaOH	-
20	Best	NOx	Lime Kilns	240 tons CaO/day	Low-NOx burners & SCR.	1.0%	$ 43,387	7,438	$ 58.62	$ 436,016	$ 367,600	$ 525,800	$ 3,009,300	$ 4,382,103	$ 657,315	$ 5,039,418	$ 1,007,884	$ 219,105	$ 219,105	$ 6,485,512	120,000	lb/hr stm	$ 113,113	113.51	tpy	urea	-
21	Good	PM	Coal Boiler	300,000 pph	ESP - 0.065 lb/106 Btu	0.0%	$ -	48,985	$ 58.62	$ 2,871,501	$ 1,207,300	$ 7,314,700	$ 694,900	$ 12,088,401	$ 1,813,260	$ 13,901,661	$ 2,780,332	$ 604,420	$ 604,420	$ 17,890,833	600,000	lb/hr stm	$ -	-	NA	NA	-
22	Best	PM	Coal Boiler	300,000 pph	ESP - 0.04 lb/106 Btu	0.0%	$ -	48,985	$ 58.62	$ 2,871,501	$ 1,207,300	$ 8,928,000	$ 867,000	$ 13,873,801	$ 2,081,070	$ 15,954,871	$ 3,190,974	$ 693,690	$ 693,690	$ 20,533,225	600,000	lb/hr stm	$ -	-	NA	NA	-
23	Good	HCl	Coal Boiler	300,000 pph	Wet scrubber - 0.048 lb/106 Btu	0.0%	$ -	26,215	$ 58.62	$ 1,536,723	$ 447,400	$ 715,100	$ 1,832,500	$ 4,531,723	$ 679,758	$ 5,211,482	$ 1,042,296	$ 226,586	$ 226,586	$ 6,706,950	300,000	lb/hr stm	$ -	8.47	lb/hr	caustic soda	-
24	Best	HCl	Coal Boiler	300,000 pph	Wet scrubber - 0.015 lb/106 Btu	0.0%	$ -	26,215	$ 58.62	$ 1,536,723	$ 447,400	$ 715,100	$ 1,832,500	$ 4,531,723	$ 679,758	$ 5,211,482	$ 1,042,296	$ 226,586	$ 226,586	$ 6,706,950	300,000	lb/hr stm	$ -	25	lb/hr	caustic soda	-
25	Good	PM	Coal/Wood Boiler (50/50)	300,000 pph	ESP - 0.065 lb/106 Btu	0.0%	$ -	48,985	$ 58.62	$ 2,871,501	$ 1,207,300	$ 7,314,700	$ 694,900	$ 12,088,401	$ 1,813,260	$ 13,901,661	$ 2,780,332	$ 604,420	$ 604,420	$ 17,890,833	600,000	lb/hr stm	$ -	-	NA	NA	-
26	Best	PM	Coal/Wood Boiler (50/50)	300,000 pph	ESP - 0.04 lb/106 Btu	0.0%	$ -	48,985	$ 58.62	$ 2,871,501	$ 1,207,300	$ 8,928,000	$ 867,000	$ 13,873,801	$ 2,081,070	$ 15,954,871	$ 3,190,974	$ 693,690	$ 693,690	$ 20,533,225	600,000	lb/hr stm	$ -	-	NA	NA	-
27	Good	SO2	Coal or Coal/Wood boiler (50/50)	300,000 pph	50% reduction, max. 0.6 lb/106 Btu	0.0%	$ -	26,215	$ 58.62	$ 1,536,723	$ 447,300	$ 715,100	$ 2,305,000	$ 5,004,123	$ 750,618	$ 5,754,742	$ 1,150,948	$ 250,206	$ 250,206	$ 7,406,102	600,000	lb/hr stm	$ -	0.57	gpm	50% NaOH	-
28	Best	SO2	Coal or Coal/Wood boiler (50/50)	300,000 pph	Scrubber - 90% reduction, max. 0.12 lb/106 Btu	0.0%	$ -	26,215	$ 58.62	$ 1,536,723	$ 447,300	$ 715,100	$ 2,305,000	$ 5,004,123	$ 750,618	$ 5,754,742	$ 1,150,948	$ 250,206	$ 250,206	$ 7,406,102	600,000	lb/hr stm	$ -	1.14	gpm	50% NaOH	-
29	Good	NOx	Coal or Coal/Wood boiler (50/50)	300,000 pph	Low-NOx burners max. 0.3 lb/10^6 Btu	0.0%	$ -	2,883	$ 58.62	$ 169,001	$ 151,400	$ 216,500	$ 1,428,400	$ 1,965,301	$ 294,795	$ 2,260,097	$ 452,019	$ 98,265	$ 98,265	$ 2,908,646	420,000	lb/hr stm	$ -	-	NA	NA	-
30	Best	NOx	Coal or Coal/Wood boiler (50/50)	300,000 pph	SCR - 0.17 lb/106 Btu, 30-day average	0.5%	$ 81,841	28,068	$ 58.62	$ 1,645,346	$ 1,386,500	$ 1,983,500	$ 11,352,800	$ 16,449,987	$ 2,467,498	$ 18,917,485	$ 3,783,497	$ 822,499	$ 822,499	$ 24,345,981	120,000	lb/hr stm	$ 426,728	428.21	tpy	urea	-
31	Best	NOx	Coal or Coal/Wood boiler (50/50)	300,000 pph	Switch from coal to gas	0.0%	$ -	7,262	$ 58.62	$ 425,698	$ 261,100	$ 541,400	$ 709,100	$ 1,937,298	$ 290,595	$ 2,227,893	$ 445,579	$ 96,865	$ 96,865	$ 2,867,202	420,000	lb/hr stm	$ -	-	NA	NA	-
32	Best	Hg	Coal or Coal/Wood boiler (50/50)	300,000 pph	Carbon injection and fabric filter	1.5%	$ 83,294	15,168	$ 58.62	$ 889,148	$ 274,900	$ 1,253,900	$ 3,135,000	$ 5,636,242	$ 845,436	$ 6,481,679	$ 1,296,336	$ 281,812	$ 281,812	$ 8,341,639	300,000	lb/hr stm	$ -	0.08	tpd	activated carbon	3,750
33	Best	CO	Coal or Coal/Wood boiler (50/50)	300,000 pph	Combustion controls to achieve a 200 ppm (24-hour average)	0.0%	$ -	402	$ 58.62	$ 23,565	$ 20,000	$ 1,852,000	$ 346,000	$ 2,241,565	$ 336,235	$ 2,577,800	$ 515,560	$ 112,078	$ 112,078	$ 3,317,517	300,000	lb/hr stm	$ -	-	NA	NA	-
34	Good	NOx	Gas boiler	120,000 pph	Combustion modification - low-Nox burners, FGR - 0.05 lb /106Btu, 30-day average	0.0%	$ -	1,928	$ 58.62	$ 113,019	$ 102,100	$ 126,100	$ 865,800	$ 1,207,019	$ 181,053	$ 1,388,072	$ 277,614	$ 60,351	$ 60,351	$ 1,786,389	420,000	lb/hr stm	$ -	-	NA	NA	-
35	Best	NOx	Gas boiler	120,000 pph	SCR- 0.015 lb/106 Btu, 30-day average	0.0%	$ -	10,682	$ 58.62	$ 626,179	$ 528,000	$ 755,200	$ 4,322,200	$ 6,231,579	$ 934,737	$ 7,166,316	$ 1,433,263	$ 311,579	$ 311,579	$ 9,222,737	120,000	lb/hr stm	$ 162,469	163.03	tpy	urea	-
36a	Good	NOx	Gas turbine	30 MW	Water injection - 25 ppm @15% Oxygen, 30-day average	0.0%	$ -	1,752	$ 58.62	$ 102,702	$ 17,100	$ 2,637,200	$ -	$ 2,757,002	$ 413,550	$ 3,170,553	$ 634,111	$ 137,850	$ 137,850	$ 4,080,363	30	MW	$ -	-	NA	NA	-
36b	Good	NOx	Gas turbine	30 MW	Steam injection - 25 ppm @15% Oxygen, 30-day average	0.0%	$ -	1,332	$ 58.62	$ 78,082	$ 14,700	$ 4,299,000	$ -	$ 4,391,782	$ 658,767	$ 5,050,549	$ 1,010,110	$ 219,589	$ 219,589	$ 6,499,837	30	MW	$ -	-	NA	NA	-
37	Best	NOx	Gas turbine	30 MW	SCR - 5 ppm @ 15% Oxygen, 30-day average	0.0%	$ -	-	$ 58.62	$ -	$ -	$ 2,182,900	$ 2,467,400	$ 4,650,300	$ 697,545	$ 5,347,845	$ 1,069,569	$ 232,515	$ 232,515	$ 6,882,444	30	MW	$ 104,393	104.76	tpy	urea	-
38	Good	PM	Oil boiler	135,000 pph	Switch to low-sulfur oil	0.0%	$ -	408	$ 58.62	$ 23,917	$ 2,000	$ 63,000	$ 9,400	$ 98,317	$ 14,748	$ 113,065	$ 22,613	$ 4,916	$ 4,916	$ 145,509	420,000	lb/hr stm	$ -	-	NA	NA	-
39	Best	PM	Oil boiler	135,000 pph	ESP - 0.02 lb/106 Btu	0.0%	$ -	32,240	$ 58.62	$ 1,889,909	$ 794,600	$ 4,763,900	$ 571,700	$ 8,020,109	$ 1,203,016	$ 9,223,125	$ 1,844,625	$ 401,005	$ 401,005	$ 11,869,761	600,000	lb/hr stm	$ -	-	NA	NA	-
40	Good	SO2	Oil boiler	135,000 pph	Scrubbing, 50% reduction, max 0.4 lb/106 Btu, 30-day average	0.0%	$ -	23,831	$ 58.62	$ 1,396,973	$ 406,700	$ 601,900	$ 1,670,600	$ 4,076,173	$ 611,426	$ 4,687,599	$ 937,520	$ 203,809	$ 203,809	$ 6,032,736	600,000	lb/hr stm	$ -	0.26	gpm	50% NaOH	-
41	Best	SO2	Oil boiler	135,000 pph	Scrubber - 90% reduction, max. 0.08 lb/106 Btu, 30-day average	0.0%	$ -	23,831	$ 58.62	$ 1,396,973	$ 406,700	$ 601,900	$ 1,670,600	$ 4,076,173	$ 611,426	$ 4,687,599	$ 937,520	$ 203,809	$ 203,809	$ 6,032,736	600,000	lb/hr stm	$ -	0.34	gpm	50% NaOH	-
42	Good	NOx	Oil boiler	135,000 pph	Combustion modification, 50% reduction, max 0.2 lb/106 Btu, 30-day average	0.0%	$ -	1,786	$ 58.62	$ 104,695	$ 94,000	$ 134,100	$ 884,700	$ 1,217,495	$ 182,624	$ 1,400,120	$ 280,024	$ 60,875	$ 60,875	$ 1,801,893	420,000	lb/hr stm	$ -	-	NA	NA	-
43	Best	NOx	Oil boiler	135,000 pph	SCR- 90% reduction, max 0.04 lb/106 Btu, 30-day average	0.5%	$ 45,560	15,620	$ 58.62	$ 915,644	$ 772,100	$ 1,104,200	$ 6,320,000	$ 9,157,504	$ 1,373,626	$ 10,531,130	$ 2,106,226	$ 457,875	$ 457,875	$ 13,553,106	120,000	lb/hr stm	$ 237,563	228.00	tpy	urea	-
44	Good	PM	Wood boiler	300,000 pph	Replace scrubber with ESP - 0.065 lb/10^6 Btu	0.0%	$ -	58,214	$ 58.62	$ 3,412,505	$ 1,434,700	$ 7,044,000	$ 763,000	$ 12,654,205	$ 1,898,131	$ 14,552,335	$ 2,910,467	$ 632,710	$ 632,710	$ 18,728,223	600,000	lb/hr stm	$ -	-	NA	NA	-
45	Best	PM	Wood boiler	300,000 pph	ESP - 0.04 lb/106 Btu	0.0%	$ -	58,214	$ 58.62	$ 3,412,505	$ 1,434,700	$ 8,589,300	$ 955,800	$ 14,392,305	$ 2,158,846	$ 16,551,150	$ 3,310,230	$ 719,615	$ 719,615	$ 21,300,611	600,000	lb/hr stm	$ -	-	NA	NA	-
46	Best	PM	Wood boiler	300,000 pph	Upgrade existing ESP from 0.1 to 0.04 lb/106 Btu	0.0%	$ -	3,074	$ 58.62	$ 180,198	$ 86,000	$ 1,305,000	$ 905,000	$ 2,476,198	$ 371,430	$ 2,847,628	$ 569,526	$ 123,810	$ 123,810	$ 3,664,773	310,000	lb/hr stm	$ -	-	NA	NA	-
47	Good	NOx	Wood boiler	300,000 pph	Combustion Controls - 0.25 lb/106 Btu	0.0%	$ -	402	$ 58.62	$ 23,565	$ 20,000	$ 1,776,500	$ 359,000	$ 2,179,065	$ 326,860	$ 2,505,925	$ 501,185	$ 108,953	$ 108,953	$ 3,225,017	120,000	lb/hr stm	$ -	-	NA	NA	-
48	Best	NOx	Wood boiler	300,000 pph	SNCR - 0.20 lb/106 Btu - 40% reduction	0.0%	$ -	2,618	$ 58.62	$ 153,467	$ 26,500	$ 477,600	$ 359,200	$ 1,016,767	$ 152,515	$ 1,169,282	$ 233,856	$ 50,838	$ 50,838	$ 1,504,815	400,000	lb/hr stm	$ -	165.16	tpy	urea	-
49	Best	NOx	Wood boiler	300,000 pph	SCR- 0.17 lb/106 Btu - 50% reduction	0.5%	$ 55,525	19,038	$ 58.62	$ 1,116,008	$ 940,900	$ 1,345,700	$ 7,702,400	$ 11,160,533	$ 1,674,080	$ 12,834,612	$ 2,566,922	$ 558,027	$ 558,027	$ 16,517,588	120,000	lb/hr stm	$ 287,197	287.09	tpy	urea	-
50	Best	Hg	Wood boiler	300,000 pph	Carbon injection and fabric filter	1.5%	$ 95,964	15,734	$ 58.62	$ 922,327	$ 305,100	$ 1,269,900	$ 3,900,300	$ 6,493,591	$ 974,039	$ 7,467,630	$ 1,493,526	$ 324,680	$ 324,680	$ 9,610,515	300,000	lb/hr stm	$ -	0.003962	tpd	activated carbon	375.00
51	Best	CO	Wood boiler	300,000 pph	Combustion controls to achieve a 200 ppm (24-hour average)	0.0%	$ -	402	$ 58.62	$ 23,565	$ 20,000	$ 1,776,500	$ 359,000	$ 2,179,065	$ 326,860	$ 2,505,925	$ 501,185	$ 108,953	$ 108,953	$ 3,225,017	350,000	lb/hr stm	$ -	-	NA	NA	-
52	Good	VOC	Paper machines	1000 tpd	Installation of screw press prior to high-density storage in pulp mill for unbleached Kraft and OCC recycle mills.	0.0%	$ -	25,575	$ 58.62	$ 1,499,207	$ 904,100	$ 235,000	$ 1,464,300	$ 4,102,607	$ 615,391	$ 4,717,997	$ 943,599	$ 205,130	$ 205,130	$ 6,071,858	1,000	ton/day	$ -	-	NA	NA	-
53	Best	VOC	Paper machines	1000 tpd	Collect & incinerate wet-end vent gases	1.5%	$ 35,750	5,719	$ 58.62	$ 335,248	$ 101,300	$ 940,800	$ 1,005,976	$ 2,419,074	$ 362,861	$ 2,781,935	$ 556,387	$ 120,954	$ 120,954	$ 3,580,229	1,000	ton/day	$ -	-	NA	NA	-
54	Best	VOC	Paper machines	1000 tpd	Collect & incinerate dry-end vent gases	1.5%	$ 51,303	5,700	$ 58.62	$ 334,134	$ 98,700	$ 1,410,400	$ 1,576,998	$ 3,471,535	$ 520,730	$ 3,992,265	$ 798,453	$ 173,577	$ 173,577	$ 5,137,872	1,000	ton/day	$ -	-	NA	NA	-
55	Good	VOC	Mechanical pulping	500 tpd	Better heat recovery from TMP mill to condense VOCs to < 0.5 lb C/ODTP	0.0%	$ -	11,908	$ 58.62	$ 698,047	$ 268,400	$ 197,800	$ 742,900	$ 1,907,147	$ 286,072	$ 2,193,219	$ 438,644	$ 95,357	$ 95,357	$ 2,822,578	500	ton/day	$ -	-	NA	NA	-
56	Best	VOC	Mechanical pulping	500 tpd	Collect & incinerate heat recovery vent gases from TMP mill	0.0%	$ -	5,473	$ 58.62	$ 320,827	$ 143,400	$ 122,900	$ 457,800	$ 1,044,927	$ 156,739	$ 1,201,666	$ 240,333	$ 52,246	$ 52,246	$ 1,546,492	500	ton/day	$ -	-	NA	NA	-
57	Best	Various	Recovery Furnace	3.7x 106 lb BLS/day	Black liquor gasifier utilizing Pulse Enhanced Steam reformation	1.5%	$1,645,212	105,780	$ 58.62	$ 6,200,824	$ 2,808,000	$ 23,712,000	$ 76,960,000	$ 111,326,036	$ 8,906,083	$ 120,232,119	$ 24,046,424	$ 5,566,302	$ 445,304	$ 150,290,149	3.7	Mmlb BLS/day	$ -	-	NA	NA	-
58	Best	PM	NDCE Kraft Recovery Furnace	3.7x 106 lb BLS/day	Add two parallel fields to upgrade ESP to Best technology	0.0%	$ -	-	$ 58.62	$ -	$ -	$ 3,630,000	$ -	$ 3,630,000	$ 544,500	$ 4,174,500	$ 834,900	$ 181,500	$ 181,500	$ 5,372,400	2.7	Mmlb BLS/day	$ -	-	NA	NA	-
59	Good	PM	NDCE Kraft Recovery Furnace	3.7x 106 lb BLS/day	Add two parallel fields to upgrade ESP to Good technology	0.0%	$ -	-	$ 58.62	$ -	$ -	$ 3,040,000	$ -	$ 3,040,000	$ 456,000	$ 3,496,000	$ 699,200	$ 152,000	$ 152,000	$ 4,499,200	2.7	Mmlb BLS/day	$ -	-	NA	NA	-
60	Best	PM	Lime Kilns	240 tons CaO/day	Add single field to upgrade ESP to Best technology	0.0%	$ -	-	$ 58.62	$ -	$ -	$ 536,000	$ 325,000	$ 861,000	$ 129,150	$ 990,150	$ 198,030	$ 43,050	$ 43,050	$ 1,274,280	540	TPD CaO	$ -	-	NA	NA	-
61	Best	PM	Coal Boiler	300,000 pph	Add single field in two chambers to upgrade ESP to Best technology	0.0%	$ -	-	$ 58.62	$ -	$ -	$ 1,992,000	$ 1,250,000	$ 3,242,000	$ 486,300	$ 3,728,300	$ 745,660	$ 162,100	$ 162,100	$ 4,798,160	600,000	lb/hr stm	$ -	-	NA	NA	-
62	Best	PM	Coal/Wood Boiler (50/50)	300,000 pph	Add single field in two chambers to upgrade ESP to Best technology	0.0%	$ -	-	$ 58.62	$ -	$ -	$ 2,153,000	$ 1,550,000	$ 3,703,000	$ 555,450	$ 4,258,450	$ 851,690	$ 185,150	$ 185,150	$ 5,480,440	600,000	lb/hr stm	$ -	-	NA	NA	-
63	Best	NOx	NDCE Kraft Recovery Furnace	3.7x 106 lb BLS/day	SCR - 80% reduction	1.5%	$ 196,955	-	$ 58.62	$ -	$ -	$ 13,130,300	$ -	$ 13,327,255	$ 1,999,088	$ 15,326,343	$ 3,065,269	$ 666,363	$ 666,363	$ 19,724,337	120,000	lb/hr stm- Coal boiler	$ 375,251	376.56	tpy	urea	-
64	Best	NOx	DCE Kraft Recovery Furnace	1.7x 106 lb BLS/day	SCR - 80% reduction	1.5%	$ 128,061	-	$ 58.62	$ -	$ -	$ 8,537,400	$ -	$ 8,665,461	$ 1,299,819	$ 9,965,280	$ 1,993,056	$ 433,273	$ 433,273	$ 12,824,882	120,000	lb/hr stm- Coal boiler	$ 243,990	244.84	tpy	urea	-
65	Best	VOC	Mechanical pulping	500 tpd	Heat recovery system from TMP mill to condense VOCs. Then collection and incineration of the NCGs.	0.0%	$ -	17,381	$ 58.62	$ 1,018,874	$ 411,800	$ 320,700	$ 1,200,700	$ 2,952,074	$ 442,811	$ 3,394,885	$ 678,977	$ 147,604	$ 147,604	$ 4,369,070	500	ton/day	$ -	-	NA	NA	-
66	Good	VOC	Mechanical pulping	500 tpd	Heat recovery system from pulping processes to condense VOCs from a pressurized groundwood	0.0%	$ -	11,908	$ 58.62	$ 698,047	$ 268,400	$ 197,800	$ 742,900	$ 1,907,147	$ 286,072	$ 2,193,219	$ 438,644	$ 95,357	$ 95,357	$ 2,822,578	500	ton/day	$ -	-	NA	NA	-
67	Best	VOC	Mechanical pulping	500 tpd	Heat recovery system from pulping processes to condense VOCs from a pressurized groundwood Then collection & incineration of the NCGs	0.0%	$ -	20,202	$ 58.62	$ 1,184,220	$ 487,600	$ 384,946	$ 1,436,877	$ 3,493,643	$ 524,046	$ 4,017,689	$ 803,538	$ 174,682	$ 174,682	$ 5,170,591	500	ton/day	$ -	-	NA	NA	-
68	Best	VOC	Mechanical pulping	500 tpd	Collection & incineration of NCGs from an atmospheric groundwood	0.0%	$ -	29,599	$ 58.62	$ 1,612,370	$ 782,300	$ 667,900	$ 2,476,719	$ 5,539,289	$ 830,893	$ 6,370,182	$ 1,274,036	$ 276,964	$ 276,964	$ 8,198,148	500	ton/day	$ -	-	NA	NA	-

No.	Good / Best	Pollutant	Equipment	Units	Type of chemical	Maintenance labor & materials, % of TIC	Energy, kw/feed rate at design rate	units	Usage Factor	Manpower hr/dy	Testing	Water, gpm at design rate	wastewater, gpm at design rate	Steam at steam rate	units	Compress air at design rate	units	Fuel cost	units	Natural gas usage	units	General Utilities	Units	Incremental Solid Waste Disposal	Units	Downtime Net downtime assumes that outage can be coordinated with scheduled equipment downtime: net downtime is additional downtime beyond the normal scheduled outage - days
1	Good	PM	NDCE Kraft Recovery Furnace	NA	NA	3.50%	546.63983	kw/Mmlb BLS	70%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
2	Best	PM	NDCE Kraft Recovery Furnace	NA	NA	3.50%	683.29978	kw/Mmlb BLS	80%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
3	Good	SO2	NDCE Kraft Recovery Furnace	NA	NA	3.50%	440.92377	kw/Mmlb BLS	70%	3.00	$ 5,000	148.00	14.80	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
4	Best	SO2	NDCE Kraft Recovery Furnace	NA	NA	3.50%	440.92377	kw/Mmlb BLS	80%	3.00	$ 5,000	148.00	14.80	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
5	Good	NOx	NDCE Kraft Recovery Furnace	NA	NA	1.00%	20.14061	kw/Mmlb BLS	70%	0.75	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
6	Best	NOx	NDCE Kraft Recovery Furnace	NA	NA	3.50%	4.26257	kw/Mmlb BLS	70%	3.00	$ 5,000	3.00	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
7	Best	VOC	NDCE Kraft Recovery Furnace	NA	NA	2.00%	4.03243	kw/Mmlb BLS	70%	1.50	$ 5,000	-	-	$ -	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
8	Good	PM	DCE Kraft Recovery Furnace	NA	NA	3.50%	746.10919	kw/Mmlb BLS	70%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
9	Best	PM	DCE Kraft Recovery Furnace	NA	NA	3.50%	932.63649	kw/Mmlb BLS	80%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
10	Good	SO2	DCE Kraft Recovery Furnace	NA	NA	3.50%	601.81726	kw/Mmlb BLS	70%	3.00	$ 5,000	68.00	6.80	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
11	Best	SO2	DCE Kraft Recovery Furnace	NA	NA	3.50%	601.81726	kw/Mmlb BLS	80%	3.00	$ 5,000	68.00	6.80	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
12	Best	NOx	DCE Kraft Recovery Furnace	NA	NA	3.50%	9.27736	kw/Mmlb BLS	70%	3.00	$ 5,000	3.00	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
13	Good	VOC	DCE Kraft Recovery Furnace	NA	NA	3.00%	88.64235	kw/Mmlb BLS	70%	3.00	$ 5,000	-	-	294.12	lb/hr/Mmlb BLS/day	-	NA	$ -	NA	-	NA	-	NA	-	NA	4
14	Best	VOC	DCE Kraft Recovery Furnace	NA	NA	3.00%	264.96165	kw/Mmlb BLS	70%	3.00	$ 5,000	-	-	(15,873)	lb/hr/Mmlb BLS/day	-	NA	$ -	NA	-	NA	-	NA	-	NA	20
15	Good	PM	Smelt Dissolving tank	NA	NA	2.00%	77.47584	kw/Mmlb BLS	70%	1.50	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
16	Best	PM	Smelt Dissolving tank	NA	NA	2.00%	85.22343	kw/Mmlb BLS	80%	1.50	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
17	Good	PM	Lime Kilns	NA	NA	3.00%	0.77961	kw/tpd CaO	70%	2.25	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
18	Best	PM	Lime Kilns	NA	NA	3.00%	0.97451	kw/tpd CaO	80%	2.25	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
19	Best	NOx	Lime Kilns	NA	NA	3.50%	0.31083	kw/tpd CaO	70%	3.00	$ 5,000	35.00	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
20	Best	NOx	Lime Kilns	NA	NA	2.00%	0.68643	kw/tpd CaO	70%	28.57	$ 5,000	1.97	-	2.30	lb/hr/tpd CaO	0.05	cfm/tpd CaO	$ -	NA	-	NA	-	NA	-	NA	5
21	Good	PM	Coal Boiler	NA	NA	3.00%	0.00444	hp/lb/hr stm	70%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	39.00	tpy of ash	3
22	Best	PM	Coal Boiler	NA	NA	3.00%	0.00555	kw/lb/hr/stm	80%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	77.00	tpy of ash	3
23	Good	HCl	Coal Boiler	NA	NA	5.00%	0.00270	kw/lb/hr/stm	70%	3.00	$ 5,000	64.00	20.00	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
24	Best	HCl	Coal Boiler	NA	NA	5.00%	0.00270	kw/lb/hr/stm	80%	3.00	$ 5,000	64.00	20.00	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
25	Good	PM	Coal/Wood Boiler (50/50)	NA	NA	3.00%	0.00444	kw/lb/hr/stm	70%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	94.00	tpy of ash	3
26	Best	PM	Coal/Wood Boiler (50/50)	NA	NA	3.00%	0.00555	kw/lb/hr/stm	80%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	137.00	tpy of ash	3
27	Good	SO2	Coal or Coal/Wood boiler (50/50)	NA	NA	3.50%	0.00381	kw/lb/hr/stm	70%	3.00	$ 5,000	142.86	14.29	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
28	Best	SO2	Coal or Coal/Wood boiler (50/50)	NA	NA	3.50%	0.00508	kw/lb/hr/stm	80%	3.00	$ 5,000	142.86	14.29	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
29	Good	NOx	Coal or Coal/Wood boiler (50/50)	NA	NA	2.00%	0.00081	kw/lb/hr/stm	70%	1.50	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
30	Best	NOx	Coal or Coal/Wood boiler (50/50)	NA	NA	2.00%	0.00207	kw/lb/hr/stm	70%	28.57	$ 5,000	7.43	-	0.006939	lb/hr/lb/hr stm	0.00015	cfm/lb/hr stm	$ -	NA	-	NA	-	NA	-	NA	5
31	Best	NOx	Coal or Coal/Wood boiler (50/50)	NA	NA	1.00%	-	NA	0%	1.50	$ 5,000	-	-	-	-	-	-	$ -	NA	0.00120	Mmbtu/hr /Mlb/hr steam	-	NA	-	NA	3
32	Best	Hg	Coal or Coal/Wood boiler (50/50)	lb/hr	lime	5.00%	0.00109	kw/lb/hr/stm	70%	3.00	$ 5,000	64.00	20.00	-	-	-	-	$ -	NA	-	NA	-	NA	15,779.65	tpy of lime & carbon	5
33	Best	CO	Coal or Coal/Wood boiler (50/50)	NA	NA	3.00%	0.00099	kw/lb/hr/stm	70%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
34	Good	NOx	Gas boiler	NA	NA	3.00%	0.00147	kw/lb/hr/stm	70%	1.50	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
35	Best	NOx	Gas boiler	NA	NA	2.00%	0.00197	kw/lb/hr/stm	70%	28.57	$ 5,000	2.83	-	0.00660	lb/hr/lb/hr stm	0.000142	cfm/lb/hr stm	$ -	NA	-	NA	-	NA	-	NA	5
36a	Good	NOx	Gas turbine	NA	NA	2.00%	0.06667	kw/MW	70%	1.50	$ 5,000	10.00	-	-	-	-	-	$ -	NA	-	NA	-	NA	-	NA	5
36b	Good	NOx	Gas turbine	NA	NA	2.00%	0.06667	kw/MW	70%	1.50	$ 5,000	4.76	-	79.3800	lb/hr/MW	-	-	$ -	NA	-	NA	-	NA	-	NA	5
37	Best	NOx	Gas turbine	NA	NA	2.00%	13.93333	kw/MW	70%	3.00	$ 5,000	5.00	-	46.67	lb/hr/MW	1.00	cfm/MW	$ -	NA	-	NA	-	NA	-	NA	5
38	Good	PM	Oil boiler	NA	NA	3.00%	-	NA	0%	-	$ 5,000	-	-	-	-	-	-	$ 21.21	$/yr/lb/hr st	-	NA	-	NA	-	NA	3
39	Best	PM	Oil boiler	NA	NA	3.00%	0.00813	kw/lb/hr/stm	70%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	99.00	tpy of ash	3
40	Good	SO2	Oil boiler	NA	NA	3.00%	0.00411	kw/lb/hr/stm	70%	3.00	$ 5,000	42.86	4.29	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
41	Best	SO2	Oil boiler	NA	NA	3.00%	0.00548	kw/lb/hr/stm	80%	3.00	$ 5,000	42.86	4.29	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
42	Good	NOx	Oil boiler	NA	NA	3.00%	0.00112	kw/lb/hr/stm	70%	1.50	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
43	Best	NOx	Oil boiler	NA	NA	2.00%	0.00256	kw/lb/hr/stm	70%	28.57	$ 5,000	4.14	-	0.00858	lb/hr/lb/hr stm	0.00018	cfm/lb/hr stm	$ -	NA	-	NA	-	NA	-	NA	5
44	Good	PM	Wood boiler	NA	NA	3.50%	0.00304	kw/lb/hr/stm	70%	3.00	$ 5,000	(200.00)	(20.00)	-	NA	-	NA	$ -	NA	-	NA	-	NA	551.00	tpy of ash	5
45	Best	PM	Wood boiler	NA	NA	3.50%	0.00659	kw/lb/hr/stm	70%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	599.00	tpy of ash	3
46	Best	PM	Wood boiler	NA	NA	2.00%	0.00083	kw/lb/hr/stm	70%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	116.00	tpy of ash	5
47	Good	NOx	Wood boiler	NA	NA	3.00%	0.00099	kw/lb/hr/stm	70%	1.50	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
48	Best	NOx	Wood boiler	NA	NA	3.50%	0.00004	kw/lb/hr/stm	80%	3.00	$ 5,000	3.00	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
49	Best	NOx	Wood boiler	NA	NA	2.00%	0.00140	kw/lb/hr/stm	75%	28.57	$ 5,000	5.00	-	0.004676	lb/hr/lb/hr stm	0.00010	cfm/lb/hr stm	$ -	NA	-	NA	-	NA	-	NA	5
50	Best	Hg	Wood boiler	lb/hr	pebble lime	5.00%	0.00087	kw/lb/hr/stm	70%	3.00	$ 5,000	89.60	28.00	-	NA	-	NA	$ -	NA	-	NA	-	NA	1,576.39	tpy of lime & carbon	5
51	Best	CO	Wood boiler	NA	NA	3.00%	0.00099	kw/lb/hr/stm	70%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
52	Good	VOC	Paper machines	NA	NA	3.00%	0.86089	kw/tpd	70%	1.50	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	5
53	Best	VOC	Paper machines	NA	NA	3.00%	0.31160	kw/tpd	70%	1.50	$ 5,000	-	-	-	NA	-	NA	$ -	NA	0.00471	Mmbtu/hr/tpd	-	NA	-	NA	5
54	Best	VOC	Paper machines	NA	NA	3.00%	0.37975	kw/tpd	70%	1.50	$ 5,000	-	-	-	NA	-	NA	$ -	NA	0.00810	Mmbtu/hr/tpd	-	NA	-	NA	5
55	Good	VOC	Mechanical pulping	NA	NA	3.00%	0.32912	kw/tpd	70%	1.50	$ 5,000	192.00	194.00	(188.51)	lb/hr/tpd pulp	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
56	Best	VOC	Mechanical pulping	NA	NA	3.50%	0.04476	kw/tpd	70%	2.25	$ 5,000	10.00	10.00	-	NA	-	NA	$ -	NA	0.00371	Mmbtu/hr/tpd	-	NA	-	NA	3
57	Best	Various	Recovery Furnace	NA	NA	3.00%	###################	kW/Mmlb BLS	70%	-	$ 5,000	-	650.00	########	lb/hr/Mmlb BLS/day	-	NA	$ -	NA	-	NA	0.10%	Of TIC	12.32	tons/day/Mm lb BLS	NA
58	Best	PM	NDCE Kraft Recovery Furnace	NA	NA	2.00%	81.08108	kw/Mmlb BLS	70%	1.50	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
59	Good	PM	NDCE Kraft Recovery Furnace	NA	NA	2.00%	74.32432	kw/Mmlb BLS	70%	1.50	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
60	Best	PM	Lime Kilns	NA	NA	1.00%	0.41667	kw/tpd CaO	70%	2.25	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
61	Best	PM	Coal Boiler	NA	NA	1.00%	0.00183	kw/lb/hr/stm	70%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	38.00	NA	3
62	Best	PM	Coal/Wood Boiler (50/50)	NA	NA	1.00%	0.00167	kw/lb/hr/stm	70%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	43.00	NA	3
63	Best	NOx	NDCE Kraft Recovery Furnace	NA	NA	2.00%	147.71161	kw/Mmlb BLS	70%	28.57	$ 5,000	6.54	-	494.73	lb/hr/Mmlb BLS/day	10.60	cfm/Mmlb BLS/day	$ -	NA	-	NA	-	NA	-	NA	5
64	Best	NOx	DCE Kraft Recovery Furnace	NA	NA	2.00%	209.03447	kw/Mmlb BLS	70%	28.57	$ 5,000	4.25	-	700.12	lb/hr/Mmlb BLS/day	25.50	cfm/Mmlb BLS/day	$ -	NA	-	NA	-	NA	-	NA	5
65	Best	VOC	Mechanical pulping	NA	NA	3.50%	0.37388	kw/tpd	70%	2.25	$ 5,000	202.00	204.00	(188.51)	lb/hr/tpd pulp	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
66	Good	VOC	Mechanical pulping	NA	NA	3.00%	0.32912	kw/tpd	70%	1.50	$ 5,000	192.00	38.80	(37.70)	lb/hr/tpd pulp	-	NA	$ -	NA	-	NA	-	NA	-	NA	
67	Best	VOC	Mechanical pulping	NA	NA	3.50%	0.39696	kw/tpd	70%	2.25	$ 5,000	202.00	48.80	(37.70)	lb/hr/tpd/pulp	-	NA	$ -	NA	0.00742	Mmbtu/hr/tpd	-	NA	-	NA	
68	Best	VOC	Mechanical pulping	NA	NA	3.50%	0.34847	kw/tpd	70%	2.25	$ 5,000	10.00	20.00	-	NA	-	NA	$ -	NA	0.03021	Mmbtu/hr/tpd	-	NA	-	NA	

ATTACHMENT 2
REGIONAL HAZE RULE FOUR FACTOR ANALYSIS FOR THE WAUNA MILL'S FIVE PAPER MACHINES

This report provides the four factor analysis (FFA) for PM_{10} and NO_X emissions from the five paper machines in operation at the Georgia-Pacific (GP) Wauna Mill. It is intended to supplement the broader "Regional Haze Rule Four Factor Analysis for Four Oregon Pulp and Paper Mills" prepared for the Northwest Pulp & Paper Association (NWPPA) by All4 Inc. that addresses other equipment common to the four pulp and paper mills operating in Oregon (e.g., power boilers, recovery furnaces, and lime kilns). Tissue and towel paper manufacturing is unique to the GP Wauna Mill; therefore, the following analysis includes only the five paper machines manufacturing tissue and towel grades of paper at the Wauna Mill:

- Paper Machine No. 1 – Dry Crepe machine with Yankee Burners
- Paper Machine No. 2 – Dry Crepe machine with Yankee Burners
- Paper Machine No. 5 – Dry Crepe machine with Yankee Burners
- Paper Machine No. 6 – Through-Air Dried (TAD) machine with TAD and Yankee Burners
- Paper Machine No. 7 – TAD machine with TAD and Yankee Burners

1. FOUR FACTOR ANALYSIS FOR PM_{10} EMISSIONS

PM_{10} emissions from the paper machines are generated as products of combustion in the TAD and Yankee burners as well as from the paper production process itself. Process emissions may escape the paper machine building through roof vents or process stacks. Emissions from each machine were grouped according to the following existing processes:

- General Building Ventilation
- Former Exhaust
- Vacuum Pump Exhaust
- Burners
- Dust System Scrubber

Each paper machine in operation at the Wauna facility already employs rotoclones and/or venturi scrubbers to control some portion of process emissions, most often from the dry end of the paper machine where the majority of paper fibers may be emitted.

1.1. AVAILABLE CONTROL TECHNOLOGIES

Potentially applicable emission control technologies were investigated by reviewing the RACT/BACT/LAER Clearinghouse (RBLC), technical literature, control equipment vendor information, and by using process knowledge and engineering experience from similar types of units in operation at other GP-owned facilities. The control technology review identified the following PM_{10} control options to be considered for paper machines in operation at the Wauna Mill:

- Baghouses
- Drum filters
- Dry electrostatic precipitators (ESPs)
- Wet ESPs

- Wet scrubbers
- Cyclone separators

1.2. Eliminate Technically Infeasible Control Options

The second step in the FFA is the elimination of any control techniques shown to be technically infeasible for implementation on the paper machines. If a control technology has been installed and operated successfully on a similar emission source, then it is assumed to have been demonstrated in practice and is considered technically feasible. If a control technology has not been demonstrated on a similar source, then it must be determined if the technology is applicable to the emission source under consideration. A control technology is eliminated from further consideration if it is shown that the technology has not been demonstrated on similar emission sources and that it also is not commercially available, or it cannot be applied to the emissions source under consideration. The technical feasibility of each control technology identified above is discussed below.

1.2.1. Baghouses

A baghouse, or fabric filter, is one of the most efficient devices for removing particulate matter from an exhaust stream. Baghouses have the capability of achieving collection efficiencies above 99% for particles down to 0.3 micrometers (μm) in diameter. The basic components of a fabric filter unit consist of woven or felted fabric, usually in the form of bags that are suspended in a housing structure (baghouse), an induced draft or forced draft fan, and a blow-back fan, reverse air fan, pulse-jet fan, or a mechanical shaking mechanism. The emission stream is distributed by means of specially designed entry and exit plenum chambers, providing equal gas flow through the filtration medium. The particle collection mechanism for fabric filters includes inertial impaction, Brownian diffusion, gravity settling, and electrostatic attraction. The particles are collected in dry form on a cake of dust supported by the fabric or on the fabric itself. The process occurs with a relatively low-pressure drop requirement (usually within the range of 2 to 6 inches of water column pressure). Periodically, most of the cake dust is removed for disposal by shaking or a “rapping” system, with the use of reverse air or a pulse jet of air. Dust is collected in a hopper at the bottom of the baghouse and is removed through a valve and dumped into a storage container. Usually, the dust is disposed of at an industrial landfill.

Baghouses can be a combustible dust risk due to the collection of dust in a confined space that can lead to a fire or explosion if a source of ignition is present. Cellulosic fibers that are prominent in the wood products industry can fuel a flash fire or explosion with potentially catastrophic consequences. Over the past several years, GP has taken many measures to reduce combustible dust explosion risks across the company including removing baghouses and installing cyclones or drum filters. As such, GP does not consider installing a baghouse on any of the paper machine exhaust streams to be technically feasible for safety reasons.

In addition, baghouses are an inherently poor choice for airstreams containing moisture. High moisture or humidity levels cannot be tolerated by a baghouse as the filter media would quickly become “blinded” due to the moisture in the stream, and as a result, would not collect dust efficiently. The collected particulate matter cannot be effectively removed from wet bag filters, which could result in plugging of the bags. The air stream entering a baghouse must be very dry in order for the technology to work effectively.

For the safety and moisture/humidity concerns identified above, the use of a baghouse for controlling any exhaust stream from the paper machines is not technically feasible and will not be considered further.

1.2.2. Drum Filters

Drum filtering systems work on the same principle as a baghouse, except that instead of using suspended bags in a housing structure, drum filtering systems use a rotating perforated drum inside of an enclosure. A main system balancing fan pulls air and particulate matter into the enclosure. The clean air passes through the filter media covering the drum. Dust and particulate matter remain on the media, and are removed by an arrangement of suction nozzles as the drum rotates against them. The dust that is removed from the rotating drum is directed to a cyclone separator that drops the dust into a collection bin. The collected dust can be reused or sent to an industrial landfill for disposal. The clean, filtered air passing through the drum is discharged from the system. The collection efficiency for a drum filtering system is equivalent to a baghouse, which can be at or above 99% for particles below 1 μm in size.

Similar to baghouses, drum filters are an inherently poor choice for airstreams containing moisture or high in humidity due to the difficulty in cleaning particulate matter from wet filter media. This is of particular concern in the paper industry because the paper dust collected on the filter media will itself become wet and sticky and will not vacuum off the filter media during cleaning. Drum filters are also not well suited to high temperature exhaust streams, such as the TAD and Yankee Burner exhausts, as they reduce the life of the filter media, bearings, and other components, making the unit unreliable.

The use of a drum filter for controlling PM_{10} emissions from all paper machine exhaust points except the general building exhaust is not technically feasible due to the high humidity and/or moisture of the exhaust gases generated by a paper machine. For a previous paper machine construction project at another facility, GP confirmed with a drum filter manufacturer that the control devices are not suited for any of the paper machine exhaust streams except possibly the building vents due to moisture and relative humidity concerns. In addition, installing a drum filter on the paper machine general building ventilation exhaust would be problematic due to the relative humidity of the stream. However, for completeness, drum filters are further analyzed for cost effectiveness for the general building ventilation exhaust points.

1.2.3. Dry Electrostatic Precipitators

Electrostatic precipitators (ESPs) use electrical energy to charge and collect particles with a very high removal efficiency. The classification of ESPs may be as wet or dry systems and/or single-stage or two-stage systems. Dry systems are the predominant type used in industrial applications, but are only suited to dry exhaust streams. Wet systems are increasing in use today since they eliminate the possibility of fires, which can sometimes occur in dry systems.

The principal components of a dry ESP include the housing, discharge and collection electrodes, power source, cleaning mechanism, and solids handling systems. The housing is gas-tight, weatherproof, and grounded for safety. Dust particles entering the housing are charged by ions from the discharge electrodes. Dry ESPs are most effective at collecting coarse, larger particles above 1.0 μm in diameter. Particles smaller than this are difficult to remove because they can inhibit the generation of the charging corona in the inlet field and thereby reduce collection efficiency.

Rappers serve as the cleaning mechanisms for dry ESPs. Dust hoppers collect the precipitated particles from a dry ESP. Dust is removed continuously or periodically from the hopper and stored in a container until final disposition. Collection efficiencies for dry ESPs are usually at or above 98%.

Similar to baghouses, dry ESPs are also considered a combustible dust risk due to the collection of dust in a confined space that can lead to a fire or explosion if a source of ignition is present. Dry ESPs are also an inherently poor choice for airstreams containing moisture due to the fact that the electrodes in these units are not designed for moisture-containing airstreams. As such, GP does not consider installing a dry ESP on any of the paper machine exhaust streams to be technically feasible.

1.2.4. Wet Electrostatic Precipitators

Wet ESPs work on the same principle as dry ESPs, except that wet ESPs operate a wet wall within the ESP with either continuous or intermittent water flow. The water flow is collected into a sump. The advantages of a wet ESP are that it has no back coronas and a reduced risk of developing fires. Wet ESPs are specifically designed to collect particulate matter from wet air streams. Therefore, wet ESPs are considered technically feasible for controlling PM_{10} emissions from the paper machines exhausts.

1.2.5. Wet Scrubbers

Wet scrubbers are collection devices that trap wet particles in order to remove them from a gas stream. They utilize inertial impaction and/or Brownian diffusion as the particle collection mechanism. Wet scrubbers generally use water as the cleaning liquid. Water usage and wastewater disposal requirements are important factors in the evaluation of a wet scrubber control device. There are various types of wet scrubbers including spray, cyclone, packed-bed, plate, and venturi scrubbers.

The most common particulate matter removal scrubber is the venturi scrubber because of its simplicity and high collection efficiency. In this type of scrubber, the gas stream entering the converging section is accelerated as a low-pressure liquid is injected into the throat. The liquid is atomized by the turbulence in the throat and begins to collect particles impacting the liquid as a result of differing velocities for the gas stream and atomized droplets. A separator is used to remove the particles or liquid from the gas stream. The most important design consideration is the pressure drop across the venturi. Generally, the higher the pressure drop, the higher the collection efficiency. Wet scrubbers are considered technically feasible for the paper machines.

1.2.6. Cyclone Separators

Cyclone separators are devices that utilize centrifugal forces and low pressure caused by spinning motion to separate materials of different density, size, and shape. Gas cyclones are used to separate particulate matter from dust-laden air streams. Cyclones are popular because they are simple to operate, inexpensive to manufacture, require little maintenance, and operate at high temperatures and pressures. There are two types of separators available, tangential and axial. In axial flow cyclones, the gas stream enters from the top of the unit and is forced to move tangentially by a grate in the top of the cyclone. In tangential cyclones, the gas stream enters from an inlet on the side that is positioned tangentially to the body of the unit. The collection efficiency of cyclones varies, anywhere from 25-90%, depending upon whether the system is comprised of a single-stage cyclone or a multi-stage cyclone system.

Cyclones can sufficiently handle gas streams with high moisture and do not present a combustible dust concern because dust is continuously removed from the system. As such, cyclone separators are considered technically feasible for controlling PM_{10} emissions from paper machine exhaust points.

1.3. COST ANALYSIS OF TECHNICALLY FEASIBLE CONTROL TECHNOLOGIES

A cost effectiveness assessment of each control device was developed to determine the economic impacts of potential controls. The economic analyses are based on cost data supplied by equipment vendors, GP's Engineering Department, and the use of U.S. EPA's Office of Air Quality Planning & Standards (OAQPS) Control Cost Manual, 6th Edition. When needed, typical values were selected from the OAQPS Manual for the various parameters used to in the analyses. Vendor quotes obtained for other recent projects were used as much as possible to estimate purchased equipment costs.

Table 1-1 presents the exhaust characteristics and estimated uncontrolled emission rates for each of the exhaust streams analyzed in this PM_{10} FFA. These exhaust characteristics are used throughout the cost effectiveness calculations.

Table 1-1. Paper Machine Exhaust Point Characteristics for PM_{10} Emissions

Emission Source	Temperature (°F)	Flow Rate (ACFM)	(DSCFM)	Uncontrolled Emission Rates (lb/hr)	(tpy)	(gr/dscf)
Paper Machine No. 1						
Building Ventilation (all vents)	96	82,500	78,416	1.368	5.990	0.0020
Former Exhaust	117	25,100	22,988	0.401	1.756	0.0020
Vacuum Pump Exhaust	117	77,100	70,614	1.232	5.394	0.0020
Burners	254	19,794	14,638	1.020	4.468	0.0081
Dust System Scrubber	72	57,189	56,802	3.960	17.345	0.0081
Paper Machine No. 2						
Building Ventilation (all vents)	96	82,500	78,416	1.637	7.170	0.0024
Former Exhaust	117	25,100	22,988	0.480	2.102	0.0024
Vacuum Pump Exhaust	117	46,200	42,313	0.883	3.869	0.0024
Burners	254	38,655	28,585	1.020	4.468	0.0042
Dust System Scrubber	74	55,140	54,490	3.960	17.345	0.0085
Paper Machine No. 5						
Building Ventilation (all vents)	96	165,000	156,832	3.679	16.114	0.0027
Former Exhaust	109	77,700	72,115	1.692	7.410	0.0027
Vacuum Pump Exhaust	117	25,100	22,988	0.539	2.362	0.0027
Burners	254	28,085	20,769	2.250	9.855	0.0126
Dust System Scrubber	83	122,952	119,539	3.960	17.345	0.0039
Paper Machine No. 6						
Building Ventilation (all vents)	120	300,000	273,103	2.700	11.826	0.0012
Vacuum Pump Exhaust	117	52,000	47,625	2.300	10.074	0.0056
Burners and Yankee Hood	196	162,514	131,278	8.120	35.566	0.0072
Dust System Scrubber	93	167,789	160,260	3.190	13.972	0.0023
Paper Machine No. 7						
Building Ventilation (all vents)	120	220,000	200,276	2.700	11.826	0.0016
Burners and Yankee Hood	213	132,783	104,304	8.300	36.354	0.0093
Dust System Scrubber	102	235,510	221,190	6.120	26.806	0.0032

1.3.1. Drum Filter

The top control technology to be evaluated for economic feasibility for controlling PM_{10} emissions is a drum filter. However, drum filters are only potentially technically feasible for the general building ventilation exhaust points. As previously stated, moisture, humidity, "sticky" material, or temperature concerns eliminate drum filters from being considered feasible for all other exhaust points associated with the paper machines.

The cost of recently installed drum filters on the converting operations of another GP facility was used as the basis for determining the total capital investment for drum filters on the general building ventilation exhaust points. A detailed cost analysis was completed for a theoretical system rated at 100,000 ACFM and then scaled to the flow rates for each of the building ventilation exhaust points of the paper machines. The recently installed system data as well as the U.S. EPA's Control Cost Manual were used to estimate the direct and indirect operating costs. In addition, U.S. EPA's methodology was followed to determine the capital recovery cost and the annualized costs. The amount of pollutant removed by each drum filter was estimated based on the uncontrolled emission rates presented in Table 1-1 and assuming a conservative control efficiency of 99.5% for PM_{10} emissions, including filterable PM (FPM) as well as condensable PM (CPM). Actual control of CPM would not be expected to be as high as filterable PM in practice.

The cost effectiveness of a control technology is calculated by dividing the annualized cost by the amount of pollutant removed by the control device. Table 1-2 provides a summary of the cost effectiveness of installing drum filters to control PM_{10} emissions from the paper machine building ventilation exhaust points. Detailed cost effectiveness spreadsheets are included in the appendix to this report.

Table 1-2. Summary of Drum Filter Control Cost Effectiveness

Emission Source	Capital Cost ($)	Annual Cost ($/yr)	Pollutant Removed (tpy)	Cost Effectiveness ($/ton removed)
Paper Machine No. 1				
Building Ventilation (all vents)	$1,353,000	$439,707	5.96	**$73,776**
Paper Machine No. 2				
Building Ventilation (all vents)	$1,353,000	$439,707	7.13	**$61,638**
Paper Machine No. 5				
Building Ventilation (all vents)	$2,706,000	$769,037	16.03	**$47,964**
Paper Machine No. 6				
Building Ventilation (all vents)	$4,920,000	$1,307,942	11.77	**$111,155**
Paper Machine No. 7				
Building Ventilation (all vents)	$3,608,000	$988,591	11.77	**$84,015**

As shown in Table 1-2, the cost effectiveness values for using drum filters to control PM_{10} emissions from the paper machine building ventilation exhaust point are well above the cost values that would justify the use of a control device. Therefore, it is not economically feasible to install drum filters on the paper machine building ventilation exhaust points.

1.3.2. Wet ESP

The next control technology to be evaluated for economic feasibility for controlling PM_{10} emissions is a wet ESP. GP has evaluated the use of a wet ESP for each of the major exhaust points of the paper machines identified in Table 1-1. GP obtained cost estimates from a wet ESP vendor for the major exhaust points on a recently permitted paper machine and used the typical cost per ACFM to calculate the purchased equipment cost for the economic analysis.

A detailed cost analysis was completed for a theoretical system rated at 100,000 ACFM and then scaled to the flow rates for each exhaust point of the paper machines. An engineering factor of 1.5 was applied to the purchased equipment cost to account for the significant number of activities required to install a wet ESP, including, but not limited to, civil engineering work, labor required to install foundations, installation of station electrical grounding, electrical switchgear, and compressed air piping, and instrumentation and valves to deliver water to and take wastewater from the wet ESP. The amount of pollutant removed by each wet ESP was estimated based on the uncontrolled emission rates presented in Table 1-1 and assuming a conservative control efficiency of 99% for total PM_{10} emissions.

Table 1-3 provides a summary of the cost effectiveness of installing wet ESPs to control PM_{10} emissions from the paper machine exhaust points. Detailed cost effectiveness spreadsheets are included in the appendix to this report.

Table 1-3. Summary of Wet ESP Control Cost Effectiveness

Emission Source	Capital Cost ($)	Annual Cost ($/yr)	Pollutant Removed (tpy)	Cost Effectiveness ($/ton removed)
Paper Machine No. 1				
Building Ventilation (all vents)	$3,093,750	$559,946	5.93	**$94,425**
Former Exhaust	$941,250	$222,775	1.74	**$128,145**
Vacuum Pump Exhaust	$2,891,250	$528,227	5.34	**$98,918**
Burners	$742,275	$191,607	4.42	**$43,321**
Dust System Scrubber	$2,144,588	$411,268	17.17	**$23,951**
Paper Machine No. 2				
Building Ventilation (all vents)	$3,093,750	$559,946	7.10	**$78,890**
Former Exhaust	$941,250	$222,775	2.08	**$107,062**
Vacuum Pump Exhaust	$1,732,500	$346,718	3.83	**$90,527**
Burners	$1,449,545	$302,395	4.42	**$68,370**
Dust System Scrubber	$2,067,750	$399,232	17.17	**$23,250**
Paper Machine No. 5				
Building Ventilation (all vents)	$6,187,500	$1,044,557	15.95	**$65,477**
Former Exhaust	$2,913,750	$531,751	7.34	**$72,489**
Vacuum Pump Exhaust	$941,250	$222,775	2.34	**$95,269**
Burners	$1,053,201	$240,311	9.76	**$24,631**
Dust System Scrubber	$4,610,700	$797,564	17.17	**$46,447**
Paper Machine No. 6				
Building Ventilation (all vents)	$11,250,000	$1,837,556	11.71	**$156,952**
Vacuum Pump Exhaust	$1,950,000	$380,787	9.97	**$38,181**
Burners and Yankee Hood	$6,094,282	$1,029,955	35.21	**$29,252**
Dust System Scrubber	$6,292,088	$1,060,940	13.83	**$76,699**
Paper Machine No. 7				
Building Ventilation (all vents)	$8,250,000	$1,367,631	11.71	**$116,814**
Burners and Yankee Hood	$4,979,359	$855,312	35.99	**$23,765**
Dust System Scrubber	$8,831,625	$1,458,737	26.54	**$54,969**

As shown in Table 1-3, the cost effectiveness values for using wet ESPs to control PM_{10} emissions from the paper machine exhaust points are well above the cost values that would justify the use of a control device. Therefore, it is not economically feasible to install wet ESPs on the paper machine emission points.

1.3.3. Wet Scrubber

Each paper machine in operation at the Wauna facility already employs wet scrubbers (rotoclones and/or venturi scrubbers) to control some portion of process emissions, most often from the dry end of the paper machine where the majority of paper fibers may be emitted from the paper machines. GP has evaluated the use of a wet scrubber for each of the sections and major exhaust points of the paper machines identified in Table 1-1, even those where wet scrubbing technology is already used although significant additional control of those streams is unlikely.

The cost of a recently installed venturi scrubber on a tissue paper machine at another GP facility was used as the basis for determining the total capital investment for venturi scrubbers. A detailed cost analysis was completed for a theoretical system rated at 100,000 ACFM and then scaled to the flow rates for each of the paper machine exhaust points. The recently installed system data as well as the U.S. EPA's Control Cost Manual were used to estimate the direct and indirect operating costs. In addition, U.S. EPA's methodology was followed to determine the capital recovery cost and the annualized costs. The amount of pollutant removed by each wet scrubber was estimated based on the uncontrolled emission rates presented in Table 1-1 and assuming a conservative control efficiency of 95% for total PM_{10} emissions.

Table 1-4 provides a summary of the cost effectiveness of installing wet scrubbers to control PM_{10} emissions from the paper machine exhaust points. Detailed cost effectiveness spreadsheets are included in the appendix to this report.

Table 1-4. Summary of Wet Venturi Scrubber Control Cost Effectiveness

Emission Source	Capital Cost ($)	Annual Cost ($/yr)	Pollutant Removed (tpy)	Cost Effectiveness ($/ton removed)
Paper Machine No. 1				
Building Ventilation (all vents)	$3,300,000	$784,076	5.69	**$137,787**
Former Exhaust	$1,004,000	$315,344	1.67	**$189,030**
Vacuum Pump Exhaust	$3,084,000	$739,979	5.12	**$144,406**
Burners	$791,760	$272,015	4.24	**$64,091**
Dust System Scrubber	$2,287,560	$577,385	16.48	**$35,041**
Paper Machine No. 2				
Building Ventilation (all vents)	$3,300,000	$784,076	6.81	**$115,118**
Former Exhaust	$1,004,000	$315,344	2.00	**$157,931**
Vacuum Pump Exhaust	$1,848,000	$487,648	3.68	**$132,685**
Burners	$1,546,182	$426,031	4.24	**$100,379**
Dust System Scrubber	$2,205,600	$560,652	16.48	**$34,025**
Paper Machine No. 5				
Building Ventilation (all vents)	$6,600,000	$1,457,775	15.31	**$95,227**
Former Exhaust	$3,108,000	$744,879	7.04	**$105,819**
Vacuum Pump Exhaust	$1,004,000	$315,344	2.24	**$140,534**
Burners	$1,123,414	$339,723	9.36	**$36,286**
Dust System Scrubber	$4,918,080	$1,114,409	16.48	**$67,632**
Paper Machine No. 6				
Building Ventilation (all vents)	$12,000,000	$2,560,193	11.23	**$227,883**
Vacuum Pump Exhaust	$2,080,000	$535,011	9.57	**$55,903**
Burners and Yankee Hood	$6,500,568	$1,437,476	33.79	**$42,545**
Dust System Scrubber	$6,711,560	$1,480,550	13.27	**$111,541**
Paper Machine No. 7				
Building Ventilation (all vents)	$8,800,000	$1,906,908	11.23	**$169,734**
Burners and Yankee Hood	$5,311,316	$1,194,689	34.54	**$34,592**
Dust System Scrubber	$9,420,400	$2,033,564	25.47	**$79,856**

As shown in Table 1-4, the cost effectiveness values for using wet scrubbers to control PM_{10} emissions from the paper machine exhaust points are well above the cost values that would justify the use of a control device. Therefore, it is not economically feasible to install additional wet scrubbers on the paper machine emission points.

1.3.4. Cyclone Separator

Cyclone separators were also evaluated for control of PM_{10} emissions from the paper machine exhaust points. A vendor cost estimate obtained for another GP facility was used to calculate the purchased equipment cost. A detailed cost analysis was completed for a theoretical system rated at 100,000 ACFM and then scaled to the flow rates for each exhaust point of the paper machines. An engineering factor of 1.5 was applied to the purchased equipment cost to account for the significant number of activities required to install a cyclone separator, including, but not limited to, civil engineering work, labor required to install foundations, installation of station electrical grounding, electrical switchgear, and instrumentation. The amount of pollutant removed by each cyclone separator was estimated based on the uncontrolled emission rates presented in Table 1-1 and assuming a conservative control efficiency of 90% for total PM_{10} emissions, including both the filterable and condensable components. Cyclone separators are not designed to removed CPM with a high degree of efficiency; therefore, actual control of CPM would not be expected to be as high as filterable PM in practice.

Table 1-5 provides a summary of the cost effectiveness of installing cyclone separators to control PM_{10} emissions from the paper machine exhaust points. Detailed cost effectiveness spreadsheets are included in the appendix to this report.

Table 1-5. Summary of Cyclone Separator Control Cost Effectiveness

Emission Source	Capital Cost ($)	Annual Cost ($/yr)	Pollutant Removed (tpy)	Cost Effectiveness ($/ton removed)
Paper Machine No. 1				
Building Ventilation (all vents)	$1,064,250	$278,557	5.39	**$51,671**
Former Exhaust	$323,790	$161,544	1.58	**$102,216**
Vacuum Pump Exhaust	$994,590	$267,549	4.85	**$55,112**
Burners	$255,343	$150,727	4.02	**$37,487**
Dust System Scrubber	$737,738	$226,959	15.61	**$14,539**
Paper Machine No. 2				
Building Ventilation (all vents)	$1,064,250	$278,557	6.45	**$43,170**
Former Exhaust	$323,790	$161,544	1.89	**$85,399**
Vacuum Pump Exhaust	$595,980	$204,557	3.48	**$58,750**
Burners	$498,644	$189,176	4.02	**$47,049**
Dust System Scrubber	$711,306	$222,782	15.61	**$14,271**
Paper Machine No. 5				
Building Ventilation (all vents)	$2,128,500	$446,738	14.50	**$30,804**
Former Exhaust	$1,002,330	$268,772	6.67	**$40,303**
Vacuum Pump Exhaust	$323,790	$161,544	2.13	**$75,992**
Burners	$362,301	$167,630	8.87	**$18,900**
Dust System Scrubber	$1,586,081	$361,021	15.61	**$23,127**
Paper Machine No. 6				
Building Ventilation (all vents)	$3,870,000	$721,944	10.64	**$67,830**
Vacuum Pump Exhaust	$670,800	$216,381	9.07	**$23,866**
Burners and Yankee Hood	$2,096,433	$441,671	32.01	**$13,798**
Dust System Scrubber	$2,164,478	$452,424	12.57	**$35,978**
Paper Machine No. 7				
Building Ventilation (all vents)	$2,838,000	$558,859	10.64	**$52,508**
Burners and Yankee Hood	$1,712,899	$381,062	32.72	**$11,647**
Dust System Scrubber	$3,038,079	$590,477	24.13	**$24,476**

As shown in Table 1-5, the cost effectiveness values for using cyclone separators to control PM_{10} emissions from the paper machine exhaust points are well above the cost values that would justify the use of a control device. Therefore, it is not economically feasible to install additional cyclone separators on the paper machine emission points.

1.4. Conclusion

Based on the FFA presented above, no additional controls were determined to be cost effective for PM_{10} emissions from the five paper machines in operation at the Wauna Mill.

2. Four Factor Analysis for NO_X Emissions

NO_X emissions from the paper machines are generated as products of combustion in the TAD and Yankee burners. Yankee burners are present on all five paper machines while Paper Machine Nos. 6 and 7 are the only TAD machines with two TAD burners each. For ease of analysis it is assumed that all burner exhausts from a given machine will be tied together prior to a potential control device. However, additional costs for duct work required for such a scenario were not factored into the economic analysis. As such, the cost of controls presented for the add-on control devices are lower than GP would expect in practice.

2.1. Available Control Technologies

Potentially applicable emission control technologies were investigated by reviewing the RBLC, technical literature, control equipment vendor information, and by using process knowledge and engineering experience from similar types of units in operation at other GP-owned facilities. There are no add-on control technologies identified for controlling NO_X emissions from paper machines within the RBLC, and GP is not aware of any add-on control devices for NO_X emissions being employed at any facility in the pulp and paper industry in the U.S.

Low-NO_X burners have been used for tissue and towel paper machine applications. These burners employ either air staging or fuel staging or a combination of air/fuel staging techniques and specialized combustion controls to minimize the formation of NO_X emissions. The burners currently in use on the two most recently constructed paper machines at the Wauna Mill (Paper Machine Nos. 6 and 7) are considered low-NO_X burners.

Other types of control technologies that reduce NO_X emissions from combustion related equipment include selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), and flue gas recirculation (FGR). Therefore, the NO_X control technologies and methods analyzed for technical feasibility include:

- Selective catalytic reduction
- Selective non-catalytic reduction
- Flue gas recirculation
- Low-NO_X burners

2.2. ELIMINATE TECHNICALLY INFEASIBLE CONTROL OPTIONS

The second step in the FFA is the elimination of any control techniques shown to be technically infeasible for implementation on the paper machine burners. If a control technology has been installed and operated successfully on a similar emission source, then it is assumed to have been demonstrated in practice and is considered technically feasible. If a control technology has not been demonstrated on a similar source, then it must be determined if the technology is applicable to the emission source under consideration. A control technology is eliminated from further consideration if it is shown that the technology has not been demonstrated on similar emission sources and that it also is not commercially available, or it cannot be applied to the emissions source under consideration. The technical feasibility of each control technology identified above is discussed below.

2.2.1. Selective Catalytic Reduction (SCR)

There are two approaches to control the emissions of NO_X in combustion gases: (1) modify the combustion operation to prevent the formation of NO_X or (2) treat the combustion gas chemically, after the flame, to convert NO_X to elemental nitrogen. SCR is a post combustion control technology that uses the injection of ammonia or urea followed by a catalyst to convert all NO_X to elemental nitrogen. Typically, vanadium oxide is used as the catalyst. The flue gas directed over the catalyst must be maintained within a specific temperature range, usually between 500 – 1,100 ºF, for the catalyst to perform correctly. The optimal temperature is 650 ºF. If the temperature is too high, the catalyst will be destroyed. If the temperature is too low, the NO_X reduction efficiency will be lower than when operating at the optimal temperature. SCR can reduce NO_X emissions by as much as 90% given the right operating conditions can be achieved. However, ammonia slip can also occur, which refers to the emissions of unreacted ammonia due to the incomplete reaction of the reagent and NO_X. Excess ammonia can result in the formation of compounds that cause corrosion and impair visibility.

Several modifications would need to be made for an SCR system to be technically feasible for controlling NO_X emissions from the paper machine burners. First, the exhaust temperatures of the burners (ranging from approximately 200 °F to 250 ºF) are too low for an SCR system to work effectively without first raising the temperature of the exhaust streams. The use of additional heat to raise the temperature of the exhaust gases would expend significant energy and produce additional products of combustion. In addition, particulate matter emissions from the paper machine process (not from the burners) would coat the SCR catalyst. Therefore, a separate control device would be needed to remove the PM emissions prior to an SCR system so that the paper dust does not clog or coat the catalyst bed and reduce the effectiveness of converting the combustion gases to CO_2 and water vapor. Lastly, a significant amount of ductwork would need to be constructed to tie together the current burner exhaust stacks into one common duct for each paper machine that is then directed to the SCR system.

Despite the concerns identified above, GP has considered an SCR system to be a technically feasible control option for NO_X emissions and performed a cost effectiveness evaluation on installation of such a system to control emissions from the combined burner exhaust streams for each paper machine.

2.2.2. Selective Non-Catalytic Reduction (SNCR)

SNCR is another post combustion control technology for NO_X reduction. This technology is similar to SCR in that ammonia or urea injection is required to convert all NO_X to elemental nitrogen. However, SNCR operates in the absence of a catalyst and requires a much higher temperature for the reaction to take place, usually in the range of 1,700 – 2,100 ºF. SNCR can reduce NO_x emissions by 25-50%, depending upon specific operating conditions. SNCR is typically only considered for use inside of boiler or gas turbine combustion chambers and is not normally considered for process burner applications.

SNCR has the same technical feasibility issues detailed for SCR system, but with the temperature issue being even more profound given the optimal range of 1,700 – 2,100 °F for an SNCR system, as compared to an estimated temperature of 200 °F – 250 °F for the combined exhaust streams of the burners on each machine. Given this vast temperature difference, SNCR is not considered technically feasible to install on paper machine burners and will not be considered further in this NO_X FFA.

2.2.3. Flue Gas Recirculation (FGR)

FGR involves recirculating part of the combustion gases back to the burners in order to reduce the flame temperature and the available oxygen content. Reducing the temperature and the available oxygen reduces the formation of NO_X emissions. FGR can reduce NO_X emissions by approximately 15% depending upon specific operating conditions. There are two operational issues with considering FGR on the paper machine burners. First, the exhaust gases from the burners do not contain enough oxygen for them to be usable as combustion air. Second, the exhaust gases contain PM emissions that could foul the burner air passages, which would create a fuel rich condition that could present a safety hazard. For these reasons, FGR is not technically feasible for controlling NO_X emissions from the paper machine burners.

2.2.4. Low-NO_X Burners

Low-NO_X burners have been used for tissue and towel paper machine applications. These burners employ either air staging or fuel staging or a combination of air/fuel staging techniques and specialized combustion controls to minimize the formation of NO_X emissions. The burners currently in use on the two most recently constructed paper machines at the Wauna Mill (Paper Machine Nos. 6 and 7) are considered low-NO_X burners.

The term "low-NO_X" is often used by vendors to try to differentiate the burners they have on the market. However, there is no consistent level of NO_X emissions that distinguishes a burner as "low-NO_X". Typical estimates for NO_X emissions from low-NO_X burners range from 0.024 – 0.084 lb/MMBtu, based on information from several paper machine burner vendors. The Yankee burners on each machine have a current NO_X emission factor of 0.0913 lb/MMBtu and the TAD burners on Paper Machine Nos. 6 and 7 have a current NO_X emission factor of 0.1265 lb/MMBtu. GP considered replacing the existing burners with low-NO_X burners that would achieve an outlet emission rate of 0.026 lb/MMBtu based on a vendor quote received for a recent project as technically feasible for this FFA. While the burners themselves may achieve an outlet emission rate of 0.026 lb/MMBtu, it is important to note that NO_X emissions in the burner stacks would be expected to be higher than this rate due to additional NO_X that may be generated from combustion of paper fibers in the airstream. In addition, burners on a paper machine often operate within a wide turndown range, which can create different levels of NO_X emissions based on the heat input at any given time. In fact, the burners considered for this analysis have an estimated outlet emission rate nearly 5 times higher when operated at 25% of capacity or lower.

2.3. Cost Analysis of Technically Feasible Control Technologies

A cost effectiveness assessment of each control technique was developed to determine the economic impacts of potential controls. The economic analysis is based on cost data supplied by equipment vendors, GP's Engineering Department, and the use of U.S. EPA's Office of Air Quality Planning & Standards (OAQPS) Control Cost Manual, 6th and 7th Editions. When needed, typical values were selected from the OAQPS Manual for the various parameters used to in the analyses.

Table 2-1 presents the exhaust characteristics and estimated uncontrolled emission rates for each of the paper machine burners. These exhaust characteristics are used throughout the cost effectiveness calculations.

Table 2-1. Paper Machine Exhaust Point Characteristics for NO_X Emissions

Emission Source	Temperature (°F)	Flow Rate (ACFM)	Flow Rate (DSCFM)	Total Burner Heat Input Rating (MMBtu/hr)	Uncontrolled Emission Rates (tpy)	Burner Factor (lb/MMBtu)
PM1 Yankee Burner	254	19,794	14,638	34	13.60	0.0913
PM2 Yankee Burner	254	38,655	28,585	34	13.60	0.0913
PM5 Yankee Burner	254	28,085	20,769	75	29.99	0.0913
PM6 Burners (Total)	196	162,514	131,278	196	104.28	0.1215
PM6 TAD1 Burner	218	82,789	64,473	84	46.54	0.1265
PM6 TAD2 Burner	203	52,062	41,474	84	46.54	0.1265
PM6 Yankee Burner	117	27,663	25,332	28	11.20	0.0913
PM7 Burners (Total)	213	132,783	104,304	202	108.53	0.1227
PM7 TAD1 Burner	213	98,573	77,347	90	49.87	0.1265
PM7 TAD2 Burner	233	28,086	21,405	90	49.87	0.1265
PM7 Yankee Burner	122	6,124	5,552	22	8.80	0.0913

2.3.1. Selective Catalytic Reduction

The only technically feasible add-on control device for reducing NO_X emissions from the collection of burners on each paper machine is an SCR system. The installation and operating costs are based on calculation methodologies presented in the U.S. EPA's Air Pollution Control Cost Manual, 7th Edition, Section 4, Chapter 2. These costs also includes additional equipment needed to make a SCR system technically feasible on paper machine burner exhausts: a cyclone separator to remove PM emissions prior to entering the oxidation catalyst followed by a duct burner to increase the temperature of the exhaust gases to the level needed for effective operation of the SCR system. Direct and indirect operating costs for an SCR system were determined based on facility data and U.S. EPA's Control Cost Manual.

Table 2-2 provides a summary of the SCR system costs and control cost effectiveness accounting for controlling NO_X emissions from each paper machine, including the necessary control of PM emissions. Detailed cost effectiveness spreadsheets are included in the appendix to this report.

Table 2-2. Summary of SCR System Cost Data and Control Cost Effectiveness

Emission Source	Capital Cost ($)	Annual Cost ($/yr)	Pollutant Removed (tpy)	Cost Effectiveness ($/ton removed)
PM1 Yankee Burner	$3,610,606	$1,121,070	13.77	**$81,389**
PM2 Yankee Burner	$4,005,317	$1,611,782	14.80	**$108,911**
PM5 Yankee Burner	$5,896,400	$1,574,155	29.04	**$54,201**
PM6 Burners (Total)	$13,681,579	$6,866,807	106.15	**$64,689**
PM7 Burners (Total)	$13,112,591	$5,700,004	107.41	**$53,066**

As shown in Table 2-2, the cost effectiveness values for using an SCR system to control NO_X emissions from the paper machine burners are well above the cost values that would justify the use of a control device. Therefore, it is not economically feasible to install an SCR system on any paper machine.

2.3.2. Low-NO_X Burners

A recently obtained vendor quote with the cost for installation of low-NO_X burners on a tissue paper machine at another GP facility was used as the basis for determining the total capital investment for burner replacements on each paper machine. The vendor data as well as the U.S. EPA's Control Cost Manual were used to estimate the direct and indirect operating costs. In addition, U.S. EPA's methodology was followed to determine the capital recovery cost and the annualized costs. The amount of pollutant removed by each low-NO_X burner was based on the vendor quote of outlet emissions of 0.026 lb/MMBtu for the new burners. As previously stated, while the burners themselves may achieve an outlet emission rate of 0.026 lb/MMBtu, it is important to note that NO_X emissions in the burner stacks would be expected to be higher than this rate due to additional NO_X that may be generated from combustion of paper fibers in the airstream. In addition, burners on a paper machine often operate within a wide turndown range, which can create different levels of NO_X emissions based on the heat input at any given time. In fact, the burners considered for this analysis have an estimated outlet emission rate nearly 5 times higher when operated at 25% of capacity or lower. However, for conservatism, the cost analyses presented assume an outlet emission rate of 0.026 lb/MMBtu for each burner.

Table 2-3 provides a summary of the low-NO_X burner replacement costs and control cost effectiveness accounting for controlling NO_X emissions from each paper machine. Detailed cost effectiveness spreadsheets are included in the appendix to this report.

Table 2-3. Summary of Low-NO_X Burner Cost Data and Control Cost Effectiveness

Emission Source	Capital Cost ($)	Annual Cost ($/yr)	Pollutant Removed (tpy)	Cost Effectiveness ($/ton removed)
PM1 Yankee Burner	$847,098	$106,777	9.72	**$10,980**
PM2 Yankee Burner	$847,098	$106,777	9.72	**$10,980**
PM5 Yankee Burner	$1,868,598	$235,538	21.45	**$10,980**
PM6 Burners (Total)	$4,883,268	$615,538	81.96	**$7,510**
PM7 Burners (Total)	$5,032,756	$634,381	85.53	**$7,417**

As shown in Table 2-3, the cost effectiveness values for replacing the existing paper machine burners with low-NO_X burners achieving an outlet emission rate of 0.026 lb/MMBtu are well above the cost values that would justify the use of a control device. Therefore, it is not economically feasible to replace the existing burners on any paper machine.

2.4. CONCLUSION

Based on the FFA presented above, no additional controls were determined to be cost effective for NO_X emissions from the burners on the five paper machines in operation at the Wauna Mill.

APPENDIX

FOUR FACTOR ANALYSIS SUPPORTING DOCUMENTATION

Table A-1. Paper Machine Exhaust Point Characteristics for PM_{10} Emissions

Emission Source	Temperature (°F)	Flow Rate (ACFM)	(DSCFM)	Uncontrolled Emission Rates (lb/hr)	(tpy)	(gr/dscf)
Paper Machine No. 1						
Building Ventilation (all vents)	96	82,500	78,416	1.368	5.990	0.0020
Former Exhaust	117	25,100	22,988	0.401	1.756	0.0020
Vacuum Pump Exhaust	117	77,100	70,614	1.232	5.394	0.0020
Burners	254	19,794	14,638	1.020	4.468	0.0081
Dust System Scrubber	72	57,189	56,802	3.960	17.345	0.0081
Paper Machine No. 2						
Building Ventilation (all vents)	96	82,500	78,416	1.637	7.170	0.0024
Former Exhaust	117	25,100	22,988	0.480	2.102	0.0024
Vacuum Pump Exhaust	117	46,200	42,313	0.883	3.869	0.0024
Burners	254	38,655	28,585	1.020	4.468	0.0042
Dust System Scrubber	74	55,140	54,490	3.960	17.345	0.0085
Paper Machine No. 5						
Building Ventilation (all vents)	96	165,000	156,832	3.679	16.114	0.0027
Former Exhaust	109	77,700	72,115	1.692	7.410	0.0027
Vacuum Pump Exhaust	117	25,100	22,988	0.539	2.362	0.0027
Burners	254	28,085	20,769	2.250	9.855	0.0126
Dust System Scrubber	83	122,952	119,539	3.960	17.345	0.0039
Paper Machine No. 6						
Building Ventilation (all vents)	120	300,000	273,103	2.700	11.826	0.0012
Vacuum Pump Exhaust	117	52,000	47,625	2.300	10.074	0.0056
Burners and Yankee Hood	196	162,514	131,278	8.120	35.566	0.0072
Dust System Scrubber	93	167,789	160,260	3.190	13.972	0.0023
Paper Machine No. 7						
Building Ventilation (all vents)	120	220,000	200,276	2.700	11.826	0.0016
Burners and Yankee Hood	213	132,783	104,304	8.300	36.354	0.0093
Dust System Scrubber	102	235,510	221,190	6.120	26.806	0.0032

Table A-2. Capital & Operating Cost Evaluation for a Drum Filter for a 100,000 ACFM Exhaust Stream

Cost Category	Value	Notes [1]
Vendor-Based Equipment Cost Factor =	$16.4 / ACFM	Based on 2013 quote for drum filtering system installed at similar GP facility.
Airflow Analyzed (ACFM) =	100,000	
Vendor-Based Equipment Cost =	$1,640,000	Cost = $/ACFM × ACFM
Engineering Factor =	1.0	Vendor quote includes auxiliary costs.
Total Capital Investment (TCI) =	**$1,640,000**	**TCI = PEC × Engineering Factor**
Capital Recovery		
Interest Rate (IR) =	4.75%	
Capital Recovery Factor (CRF) [2] =	0.0786	CRF = 4.75% interest and 20-yr equipment life
Capital Recovery Cost (CRC) =	***$128,823***	***CRC = TCI × CRF***
Operating Costs		
Direct Operating Costs (DOC)		
Operating Labor =	$21,900	A = 1 hr per day
Supervisory Labor =	$3,285	B = 15% of operating labor
Maintenance Labor =	$21,900	C = 1 hr per day
Maintenance Materials =	$21,900	D = Equivalent to maintenance labor
Electricity Usage for Fan Power [3] =	3,029,081 kWh/yr	E = Power (kWh/yr) = (960 hp / 207,000 ACFM) × 0.7456 kWh/hp × ACFM × 8,760 hr/yr
Cost of Electricity Usage for Fan Power =	$204,766	F = E × Electricity Cost
Dust Disposal =	-	Not including for conservatism.
Total Direct Operating Costs (DOC) =	***$273,751***	***DOC = A + B + C + D + F***
Indirect Operating Costs (IOC)		
Overhead =	$41,391	G = 60% × (A + B + C + D)
Property Tax =	$16,400	H = 1% × TCI
Insurance =	$16,400	I = 1% × TCI
Administrative Charges =	$32,800	J = 2% × TCI
Total Indirect Operating Costs (IOC) =	***$106,991***	***IOC = G + H + I + J***
Total Annualized Cost (AC) =	**$509,565**	*AC = CRC + DOC + IOC*

1. Vendor data used where available. Other factors and cost estimates reflect U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition)* .
2. U.S. EPA OAQPS, EPA Air Pollution Control Cost Manual (6th Edition), January 2002, Equation 2.8a, Page 2-21 of Section 1, Chapter 2.
3. Based on fan power requirements for similar GP filtering systems.

Table A-3. Summary of Drum Filter Cost Effectiveness

Emission Source	Flow Rate (ACFM)	Total Capital Investment (TCI)	Capital Recovery Cost [1] (CRC)	Direct Operating Costs (DOC) [2] Labor	Materials	Utilities	Total	Indirect Operating Costs [2] Overhead	Tax, Ins, Admin	Total	Annualized Costs [3] (AC)	Uncontrolled PM_{10} Emissions (tpy)	Pollutant Removed [4] (tpy)	Cost Effectiveness [5] ($/ton removed)
Cost for 100,000 ACFM System	100,000	$1,640,000	**$128,823**	$47,085	$21,900	$204,766	**$273,751**	$41,391	$65,600	**$106,991**	**$509,565**			
Paper Machine No. 1														
Building Ventilation (all vents)	82,500	$1,353,000	**$106,279**	$47,085	$21,900	$168,932	**$237,917**	$41,391	$54,120	**$95,511**	**$439,707**	5.99	5.96	**$73,776**
Paper Machine No. 2														
Building Ventilation (all vents)	82,500	$1,353,000	**$106,279**	$47,085	$21,900	$168,932	**$237,917**	$41,391	$54,120	**$95,511**	**$439,707**	7.17	7.13	**$61,638**
Paper Machine No. 5														
Building Ventilation (all vents)	165,000	$2,706,000	**$212,558**	$47,085	$21,900	$337,864	**$406,849**	$41,391	$108,240	**$149,631**	**$769,037**	16.11	16.03	**$47,964**
Paper Machine No. 6														
Building Ventilation (all vents)	300,000	$4,920,000	**$386,468**	$47,085	$21,900	$614,298	**$683,283**	$41,391	$196,800	**$238,191**	**$1,307,942**	11.83	11.77	**$111,155**
Paper Machine No. 7														
Building Ventilation (all vents)	220,000	$3,608,000	**$283,410**	$47,085	$21,900	$450,485	**$519,470**	$41,391	$144,320	**$185,711**	**$988,591**	11.83	11.77	**$84,015**

1. CRC is based on TCI and assumes a control equipment life of 20 years and an interest rate of 4.75%.
2. A detailed cost analysis was performed for a theoretical 100,000 ACFM system and scaled appropriately for each stream analyzed.
3. AC = CRC + DOC + IOC
4. Assumed PM_{10} Pollutant Removal Efficiency: 99.5%
5. The minimum cost effectiveness value is identified with red font.

Table A-4. Capital & Operating Cost Evaluation for a WESP for a 100,000 ACFM Exhaust Stream

Cost Category	Value	Notes [1]
Vendor-Based Equipment Cost Factor =	$25.0 / ACFM	Based on vendor quote for various paper machine exhaust points, February 2017
Airflow Analyzed (ACFM) =	100,000	
Purchased Equipment Cost (PEC) =	$2,500,000	PEC = $/ACFM × ACFM
Engineering Factor =	1.5	Accounts for costs of additional activities not included in vendor quote (ducting, engineering, utilities, etc.).
Total Capital Investment (TCI)	**$3,750,000**	**TCI = PEC × Engineering Factor**
Capital Recovery		
Interest Rate (IR) =	4.75%	
Capital Recovery Factor (CRF) [2] =	0.0786	CRF = 4.75% interest and 20-yr equipment life
Capital Recovery Cost (CRC)	***$294,564***	***CRC = TCI × CRF***
Operating Costs		
Direct Operating Costs (DOC)		
Operating Labor	$21,900	A = 1 hr per day
Supervisory Labor	$3,285	B = 15% of operating labor
Maintenance Labor	$21,900	C = 1 hr per day
Maintenance Materials	$25,000	D = 1% of PEC (from EPA Cost Control Manual, WESP)
Electricity Usage for Fan Power [3]	1,314,000 kWh/yr	E = Power (kWh/yr) = (90 kWh / 60,000 ACFM) × ACFM × 8,760 hr/yr
Cost of Electricity Usage for Fan Power	$88,826	F = E × Electricity Cost
Water Usage [3]	3,504 Mgal/yr	G = (4 gpm / 60,000 ACFM) × ACFM
Cost of Water	$701	H = G × Water Cost
Cost of Wastewater Treatment	$13,315	I = G × Wastewater Treatment Cost
Total Direct Operating Costs (DOC)	***$174,927***	***DOC = A + B + C + D + F + H + I***
Indirect Operating Costs (IOC)		
Overhead	$43,251	J = 60% × (A + B + C + D)
Property Tax	$37,500	K = 1% × TCI
Insurance	$37,500	L = 1% × TCI
Administrative Charges	$75,000	M = 2% × TCI
Total Indirect Operating Costs (IOC)	***$193,251***	***IOC = J + K + L + M***
Total Annualized Cost (AC) =	**$662,743**	*AC = CRC + DOC + IOC*

1. Vendor data used where available. Other factors and cost estimates reflect U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition)* .
2. U.S. EPA OAQPS, EPA Air Pollution Control Cost Manual (6th Edition), January 2002, Equation 2.8a, Page 2-21 of Section 1, Chapter 2.
3. Total electrical and water requirements were provided by a vendor for a 60,000 ACFM system and prorated accordingly.

Table A-5. Summary of Wet ESP Cost Effectiveness

Emission Source	Flow Rate (ACFM)	Purchased Equipment cost (PEC)	Total Capital Investment (TCI)	Capital Recovery Cost [1] (CRC)	Direct Operating Costs (DOC) [2]				Indirect Operating Costs [2]			Annualized Costs [3] (AC)	Uncontrolled PM_{10} Emissions (tpy)	Pollutant Removed [4] (tpy)	Cost Effectiveness [5] ($/ton removed)
					Labor	Materials	Utilities	Total	Overhead	Tax, Ins, Admin	Total				
Cost for 100,000 ACFM System	100,000	$2,500,000	$3,750,000	**$294,564**	$47,085	$25,000	$102,842	**$174,927**	$43,251	$150,000	**$193,251**	**$662,743**			
Paper Machine No. 1															
Building Ventilation (all vents)	82,500	$2,062,500	$3,093,750	**$243,016**	$47,085	$20,625	$84,845	**$152,555**	$40,626	$123,750	**$164,376**	**$559,946**	5.99	5.93	**$94,425**
Former Exhaust	25,100	$627,500	$941,250	**$73,936**	$47,085	$6,275	$25,813	**$79,173**	$32,016	$37,650	**$69,666**	**$222,775**	1.76	1.74	**$128,145**
Vacuum Pump Exhaust	77,100	$1,927,500	$2,891,250	**$227,109**	$47,085	$19,275	$79,291	**$145,651**	$39,816	$115,650	**$155,466**	**$528,227**	5.39	5.34	**$98,918**
Burners	19,794	$494,850	$742,275	**$58,306**	$47,085	$4,949	$20,357	**$72,390**	$31,220	$29,691	**$60,911**	**$191,607**	4.47	4.42	**$43,321**
Dust System Scrubber	57,189	$1,429,725	$2,144,588	**$168,458**	$47,085	$14,297	$58,815	**$120,197**	$36,829	$85,784	**$122,613**	**$411,268**	17.34	17.17	**$23,951**
Paper Machine No. 2															
Building Ventilation (all vents)	82,500	$2,062,500	$3,093,750	**$243,016**	$47,085	$20,625	$84,845	**$152,555**	$40,626	$123,750	**$164,376**	**$559,946**	7.17	7.10	**$78,890**
Former Exhaust	25,100	$627,500	$941,250	**$73,936**	$47,085	$6,275	$25,813	**$79,173**	$32,016	$37,650	**$69,666**	**$222,775**	2.10	2.08	**$107,062**
Vacuum Pump Exhaust	46,200	$1,155,000	$1,732,500	**$136,089**	$47,085	$11,550	$47,513	**$106,148**	$35,181	$69,300	**$104,481**	**$346,718**	3.87	3.83	**$90,527**
Burners	38,655	$966,364	$1,449,545	**$113,862**	$47,085	$9,664	$39,753	**$96,502**	$34,049	$57,982	**$92,031**	**$302,395**	4.47	4.42	**$68,370**
Dust System Scrubber	55,140	$1,378,500	$2,067,750	**$162,423**	$47,085	$13,785	$56,707	**$117,577**	$36,522	$82,710	**$119,232**	**$399,232**	17.34	17.17	**$23,250**
Paper Machine No. 5															
Building Ventilation (all vents)	165,000	$4,125,000	$6,187,500	**$486,031**	$47,085	$41,250	$169,690	**$258,025**	$53,001	$247,500	**$300,501**	**$1,044,557**	16.11	15.95	**$65,477**
Former Exhaust	77,700	$1,942,500	$2,913,750	**$228,876**	$47,085	$19,425	$79,909	**$146,419**	$39,906	$116,550	**$156,456**	**$531,751**	7.41	7.34	**$72,489**
Vacuum Pump Exhaust	25,100	$627,500	$941,250	**$73,936**	$47,085	$6,275	$25,813	**$79,173**	$32,016	$37,650	**$69,666**	**$222,775**	2.36	2.34	**$95,269**
Burners	28,085	$702,134	$1,053,201	**$82,729**	$47,085	$7,021	$28,884	**$82,990**	$32,464	$42,128	**$74,592**	**$240,311**	9.86	9.76	**$24,631**
Dust System Scrubber	122,952	$3,073,800	$4,610,700	**$362,173**	$47,085	$30,738	$126,447	**$204,270**	$46,694	$184,428	**$231,122**	**$797,564**	17.34	17.17	**$46,447**
Paper Machine No. 6															
Building Ventilation (all vents)	300,000	$7,500,000	$11,250,000	**$883,693**	$47,085	$75,000	$308,527	**$430,612**	$73,251	$450,000	**$523,251**	**$1,837,556**	11.83	11.71	**$156,952**
Vacuum Pump Exhaust	52,000	$1,300,000	$1,950,000	**$153,173**	$47,085	$13,000	$53,478	**$113,563**	$36,051	$78,000	**$114,051**	**$380,787**	10.07	9.97	**$38,181**
Burners and Yankee Hood	162,514	$4,062,855	$6,094,282	**$478,709**	$47,085	$40,629	$167,133	**$254,847**	$52,628	$243,771	**$296,399**	**$1,029,955**	35.57	35.21	**$29,252**
Dust System Scrubber	167,789	$4,194,725	$6,292,088	**$494,246**	$47,085	$41,947	$172,558	**$261,590**	$53,419	$251,684	**$305,103**	**$1,060,940**	13.97	13.83	**$76,699**
Paper Machine No. 7															
Building Ventilation (all vents)	220,000	$5,500,000	$8,250,000	**$648,041**	$47,085	$55,000	$226,253	**$328,338**	$61,251	$330,000	**$391,251**	**$1,367,631**	11.83	11.71	**$116,814**
Burners and Yankee Hood	132,783	$3,319,573	$4,979,359	**$391,131**	$47,085	$33,196	$136,557	**$216,838**	$48,168	$199,174	**$247,343**	**$855,312**	36.35	35.99	**$23,765**
Dust System Scrubber	235,510	$5,887,750	$8,831,625	**$693,728**	$47,085	$58,878	$242,204	**$348,167**	$63,578	$353,265	**$416,843**	**$1,458,737**	26.81	26.54	**$54,969**

1. CRC is based on TCI and assumes a control equipment life of 20 years and an interest rate of 4.75%.
2. A detailed cost analysis was performed for a theoretical 100,000 ACFM system and scaled appropriately for each stream analyzed.
3. AC = CRC + DOC + IOC
4. Assumed PM_{10} Pollutant Removal Efficiency: 99%
5. The minimum cost effectiveness value is identified with red font.

Table A-6. Capital & Operating Cost Evaluation for a Venturi Scrubber for a 100,000 ACFM Exhaust Stream

Cost Category	Value	Notes [1]
Cost Data for Recent GP Installation =	$40.0 / ACFM	Based on data from a recent installation at another GP facility.
Airflow Analyzed (ACFM) =	100,000	
Vendor-Based Equipment Cost =	$4,000,000	Cost = $/ACFM × ACFM
Engineering Factor =	1.0	Costs from recent installation include auxiliary costs.
Total Capital Investment (TCI)	**$4,000,000**	Prorated from previous vendor quote × Engineering Factor
Capital Recovery		
Interest Rate (IR) =	4.75%	
Capital Recovery Factor (CRF) [2]	0.0786	CRF = 4.75% interest and 20-yr equipment life
Capital Recovery Cost (CRC)	***$314,202***	***CRC = TCI × CRF***
Operating Costs		
Direct Operating Costs (DOC)		
Operating Labor	$21,900	A = 1 hr per day
Supervisory Labor	$3,285	B = 15% of operating labor
Maintenance Labor	$21,900	C = 1 hr per day
Maintenance Materials	$21,900	D = Equivalent to maintenance labor
Electricity Usage for Fan Power [3]	3,732,261 kWh/yr	E = Power (kWh/yr) = (400 hp / 70,000 ACFM) × 0.7456 kWh/hp × ACFM × 8,760 hr/yr
Cost of Electricity Usage for Fan Power	$252,301	F = E × Electricity Cost
Water Usage [3]	22,526 Mgal/yr	G = (30 gpm / 70,000 ACFM) × ACFM
Cost of Water	$4,505	H = G × Water Cost
Cost of Wastewater Treatment	$85,598	I = G × Wastewater Treatment Cost
Total Direct Operating Costs (DOC)	***$411,389***	***DOC = A + B + C + D + F + H + I***
Indirect Operating Costs (IOC)		
Overhead	$41,391	J = 60% × (A + B + C + D)
Property Tax	$40,000	K = 1% × TCI
Insurance	$40,000	L = 1% × TCI
Administrative Charges	$80,000	M = 2% × TCI
Total Indirect Operating Costs (IOC)	***$201,391***	***IOC = J + K + L + M***
Total Annualized Cost (AC) =	**$926,982**	*AC = CRC + DOC + IOC*

1. Vendor data used where available. Other factors and cost estimates reflect U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition)* .
2. U.S. EPA OAQPS, EPA Air Pollution Control Cost Manual (6th Edition), January 2002, Equation 2.8a, Page 2-21 of Section 1, Chapter 2.
3. Total electrical and water requirements are based on similar GP Winder Scrubber.

Table A-7. Summary of Venturi Scrubber Cost Effectiveness

Emission Source	Flow Rate (ACFM)	Total Capital Investment (TCI)	Capital Recovery Cost [1] (CRC)	Direct Operating Costs (DOC) [2]				Indirect Operating Costs [2]			Annualized Costs [3] (AC)	Uncontrolled PM_{10} Emissions (tpy)	Pollutant Removed [4] (tpy)	Cost Effectiveness [5] ($/ton removed)
				Labor	Materials	Utilities	Total	Overhead	Tax, Ins, Admin	Total				
Cost for 100,000 ACFM System	100,000	$4,000,000	**$314,202**	$47,085	$21,900	$342,404	**$411,389**	$41,391	$160,000	**$201,391**	**$926,982**			
Paper Machine No. 1														
Building Ventilation (all vents)	82,500	$3,300,000	**$259,217**	$47,085	$21,900	$282,483	**$351,468**	$41,391	$132,000	**$173,391**	**$784,076**	5.99	5.69	**$137,787**
Former Exhaust	25,100	$1,004,000	**$78,865**	$47,085	$21,900	$85,943	**$154,928**	$41,391	$40,160	**$81,551**	**$315,344**	1.76	1.67	**$189,030**
Vacuum Pump Exhaust	77,100	$3,084,000	**$242,250**	$47,085	$21,900	$263,993	**$332,978**	$41,391	$123,360	**$164,751**	**$739,979**	5.39	5.12	**$144,406**
Burners	19,794	$791,760	**$62,193**	$47,085	$21,900	$67,775	**$136,760**	$41,391	$31,670	**$73,061**	**$272,015**	4.47	4.24	**$64,091**
Dust System Scrubber	57,189	$2,287,560	**$179,689**	$47,085	$21,900	$195,817	**$264,802**	$41,391	$91,502	**$132,893**	**$577,385**	17.34	16.48	**$35,041**
Paper Machine No. 2														
Building Ventilation (all vents)	82,500	$3,300,000	**$259,217**	$47,085	$21,900	$282,483	**$351,468**	$41,391	$132,000	**$173,391**	**$784,076**	7.17	6.81	**$115,118**
Former Exhaust	25,100	$1,004,000	**$78,865**	$47,085	$21,900	$85,943	**$154,928**	$41,391	$40,160	**$81,551**	**$315,344**	2.10	2.00	**$157,931**
Vacuum Pump Exhaust	46,200	$1,848,000	**$145,161**	$47,085	$21,900	$158,190	**$227,175**	$41,391	$73,920	**$115,311**	**$487,648**	3.87	3.68	**$132,685**
Burners	38,655	$1,546,182	**$121,453**	$47,085	$21,900	$132,355	**$201,340**	$41,391	$61,847	**$103,238**	**$426,031**	4.47	4.24	**$100,379**
Dust System Scrubber	55,140	$2,205,600	**$173,251**	$47,085	$21,900	$188,801	**$257,786**	$41,391	$88,224	**$129,615**	**$560,652**	17.34	16.48	**$34,025**
Paper Machine No. 5														
Building Ventilation (all vents)	165,000	$6,600,000	**$518,433**	$47,085	$21,900	$564,966	**$633,951**	$41,391	$264,000	**$305,391**	**$1,457,775**	16.11	15.31	**$95,227**
Former Exhaust	77,700	$3,108,000	**$244,135**	$47,085	$21,900	$266,048	**$335,033**	$41,391	$124,320	**$165,711**	**$744,879**	7.41	7.04	**$105,819**
Vacuum Pump Exhaust	25,100	$1,004,000	**$78,865**	$47,085	$21,900	$85,943	**$154,928**	$41,391	$40,160	**$81,551**	**$315,344**	2.36	2.24	**$140,534**
Burners	28,085	$1,123,414	**$88,245**	$47,085	$21,900	$96,165	**$165,150**	$41,391	$44,937	**$86,328**	**$339,723**	9.86	9.36	**$36,286**
Dust System Scrubber	122,952	$4,918,080	**$386,317**	$47,085	$21,900	$420,992	**$489,977**	$41,391	$196,723	**$238,114**	**$1,114,409**	17.34	16.48	**$67,632**
Paper Machine No. 6														
Building Ventilation (all vents)	300,000	$12,000,000	**$942,606**	$47,085	$21,900	$1,027,211	**$1,096,196**	$41,391	$480,000	**$521,391**	**$2,560,193**	11.83	11.23	**$227,883**
Vacuum Pump Exhaust	52,000	$2,080,000	**$163,385**	$47,085	$21,900	$178,050	**$247,035**	$41,391	$83,200	**$124,591**	**$535,011**	10.07	9.57	**$55,903**
Burners and Yankee Hood	162,514	$6,500,568	**$510,623**	$47,085	$21,900	$556,455	**$625,440**	$41,391	$260,023	**$301,414**	**$1,437,476**	35.57	33.79	**$42,545**
Dust System Scrubber	167,789	$6,711,560	**$527,196**	$47,085	$21,900	$574,516	**$643,501**	$41,391	$268,462	**$309,853**	**$1,480,550**	13.97	13.27	**$111,541**
Paper Machine No. 7														
Building Ventilation (all vents)	220,000	$8,800,000	**$691,244**	$47,085	$21,900	$753,288	**$822,273**	$41,391	$352,000	**$393,391**	**$1,906,908**	11.83	11.23	**$169,734**
Burners and Yankee Hood	132,783	$5,311,316	**$417,206**	$47,085	$21,900	$454,654	**$523,639**	$41,391	$212,453	**$253,844**	**$1,194,689**	36.35	34.54	**$34,592**
Dust System Scrubber	235,510	$9,420,400	**$739,977**	$47,085	$21,900	$806,395	**$875,380**	$41,391	$376,816	**$418,207**	**$2,033,564**	26.81	25.47	**$79,856**

1. CRC is based on TCI and assumes a control equipment life of 20 years and an interest rate of 4.75%.
2. A detailed cost analysis was performed for a theoretical 100,000 ACFM system and scaled appropriately for each stream analyzed.
3. AC = CRC + DOC + IOC
4. Assumed PM_{10} Pollutant Removal Efficiency: 95%
5. The minimum cost effectiveness value is identified with red font.

Table A-8. Capital & Operating Cost Evaluation for a Cyclone Separator for a 100,000 ACFM Exhaust Stream

Cost Category	Value	Notes [1]
Vendor-Based Equipment Cost Factor =	$8.6 / ACFM	Based on 2017 vendor quote for another GP facility.
Airflow Analyzed (ACFM) =	100,000	
Purchased Equipment Cost (PEC) =	$860,000	PEC = $/ACFM × ACFM
Engineering Factor =	1.5	Accounts for costs of additional activities not included in vendor quote (ducting, engineering, utilities, etc.).
Total Capital Investment (TCI)	**$1,290,000**	Prorated from previous vendor quote × Engineering Factor
Capital Recovery		
Interest Rate (IR) =	4.75%	
Capital Recovery Factor (CRF) [2]	0.0786	CRF = 4.75% interest and 20-yr equipment life
Capital Recovery Cost (CRC)	***$101,330***	***CRC = TCI × CRF***
Operating Costs		
Direct Operating Costs (DOC)		
Operating Labor	$21,900	A = 1 hr per day
Supervisory Labor	$3,285	B = 15% of operating labor
Maintenance Labor	$21,900	C = 1 hr per day
Maintenance Materials	$21,900	D = Equivalent to maintenance labor
Electricity Usage for Fan Power [3]	753,340 kWh/yr	E = Power (kWh/yr) = (100 hp / 86,700 ACFM) × 0.7456 kWh/hp × ACFM × 8,760 hr/yr
Cost of Electricity Usage for Fan Power	$50,926	F = E × Electricity Cost
Total Direct Operating Costs (DOC)	***$119,911***	***DOC = A + B + C + D + F***
Indirect Operating Costs (IOC)		
Overhead	$41,391	G = 60% × (A + B + C + D)
Property Tax	$12,900	H = 1% × TCI
Insurance	$12,900	I = 1% × TCI
Administrative Charges	$25,800	J = 2% × TCI
Total Indirect Operating Costs (IOC)	***$92,991***	***IOC = G + H + I + J***
Total Annualized Cost (AC) =	**$314,232**	*AC = CRC + DOC + IOC*

1. Vendor data used where available. Other factors and cost estimates reflect U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition)* .
2. U.S. EPA OAQPS, EPA Air Pollution Control Cost Manual (6th Edition), January 2002, Equation 2.8a, Page 2-21 of Section 1, Chapter 2.
3. Total electrical requirement was provided by a vendor for a 86,700 ACFM system and prorated accordingly.

Table A-9. Summary of Cyclone Separator Cost Effectiveness

Emission Source	Flow Rate (ACFM)	Total Capital Investment (TCI)	Capital Recovery Cost [1] (CRC)	Direct Operating Costs (DOC) [2]				Indirect Operating Costs [2]			Annualized Costs [3] (AC)	Uncontrolled PM_{10} Emissions (tpy)	Pollutant Removed [4] (tpy)	Cost Effectiveness [5] ($/ton removed)
				Labor	Materials	Utilities	Total	Overhead	Tax, Ins, Admin	Total				
Cost for 100,000 ACFM System	100,000	$1,290,000	**$101,330**	$47,085	$21,900	$50,926	**$119,911**	$41,391	$51,600	**$92,991**	**$314,232**			
Paper Machine No. 1														
Building Ventilation (all vents)	82,500	$1,064,250	**$83,597**	$47,085	$21,900	$42,014	**$110,999**	$41,391	$42,570	**$83,961**	**$278,557**	5.99	5.39	**$51,671**
Former Exhaust	25,100	$323,790	**$25,434**	$47,085	$21,900	$12,782	**$81,767**	$41,391	$12,952	**$54,343**	**$161,544**	1.76	1.58	**$102,216**
Vacuum Pump Exhaust	77,100	$994,590	**$78,126**	$47,085	$21,900	$39,264	**$108,249**	$41,391	$39,784	**$81,175**	**$267,549**	5.39	4.85	**$55,112**
Burners	19,794	$255,343	**$20,057**	$47,085	$21,900	$10,080	**$79,065**	$41,391	$10,214	**$51,605**	**$150,727**	4.47	4.02	**$37,487**
Dust System Scrubber	57,189	$737,738	**$57,950**	$47,085	$21,900	$29,124	**$98,109**	$41,391	$29,510	**$70,901**	**$226,959**	17.34	15.61	**$14,539**
Paper Machine No. 2														
Building Ventilation (all vents)	82,500	$1,064,250	**$83,597**	$47,085	$21,900	$42,014	**$110,999**	$41,391	$42,570	**$83,961**	**$278,557**	7.17	6.45	**$43,170**
Former Exhaust	25,100	$323,790	**$25,434**	$47,085	$21,900	$12,782	**$81,767**	$41,391	$12,952	**$54,343**	**$161,544**	2.10	1.89	**$85,399**
Vacuum Pump Exhaust	46,200	$595,980	**$46,815**	$47,085	$21,900	$23,528	**$92,513**	$41,391	$23,839	**$65,230**	**$204,557**	3.87	3.48	**$58,750**
Burners	38,655	$498,644	**$39,169**	$47,085	$21,900	$19,685	**$88,670**	$41,391	$19,946	**$61,337**	**$189,176**	4.47	4.02	**$47,049**
Dust System Scrubber	55,140	$711,306	**$55,873**	$47,085	$21,900	$28,080	**$97,065**	$41,391	$28,452	**$69,843**	**$222,782**	17.34	15.61	**$14,271**
Paper Machine No. 5														
Building Ventilation (all vents)	165,000	$2,128,500	**$167,195**	$47,085	$21,900	$84,028	**$153,013**	$41,391	$85,140	**$126,531**	**$446,738**	16.11	14.50	**$30,804**
Former Exhaust	77,700	$1,002,330	**$78,733**	$47,085	$21,900	$39,569	**$108,554**	$41,391	$40,093	**$81,484**	**$268,772**	7.41	6.67	**$40,303**
Vacuum Pump Exhaust	25,100	$323,790	**$25,434**	$47,085	$21,900	$12,782	**$81,767**	$41,391	$12,952	**$54,343**	**$161,544**	2.36	2.13	**$75,992**
Burners	28,085	$362,301	**$28,459**	$47,085	$21,900	$14,303	**$83,288**	$41,391	$14,492	**$55,883**	**$167,630**	9.86	8.87	**$18,900**
Dust System Scrubber	122,952	$1,586,081	**$124,587**	$47,085	$21,900	$62,614	**$131,599**	$41,391	$63,443	**$104,834**	**$361,021**	17.34	15.61	**$23,127**
Paper Machine No. 6														
Building Ventilation (all vents)	300,000	$3,870,000	**$303,990**	$47,085	$21,900	$152,777	**$221,762**	$41,391	$154,800	**$196,191**	**$721,944**	11.83	10.64	**$67,830**
Vacuum Pump Exhaust	52,000	$670,800	**$52,692**	$47,085	$21,900	$26,481	**$95,466**	$41,391	$26,832	**$68,223**	**$216,381**	10.07	9.07	**$23,866**
Burners and Yankee Hood	162,514	$2,096,433	**$164,676**	$47,085	$21,900	$82,762	**$151,747**	$41,391	$83,857	**$125,248**	**$441,671**	35.57	32.01	**$13,798**
Dust System Scrubber	167,789	$2,164,478	**$170,021**	$47,085	$21,900	$85,448	**$154,433**	$41,391	$86,579	**$127,970**	**$452,424**	13.97	12.57	**$35,978**
Paper Machine No. 7														
Building Ventilation (all vents)	220,000	$2,838,000	**$222,926**	$47,085	$21,900	$112,037	**$181,022**	$41,391	$113,520	**$154,911**	**$558,859**	11.83	10.64	**$52,508**
Burners and Yankee Hood	132,783	$1,712,899	**$134,549**	$47,085	$21,900	$67,621	**$136,606**	$41,391	$68,516	**$109,907**	**$381,062**	36.35	32.72	**$11,647**
Dust System Scrubber	235,510	$3,038,079	**$238,643**	$47,085	$21,900	$119,935	**$188,920**	$41,391	$121,523	**$162,914**	**$590,477**	26.81	24.13	**$24,476**

1. CRC is based on TCI and assumes a control equipment life of 20 years and an interest rate of 4.75%.
2. A detailed cost analysis was performed for a theoretical 100,000 ACFM system and scaled appropriately for each stream analyzed.
3. AC = CRC + DOC + IOC
4. Assumed PM_{10} Pollutant Removal Efficiency: 90%
5. The minimum cost effectiveness value is identified with red font.

Table A-10. Paper Machine Exhaust Point Characteristics for NO_X Emissions

Emission Source	Temperature (°F)	Flow Rate (ACFM)	Flow Rate (DSCFM)	Total Burner Heat Input Rating (MMBtu/hr)	Uncontrolled Emission Rates (tpy)	Burner Factor (lb/MMBtu)	Duct Burner Size Determination: NG Required Flow Rate [1] (cfh)	NG Required Burner Rating (MMBtu/hr)	Recommended Burner Rating [2] (MMBtu/hr)	Additional NG Emissions [3] (tpy)	Duct Burner Airflow (ACFM)	Duct Burner Airflow (DSCFM)	Calculated Total Emission Factor (lb/MMBtu)
PM1 Yankee Burner	254	19,794	14,638	34	13.60	0.0913	9,798.0	10	15	1.71	4,579	2,178	0.071
PM2 Yankee Burner	254	38,655	28,585	34	13.60	0.0913	19,134.0	20	25	2.85	7,629	3,629	0.064
PM5 Yankee Burner	254	28,085	20,769	75	29.99	0.0913	13,902.2	15	20	2.28	6,103	2,903	0.078
PM6 Burners (Total)	196	162,514	131,278	196	104.28	0.1215	92,253.2	97	120	13.67	36,622	17,420	0.085
PM6 TAD1 Burner	218	82,789	64,473	84	46.54	0.1265	44,706.1	47					
PM6 TAD2 Burner	203	52,062	41,474	84	46.54	0.1265	29,102.7	31					
PM6 Yankee Burner	117	27,663	25,332	28	11.20	0.0913	18,444.4	19					
PM7 Burners (Total)	213	132,783	104,304	202	108.53	0.1227	72,543.4	76	95	10.82	28,992	13,791	0.092
PM7 TAD1 Burner	213	98,573	77,347	90	49.87	0.1265	53,857.8	57					
PM7 TAD2 Burner	233	28,086	21,405	90	49.87	0.1265	14,646.8	15					
PM7 Yankee Burner	122	6,124	5,552	22	8.80	0.0913	4,038.7	4					

1. NG flow required to raise the temperature of the exhaust air to: 650 °F, estimated from: CFH = (CFM AIR) * (°F OUT - °F IN) ÷ 800
   Assumed natural gas heating value of: 1,050 Btu/scf
2. Recommended duct burner rating includes an upsizing safety factor of: 20%
3. Based on assumed emission factor for the duct burners of: 0.026 lb/MMBtu

Table A-11. Capital & Operating Cost Evaluation for an SCR System for Paper Machine 1

Cost Category	Value	Notes [1]
Total Capital Investment (TCI) =	$2,085,337	TCI = 10,530 x $(1,640/Q_B)^{0.35}$ x Q_B x ELEVF x RF
Total Burner Heat Rating (MMBtu/hr) =	34	Q_B
Airflow Analyzed (ACFM) =	24,373	$q_{fluegas}$ (includes airflow of required duct burner)
Engineering Factor =	1.5	Accounts for costs of additional activities not included in vendor quote (ducting, engineering, utilities, etc.).
Duct Burner Heat Input Rating =	15.0	MMBtu/hr (required to raise temperature of inlet stream to ideal range)
Additional Cost for Duct Burner to Raise Temp =	$168,450	Based on previous quote of $1,123,000 for a 100 MMBtu/hr burner
Total Capital Investment (TCI)	**$3,296,456**	Prorated from previous vendor quote × Engineering Factor
System Design		
Future Worth Factor (FWF) =	0.35	FWF = IR × 1 ÷ $((1 + IR)^Y - 1)$, where Y = $H_{catalyst}/(t_{SCR}$ x 24 hours)
Interest Rate (IR) =	4.75%	
Catalyst Volume (ft^3)	133.89	$Vol_{catalyst} = 2.81 \times Q_B \times \eta_{adj} \times Slip_{adj} \times NO_{Xadj} \times S_{adj} \times T_{adj} \div N_{SCR}$
η_{adj} = NO_X Efficiency Adjustment Factor =	1.24	$\eta_{adj} = 0.2869 + 1.058\eta_{NOX}$
$Slip_{adj}$ = Ammonia Slip Adjustment Factor =	1.17	$Slip_{adj} = 1.2835 - (0.0567 \times Slip)$; Slip assumed to be 2 ppm
NO_{Xadj} = Inlet NO_X Adjustment Factor =	0.88	$NO_{Xadj} = 0.8524 + (0.3208 \times NO_{Xin})$
S_{adj} = Sulfur Adjustment Factor =	0.9636	S_{adj} = 0.9636 for natural gas
T_{adj} = Temperature Adjustment Factor =	1.15	$T_{adj} = 15.16 - (0.03937 \times T) + (0.0000274 \times T^2)$
N_{SCR} = Number of Reactor Chambers =	1	N_{SCR} = Number of reactor chambers
Catalyst Cross-sectional Area (ft^2) =	25.39	$A_{catalyst} = q_{fluegas} \div$ (16 ft/sec × 60 sec/min)
Height of each catalyst layer (ft) =	3	$H_{layer} = Vol_{catalyst} \div (R_{layer} \times A_{catalyst}) + 1$; where, R_{layer} = 3
SCR Reactor Cross-sectional Area (ft^2) =	29.20	$A_{SCR} = 1.15 \times A_{catalyst}$
n_{layer} = Number of Catalyst Layers =	2	$n_{layer} = Vol_{catalyst} \div (h'_{layer} \times A_{catalyst})$; where, h'_{layer} = 3.1
n_{total} = Total Number of Catalyst Layers =	3	$n_{total} = n_{layer} + n_{empty}$; where, n_{empty} = 1
h_{SCR} = Height of Catalyst Reactor =	39.00	$h_{SCR} = n_{total} \times (c1 + h_{layer}) + c_2$; where c_1 = 7 ft and c_2 = 9 ft
Mass flow of reagent (lb/hr) =	0.85	$m_{reagent} = NO_{Xin} \times Q_B \times \eta_{NOX} \times SRF \times M_{reagent} \div M_{NOX}$
Reagent mass usage rate (lb/hr) =	2.92	$m_{sol} = m_{reagent} \div C_{sol}$; where C_{sol} = 29%
Reagent volume usage rate (gal/hr) =	0.39	$q_{sol} = m_{sol} \div \rho_{sol} \times 7.4805$ gal/ft^3 ; where ρ_{sol} for 29% ammonia is 56.0 lb/ft^3
Electricity consumption (kW) =	17.48	$P = 0.1 \times Q_B \times 1{,}000 \times 0.0056 \times (NPHR \div 10)^{0.43}$; NPHR = 8.2 for natural gas
Direct Operating Costs (DOC)		
Annual Maintenance Cost =	$16,482	A = 0.005 × TCI
Annual Reagent Cost =	$12,069	$B = m_{sol} \times Cost_{reag} \times t_{op}$
Annual Electricity Cost =	$10,353	$C = P \times Cost_{elec} \times t_{op}$
Annual Catalyst Replacement Cost =	$3,549	$D = n_{SCR} \times Vol_{catalyst} \times CC_{replace} \div R_{layer} \times FWF$
Duct Burner Natural Gas Usage (MMBtu/yr) =	131,400	E = Duct Burner Rating in MMBtu/hr × 8,760 hr/yr
Cost of Natural Gas Usage =	$657,000	F = E × Natural Gas Cost
Total Direct Operating Costs (DOC)	***$699,453***	***DOC = A + B + C + D + F***
Indirect Operating Costs (IOC)		
Administrative Charges (AC) =	$2,648	J = 0.03 × (Operator Cost + 0.4 × A); Operator Cost based on 4 hr/day
Capital Recovery Costs (CR) =	$258,938	K = TCI × CRF
Capital Recovery Factor (CRF) =	0.0786	CRF = 4.75% interest and 20-yr equipment life
Total Indirect Operating Costs (IOC)	***$261,586***	***IOC = J + K***
Total SCR Annualized Cost (AC) =	**$961,039**	*AC = DOC + IOC*
Total Cyclone Annualized Cost (AC) =	**$160,031**	*See cyclone costs below*
Total System Annualized Cost (AC) =	**$1,121,070**	*Sum of SCR AC and Cyclone AC*
NO_X Uncontrolled Emissions (tpy) =	15.30	Paper Machine + Duct Burner
NO_X Removed (tpy) =	13.77	90% Removal Efficiency (η_{NOX})
Cost per ton of NO_X and PM Removed ($/ton)	**$81,389**	**$/ton = System AC / Pollutant Removed**

1. Factors and cost estimates reflect U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (7th Edition), June 2019* .

Capital & Operating Cost Evaluation for a Cyclone Upstream of an SCR System for Paper Machine 1

Cost Category	Value	Notes [1]
Vendor Quoted System Costs ($) =	$745,000	
Vendor Quoted System Air Flow Rate (ACFM) =	86,700	
Airflow Analyzed (ACFM) =	24,373	
Engineering Factor =	1.5	Accounts for costs of additional activities not included in vendor quote (ducting, engineering, utilities, etc.).
Total Capital Investment (TCI)	**$314,150**	Prorated from previous vendor quote × Engineering Factor
Capital Recovery		
Capital Recovery Factor (CRF)	0.0786	CRF = 4.75% interest and 20-yr equipment life
Capital Recovery Cost (CRC)	***$24,677***	***CRC = TCI × CRF***
Operating Costs		
Direct Operating Costs (DOC)		
Operating Labor	$21,900	A = 1 hr per day
Supervisory Labor	$3,285	B = 15% of operating labor
Maintenance Labor	$21,900	C = 1 hr per day
Maintenance Materials	$21,900	D = Equivalent to maintenance labor
Electricity Usage for Fan Power	183,612 kWh/yr	E = Power (kWh/yr) = (100 hp / 86,700 ACFM) × 0.7456 kWh/hp × ACFM × 8,760 hr/yr
Cost of Electricity Usage for Fan Power	$12,412	F = E × Electricity Cost
Total Direct Operating Costs (DOC)	***$81,397***	***DOC = A + B + C + D + F + H + I***
Indirect Operating Costs (IOC)		
Overhead	$41,391	J = 60% × (A + B + C + D)
Property Tax	$3,142	K = 1% × TCI
Insurance	$3,142	L = 1% × TCI
Administrative Charges	$6,283	M = 2% × TCI
Total Indirect Operating Costs (IOC)	***$53,957***	***IOC = J + K + L + M***
Total Annualized Cost (AC) =	**$160,031**	*AC = CRC + DOC + IOC*

1. Factors and cost estimates reflect U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition), December 1998* .

Table A-12. Capital & Operating Cost Evaluation for an SCR System for Paper Machine 2

Cost Category	Value	Notes [1]
Total Capital Investment (TCI) =	$2,085,337	TCI = 10,530 x $(1{,}640/Q_B)^{0.35}$ x Q_B x ELEVF x RF
Total Burner Heat Rating (MMBtu/hr) =	34	Q_B
Airflow Analyzed (ACFM) =	46,284	$q_{fluegas}$ (includes airflow of required duct burner)
Engineering Factor =	1.5	Accounts for costs of additional activities not included in vendor quote (ducting, engineering, utilities, etc.).
Duct Burner Heat Input Rating =	25.0	MMBtu/hr (required to raise temperature of inlet stream to ideal range)
Additional Cost for Duct Burner to Raise Temp =	$280,750	Based on previous quote of $1,123,000 for a 100 MMBtu/hr burner
Total Capital Investment (TCI)	**$3,408,756**	Prorated from previous vendor quote × Engineering Factor
System Design		
Future Worth Factor (FWF) =	0.35	FWF = IR × 1 ÷ ((1 + IR)^Y -1) , where Y = $H_{catalyst}/(t_{SCR}$ x 24 hours)
Interest Rate (IR) =	4.75%	
Catalyst Volume (ft^3)	133.51	$Vol_{catalyst} = 2.81 \times Q_B \times \eta_{adj} \times Slip_{adj} \times NO_{Xadj} \times S_{adj} \times T_{adj} \div N_{SCR}$
η_{adj} = NO_X Efficiency Adjustment Factor =	1.24	$\eta_{adj} = 0.2869 + 1.058\eta_{NOX}$
$Slip_{adj}$ = Ammonia Slip Adjustment Factor =	1.17	$Slip_{adj}$ = 1.2835 – (0.0567 × Slip); Slip assumed to be 2 ppm
NO_{Xadj} = Inlet NO_X Adjustment Factor =	0.87	$NO_{Xadj} = 0.8524 + (0.3208 \times NO_{Xin})$
S_{adj} = Sulfur Adjustment Factor =	0.9636	S_{adj} = 0.9636 for natural gas
T_{adj} = Temperature Adjustment Factor =	1.15	$T_{adj} = 15.16 - (0.03937 \times T) + (0.0000274 \times T^2)$
N_{SCR} = Number of Reactor Chambers =	1	N_{SCR} = Number of reactor chambers
Catalyst Cross-sectional Area (ft^2) =	48.21	$A_{catalyst} = q_{fluegas} \div$ (16 ft/sec × 60 sec/min)
Height of each catalyst layer (ft) =	2	$H_{layer} = Vol_{catalyst} \div (R_{layer} \times A_{catalyst}) + 1$; where, $R_{layer} = 3$
SCR Reactor Cross-sectional Area (ft^2) =	55.44	$A_{SCR} = 1.15 \times A_{catalyst}$
n_{layer} = Number of Catalyst Layers =	1	$n_{layer} = Vol_{catalyst} \div (h'_{layer} \times A_{catalyst})$; where, $h'_{layer} = 3.1$
n_{total} = Total Number of Catalyst Layers =	2	$n_{total} = n_{layer} + n_{empty}$; where, $n_{empty} = 1$
h_{SCR} = Height of Catalyst Reactor =	27.00	$h_{SCR} = n_{total} \times (c1 + h_{layer}) + c_2$; where c_1 = 7 ft and c_2 = 9 ft
Mass flow of reagent (lb/hr) =	0.76	$m_{reagent} = NO_{Xin} \times Q_B \times \eta_{NOX} \times SRF \times M_{reagent} \div M_{NOX}$
Reagent mass usage rate (lb/hr) =	2.61	$m_{sol} = m_{reagent} \div C_{sol}$; where C_{sol} = 29%
Reagent volume usage rate (gal/hr) =	0.35	$q_{sol} = m_{sol} \div \rho_{sol} \times 7.4805$ gal/ft^3 ; where ρ_{sol} for 29% ammonia is 56.0 lb/ft^3
Electricity consumption (kW) =	17.48	P = 0.1 × Q_B × 1,000 × 0.0056 × (NPHR ÷ 10)$^{0.43}$; NPHR = 8.2 for natural gas
Direct Operating Costs (DOC)		
Annual Maintenance Cost =	$17,044	A = 0.005 × TCI
Annual Reagent Cost =	$10,769	B = $m_{sol} \times Cost_{reag} \times t_{op}$
Annual Electricity Cost =	$10,353	C = P × $Cost_{elec} \times t_{op}$
Annual Catalyst Replacement Cost =	$3,539	D = $n_{SCR} \times Vol_{catalyst} \times CC_{replace} \div R_{layer}$ × FWF
Duct Burner Natural Gas Usage (MMBtu/yr) =	219,000	E = Duct Burner Rating in MMBtu/hr × 8,760 hr/yr
Cost of Natural Gas Usage =	$1,095,000	F = E × Natural Gas Cost
Total Direct Operating Costs (DOC)	***$1,136,705***	***DOC = A + B + C + D + F***
Indirect Operating Costs (IOC)		
Administrative Charges (AC) =	$2,648	J = 0.03 × (Operator Cost + 0.4 × A); Operator Cost based on 4 hr/day
Capital Recovery Costs (CR) =	$267,759	K = TCI × CRF
Capital Recovery Factor (CRF) =	0.0786	CRF = 4.75% interest and 20-yr equipment life
Total Indirect Operating Costs (IOC)	***$270,408***	***IOC = J + K***
Total SCR Annualized Cost (AC) =	**$1,407,113**	*AC = DOC + IOC*
Total Cyclone Annualized Cost (AC) =	**$204,669**	*See cyclone costs below*
Total System Annualized Cost (AC) =	**$1,611,782**	*Sum of SCR AC and Cyclone AC*
NO_X Uncontrolled Emissions (tpy) =	16.44	Paper Machine + Duct Burner
NO_X Removed (tpy) =	14.80	90% Removal Efficiency (η_{NOX})
Cost per ton of NO_X and PM Removed ($/ton)	**$108,911**	**$/ton = System AC / Pollutant Removed**

1. Factors and cost estimates reflect U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (7th Edition), June 2019* .

Capital & Operating Cost Evaluation for a Cyclone Upstream of an SCR System for Paper Machine 1

Cost Category	Value	Notes [1]
Vendor Quoted System Costs ($) =	$745,000	
Vendor Quoted System Air Flow Rate (ACFM) =	86,700	
Airflow Analyzed (ACFM) =	46,284	
Engineering Factor =	1.5	Accounts for costs of additional activities not included in vendor quote (ducting, engineering, utilities, etc.).
Total Capital Investment (TCI)	**$596,561**	Prorated from previous vendor quote × Engineering Factor
Capital Recovery		
Capital Recovery Factor (CRF)	0.0786	CRF = 4.75% interest and 20-yr equipment life
Capital Recovery Cost (CRC)	***$46,860***	***CRC = TCI × CRF***
Operating Costs		
Direct Operating Costs (DOC)		
Operating Labor	$21,900	A = 1 hr per day
Supervisory Labor	$3,285	B = 15% of operating labor
Maintenance Labor	$21,900	C = 1 hr per day
Maintenance Materials	$21,900	D = Equivalent to maintenance labor
Electricity Usage for Fan Power	348,672 kWh/yr	E = Power (kWh/yr) = (100 hp / 86,700 ACFM) × 0.7456 kWh/hp × ACFM × 8,760 hr/yr
Cost of Electricity Usage for Fan Power	$23,570	F = E × Electricity Cost
Total Direct Operating Costs (DOC)	***$92,555***	***DOC = A + B + C + D + F + H + I***
Indirect Operating Costs (IOC)		
Overhead	$41,391	J = 60% × (A + B + C + D)
Property Tax	$5,966	K = 1% × TCI
Insurance	$5,966	L = 1% × TCI
Administrative Charges	$11,931	M = 2% × TCI
Total Indirect Operating Costs (IOC)	***$65,253***	***IOC = J + K + L + M***
Total Annualized Cost (AC) =	**$204,669**	*AC = CRC + DOC + IOC*

1. Factors and cost estimates reflect U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition), December 1998* .

Table A-13. Capital & Operating Cost Evaluation for an SCR System for Paper Machine 5

Cost Category	Value	Notes [1]
Total Capital Investment (TCI) =	$3,487,424	TCI = 10,530 x $(1{,}640/Q_B)^{0.35}$ x Q_B x ELEVF x RF
Total Burner Heat Rating (MMBtu/hr) =	75	Q_B
Airflow Analyzed (ACFM) =	34,188	$q_{fluegas}$ (includes airflow of required duct burner)
Engineering Factor =	1.5	Accounts for costs of additional activities not included in vendor quote (ducting, engineering, utilities, etc.).
Duct Burner Heat Input Rating =	20.0	MMBtu/hr (required to raise temperature of inlet stream to ideal range)
Additional Cost for Duct Burner to Raise Temp =	$224,600	Based on previous quote of $1,123,000 for a 100 MMBtu/hr burner
Total Capital Investment (TCI)	**$5,455,737**	Prorated from previous vendor quote × Engineering Factor
System Design		
Future Worth Factor (FWF) =	0.35	FWF = IR × 1 ÷ $((1 + IR)^Y - 1)$, where Y = $H_{catalyst}/(t_{SCR}$ x 24 hours)
Interest Rate (IR) =	4.75%	
Catalyst Volume (ft^3)	296.02	$Vol_{catalyst} = 2.81 \times Q_B \times \eta_{adj} \times Slip_{adj} \times NO_{Xadj} \times S_{adj} \times T_{adj} \div N_{SCR}$
η_{adj} = NO_X Efficiency Adjustment Factor =	1.24	$\eta_{adj} = 0.2869 + 1.058\eta_{NOX}$
$Slip_{adj}$ = Ammonia Slip Adjustment Factor =	1.17	$Slip_{adj} = 1.2835 - (0.0567 \times Slip)$; Slip assumed to be 2 ppm
NO_{Xadj} = Inlet NO_X Adjustment Factor =	0.88	$NO_{Xadj} = 0.8524 + (0.3208 \times NO_{Xin})$
S_{adj} = Sulfur Adjustment Factor =	0.9636	S_{adj} = 0.9636 for natural gas
T_{adj} = Temperature Adjustment Factor =	1.15	$T_{adj} = 15.16 - (0.03937 \times T) + (0.0000274 \times T^2)$
N_{SCR} = Number of Reactor Chambers =	1	N_{SCR} = Number of reactor chambers
Catalyst Cross-sectional Area (ft^2) =	35.61	$A_{catalyst} = q_{fluegas} \div$ (16 ft/sec × 60 sec/min)
Height of each catalyst layer (ft) =	4	$H_{layer} = Vol_{catalyst} \div (R_{layer} \times A_{catalyst}) + 1$; where, $R_{layer} = 3$
SCR Reactor Cross-sectional Area (ft^2) =	40.95	$A_{SCR} = 1.15 \times A_{catalyst}$
n_{layer} = Number of Catalyst Layers =	2	$n_{layer} = Vol_{catalyst} \div (h'_{layer} \times A_{catalyst})$; where, $h'_{layer} = 3.1$
n_{total} = Total Number of Catalyst Layers =	3	$n_{total} = n_{layer} + n_{empty}$; where, $n_{empty} = 1$
h_{SCR} = Height of Catalyst Reactor =	42.00	$h_{SCR} = n_{total} \times (c1 + h_{layer}) + c_2$; where c_1 = 7 ft and c_2 = 9 ft
Mass flow of reagent (lb/hr) =	2.03	$m_{reagent} = NO_{Xin} \times Q_B \times \eta_{NOX} \times SRF \times M_{reagent} \div M_{NOX}$
Reagent mass usage rate (lb/hr) =	7.02	$m_{sol} = m_{reagent} \div C_{sol}$; where C_{sol} = 29%
Reagent volume usage rate (gal/hr) =	0.94	$q_{sol} = m_{sol} \div \rho_{sol} \times 7.4805$ gal/ft^3 ; where ρ_{sol} for 29% ammonia is 56.0 lb/ft^3
Electricity consumption (kW) =	38.56	$P = 0.1 \times Q_B \times 1{,}000 \times 0.0056 \times (NPHR \div 10)^{0.43}$; NPHR = 8.2 for natural gas
Direct Operating Costs (DOC)		
Annual Maintenance Cost =	$27,279	A = 0.005 × TCI
Annual Reagent Cost =	$28,953	$B = m_{sol} \times Cost_{reag} \times t_{op}$
Annual Electricity Cost =	$22,837	$C = P \times Cost_{elec} \times t_{op}$
Annual Catalyst Replacement Cost =	$7,847	$D = n_{SCR} \times Vol_{catalyst} \times CC_{replace} \div R_{layer} \times FWF$
Duct Burner Natural Gas Usage (MMBtu/yr) =	175,200	E = Duct Burner Rating in MMBtu/hr × 8,760 hr/yr
Cost of Natural Gas Usage =	$876,000	F = E × Natural Gas Cost
Total Direct Operating Costs (DOC)	***$962,916***	***DOC = A + B + C + D + F***
Indirect Operating Costs (IOC)		
Administrative Charges (AC) =	$2,661	J = 0.03 × (Operator Cost + 0.4 × A); Operator Cost based on 4 hr/day
Capital Recovery Costs (CR) =	$428,551	K = TCI × CRF
Capital Recovery Factor (CRF) =	0.0786	CRF = 4.75% interest and 20-yr equipment life
Total Indirect Operating Costs (IOC)	***$431,211***	***IOC = J + K***
Total SCR Annualized Cost (AC) =	**$1,394,127**	*AC = DOC + IOC*
Total Cyclone Annualized Cost (AC) =	**$180,027**	*See cyclone costs below*
Total System Annualized Cost (AC) =	**$1,574,155**	*Sum of SCR AC and Cyclone AC*
NO_X Uncontrolled Emissions (tpy) =	32.27	Paper Machine + Duct Burner
NO_X Removed (tpy) =	29.04	90% Removal Efficiency (η_{NOX})
Cost per ton of NO_X and PM Removed ($/ton)	**$54,201**	**$/ton = System AC / Pollutant Removed**

1. Factors and cost estimates reflect U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (7th Edition), June 2019* .

Capital & Operating Cost Evaluation for a Cyclone Upstream of an SCR System for Paper Machine 1

Cost Category	Value	Notes [1]
Vendor Quoted System Costs ($) =	$745,000	
Vendor Quoted System Air Flow Rate (ACFM) =	86,700	
Airflow Analyzed (ACFM) =	34,188	
Engineering Factor =	1.5	Accounts for costs of additional activities not included in vendor quote (ducting, engineering, utilities, etc.).
Total Capital Investment (TCI)	**$440,663**	Prorated from previous vendor quote × Engineering Factor
Capital Recovery		
Capital Recovery Factor (CRF)	0.0786	CRF = 4.75% interest and 20-yr equipment life
Capital Recovery Cost (CRC)	***$34,614***	***CRC = TCI × CRF***
Operating Costs		
Direct Operating Costs (DOC)		
Operating Labor	$21,900	A = 1 hr per day
Supervisory Labor	$3,285	B = 15% of operating labor
Maintenance Labor	$21,900	C = 1 hr per day
Maintenance Materials	$21,900	D = Equivalent to maintenance labor
Electricity Usage for Fan Power	257,554 kWh/yr	E = Power (kWh/yr) = (100 hp / 86,700 ACFM) × 0.7456 kWh/hp × ACFM × 8,760 hr/yr
Cost of Electricity Usage for Fan Power	$17,411	F = E × Electricity Cost
Total Direct Operating Costs (DOC)	***$86,396***	***DOC = A + B + C + D + F + H + I***
Indirect Operating Costs (IOC)		
Overhead	$41,391	J = 60% × (A + B + C + D)
Property Tax	$4,407	K = 1% × TCI
Insurance	$4,407	L = 1% × TCI
Administrative Charges	$8,813	M = 2% × TCI
Total Indirect Operating Costs (IOC)	***$59,018***	***IOC = J + K + L + M***
Total Annualized Cost (AC) =	**$180,027**	*AC = CRC + DOC + IOC*

1. Factors and cost estimates reflect U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition), December 1998* .

Table A-14. Capital & Operating Cost Evaluation for an SCR System for Paper Machine 6

Cost Category	Value	Notes [1]
Total Capital Investment (TCI) =	$6,511,506	TCI = 10,530 x $(1,640/Q_B)^{0.35}$ x Q_B x ELEVF x RF
Total Burner Heat Rating (MMBtu/hr) =	196	Q_B
Airflow Analyzed (ACFM) =	199,136	$q_{fluegas}$ (includes airflow of required duct burner)
Engineering Factor =	1.5	Accounts for costs of additional activities not included in vendor quote (ducting, engineering, utilities, etc.).
Duct Burner Heat Input Rating =	120.0	MMBtu/hr (required to raise temperature of inlet stream to ideal range)
Additional Cost for Duct Burner to Raise Temp =	$1,347,600	Based on previous quote of $1,123,000 for a 100 MMBtu/hr burner
Total Capital Investment (TCI)	**$11,114,859**	Prorated from previous vendor quote × Engineering Factor
System Design		
Future Worth Factor (FWF) =	0.35	FWF = IR × 1 ÷ $((1 + IR)^Y$ -1) , where Y = $H_{catalyst}/(t_{SCR}$ x 24 hours)
Interest Rate (IR) =	4.75%	
Catalyst Volume (ft^3)	775.76	$Vol_{catalyst}$ = 2.81 × Q_B × η_{adj} × $Slip_{adj}$ × NO_{Xadj} × S_{adj} × T_{adj} ÷ N_{SCR}
η_{adj} = NO_X Efficiency Adjustment Factor =	1.24	η_{adj} = 0.2869 + 1.058η_{NOX}
$Slip_{adj}$ = Ammonia Slip Adjustment Factor =	1.17	$Slip_{adj}$ = 1.2835 – (0.0567 × Slip); Slip assumed to be 2 ppm
NO_{Xadj} = Inlet NO_X Adjustment Factor =	0.88	NO_{Xadj} = 0.8524 + (0.3208 × NO_{Xin})
S_{adj} = Sulfur Adjustment Factor =	0.9636	S_{adj} = 0.9636 for natural gas
T_{adj} = Temperature Adjustment Factor =	1.15	T_{adj} = 15.16 – (0.03937 × T) + (0.0000274 × T^2)
N_{SCR} = Number of Reactor Chambers =	1	N_{SCR} = Number of reactor chambers
Catalyst Cross-sectional Area (ft^2) =	207.43	$A_{catalyst}$ = $q_{fluegas}$ ÷ (16 ft/sec × 60 sec/min)
Height of each catalyst layer (ft) =	2	H_{layer} = $Vol_{catalyst}$ ÷ (R_{layer} × $A_{catalyst}$) + 1; where, R_{layer} = 3
SCR Reactor Cross-sectional Area (ft^2) =	238.55	A_{SCR} = 1.15 × $A_{catalyst}$
n_{layer} = Number of Catalyst Layers =	2	n_{layer} = $Vol_{catalyst}$ ÷ (h'_{layer} × $A_{catalyst}$); where, h'_{layer} = 3.1
n_{total} = Total Number of Catalyst Layers =	3	n_{total} = n_{layer} + n_{empty}; where, n_{empty} = 1
h_{SCR} = Height of Catalyst Reactor =	36.00	h_{SCR} = n_{total} × (c1 + h_{layer}) + c_2 ; where c_1 = 7 ft and c_2 = 9 ft
Mass flow of reagent (lb/hr) =	5.84	$m_{reagent}$ = NO_{Xin} × Q_B × η_{NOX} × SRF × $M_{reagent}$ ÷ M_{NOX}
Reagent mass usage rate (lb/hr) =	20.15	m_{sol} = $m_{reagent}$ ÷ C_{sol}; where C_{sol} = 29%
Reagent volume usage rate (gal/hr) =	2.69	q_{sol} = m_{sol} ÷ ρ_{sol} × 7.4805 gal/ft^3 ; where ρ_{sol} for 29% ammonia is 56.0 lb/ft^3
Electricity consumption (kW) =	100.78	P = 0.1 × Q_B × 1,000 × 0.0056 × $(NPHR ÷ 10)^{0.43}$; NPHR = 8.2 for natural gas
Direct Operating Costs (DOC)		
Annual Maintenance Cost =	$55,574	A = 0.005 × TCI
Annual Reagent Cost =	$83,141	B = m_{sol} × $Cost_{reag}$ × t_{op}
Annual Electricity Cost =	$59,681	C = P × $Cost_{elec}$ × t_{op}
Annual Catalyst Replacement Cost =	$20,565	D = n_{SCR} × $Vol_{catalyst}$ × $CC_{replace}$ ÷ R_{layer} × FWF
Duct Burner Natural Gas Usage (MMBtu/yr) =	1,051,200	E = Duct Burner Rating in MMBtu/hr × 8,760 hr/yr
Cost of Natural Gas Usage =	$5,256,000	F = E × Natural Gas Cost
Total Direct Operating Costs (DOC)	***$5,474,961***	***DOC = A + B + C + D + F***
Indirect Operating Costs (IOC)		
Administrative Charges (AC) =	$2,695	J = 0.03 × (Operator Cost + 0.4 × A); Operator Cost based on 4 hr/day
Capital Recovery Costs (CR) =	$873,077	K = TCI × CRF
Capital Recovery Factor (CRF) =	0.0786	CRF = 4.75% interest and 20-yr equipment life
Total Indirect Operating Costs (IOC)	***$875,772***	***IOC = J + K***
Total SCR Annualized Cost (AC) =	**$6,350,733**	*AC = DOC + IOC*
Total Cyclone Annualized Cost (AC) =	**$516,074**	*See cyclone costs below*
Total System Annualized Cost (AC) =	**$6,866,807**	*Sum of SCR AC and Cyclone AC*
NO_X Uncontrolled Emissions (tpy) =	117.95	Paper Machine + Duct Burner
NO_X Removed (tpy) =	106.15	90% Removal Efficiency (η_{NOX})
Cost per ton of NO_X and PM Removed ($/ton)	**$64,689**	**$/ton = System AC / Pollutant Removed**

1. Factors and cost estimates reflect U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (7th Edition), June 2019* .

Capital & Operating Cost Evaluation for a Cyclone Upstream of an SCR System for Paper Machine 1

Cost Category	Value	Notes [1]
Vendor Quoted System Costs ($) =	$745,000	
Vendor Quoted System Air Flow Rate (ACFM) =	86,700	
Airflow Analyzed (ACFM) =	199,136	
Engineering Factor =	1.5	Accounts for costs of additional activities not included in vendor quote (ducting, engineering, utilities, etc.).
Total Capital Investment (TCI)	**$2,566,721**	Prorated from previous vendor quote × Engineering Factor
Capital Recovery		
Capital Recovery Factor (CRF)	0.0786	CRF = 4.75% interest and 20-yr equipment life
Capital Recovery Cost (CRC)	***$201,617***	***CRC = TCI × CRF***
Operating Costs		
Direct Operating Costs (DOC)		
Operating Labor	$21,900	A = 1 hr per day
Supervisory Labor	$3,285	B = 15% of operating labor
Maintenance Labor	$21,900	C = 1 hr per day
Maintenance Materials	$21,900	D = Equivalent to maintenance labor
Electricity Usage for Fan Power	1,500,172 kWh/yr	E = Power (kWh/yr) = (100 hp / 86,700 ACFM) × 0.7456 kWh/hp × ACFM × 8,760 hr/yr
Cost of Electricity Usage for Fan Power	$101,412	F = E × Electricity Cost
Total Direct Operating Costs (DOC)	***$170,397***	***DOC = A + B + C + D + F + H + I***
Indirect Operating Costs (IOC)		
Overhead	$41,391	J = 60% × (A + B + C + D)
Property Tax	$25,667	K = 1% × TCI
Insurance	$25,667	L = 1% × TCI
Administrative Charges	$51,334	M = 2% × TCI
Total Indirect Operating Costs (IOC)	***$144,060***	***IOC = J + K + L + M***
Total Annualized Cost (AC) =	**$516,074**	*AC = CRC + DOC + IOC*

1. Factors and cost estimates reflect U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition), December 1998* .

Table A-15. Capital & Operating Cost Evaluation for an SCR System for Paper Machine 7

Cost Category	Value	Notes [1]
Total Capital Investment (TCI) =	$6,640,387	TCI = 10,530 x $(1{,}640/Q_B)^{0.35}$ x Q_B x ELEVF x RF
Total Burner Heat Rating (MMBtu/hr) =	202	Q_B
Airflow Analyzed (ACFM) =	161,775	$q_{fluegas}$ (includes airflow of required duct burner)
Engineering Factor =	1.5	Accounts for costs of additional activities not included in vendor quote (ducting, engineering, utilities, etc.).
Duct Burner Heat Input Rating =	95.0	MMBtu/hr (required to raise temperature of inlet stream to ideal range)
Additional Cost for Duct Burner to Raise Temp =	$1,066,850	Based on previous quote of $1,123,000 for a 100 MMBtu/hr burner
Total Capital Investment (TCI)	**$11,027,430**	Prorated from previous vendor quote × Engineering Factor
System Design		
Future Worth Factor (FWF) =	0.35	FWF = IR × 1 ÷ ((1 + IR)^Y -1) , where Y = $H_{catalyst}/(t_{SCR}$ x 24 hours)
Interest Rate (IR) =	4.75%	
Catalyst Volume (ft^3)	801.41	$Vol_{catalyst} = 2.81 \times Q_B \times \eta_{adj} \times Slip_{adj} \times NO_{Xadj} \times S_{adj} \times T_{adj} \div N_{SCR}$
η_{adj} = NO_X Efficiency Adjustment Factor =	1.24	$\eta_{adj} = 0.2869 + 1.058\eta_{NOX}$
$Slip_{adj}$ = Ammonia Slip Adjustment Factor =	1.17	$Slip_{adj}$ = 1.2835 – (0.0567 × Slip); Slip assumed to be 2 ppm
NO_{Xadj} = Inlet NO_X Adjustment Factor =	0.88	$NO_{Xadj} = 0.8524 + (0.3208 \times NO_{Xin})$
S_{adj} = Sulfur Adjustment Factor =	0.9636	S_{adj} = 0.9636 for natural gas
T_{adj} = Temperature Adjustment Factor =	1.15	$T_{adj} = 15.16 - (0.03937 \times T) + (0.0000274 \times T^2)$
N_{SCR} = Number of Reactor Chambers =	1	N_{SCR} = Number of reactor chambers
Catalyst Cross-sectional Area (ft^2) =	168.52	$A_{catalyst} = q_{fluegas} \div$ (16 ft/sec × 60 sec/min)
Height of each catalyst layer (ft) =	3	$H_{layer} = Vol_{catalyst} \div (R_{layer} \times A_{catalyst}) + 1$; where, $R_{layer} = 3$
SCR Reactor Cross-sectional Area (ft^2) =	193.79	$A_{SCR} = 1.15 \times A_{catalyst}$
n_{layer} = Number of Catalyst Layers =	2	$n_{layer} = Vol_{catalyst} \div (h'_{layer} \times A_{catalyst})$; where, $h'_{layer} = 3.1$
n_{total} = Total Number of Catalyst Layers =	3	$n_{total} = n_{layer} + n_{empty}$; where, $n_{empty} = 1$
h_{SCR} = Height of Catalyst Reactor =	39.00	$h_{SCR} = n_{total} \times (c1 + h_{layer}) + c_2$; where c_1 = 7 ft and c_2 = 9 ft
Mass flow of reagent (lb/hr) =	6.48	$m_{reagent} = NO_{Xin} \times Q_B \times \eta_{NOX} \times SRF \times M_{reagent} \div M_{NOX}$
Reagent mass usage rate (lb/hr) =	22.35	$m_{sol} = m_{reagent} \div C_{sol}$; where C_{sol} = 29%
Reagent volume usage rate (gal/hr) =	2.99	$q_{sol} = m_{sol} \div \rho_{sol} \times 7.4805$ gal/ft^3 ; where ρ_{sol} for 29% ammonia is 56.0 lb/ft^3
Electricity consumption (kW) =	103.87	$P = 0.1 \times Q_B \times 1{,}000 \times 0.0056 \times (NPHR \div 10)^{0.43}$; NPHR = 8.2 for natural gas
Direct Operating Costs (DOC)		
Annual Maintenance Cost =	$55,137	A = 0.005 × TCI
Annual Reagent Cost =	$92,251	$B = m_{sol} \times Cost_{reag} \times t_{op}$
Annual Electricity Cost =	$61,508	$C = P \times Cost_{elec} \times t_{op}$
Annual Catalyst Replacement Cost =	$21,246	$D = n_{SCR} \times Vol_{catalyst} \times CC_{replace} \div R_{layer} \times FWF$
Duct Burner Natural Gas Usage (MMBtu/yr) =	832,200	E = Duct Burner Rating in MMBtu/hr × 8,760 hr/yr
Cost of Natural Gas Usage =	$4,161,000	F = E × Natural Gas Cost
Total Direct Operating Costs (DOC)	***$4,391,142***	***DOC = A + B + C + D + F***
Indirect Operating Costs (IOC)		
Administrative Charges (AC) =	$2,694	J = 0.03 × (Operator Cost + 0.4 × A); Operator Cost based on 4 hr/day
Capital Recovery Costs (CR) =	$866,210	K = TCI × CRF
Capital Recovery Factor (CRF) =	0.0786	CRF = 4.75% interest and 20-yr equipment life
Total Indirect Operating Costs (IOC)	***$868,904***	***IOC = J + K***
Total SCR Annualized Cost (AC) =	**$5,260,046**	*AC = DOC + IOC*
Total Cyclone Annualized Cost (AC) =	**$439,958**	*See cyclone costs below*
Total System Annualized Cost (AC) =	**$5,700,004**	*Sum of SCR AC and Cyclone AC*
NO_X Uncontrolled Emissions (tpy) =	119.35	Paper Machine + Duct Burner
NO_X Removed (tpy) =	107.41	90% Removal Efficiency (η_{NOX})
Cost per ton of NO_X and PM Removed ($/ton)	**$53,066**	**$/ton = System AC / Pollutant Removed**

1. Factors and cost estimates reflect U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (7th Edition), June 2019* .

Capital & Operating Cost Evaluation for a Cyclone Upstream of an SCR System for Paper Machine 1

Cost Category	Value	Notes [1]
Vendor Quoted System Costs ($) =	$745,000	
Vendor Quoted System Air Flow Rate (ACFM) =	86,700	
Airflow Analyzed (ACFM) =	161,775	
Engineering Factor =	1.5	Accounts for costs of additional activities not included in vendor quote (ducting, engineering, utilities, etc.).
Total Capital Investment (TCI)	**$2,085,161**	Prorated from previous vendor quote × Engineering Factor
Capital Recovery		
Capital Recovery Factor (CRF)	0.0786	CRF = 4.75% interest and 20-yr equipment life
Capital Recovery Cost (CRC)	***$163,790***	***CRC = TCI × CRF***
Operating Costs		
Direct Operating Costs (DOC)		
Operating Labor	$21,900	A = 1 hr per day
Supervisory Labor	$3,285	B = 15% of operating labor
Maintenance Labor	$21,900	C = 1 hr per day
Maintenance Materials	$21,900	D = Equivalent to maintenance labor
Electricity Usage for Fan Power	1,218,715 kWh/yr	E = Power (kWh/yr) = (100 hp / 86,700 ACFM) × 0.7456 kWh/hp × ACFM × 8,760 hr/yr
Cost of Electricity Usage for Fan Power	$82,385	F = E × Electricity Cost
Total Direct Operating Costs (DOC)	***$151,370***	***DOC = A + B + C + D + F + H + I***
Indirect Operating Costs (IOC)		
Overhead	$41,391	J = 60% × (A + B + C + D)
Property Tax	$20,852	K = 1% × TCI
Insurance	$20,852	L = 1% × TCI
Administrative Charges	$41,703	M = 2% × TCI
Total Indirect Operating Costs (IOC)	***$124,797***	***IOC = J + K + L + M***
Total Annualized Cost (AC) =	**$439,958**	*AC = CRC + DOC + IOC*

1. Factors and cost estimates reflect U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition), December 1998* .

Table A-16. Capital & Operating Cost Evaluation for a Low NO_X Burner Retrofit for GP Wauna Paper Machine 1

Cost Category	Value	Notes [1]
Total Capital Investment (TCI) =	$564,732	Based on previous quote of $340,500 for a 20.5 MMBtu/hr burner
Burner Emission Guarantee =	0.026	lb NO_X/MMBtu
Total Burner Heat Rating (MMBtu/hr) =	34	Q_B
Engineering Factor =	1.5	Accounts for costs of additional activities not included in vendor quote (ducting, engineering, utilities, etc.).
Total Capital Investment (TCI)	**$847,098**	Prorated from previous vendor quote × Engineering Factor
Direct Operating Costs (DOC)		
Annual Maintenance Cost =	$23,295	A = 2.75% × TCI
Total Direct Operating Costs (DOC)	***$23,295***	***DOC = A***
Indirect Operating Costs (IOC)		
Administrative Charges (AC) =	$16,942	B = Assumed to be 2% of TCI
Capital Recovery Costs (CR) =	$66,540	C = TCI × CRF
Interest Rate (IR) =	4.75%	
Capital Recovery Factor (CRF) =	0.0786	CRF = 4.75% interest and 20-yr equipment life
Total Indirect Operating Costs (IOC)	***$83,482***	***IOC = B + C***
Total System Annualized Cost (AC) =	**$106,777**	***Sum of DOC and IOC***
NO_X Uncontrolled Emissions (tpy) =	13.60	
NO_X Controlled Emissions (tpy) =	3.87	
NO_X Removed (tpy) =	9.72	
Cost per ton of NO_X and PM Removed ($/ton)	**$10,980**	**$/ton = System AC / Pollutant Removed**

1. DOC and IOC factors and cost estimates reflect U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition), Section 1, Chapter 2, January 2002* .

Table A-17. Capital & Operating Cost Evaluation for a Low NO_X Burner Retrofit for GP Wauna Paper Machine 2

Cost Category	Value	Notes [1]
Total Capital Investment (TCI) =	$564,732	Based on previous quote of $340,500 for a 20.5 MMBtu/hr burner
Burner Emission Guarantee =	0.026	lb NO_X/MMBtu
Total Burner Heat Rating (MMBtu/hr) =	34	Q_B
Engineering Factor =	1.5	Accounts for costs of additional activities not included in vendor quote (ducting, engineering, utilities, etc.).
Total Capital Investment (TCI)	**$847,098**	Prorated from previous vendor quote × Engineering Factor
Direct Operating Costs (DOC)		
Annual Maintenance Cost =	$23,295	A = 2.75% × TCI
Total Direct Operating Costs (DOC)	***$23,295***	***DOC = A***
Indirect Operating Costs (IOC)		
Administrative Charges (AC) =	$16,942	B = Assumed to be 2% of TCI
Capital Recovery Costs (CR) =	$66,540	C = TCI × CRF
Interest Rate (IR) =	4.75%	
Capital Recovery Factor (CRF) =	0.0786	CRF = 4.75% interest and 20-yr equipment life
Total Indirect Operating Costs (IOC)	***$83,482***	***IOC = B + C***
Total System Annualized Cost (AC) =	**$106,777**	***Sum of DOC and IOC***
NO_X Uncontrolled Emissions (tpy) =	13.60	
NO_X Controlled Emissions (tpy) =	3.87	
NO_X Removed (tpy) =	9.72	
Cost per ton of NO_X and PM Removed ($/ton)	**$10,980**	**$/ton = System AC / Pollutant Removed**

1. DOC and IOC factors and cost estimates reflect U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition), Section 1, Chapter 2, January 2002* .

Table A-18. Capital & Operating Cost Evaluation for a Low NO_X Burner Retrofit for GP Wauna Paper Machine 5

Cost Category	Value	Notes [1]
Total Capital Investment (TCI) =	$1,245,732	Based on previous quote of $340,500 for a 20.5 MMBtu/hr burner
Burner Emission Guarantee =	0.026	lb NO_X/MMBtu
Total Burner Heat Rating (MMBtu/hr) =	75	Q_B
Engineering Factor =	1.5	Accounts for costs of additional activities not included in vendor quote (ducting, engineering, utilities, etc.).
Total Capital Investment (TCI)	**$1,868,598**	Prorated from previous vendor quote × Engineering Factor
Direct Operating Costs (DOC)		
Annual Maintenance Cost =	$51,386	A = 2.75% × TCI
Total Direct Operating Costs (DOC)	***$51,386***	***DOC = A***
Indirect Operating Costs (IOC)		
Administrative Charges (AC) =	$37,372	B = Assumed to be 2% of TCI
Capital Recovery Costs (CR) =	$146,779	C = TCI × CRF
Interest Rate (IR) =	4.75%	
Capital Recovery Factor (CRF) =	0.0786	CRF = 4.75% interest and 20-yr equipment life
Total Indirect Operating Costs (IOC)	***$184,151***	***IOC = B + C***
Total System Annualized Cost (AC) =	**$235,538**	***Sum of DOC and IOC***
NO_X Uncontrolled Emissions (tpy) =	29.99	
NO_X Controlled Emissions (tpy) =	8.54	
NO_X Removed (tpy) =	21.45	
Cost per ton of NO_X and PM Removed ($/ton)	**$10,980**	**$/ton = System AC / Pollutant Removed**

1. DOC and IOC factors and cost estimates reflect U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition), Section 1, Chapter 2, January 2002* .

Table A-19. Capital & Operating Cost Evaluation for a Low NO_X Burner Retrofit for GP Wauna Paper Machine 6

Cost Category	Value	Notes [1]
Total Capital Investment (TCI) =	$3,255,512	Based on previous quote of $340,500 for a 20.5 MMBtu/hr burner
Burner Emission Guarantee =	0.026	lb NO_X/MMBtu
Total Burner Heat Rating (MMBtu/hr) =	196	Q_B
Engineering Factor =	1.5	Accounts for costs of additional activities not included in vendor quote (ducting, engineering, utilities, etc.).
Total Capital Investment (TCI)	**$4,883,268**	Prorated from previous vendor quote × Engineering Factor
Direct Operating Costs (DOC)		
Annual Maintenance Cost =	$134,290	A = 2.75% × TCI
Total Direct Operating Costs (DOC)	***$134,290***	***DOC = A***
Indirect Operating Costs (IOC)		
Administrative Charges (AC) =	$97,665	B = Assumed to be 2% of TCI
Capital Recovery Costs (CR) =	$383,583	C = TCI × CRF
Interest Rate (IR) =	4.75%	
Capital Recovery Factor (CRF) =	0.0786	CRF = 4.75% interest and 20-yr equipment life
Total Indirect Operating Costs (IOC)	***$481,248***	***IOC = B + C***
Total System Annualized Cost (AC) =	**$615,538**	***Sum of DOC and IOC***
NO_X Uncontrolled Emissions (tpy) =	104.28	
NO_X Controlled Emissions (tpy) =	22.32	
NO_X Removed (tpy) =	81.96	
Cost per ton of NO_X and PM Removed ($/ton)	**$7,510**	**$/ton = System AC / Pollutant Removed**

1. DOC and IOC factors and cost estimates reflect U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition), Section 1, Chapter 2, January 2002* .

Table A-20. Capital & Operating Cost Evaluation for a Low NO_X Burner Retrofit for GP Wauna Paper Machine 7

Cost Category	Value	Notes [1]
Total Capital Investment (TCI) =	$3,355,171	Based on previous quote of $340,500 for a 20.5 MMBtu/hr burner
Burner Emission Guarantee =	0.026	lb NO_X/MMBtu
Total Burner Heat Rating (MMBtu/hr) =	202	Q_B
Engineering Factor =	1.5	Accounts for costs of additional activities not included in vendor quote (ducting, engineering, utilities, etc.).
Total Capital Investment (TCI)	**$5,032,756**	Prorated from previous vendor quote × Engineering Factor
Direct Operating Costs (DOC)		
Annual Maintenance Cost =	$138,401	A = 2.75% × TCI
Total Direct Operating Costs (DOC)	***$138,401***	***DOC = A***
Indirect Operating Costs (IOC)		
Administrative Charges (AC) =	$100,655	B = Assumed to be 2% of TCI
Capital Recovery Costs (CR) =	$395,325	C = TCI × CRF
Interest Rate (IR) =	4.75%	
Capital Recovery Factor (CRF) =	0.0786	CRF = 4.75% interest and 20-yr equipment life
Total Indirect Operating Costs (IOC)	***$495,980***	***IOC = B + C***
Total System Annualized Cost (AC) =	**$634,381**	***Sum of DOC and IOC***
NO_X Uncontrolled Emissions (tpy) =	108.53	
NO_X Controlled Emissions (tpy) =	23.00	
NO_X Removed (tpy) =	85.53	
Cost per ton of NO_X and PM Removed ($/ton)	**$7,417**	**$/ton = System AC / Pollutant Removed**

1. DOC and IOC factors and cost estimates reflect U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition), Section 1, Chapter 2, January 2002* .

Oregon
Kate Brown, Governor

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

August 14, 2020

Kimberly May
Georgia Pacific
92326 Taylorville Rd
Clatskanie, OR 97016-8264
Kimberly.May@GAPAC.com

Sent via EMAIL

Re: Round 2 Regional Haze Program, Four Factor Analysis
GP Wauna, 04-0004

Dear Kimberly May,

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

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

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

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

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

After initial review, DEQ ruled out control devices that:

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

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

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

Emission Unit(s)	Control Device	Status Notes
24 - Recovery Furnace	ESP Upgrade	The control efficiency of the current ESP is a key parameter for this cost estimate, and was listed at 99.5% in the previous submittal. Please provide documentation or data to support that control efficiency estimate.
33 - Power Boiler	LNB/FGR	
Paper Machine 5: Yankee Burner	LNB/FGR	The previous 4FA submittal used LNB/FGR costs from a 2001 BE&K Engineering study. Please provide a recent vendor quote or other more recent information.
Paper Machine 6: Burners	LNB/FGR	The previous 4FA submittal used LNB/FGR costs from a 2001 BE&K Engineering study. Please provide a recent vendor quote or other more recent information.
Paper Machine 7: Burners	LNB/FGR	The previous 4FA submittal used LNB/FGR costs from a 2001 BE&K Engineering study. Please provide a recent vendor quote or other more recent information.
33 - Power Boiler	SCR	
24 - Recovery Furnace	SCR	The previous 4FA submittal indicated that SCR was not technically feasible for recovery boilers, but NCASI technical bulletin #1051, sections 3.1.6 and 3.1.7, suggest that it may be technically feasible. Please provide additional explanation as to why SCR is not feasible, or contact a vendor and provide a statement (if the vendor feels it is infeasible) or a cost estimate (if the vendor feels it is feasible).
33 - Power Boiler	SNCR	

[1] Per EPA Cost Control Manual, pages 14-17: https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

24 - Recovery Furnace	Wet ESP	

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

(1) Agree that the control device is cost effective. In this case, DEQ does not need more detailed cost analysis, and work can shift to planning for installation.

(2) If your facility's Q/d based on actual emissions is less than the screening value of 5.00, you have the option to reduce PSELs to a level below 5.00 Q/d. Facilities with Q/d below 5.00 are not required to do further regional haze analysis or control device installation during Round 2.

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

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

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

Sincerely,

Ali Mirzakhalili
Air Quality Division Administrator
Department of Environmental Quality

Cc: Karen Williams
D Pei Wu, PhD
Joe Westersund
Michael Orman
David Graiver
Matt Hoffman

Georgia-Pacific Consumer Operations LLC
Wauna Mill
92326 Taylorville Road
Clatskanie, Oregon 97016

Submitted via electronic mail

September 14, 2020

Dr. D Pei Wu
Air Quality Planner
wu.d@deq.state.or.us
Oregon Department of Environmental Quality
700 NE Multnomah Street, Suite 600
Portland, OR 97232-4100

Re: Georgia-Pacific Consumer Operations LLC – Wauna Mill
Regional Haze Four Factor Analysis – Response to DEQ Letter

Dear Dr. Wu:

Georgia-Pacific Consumer Operations LLC – Wauna Mill (GP) is providing this response to the Regional Haze Four Factor Analysis (FFA) further analysis letter sent from the Oregon Department of Environmental Quality (DEQ) to the Wauna Mill on August 14, 2020. In this letter, DEQ outlined the criteria used to review the FFA submitted by the Wauna Mill on June 15, 2020. DEQ also identified emissions units requiring additional review and asked GP to respond for each emission unit/control device combination by either (1) agreeing to install a control device, (2) agreeing to reduce facility Plant Site Emission Limits (PSELs) to a level where a Q/d analysis performed with PSELs rather than actual emissions would be less than 5.00 for the facility, or (3) providing a site-specific cost estimate for each unit/device. DEQ stated control devices with a cost greater than $10,000 per ton of pollutant removed ($/ton) were ruled out from requiring further analysis.

In the referenced letter, DEQ provided a table of the Wauna Mill's nine emission unit/control device combinations that met DEQ's criteria for needing further analysis. GP would first like to address several overarching issues and concerns prior to concentrating on each identified emission unit.

COMMUNITY IMPACTS

GP has a strong manufacturing presence in the state of Oregon, operating six facilities across the paper and wood products and chemicals sectors and one service center. Approximately 1,850 people are directly employed by GP in the state of Oregon and an additional 6,070 jobs are indirectly created from our operating footprint within the state. GP's direct wages and benefits contribute over $150 million to the people of Oregon.[1] The Wauna Mill is one of the largest employers in Clatsop County providing jobs for approximately 700 Oregonians.

GP employees continually look for ways to increase the efficiency of the mill by reducing energy and raw material use, and, as a result, lowering generation of air emissions to the atmosphere. In fact, the Wauna

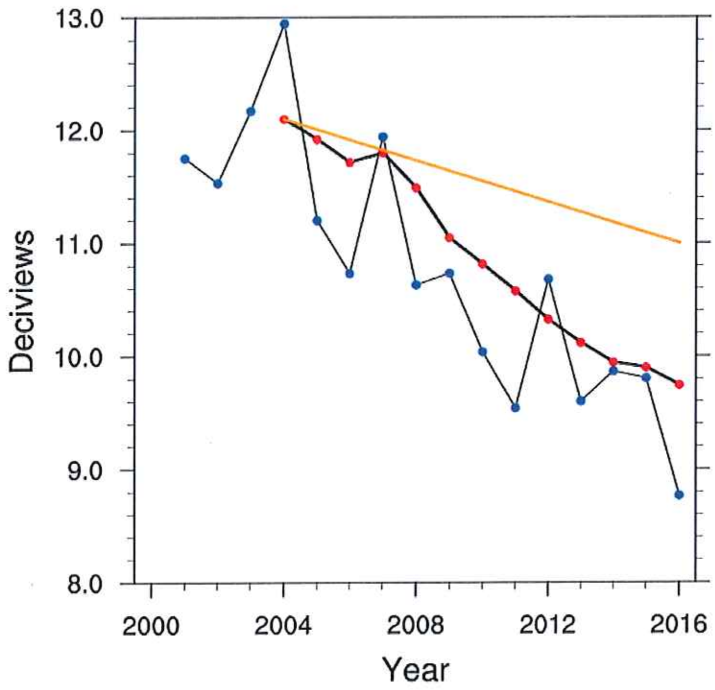
[1] https://www.gp.com/about-us/locations/oregon

Mill recently submitted data in support of renewing the facility's Title V permit that included PSELs of the relevant Regional Haze pollutants of particulate matter less than 10 microns in aerodynamic diameter (PM_{10}), oxides of nitrogen (NO_X), and sulfur dioxide (SO_2), of approximately 1,000 tons per year (tpy) less than the currently permitted rates. The Wauna Mill also completely eliminated the use of No. 6 fuel oil in 2009 and removed their Non-Condensable Gas (NCG) Incinerator in 2010. In short, the Wauna Mill has a history of seeking out ways to reduce air emissions, including substantial reductions in emissions of visibility affecting pollutants over the last 11 years.

VISIBILITY CONSIDERATIONS

Further emissions reductions at the Wauna Mill are not necessary to meet the Regional Haze rule requirements. The goal of the Regional Haze Rule is to protect visibility at Class I areas. In the current second implementation period, states must implement control measures to make reasonable progress towards visibility goals. However, Oregon has not demonstrated that changes to emissions at the Wauna Mill will have any impact on visibility at Class I areas in Oregon. The nearest Oregon Class I area, Mount Hood, is already demonstrating progress well below the glidepath as shown in the EPA chart below, where the yellow line is the "glidepath", red dots are the five year average measured visibility and blue dots are the annual average measured visibility.

FIGURE 1. MT. HOOD MEASURED VISIBILITY AND GLIDEPATH FOR 20% MOST IMPAIRED DAYS[2]

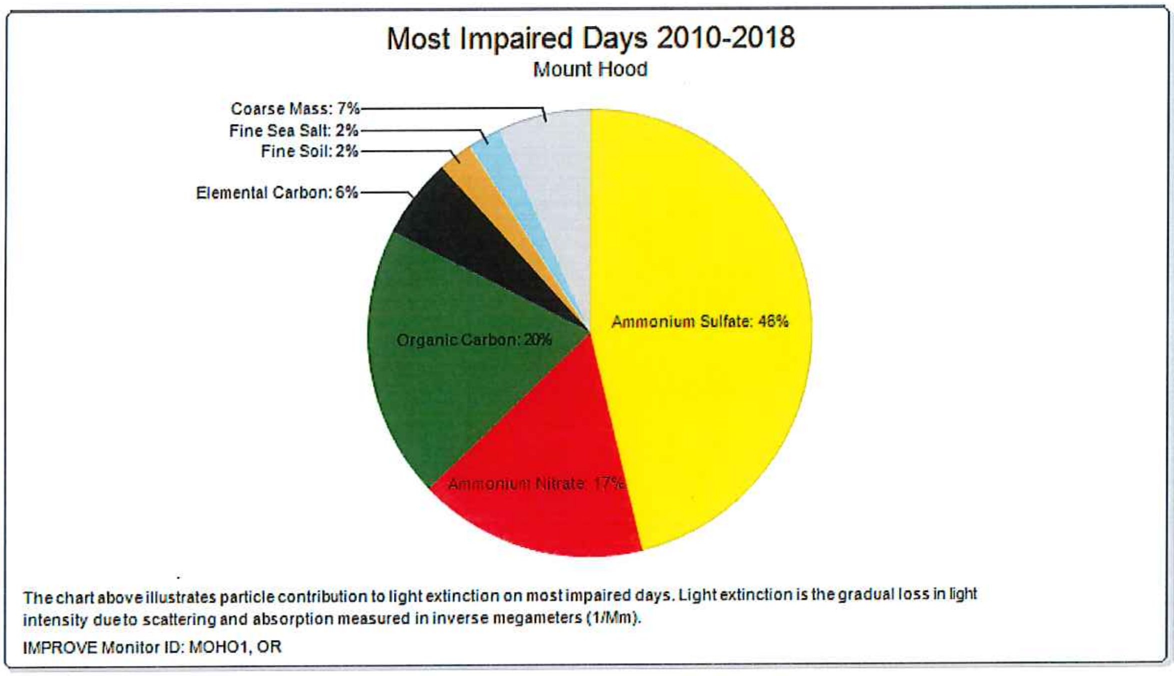


[2] *Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program*, December 20, 2018. https://www.epa.gov/sites/production/files/2018-12/documents/technical_guidance_tracking_visibility_progress.pdf

The 2028 glidepath for the unadjusted 20% most impaired days is 9.9 deciviews (dv) as compared to 2014-2017 observed values of 9.25 dv and predicted 2028 values of 8.95 dv.[3] The 2019 EPA guidance allows for adjustment of the 2028 glidepath based on prescribed fires and international contributions. The adjusted glidepath values for Mt. Hood range from 10.62 to 12.62. Therefore, reasonable progress is currently being made at Mt. Hood by a wide margin without any additional emissions reductions.

Further, most of the controls being considered for the Wauna Mill are for NO_X, and its contribution to visibility degradation at Mount Hood is small relative to the other contributions as shown in Figure 2. NO_X leads to the formation of ammonium nitrate which contributes only 17% of the total visibility degradation at Mount Hood.

FIGURE 2. CONTRIBUTION TO VISIBILITY DEGRADATION ON MOST IMPAIRED DAYS, MOUNT HOOD[4]



As outlined in the EPA state implementation plan (SIP) guidance[5], visibility benefits should be included in the determination of what controls are necessary for reasonable progress. As controls at the Wauna Mill will not likely result in any measurable visibility benefits or have any impact on Mount Hood meeting reasonable further progress goals, no controls are required.

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[3] *Availability of Modeling Data and Associated Technical Support Document for the EPA's Updated 2028 Visibility Air Quality Modeling*, September 19, 2019. https://www.epa.gov/sites/production/files/2019-10/documents/updated_2028_regional_haze_modeling-tsd-2019_0.pdf

[4] http://views.cira.colostate.edu/fed/SiteBrowser/Default.aspx?appkey=SBCF_VisSum

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

COST EFFECTIVENESS THRESHOLDS

A cost effectiveness threshold of $10,000/ton is inappropriate for Regional Haze emission reductions. To GP's knowledge, a $10,000/ton threshold is well above what any other state has utilized. Although many states did not define a precise threshold that would be considered cost effective in advance, GP is aware of several examples that are relevant comparisons:

- Texas evaluated visibility impacts for controls with an estimated cost effectiveness of $5,000/ton or less,
- North Carolina has indicated a cost effectiveness threshold of less than $5,000/ton will be used to determine what controls are cost effective for Regional Haze,
- EPA has used a cost effectiveness threshold of less than $5,000/ton when determining if it was cost effective to require NO_X controls as part of regional transport rules,
- EPA did not further examine control options above $3,400/ton for the 2016 CSAPR update rule,
- EPA used $2,000/ton in the NO_X SIP call as the threshold for cost-effective controls,
- the Western Regional Air Partnership (WRAP) Annex to the Grand Canyon Visibility Transport Report (June 1999) indicated that control costs greater than $3,000/ton were high, and
- states such as New York and Pennsylvania consider NO_X controls less than approximately $5,000/ton as cost effective for Reasonably Available Control Technology (RACT).

A cost threshold of $10,000/ton is not appropriate for use in a Regional Haze rulemaking, especially without a corresponding determination that the capital investment in controls will result in a significant improvement in visibility in nearby Class I areas. This is particularly true in these circumstances where the potentially impacted Class I areas are ahead of the glidepath and the potentially applicable controls do little to reduce the primary contributions to visibility impairments.

EMISSION UNIT ANALYSIS

As previously stated, DEQ provided a table of the Wauna Mill's emission unit/control device combinations that met DEQ's criteria for needing further analysis and requested that GP either commit to installing controls requiring multimillion-dollar investments or provide site-specific cost estimates for the nine identified emission unit/control device combinations. Providing only a month for this type of evaluation is woefully insufficient for any manufacturing site to work with vendors to gather site-specific cost estimates that are more accurate than ±50% at best. In fact, many vendors require monetary resources simply to work through the extensive site-specific project planning process as it requires reviewing facility data, process and structural drawings, and, often, at least one actual onsite visit (if not more) to fully characterize retrofit projects of this size and scope. GP's internal project approval process requires very specific bids that are no less accurate than ±10% before a project can be advanced for full funding approval. Most often it takes at least six months of detailed engineering and design work with a vendor to reach that level of accuracy, and, importantly, requires compensating the vendor for their time and resources.

The breadth and detail required throughout this process is simply not possible in a month. Despite those challenges, GP has gathered as much additional data as possible on the emission unit/control device combinations and updated various cost effectiveness analyses. Even if estimated cost effectiveness values remain less than $10,000/ton of pollutant removed, **GP is unable to commit to installing any control measures with this submittal** in the absence of sufficient additional time to complete a proper engineering analysis.

Each entry from the table DEQ listed in the letter is provided below with GP's responses. Note that table entries may be grouped together based on emission units and pollutant controlled.

Recovery Furnace Particulate Matter Control Devices

Emission Unit	Control Device	Status Notes
24 – Recovery Furnace	ESP Upgrade	The control efficiency of the current ESP is a key parameter for this cost estimate, and was listed at 99.5% in the previous submittal. Please provide documentation or data to support that control efficiency estimate.
	Wet ESP	

As stated on Page 3-5 of the submitted report, the PM_{10} control options for the recovery furnace included upgrading the existing dry electrostatic precipitator (ESP) to provide more control or installing a wet ESP (WESP). DEQ's note that the control efficiency of the current ESP was listed as 99.5% is inaccurate. The emission reductions for the dry ESP upgrades were calculated assuming the current ESP provides 99% control and an upgraded ESP would achieve 99.5% control. Since the original submittal, GP has located the bid specifications from an ESP upgrade project performed on the control device in 2002. At that time, the ESP was upgraded to reliably meet the applicable particulate matter (PM) emission limit under the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Chemical Recovery Combustion Sources (known as MACT II) of 0.044 gr/dscf @ 8% O_2. The inlet dust loading was specified as 7 gr/dscf @ 8% O_2; therefore, the resulting guaranteed control efficiency of the existing dry ESP is actually 99.37%. As such, an upgrade of the current ESP would provide less additional control than previously estimated.

Also, it is important to note that a dry ESP would only be expected to provide control of filterable particulate matter (FPM) although the original FFA cost effectiveness analysis used the total PM_{10} emission rate when calculating the amount of pollutant removed. The recovery furnace PM_{10} PSEL is 290 tpy and stack testing over the past 5 years has averaged approximately 60% FPM and 40% condensable particulate matter (CPM). Therefore, the filterable PM_{10} component of the PSEL emission rate for the Recovery Furnace is estimated to be 174 tpy.

GP discussed potential ESP upgrade projects with three control device vendors. Possible options include (1) rebuilding the existing unit, (2) rebuilding the existing unit with adding a third chamber, and (3) building two new chambers to replace the existing chambers. Initial purchased equipment cost estimates (±50% at best) ranged from $3,879,000 (Option 1) to $15,000,000 (Option 3). Expected FPM performance guarantees were either 0.010 gr/dscf @ 8% O_2 or 0.015 gr/dscf @ 8% O_2 for Option 1, depending on the vendor and cost, and 0.010 gr/dscf @ 8% O_2 for Options 2 and 3.

GP updated the previous cost effectiveness calculations to account for only FPM_{10} emissions, the vendor-based outlet emission rates, and the vendor provided cost data, and found the cost effectiveness values to range from $11,660/ton to $28,409/ton, none of which are cost effective. The cost effectiveness analyses for the three options for upgrading or replacing the existing dry ESP on the Wauna Mill's Recovery Furnace are included as Tables A-1 through A-4 in Attachment A to this letter.

GP also discussed installation of a polishing WESP downstream of the existing dry ESP with the three control device vendors. These vendors are only aware of one installation of a WESP in this same setup within the pulp and paper industry. Each vendor stated the lack of experience with this control scenario greatly increases the risk of underestimating costs and achieving a successful implementation, and it could potentially create additional operating and environmental issues. In fact, a significant amount of water would be required to quench the flue gas stream to decrease the ESP exhaust temperature from approximately 400°F to roughly 130-150°F, and additional water would be required for operation of the WESP itself. It is estimated that an increase in water flow of greater than 110,000 gallons per day would be needed, which also generates an additional wastewater stream from the system. Acid gases could also be formed, possibly requiring installation of a packed bed scrubber and increased maintenance of the WESP due to fouling and plugging of the electrodes.

Despite the challenges identified above, the control device vendors provided very rough estimates of total installed costs (±50% at best) and expected outlet emission rates of a potential WESP downstream of the existing dry ESP. The costs provided do not include a packed bed scrubber, increased annual maintenance estimates, or site-specific construction concerns related to the area the unit would need to be installed. The outlet emission rate data is only specified for FPM_{10}, as the control device vendors will not guarantee any control of CPM.

The first vendor provided an estimated outlet emission rate of 0.010 gr/dscf @ 8% O_2 of FPM_{10} for a total installed cost of $10,000,000. Using this data in the cost effectiveness analysis results in a removal cost of $14,813/ton, which is not cost effective.

The second vendor provided an estimated outlet emission rate of 0.008 gr/dscf @ 8% O_2 of FPM_{10} for a total purchased equipment cost of roughly $8,000,000. The estimated total installed cost is $13,360,000 for direct comparison to the other vendor cost data. Using this data in the cost effectiveness analysis results in a removal cost of $16,901/ton, which is not cost effective.

The final vendor provided an estimated outlet emission rate of 0.005 gr/dscf @ 8% O_2 of FPM_{10} for a total installed cost of roughly $19,000,000. Using this data in the cost effectiveness analysis results in a removal cost of $19,859/ton, which is not cost effective.

Based on the analyses presented above, neither upgrading the existing dry ESP nor installing a polishing WESP downstream of the existing ESP on the recovery furnace is cost effective. The cost effectiveness analyses for adding a polishing WESP downstream of the existing dry ESP on the Wauna Mill's Recovery Furnace are included as Tables A-5 through A-7 in Attachment A to this letter.

Recovery Furnace NO_X Control Devices

24 – Recovery Furnace	SCR	The previous 4FA submittal indicated that SCR was not technically feasible for recovery boilers, but NCASI technical bulletin #1051, sections 3.1.6 and 3.1.7, suggest that it may be technically feasible. Please provide additional explanation as to why SCR is not feasible, or contact a vendor and provide a statement (if the vendor feels it is infeasible) or a cost estimate (if the vendor feels it is feasible).

Dr. Vipin Varma of NCASI issued a memorandum addressing the discussion of SCR on Kraft recovery furnaces in NCASI Technical Bulletin No. 1501. Dr. Varma concludes that installing an SCR system on a Kraft recovery furnace is technically infeasible. This memorandum, dated September 10, 2020, is included as Attachment B to this letter.

Power Boiler NO_X Control Devices

Emission Unit	Control Device	Status Notes
33 – Power Boiler	LNB/FGR	
	SCR	
	SNCR	

The limited amount of vendor data GP was able to obtain for NO_X reduction measures on the Power Boiler did not significantly alter the cost effectiveness values after DEQ adjusted the original analyses. Those DEQ-adjusted cost effectiveness results were \$3,289/ton for low-NO_X burners with flue gas recirculation (LNB/FGR), \$7,907/ton for a selective catalytic reduction (SCR) system, and \$8,389/ton for a selective non-catalytic reduction (SNCR) system. Each of these control measures requires detailed review of the Power Boiler's burner box for proper assessment of available furnace volume and flow characteristics. In particular, SCR requires a more detailed engineering evaluation specific to the configuration of the boiler to fully characterize the retrofit costs. And, an SNCR system may require multiples levels of reagent injectors within a boiler depending on boiler temperature swings. Depending on space available for installation, additional ductwork and custom configurations may be required. Duct burners may also be needed to reheat the flue gas to proper temperatures resulting in additional capital and annual operating cost. Essentially a detailed site visit is needed for vendors to thoroughly review these control measures and that simply was not possible within the allotted time for this response. Given the short response time allowed and current travel concerns, GP has been unable to gather more accurate cost data for the actual application of LNB/FGR, SCR, or SNCR systems for the Wauna Mill's Power Boiler. As outlined above, GP's stance is that making final control equipment decisions on the basis of ±50% control estimates (at best) is inappropriate. Further refinement of the engineering details and alternatives would be necessary to determine whether these reductions are cost effective. Therefore, GP is not committing to installation of any of the NO_X control measures identified for the Power Boiler with this submittal.

Paper Machine NO_X Control Devices

Emission Unit	Control Device	Status Notes
Paper Machine 5: Yankee Burner	LNB/FGR	The previous 4FA submittal used LNB/FGR costs from a 2001 BE&K Engineering study. Please provide a recent vendor quote or other more recent information.
Paper Machine 6: Burners	LNB/FGR	The previous 4FA submittal used LNB/FGR costs from a 2001 BE&K Engineering study. Please provide a recent vendor quote or other more recent information.
Paper Machine 7: Burners	LNB/FGR	The previous 4FA submittal used LNB/FGR costs from a 2001 BE&K Engineering study. Please provide a recent vendor quote or other more recent information.

DEQ's note on the LNB/FGR analysis for the paper machines is inaccurate. GP used an actual vendor quote obtained in December 2015 for a sister facility with similar paper machine burners to estimate the costs for the low-NO_X burners for the Wauna Mill's paper machines.

Separately, as part of the Title V renewal efforts, GP has reviewed the paper machine burner heat ratings and will make the adjustments shown in the table below to burner sizes and corresponding NO_X emission rates:

Paper Machine Burner	Burner Heat Input Rating Current (MMBtu/hr)	Burner Heat Input Rating Updated (MMBtu/hr)	NO_X Emission Factor (lb/MMBtu)	NO_X Emission Rates Current (tpy)	NO_X Emission Rates Updated (tpy)
PM1 Yankee Burner	34	31	0.0913	13.6	12.4
PM2 Yankee Burner	34	31	0.0913	13.6	12.4
PM5 Yankee Burner	75	60	0.0913	30.0	24.0
PM6 Yankee Burner	28	9	0.0913	11.2	3.6
PM6 TAD1 Burner	84	90	0.1265	46.5	49.9
PM6 TAD2 Burner	84	50	0.1265	46.5	27.7
PM7 Yankee Burner	22	9	0.0913	8.8	3.6
PM7 TAD1 Burner	90	90	0.1265	49.9	49.9
PM7 TAD2 Burner	90	50	0.1265	49.9	27.7
Totals =	**541**	**420**		**270.0**	**211.1**

These updates will result in an additional reduction of 58.9 tpy in the NO_X PSEL. Further reduction of the NO_X PSELs for the paper machine burners is not needed.

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The GP Wauna Mill has attempted to provide as much additional information in support of the Regional Haze FFA as possible in the time allowed. To the extent that additional relevant information is identified following this submission, GP will supplement this response as appropriate. GP maintains that all control measures investigated are not cost effective and there is no evidence that further reductions will result in any measurable visibility benefits or have any impact on meeting reasonable further progress goals of
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relevant Class I areas. As such, GP is not committing to installation of any additional control measures with this submittal. Additionally, given that GP has submitted the best information available to us by the September 14, 2020 deadline, we request that DEQ consult us prior to making control decisions based on these analyses. If you have questions regarding this letter, please contact Kimberly May at (503) 455-3042 or kimberly.may@gapac.com.

I, the undersigned, am the responsible official of the source for which this document is being submitted. I hereby certify, based on the information and belief formed after reasonable inquiry, that the statements made, and the data contained in this document are true, accurate, and complete.

Sincerely,

Jeremy Ness
Vice-President – Manufacturing

Attachments

CC (electronic only):
David Graiver, david.graiver@state.or.us

ATTACHMENT A

UPDATED COST EFFECTIVENESS CALCULATIONS

Table A-1
Georgia-Pacific Consumer Products LP - Wauna
Capital and Annual Costs Associated with ESP Upgrade for Recovery Furnace - Option 1, 0.015 gr/dscf @ 8% O_2 Emission Rate

CAPITAL COSTS[(a)]

	COST ITEM	COST FACTOR	COST ($)
	Direct Costs		
	Purchased Equipment Costs		
(a)	*A* ESP		$3,879,000
(b)	Instrumentation	0.10 A	$387,900
(b)	Sales Tax	0.03 A	$116,370
(b)	Freight	0.05 A	$193,950
	B Total Purchased Equipment Cost		***$4,577,220***
	Direct Installation Costs		
(b)	Foundations and Supports[(c)]	0.04 B	$0
(b)	Handling and Erection	0.50 B	$2,288,610
(b)	Electrical	0.08 B	$366,178
(b)	Piping	0.01 B	$45,772
(b)	Insulation	0.02 B	$91,544
(b)	Painting	0.02 B	$91,544
	Direct Installation Cost		***$2,883,649***
	Total Direct Costs		***$7,460,869***
	Indirect Costs		
(b)	Engineering	0.20 B	$915,444
(b)	Construction Management	0.20 B	$915,444
(b)	Contractor fees	0.10 B	$457,722
(b)	Start-up	0.01 B	$45,772
(b)	Performance test	0.01 B	$45,772
(b)	Model Study	0.02 B	$91,544
(b)	Contingencies	0.03 B	$137,317
	Total Indirect Costs		***$2,609,015***
	Total Capital Investment (TCI) [(a)]		***$10,069,884***

ANNUALIZED COSTS

	COST ITEM	COST FACTOR	RATE	COST ($)
	Direct Annual Costs			
	Operating Labor[(c)]			
(b)	Operator	hours/shift	$31.00 per hour[(d)]	$0
(b)	Supervisor	of operator labor		$0
(b)	Coordinator	of operator labor		$0
	Maintenance[(c)]			
(b)	Maintenance labor	hours/shift	$34.00 per hour[(d)]	$0
(b)	Maintenance materials	of purchased equipment costs		$0
	Utilities[(e)]			
	Electricity	400 kW	$0.060 per kWh[(b)]	$210,183
	Total Direct Annual Costs			***$210,183***
	Indirect Annual Costs			
(c)	Overhead	60% Labor and Material Costs		$0
(c)	General and administrative	2% of TCI		$0
(b)	Property taxes	1% of TCI		$100,699
(b)	Insurance	1% of TCI		$100,699
(b)	Capital recovery	0.053 x TCI		$530,499
		Life of the control: 30 years at	3.25% interest	
	Total Indirect Annual Costs			***$731,896***
	Total Annual Costs			***$942,080***
	Cost Effectiveness ($/ton)			
	Current Emission Rates / Control Efficiency			
	Controlled FPM_{10} Emissions[(f)]:	174 tpy		
	Current FPM_{10} Control Efficiency[(g)]:	99.37% tpy		
	Post ESP Upgrade Emission Rates / Control Efficiency			
	Future FPM_{10} Emission Rate [(h)]:	0.015 gr/dscf @ 8% O_2		
	Avg Flow Rate from Stack Tests [(i)]:	178,402 dscfm @ 8% O_2		
	Controlled FPM_{10} Emissions [(j)]:	100 tpy	***Total Annual Costs/Controlled PM_{10} Emissions:***	
	Additional FPM_{10} Removed [(k)]:	73.5 tons of additional PM_{10} removed annually		***$12,811***

(a) The purchased equipment cost of just the components needed to upgrade the existing ESP was estimated by the control device vendor in September 2020.
(b) Cost information estimated based on the U.S. EPA OAQPS Control Cost Manual, Section 6, Chapter 3, September 1999.
(c) Costs associated with these parameters are zero because ESP system is already installed on the source. This cost analysis represents an upgrade to the existing ESP System.
(d) Nominal Pacific NW pulp and paper mill rates.
(e) The electricity requirement for new equipment is based on the report BE&K Engineering completed for AF&PA in September 2001, titled, "Emission Control Study - Technology Cost Estimates" and scaled based on the furnace size.
(f) Filterable portion of the recovery furnace PM_{10} PSEL. Calculated by applying the average % FPM from stack test data from January 2014 through March 2019 of 60%: FPM = 290 tpy * 60% = 174 tpy
(g) Control efficiency of the existing dry ESP based on data from prior ESP upgrade project performed in 2002. Inlet dust loading = 7 gr/dscf @ 8% O_2 and outlet emissions guarantee = 0.044 gr/dscf @ 8% O_2.
(h) Future outlet emission rate of filterable PM from upgrading the existing dry ESP was estimated by the control device vendor.
(i) The average flow rate as measured during stack test events performed from January 2014 through March 2019. Flow rate was converted from "as measured" to 8% O_2 to align with the future FPM10 emission rate.
(j) Controlled FPM_{10} emissions is calculated from the Future FPM_{10} Emission Rate and the Avg Flow Rate from Stack Tests.
(k) Additional FPM_{10} Removed represents the additional amount of FPM_{10} expected to be captured by upgrading the existing ESP: Current Controlled Emission Rate - Future Controlled Emission Rate

Table A-2

Georgia-Pacific Consumer Products LP - Wauna

Capital and Annual Costs Associated with ESP Upgrade for Recovery Furnace - Option 1, 0.010 gr/dscf @ 8% O_2 Emission Rate

CAPITAL COSTS[a]

	COST ITEM	COST FACTOR	COST ($)
	Direct Costs		
	Purchased Equipment Costs		
(a)	A ESP		$5,500,000
(b)	Instrumentation	0.10 A	$550,000
(b)	Sales Tax	0.03 A	$165,000
(b)	Freight	0.05 A	$275,000
	B Total Purchased Equipment Cost		***$6,490,000***
	Direct Installation Costs		
(b)	Foundations and Supports[c]	0.04 B	$0
(b)	Handling and Erection	0.50 B	$3,245,000
(b)	Electrical	0.08 B	$519,200
(b)	Piping	0.01 B	$64,900
(b)	Insulation	0.02 B	$129,800
(b)	Painting	0.02 B	$129,800
	Direct Installation Cost		***$4,088,700***
	Total Direct Costs		***$10,578,700***
	Indirect Costs		
(b)	Engineering	0.20 B	$1,298,000
(b)	Construction Management	0.20 B	$1,298,000
(b)	Contractor fees	0.10 B	$649,000
(b)	Start-up	0.01 B	$64,900
(b)	Performance test	0.01 B	$64,900
(b)	Model Study	0.02 B	$129,800
(b)	Contingencies	0.03 B	$194,700
	Total Indirect Costs		***$3,699,300***
	Total Capital Investment (TCI) [a]		***$14,278,000***

ANNUALIZED COSTS

	COST ITEM	COST FACTOR	RATE	COST ($)
	Direct Annual Costs			
	Operating Labor [c]			
(b)	Operator	hours/shift	$31.00 per hour[d]	$0
(b)	Supervisor	of operator labor		$0
(b)	Coordinator	of operator labor		$0
	Maintenance [c]			
(b)	Maintenance labor	hours/shift	$34.00 per hour[d]	$0
(b)	Maintenance materials	of purchased equipment costs		$0
	Utilities [e]			
	Electricity	400 kW	$0.060 per kWh[b]	$210,183
	Total Direct Annual Costs			***$210,183***
	Indirect Annual Costs			
(c)	Overhead	60% Labor and Material Costs		$0
(c)	General and administrative	2% of TCI		$0
(b)	Property taxes	1% of TCI		$142,780
(b)	Insurance	1% of TCI		$142,780
(b)	Capital recovery	0.053 x TCI		$752,190
	Life of the control:	30 years at	3.25% interest	
	Total Indirect Annual Costs			***$1,037,750***
	Total Annual Costs			***$1,247,933***

Cost Effectiveness ($/ton)

Current Emission Rates / Control Efficiency

Controlled FPM_{10} Emissions[f]: 174 tpy

Current FPM_{10} Control Efficiency[g]: 99.37% tpy

Post ESP Upgrade Emission Rates / Control Efficiency

Future FPM_{10} Emission Rate [h]: 0.010 gr/dscf @ 8% O_2

Avg Flow Rate from Stack Tests [i]: 178,402 dscfm @ 8% O_2

Controlled FPM_{10} Emissions [j]: 67 tpy

Additional FPM_{10} Removed [k]: 107.0 tons of additional PM_{10} removed annually

Total Annual Costs/Controlled PM_{10} Emissions: ***$11,660***

(a) The purchased equipment cost of just the components needed to upgrade the existing ESP was estimated by the control device vendor in September 2020.
(b) Cost information estimated based on the U.S. EPA OAQPS Control Cost Manual, Section 6, Chapter 3, September 1999.
(c) Costs associated with these parameters are zero because ESP system is already installed on the source. This cost analysis represents an upgrade to the existing ESP System.
(d) Nominal Pacific NW pulp and paper mill rates.
(e) The electricity requirement for new equipment is based on the report BE&K Engineering completed for AF&PA in September 2001, titled, "Emission Control Study - Technology Cost Estimates" and scaled based on the furnace size.
(f) Filterable portion of the recovery furnace PM_{10} PSEL. Calculated by applying the average % FPM from stack test data from January 2014 through March 2019 of 60%: FPM = 290 tpy * 60% = 174 tpy
(g) Control efficiency of the existing dry ESP based on data from prior ESP upgrade project performed in 2002. Inlet dust loading = 7 gr/dscf @ 8% O_2 and outlet emissions guarantee = 0.044 gr/dscf @ 8% O_2.
(h) Future outlet emission rate of filterable PM from upgrading the existing dry ESP was estimated by the control device vendor.
(i) The average flow rate as measured during stack test events performed from January 2014 through March 2019. Flow rate was converted from "as measured" to 8% O_2 to align with the future FPM10 emission rate.
(j) Controlled FPM_{10} emissions is calculated from the Future FPM_{10} Emission Rate and the Avg Flow Rate from Stack Tests.
(k) Additional FPM_{10} Removed represents the additional amount of FPM_{10} expected to be captured by upgrading the existing ESP: Current Controlled Emission Rate - Future Controlled Emission Rate

Table A-3
Georgia-Pacific Consumer Products LP - Wauna
Capital and Annual Costs Associated with ESP Upgrade for Recovery Furnace - Option 2

CAPITAL COSTS[a]			
	COST ITEM	COST FACTOR	COST ($)
	Direct Costs		
	Purchased Equipment Costs		
(a)	A ESP		$13,500,000
(b)	Instrumentation	0.10 A	$1,350,000
(b)	Sales Tax	0.03 A	$405,000
(b)	Freight	0.05 A	$675,000
	B *Total Purchased Equipment Cost*		*$15,930,000*
	Direct Installation Costs		
(b)	Foundations and Supports[c]	0.04 B	$0
(b)	Handling and Erection	0.50 B	$7,965,000
(b)	Electrical	0.08 B	$1,274,400
(b)	Piping	0.01 B	$159,300
(b)	Insulation	0.02 B	$318,600
(b)	Painting	0.02 B	$318,600
	Direct Installation Cost		*$10,035,900*
	Total Direct Costs		*$25,965,900*
	Indirect Costs		
(b)	Engineering	0.20 B	$3,186,000
(b)	Construction Management	0.20 B	$3,186,000
(b)	Contractor fees	0.10 B	$1,593,000
(b)	Start-up	0.01 B	$159,300
(b)	Performance test	0.01 B	$159,300
(b)	Model Study	0.02 B	$318,600
(b)	Contingencies	0.03 B	$477,900
	Total Indirect Costs		*$9,080,100*
	Total Capital Investment (TCI) [a]		*$35,046,000*

ANNUALIZED COSTS				
	COST ITEM	COST FACTOR	RATE	COST ($)
	Direct Annual Costs			
	Operating Labor[c]			
(b)	Operator	hours/shift	$31.00 per hour[d]	$0
(b)	Supervisor	of operator labor		$0
(b)	Coordinator	of operator labor		$0
	Maintenance[c]			
(b)	Maintenance labor	hours/shift	$34.00 per hour[d]	$0
(b)	Maintenance materials	of purchased equipment costs		$0
	Utilities[e]			
	Electricity	400 kW	$0.060 per kWh[b]	$210,183
	Total Direct Annual Costs			*$210,183*
	Indirect Annual Costs			
(c)	Overhead	60% Labor and Material Costs		$0
(c)	General and administrative	2% of TCI		$0
(b)	Property taxes	1% of TCI		$350,460
(b)	Insurance	1% of TCI		$350,460
(b)	Capital recovery	0.053 x TCI		$1,846,283
	Life of the control:	30 years at	3.25% interest	
	Total Indirect Annual Costs			*$2,547,203*
	Total Annual Costs			*$2,757,387*
	Cost Effectiveness ($/ton)			
	Current Emission Rates / Control Efficiency			
	Controlled FPM_{10} Emissions[f]:	174 tpy		
	Current FPM_{10} Control Efficiency[g]:	99.37% tpy		
	Post ESP Upgrade Emission Rates / Control Efficiency			
	Future FPM_{10} Emission Rate [h]:	0.010 gr/dscf @ 8% O_2		
	Avg Flow Rate from Stack Tests [i]:	178,402 dscfm @ 8% O_2		
	Controlled FPM_{10} Emissions [j]:	67 tpy	*Total Annual Costs/Controlled PM_{10} Emissions:*	
	Additional FPM_{10} Removed [k]:	107.0 tons of additional PM_{10} removed annually		*$25,764*

(a) The purchased equipment cost of just the components needed to rebuild the existing ESP and add a third chamber was estimated by the control device vendor in September 2020.
(b) Cost information estimated based on the U.S. EPA OAQPS Control Cost Manual, Section 6, Chapter 3, September 1999.
(c) Costs associated with these parameters are zero because ESP system is already installed on the source. This cost analysis represents an upgrade to the existing ESP System.
(d) Nominal Pacific NW pulp and paper mill rates.
(e) The electricity requirement for new equipment is based on the report BE&K Engineering completed for AF&PA in September 2001, titled, "Emission Control Study - Technology Cost Estimates" and scaled based on the furnace size.
(f) Filterable portion of the recovery furnace PM_{10} PSEL. Calculated by applying the average % FPM from stack test data from January 2014 through March 2019 of 60%: FPM = 290 tpy * 60% = 174 tpy
(g) Control efficiency of the existing dry ESP based on data from prior ESP upgrade project performed in 2002. Inlet dust loading = 7 gr/dscf @ 8% O_2 and outlet emissions guarantee = 0.044 gr/dscf @ 8% O_2.
(h) Future outlet emission rate of filterable PM from upgrading the existing dry ESP was estimated by the control device vendor.
(i) The average flow rate as measured during stack test events performed from January 2014 through March 2019. Flow rate was converted from "as measured" to 8% O_2 to align with the future FPM10 emission rate.
(j) Controlled FPM_{10} emissions is calculated from the Future FPM_{10} Emission Rate and the Avg Flow Rate from Stack Tests.
(k) Additional FPM_{10} Removed represents the additional amount of FPM_{10} expected to be captured by upgrading the existing ESP: Current Controlled Emission Rate - Future Controlled Emission Rate

Table A-4

Georgia-Pacific Consumer Products LP - Wauna

Capital and Annual Costs Associated with ESP Upgrade for Recovery Furnace - Option 3

CAPITAL COSTS[(a)]

	COST ITEM	COST FACTOR	COST ($)
	Direct Costs		
	Purchased Equipment Costs		
(a)	*A* ESP		$15,000,000
(b)	Instrumentation	0.10 A	$1,500,000
(b)	Sales Tax	0.03 A	$450,000
(b)	Freight	0.05 A	$750,000
	B Total Purchased Equipment Cost		***$17,700,000***
	Direct Installation Costs		
(b)	Foundations and Supports[(c)]	0.04 B	$0
(b)	Handling and Erection	0.50 B	$8,850,000
(b)	Electrical	0.08 B	$1,416,000
(b)	Piping	0.01 B	$177,000
(b)	Insulation	0.02 B	$354,000
(b)	Painting	0.02 B	$354,000
	Direct Installation Cost		***$11,151,000***
	Total Direct Costs		***$28,851,000***
	Indirect Costs		
(b)	Engineering	0.20 B	$3,540,000
(b)	Construction Management	0.20 B	$3,540,000
(b)	Contractor fees	0.10 B	$1,770,000
(b)	Start-up	0.01 B	$177,000
(b)	Performance test	0.01 B	$177,000
(b)	Model Study	0.02 B	$354,000
(b)	Contingencies	0.03 B	$531,000
	Total Indirect Costs		***$10,089,000***
	Total Capital Investment (TCI) [(a)]		***$38,940,000***

ANNUALIZED COSTS

	COST ITEM	COST FACTOR	RATE	COST ($)
	Direct Annual Costs			
	Operating Labor[(c)]			
(b)	Operator	hours/shift	$31.00 per hour[(d)]	$0
(b)	Supervisor	of operator labor		$0
(b)	Coordinator	of operator labor		$0
	Maintenance[(c)]			
(b)	Maintenance labor	hours/shift	$34.00 per hour[(d)]	$0
(b)	Maintenance materials	of purchased equipment costs		$0
	Utilities[(e)]			
	Electricity	400 kW	$0.060 per kWh[(b)]	$210,183
	Total Direct Annual Costs			***$210,183***
	Indirect Annual Costs			
(c)	Overhead	60% Labor and Material Costs		$0
(c)	General and administrative	2% of TCI		$0
(b)	Property taxes	1% of TCI		$389,400
(b)	Insurance	1% of TCI		$389,400
(b)	Capital recovery	0.053 x TCI		$2,051,426
		Life of the control: 30 years at	3.25% interest	
	Total Indirect Annual Costs			***$2,830,226***
	Total Annual Costs			***$3,040,409***
	Cost Effectiveness ($/ton)			
	Current Emission Rates / Control Efficiency			
	Controlled FPM_{10} Emissions[(f)]:	174 tpy		
	Current FPM_{10} Control Efficiency[(g)]:	99.37% tpy		
	Post ESP Upgrade Emission Rates / Control Efficiency			
	Future FPM_{10} Emission Rate [(h)]:	0.010 gr/dscf @ 8% O_2		
	Avg Flow Rate from Stack Tests [(i)]:	178,402 dscfm @ 8% O_2		
	Controlled FPM_{10} Emissions [(j)]:	67 tpy	***Total Annual Costs/Controlled PM_{10} Emissions:***	
	Additional FPM_{10} Removed [(k)]:	107.0 tons of additional PM_{10} removed annually		***$28,409***

(a) The purchased equipment cost of just the components needed to build new ESP chambers was estimated by the control device vendor in September 2020.
(b) Cost information estimated based on the U.S. EPA OAQPS Control Cost Manual, Section 6, Chapter 3, September 1999.
(c) Costs associated with these parameters are zero because ESP system is already installed on the source. This cost analysis represents an upgrade to the existing ESP System.
(d) Nominal Pacific NW pulp and paper mill rates.
(e) The electricity requirement for new equipment is based on the report BE&K Engineering completed for AF&PA in September 2001, titled, "Emission Control Study - Technology Cost Estimates" and scaled based on the furnace size.
(f) Filterable portion of the recovery furnace PM_{10} PSEL. Calculated by applying the average % FPM from stack test data from January 2014 through March 2019 of 60%: FPM = 290 tpy * 60% = 174 tpy
(g) Control efficiency of the existing dry ESP based on data from prior ESP upgrade project performed in 2002. Inlet dust loading = 7 gr/dscf @ 8% O_2 and outlet emissions guarantee = 0.044 gr/dscf @ 8% O_2.
(h) Future outlet emission rate of filterable PM from upgrading the existing dry ESP was estimated by the control device vendor.
(i) The average flow rate as measured during stack test events performed from January 2014 through March 2019. Flow rate was converted from "as measured" to 8% O_2 to align with the future FPM10 emission rate.
(j) Controlled FPM_{10} emissions is calculated from the Future FPM_{10} Emission Rate and the Avg Flow Rate from Stack Tests.
(k) Additional FPM_{10} Removed represents the additional amount of FPM_{10} expected to be captured by upgrading the existing ESP: Current Controlled Emission Rate - Future Controlled Emission Rate

Table A-5
Georgia-Pacific - Wauna
Capital and Annual Costs Associated with WESP for Recovery Furnace - Vendor 1 Estimates

CAPITAL COSTS

	COST ITEM	COST FACTOR	COST ($)
	Direct Costs		
	Purchased Equipment Costs		
(a)	*A* WESP		$5,074,597
(b)	Instrumentation and controls	0.10 A	$507,460
(b)	Sales Tax	0.03 A	$152,238
(b)	Freight	0.05 A	$253,730
	B ***Total Purchased Equipment Cost***		***$5,988,024***
	Direct Installation Costs		
(b)	Foundations and Supports	0.04 B	$239,521
(b)	Handling and Erection	0.50 B	$2,994,012
(b)	Electrical	0.08 B	$479,042
(b)	Piping	0.01 B	$59,880
(b)	Insulation for Ductwork	0.02 B	$119,760
(b)	Painting	0.02 B	$119,760
	Direct Installation Cost		***$4,011,976***
	Total Direct Costs		***$10,000,001***
	Indirect Costs		
(b)	Engineering	0.20 B	$1,197,605
(b)	Construction and Field Expenses	0.20 B	$1,197,605
(b)	Contractor fees	0.10 B	$598,802
(b)	Start-up	0.01 B	$59,880
(b)	Performance test	0.01 B	$59,880
(b)	Model Study	0.02 B	$119,760
(b)	Contingencies	0.03 B	$179,641
	Total Indirect Costs		***$3,413,174***
	Total Capital Investment (TCI)		***$13,413,175***

ANNUALIZED COSTS

	COST ITEM	COST FACTOR	RATE	COST ($)
	Direct Annual Costs			
	Operating Labor			
(b)	Operator[c]	1 hours/shift	$29.06 per hour[d]	$31,821
(b)	Supervisor	15% of operator labor		$4,773.11
(b)	Coordinator	33% of operator labor		$10,500.83
	Maintenance			
(b)	Maintenance labor[c]	0.5 hours/shift	$24.82 per hour[d]	$13,589
(b)	Maintenance materials	1% of purchased equipment costs		$59,880
	Utilities[c][e]			
	Electricity	215 kW	$0.060 per kWh	$112,785
	Water	10,000 gal/day	$0.01 per gal	$36,500
	Total Direct Annual Costs			***$269,849***
	Indirect Annual Costs			
(b)	Overhead	60% Labor and Material Costs		$72,338.30
(b)	General and administrative	2% of TCI		$268,263
(b)	Property taxes	1% of TCI		$134,132
(b)	Insurance	1% of TCI		$134,132
(b)	Capital recovery	0.053 x TCI		$706,629
		Life of the control: 30 years at	3.25% interest	
	Total Indirect Annual Costs			***$1,315,494***
	Total Annual Costs			***$1,585,343***
	Cost Effectiveness ($/ton)			
	Current Emission Rates / Control Efficiency			
	Current FPM_{10} Emission Rate[f]:	174 tpy		
	Post WESP Emission Rates / Control Efficiency			
	Future FPM_{10} Emission Rate[g]:	0.010 gr/dscf @ 8% O_2		
	Avg Flow Rate from Stack Tests[h]:	178,402 dscfm @ 8% O_2		
	Controlled FPM_{10} Emissions[i]:	67 tpy	***Total Annual Costs/Controlled PM_{10} Emissions:***	
	FPM_{10} Removed[j]:	107 tons of PM_{10} removed annually		***$14,813***

(a) The WESP cost shown as "A" is back-calculated based on the control device vendor estimate of $10,000,000 for Total Direct Cost (provided in September 2020). This back-calculation is needed because the vendor estimate does not included indirect costs, which are based on the Total Purchased Equipment Cost, or "B".
(b) Cost information estimated based on the U.S. EPA OAQPS Control Cost Manual, Section 6, Chapter 3, September 1999 except labor hours based on Section 6, Chapter 2.
(c) Based on 8760 operating hours.
(d) Nominal Pacific NW pulp and paper mill rates.
(e) Based on Washington pulp and paper mill boiler WESP electricity and water usage.
(f) Filterable portion of the recovery furnace PM_{10} PSEL. Calculated by applying the average % FPM from stack test data from January 2014 through March 2019 of 60%: FPM = 290 tpy * 60% = 174 tpy
(g) Future emission rate of filterable PM from installing a polishing WESP after the existing dry ESP was estimated by the control device vendor.
(h) The average flow rate as measured during stack test events performed from January 2014 through March 2019. Flow rate was converted from "as measured" to 8% O_2 to align with the future FPM10 emission rate.
(i) Controlled FPM_{10} emissions is calculated from the Future FPM_{10} Emission Rate and the Avg Flow Rate from Stack Tests.
(j) Additional FPM_{10} Removed represents the additional amount of FPM_{10} expected to be captured by installation of a polishing WESP: Current Controlled Emission Rate - Future Controlled Emission Rate

Table A-6
Georgia-Pacific - Wauna
Capital and Annual Costs Associated with WESP for Recovery Furnace - Vendor 2 Estimates

CAPITAL COSTS

	COST ITEM	COST FACTOR	COST ($)
	Direct Costs		
	Purchased Equipment Costs		
(a)	*A* WESP		-
(b)	Instrumentation and controls	0.10 A	-
(b)	Sales Tax	0.03 A	-
(b)	Freight	0.05 A	-
	B Total Purchased Equipment Cost		***$8,000,000***
	Direct Installation Costs		
(b)	Foundations and Supports	0.04 B	$320,000
(b)	Handling and Erection	0.50 B	$4,000,000
(b)	Electrical	0.08 B	$640,000
(b)	Piping	0.01 B	$80,000
(b)	Insulation for Ductwork	0.02 B	$160,000
(b)	Painting	0.02 B	$160,000
	Direct Installation Cost		***$5,360,000***
	Total Direct Costs		***$13,360,000***
	Indirect Costs		
(b)	Engineering	0.20 B	$1,600,000
(b)	Construction and Field Expenses	0.20 B	$1,600,000
(b)	Contractor fees	0.10 B	$800,000
(b)	Start-up	0.01 B	$80,000
(b)	Performance test	0.01 B	$80,000
(b)	Model Study	0.02 B	$160,000
(b)	Contingencies	0.03 B	$240,000
	Total Indirect Costs		***$4,560,000***
	Total Capital Investment (TCI)		***$17,920,000***

ANNUALIZED COSTS

	COST ITEM	COST FACTOR	RATE	COST ($)
	Direct Annual Costs			
	Operating Labor			
(b)	Operator[c]	1 hours/shift	$29.06 per hour[d]	$31,821
(b)	Supervisor	15% of operator labor		$4,773.11
(b)	Coordinator	33% of operator labor		$10,500.83
	Maintenance			
(b)	Maintenance labor[c]	0.5 hours/shift	$24.82 per hour[d]	$13,589
(b)	Maintenance materials	1% of purchased equipment costs		$80,000
	Utilities [c][e]			
	Electricity	215 kW	$0.060 per kWh	$112,785
	Water	10,000 gal/day	$0.01 per gal	$36,500
	Total Direct Annual Costs			***$289,969***
	Indirect Annual Costs			
(b)	Overhead	60% Labor and Material Costs		$84,410.15
(b)	General and administrative	2% of TCI		$358,400
(b)	Property taxes	1% of TCI		$179,200
(b)	Insurance	1% of TCI		$179,200
(b)	Capital recovery	0.053 x TCI		$944,056
	Life of the control:	30 years at	3.25% interest	
	Total Indirect Annual Costs			***$1,745,267***
	Total Annual Costs			***$2,035,235***
	Cost Effectiveness ($/ton)			
	Current Emission Rates / Control Efficiency			
	Current FPM_{10} Emission Rate[f]:	174 tpy		
	Post WESP Emission Rates / Control Efficiency			
	Future FPM_{10} Emission Rate[g]:	0.008 gr/dscf @ 8% O_2		
	Avg Flow Rate from Stack Tests[h]:	178,402 dscfm @ 8% O_2		
	Controlled FPM_{10} Emissions[i]:	54 tpy	***Total Annual Costs/Controlled PM_{10} Emissions:***	
	FPM_{10} Removed[j]:	120 tons of PM_{10} removed annually		***$16,901***

(a) The control device vendor estimate of $8,000,000 (provided in September 2020) is for Total Purchased Equipment Cost, or "B".
(b) Cost information estimated based on the U.S. EPA OAQPS Control Cost Manual, Section 6, Chapter 3, September 1999 except labor hours based on Section 6, Chapter 2.
(c) Based on 8760 operating hours.
(d) Nominal Pacific NW pulp and paper mill rates.
(e) Based on Washington pulp and paper mill boiler WESP electricity and water usage.
(f) Filterable portion of the recovery furnace PM_{10} PSEL. Calculated by applying the average % FPM from stack test data from January 2014 through March 2019 of 60%: FPM = 290 tpy * 60% = 174 tpy
(g) Future emission rate of filterable PM from installing a polishing WESP after the existing dry ESP was estimated by the control device vendor.
(h) The average flow rate as measured during stack test events performed from January 2014 through March 2019. Flow rate was converted from "as measured" to 8% O_2 to align with the future FPM_{10} outlet emission rate.
(i) Controlled FPM_{10} emissions is calculated from the Future FPM_{10} Emission Rate and the Avg Flow Rate from Stack Tests.
(j) Additional FPM_{10} Removed represents the additional amount of FPM_{10} expected to be captured by installation of a polishing WESP: Current Controlled Emission Rate - Future Controlled Emission Rate

Table A-7
Georgia-Pacific - Wauna
Capital and Annual Costs Associated with WESP for Recovery Furnace - Vendor 3 Estimates

CAPITAL COSTS

	COST ITEM	COST FACTOR	COST ($)
	Direct Costs		
	Purchased Equipment Costs		
(a)	*A* WESP		$9,641,734
(b)	Instrumentation and controls	0.10 A	$964,173
(b)	Sales Tax	0.03 A	$289,252
(b)	Freight	0.05 A	$482,087
	B Total Purchased Equipment Cost		***$11,377,246***
	Direct Installation Costs		
(b)	Foundations and Supports	0.04 B	$455,090
(b)	Handling and Erection	0.50 B	$5,688,623
(b)	Electrical	0.08 B	$910,180
(b)	Piping	0.01 B	$113,772
(b)	Insulation for Ductwork	0.02 B	$227,545
(b)	Painting	0.02 B	$227,545
	Direct Installation Cost		***$7,622,755***
	Total Direct Costs		***$19,000,001***
	Indirect Costs		
(b)	Engineering	0.20 B	$2,275,449
(b)	Construction and Field Expenses	0.20 B	$2,275,449
(b)	Contractor fees	0.10 B	$1,137,725
(b)	Start-up	0.01 B	$113,772
(b)	Performance test	0.01 B	$113,772
(b)	Model Study	0.02 B	$227,545
(b)	Contingencies	0.03 B	$341,317
	Total Indirect Costs		***$6,485,030***
	Total Capital Investment (TCI)		***$25,485,031***

ANNUALIZED COSTS

	COST ITEM	COST FACTOR	RATE	COST ($)
	Direct Annual Costs			
	Operating Labor			
(b)	Operator[c]	1 hours/shift	$29.06 per hour[d]	$31,821
(b)	Supervisor	15% of operator labor		$4,773.11
(b)	Coordinator	33% of operator labor		$10,500.83
	Maintenance			
(b)	Maintenance labor[c]	0.5 hours/shift	$24.82 per hour[d]	$13,589
(b)	Maintenance materials	1% of purchased equipment costs		$113,772
	Utilities [c][e]			
	Electricity	215 kW	$0.060 per kWh	$112,785
	Water	10,000 gal/day	$0.01 per gal	$36,500
	Total Direct Annual Costs			***$323,741***
	Indirect Annual Costs			
(b)	Overhead	60% Labor and Material Costs		$104,673.63
(b)	General and administrative	2% of TCI		$509,701
(b)	Property taxes	1% of TCI		$254,850
(b)	Insurance	1% of TCI		$254,850
(b)	Capital recovery	0.053 x TCI		$1,342,595
		Life of the control: 30 years at	3.25% interest	
	Total Indirect Annual Costs			***$2,466,670***
	Total Annual Costs			***$2,790,411***
	Cost Effectiveness ($/ton)			
	Current Emission Rates / Control Efficiency			
	Current FPM_{10} Emission Rate[f]:	174 tpy		
	Post WESP Emission Rates / Control Efficiency			
	Future FPM_{10} Emission Rate [g]:	0.005 gr/dscf @ 8% O_2		
	Avg Flow Rate from Stack Tests [h]:	178,402 dscfm @ 8% O_2		
	Controlled FPM_{10} Emissions [i]:	33 tpy	***Total Annual Costs/Controlled PM_{10} Emissions:***	
	FPM_{10} Removed [j]:	141 tons of PM_{10} removed annually		***$19,859***

(a) The WESP cost shown as "A" is back-calculated based on the control device vendor estimate of $19,000,000 for Total Direct Cost (provided in September 2020). This back-calculation is needed because the vendor estimate does not included indirect costs, which are based on the Total Purchased Equipment Cost, or "B".
(b) Cost information estimated based on the U.S. EPA OAQPS Control Cost Manual, Section 6, Chapter 3, September 1999 except labor hours based on Section 6, Chapter 2.
(c) Based on 8760 operating hours.
(d) Nominal Pacific NW pulp and paper mill rates.
(e) Based on Washington pulp and paper mill boiler WESP electricity and water usage.
(f) Filterable portion of the recovery furnace PM_{10} PSEL. Calculated by applying the average % FPM from stack test data from January 2014 through March 2019 of 60%: FPM = 290 tpy * 60% = 174 tpy
(g) Future emission rate of filterable PM from installing a polishing WESP after the existing dry ESP was estimated by the control device vendor.
(h) The average flow rate as measured during stack test events performed from January 2014 through March 2019. Flow rate was converted from "as measured" to 8% O_2 to align with the future FPM_{10} outlet emission rate.
(i) Controlled FPM_{10} emissions are calculated from the Future FPM_{10} Emission Rate and the Avg Flow Rate from Stack Tests.
(j) Additional FPM_{10} Removed represents the additional amount of FPM_{10} expected to be captured by installation of a polishing WESP: Current Controlled Emission Rate - Future Controlled Emission Rate

ATTACHMENT B
NCASI MEMORANDUM REGARDING FEASIBILITY OF SELECTIVE CATALYTIC REDUCTION ON KRAFT RECOVERY FURNACES

NCASI
IMPACT. SCIENCE. SOLUTIONS.

September 10, 2020

To: Brian Brazil, International Paper
Lisa Scott, Cascade Pacific Pulp
Jeff Sorensen, Georgia-Pacific

From: Vipin Varma, NCASI

Re: Additional perspective on feasibility of Selective Catalytic Reduction (SCR) on kraft recovery furnaces

This Memorandum is in response to Member Company requests that NCASI provide additional information that expands on the discussion, in sections 3.1.6 and 3.1.7 of NCASI Technical Bulletin (TB) No. 1051, regarding the applicability of SCR on kraft recovery furnaces.

Section 3.1 of the above technical bulletin summarizes fundamental research, made available in literature in the past decade, on NOx formation and emissions control in kraft recovery furnaces. Specifically, sections 3.1.6 and 3.1.7 discuss the abstracts and summaries of two papers presented during the 2017 International Recovery Conference held at Halifax, Nova Scotia, Canada.

The first paper was a **theoretical study** for the retrofit of a recovery furnace where an SCR could be utilized to lower NOx from 200 to 100 mg/m^3 (6% O2, dry gas). The paper went on to identify the key challenges in deploying SCR technology as being a) maintaining flue gas temperature at the appropriate level at the SCR reactor inlet, b) potential for higher SO_2 in the flue gas, and c) potential for high particulate concentration after the electrostatic precipitator. The above theoretical study therefore contemplated a retrofit that included a dedicated flue gas bypass, with an ESP, for scenarios where either the flue gas temperature was too low or the dust loading and/or SO_2 was too high for the SCR.

The second paper (section 3.1.7) presented results **from pilot tests** and first experiences with full-scale installation in a kraft recovery furnace. This paper contemplated a tail-end application, as opposed to a high or low-dust loading application, citing the above-identified issues with dust loading and the resulting catalyst poisoning. We are not aware of follow-up studies or long-term performance data from full-scale installations.

The use of SCR on a kraft recovery furnace has not been demonstrated on a full-scale due to the above challenges. The impact of high particulate matter concentrations in the economizer region and fine dust particles on catalyst effectiveness is a major concern. Catalyst poisoning by soluble alkali metals in the gas stream is also a concern. In the case of SCRs installed after the ESP to get around the particulate concern, the additional energy penalty associated with reheating the flue gas is another aspect that makes this infeasible.

Please do not hesitate to contact me at vvarma@ncasi.org or (352) 244 0965 if you have additional questions.

NATIONAL COUNCIL FOR AIR
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Summary- DEQ Cost estimates for Lower-NOx Burner installation at Lime Kilns at GP Wauna and GP Toledo
2/12/2021

Potential Reductions:
DEQ used this information to estimate the potential pollutant reductions from installing Lower-NOx burners (LNB):
At GP Toledo, the current NOx emissions rate for the lime kilns is based on a 2013 source test which measured 271 ppmvd at 5.2% O2, which converts to 188 ppmvd at 10% O2. An LNB vendor quote prepared for GP Toledo listed 130 ppmvd at 10% O2 as "typically achievable".
At GP Wauna, the current NOx emissions factor for the lime kiln is 1.69 lb/ton CaO (from NCASI TB1020). Assuming it was running at maximum capacity, that emissions factor corresponds to 0.312 lb/MMBtu.
Based on a review of the EPA RACT/BACT/LAER clearinghouse, 100 ppm or ~0.15 lb/MMBtu appears to be achievable.

Costs:
GP did not provide a cost estimate for installation of LNB on lime kilns at the Wauna and Toledo mills.
However, DEQ received cost estimates from the Northwest Pulp and Paper Assocation and GP for LNB installation on other units at these facilities, using 3 different methodologies.
DEQ applied those 3 methodologies to the lime kilns, then took an average of the 3 to generate a cost estimate for each unit.

		Estimated $/ton of NOx reduced			
Facility	Emissions Unit	Formula 1 (from NWPPA 4FAs cost estimates for boilers)	Formula 2 (from GP Wauna 4FA for paper machines)	Formula 3 (from 9/14/2020 GP Toledo Response letter)	Average of 3 formulas
GP Toledo	EU-1 Lime Kiln	$10,184	$4,068	$8,979	**$7,744**
	EU-2 Lime Kiln	$10,184	$4,068	$8,979	**$7,744**
	EU-3 Lime Kiln	$10,184	$4,068	$8,979	**$7,744**
GP Wauna	Lime Kiln	$6,125	$3,099	$6,841	**$5,355**

								As submitted				Adjusted													
	Facility	Unit	estimate source	capacity (MMBTU/hr)	LNB Cost	Total Capital Cost	Annual Costs (all except capital recovery)	Interest Rate	Lifetime of Control Device (years)	Capital Recovery Factor	Total Annual Costs	Interest Rate	Lifetime of Control Device (years)	Capital Recovery Factor	Total Annual Costs	current EF	current actual ER	target EF	Emissions Rate Units	control efficiency (%)	PSEL (tons/year)	tons/year reduced at PSEL	$/ton at PSEL (as submitted)	$/ton at PSEL (adjusted)	
Cost Estimates Submitted	GP Toledo	#4 Hog Boiler (EU-11)	4FA	296.6	$2,799,508	$4,492,650	$560,297	4.75%	10	12.794%	$1,135,073	3.25%	30	5.268%	$796,978	107.5		50	ppm	53%	218.4	116.8	$9,717	$6,822	
			9/14/2020 letter	296.6	$5,925,900	$8,058,000	$850,994					3.25%	30	5.268%	$1,275,503	107.5		85	ppm	21%	218.4	45.7		$27,903	
		#1 Power Boiler (EU-13)	4FA	187.5	$2,126,081	$3,411,934	$402,234	4.75%	10	12.794%	$838,747	3.25%	30	5.268%	$581,981	234		50	ppm	79%	223.7	175.9	$4,768	$3,309	
			9/14/2020 letter	187.5	$5,925,900	$8,058,000	$809,583					3.25%	30	5.268%	$1,234,092	234		35	ppm	85%	223.7	190.2	$0	$6,487	
		#3 Power Boiler (EU-18)	4FA	156.3	$1,906,138	$3,058,970	$353,344	4.75%	10	12.794%	$744,700	3.25%	30	5.268%	$514,496	93.8		50	ppm	47%	107.6	50.2	$14,822	$10,240	
			9/14/2020 letter	156.3	$4,935,000	$6,711,600	$665,218					3.25%	30	5.268%	$1,018,797	93.8		23	ppm	75%	107.6	81.2	$0	$12,544	
	GP Wauna	Power Boiler (EU-33)	4FA	560	$4,099,131	$6,578,285	$897,930	4.75%	10	12.794%	$1,739,536	3.25%	30	5.268%	$1,244,486					64%	591.2	378.4	$4,597	$3,289	
	GP Wauna	Paper Machine 1	4FA	34	$564,732	$847,098	$40,237	4.75%	20	7.855%	$106,777	3.25%	30	5.268%	$84,864	13.6		3.87	tons/year	72%	13.6	9.7	$10,974	$8,722	
	GP Wauna	Paper Machine 2	4FA	34	$564,732	$847,098	$40,237	4.75%	20	7.855%	$106,777	3.25%	30	5.268%	$84,864	13.6		3.87	tons/year	72%	13.6	9.7	$10,974	$8,722	
	GP Wauna	Paper Machine 5	4FA	75	$1,245,732	$1,868,598	$88,758	4.75%	20	7.855%	$235,538	3.25%	30	5.268%	$187,199	29.99		8.54	tons/year	72%	29.99	21.5	$10,981	$8,727	
	GP Wauna	Paper Machine 6	4FA	196	$3,255,512	$4,883,268	$231,955	4.75%	20	7.855%	$615,538	3.25%	30	5.268%	$489,214	104.28		22.32	tons/year	79%	104.28	82.0	$7,510	$5,969	
	GP Wauna	Paper Machine 7	4FA	202	$3,355,171	$5,032,756	$239,056	4.75%	20	7.855%	$634,381	3.25%	30	5.268%	$504,190	108.53		23	tons/year	79%	108.53	85.5	$7,417	$5,895	
	Cascade Pacific Pulp	Power Boiler #1 PB1EU	4FA	236	$2,440,766	$3,916,942	$474,565	4.75%	10	12.794%	$975,687	3.25%	30	5.268%	$680,916	280		100	ppm?	64%	132.5	85.2	$11,455	$7,994	
	Cascade Pacific Pulp	Power Boiler #2 PB2EU	4FA	236	$2,440,766	$3,916,942	$474,565	4.75%	10	12.794%	$975,687	3.25%	30	5.268%	$680,916	280		100	ppm?	64%	75.1	48.3	$20,210	$14,104	
	International Paper Springfield	Power Boiler EU-150A	4FA	544	$4,028,453	$6,464,862	$810,081	4.75%	10	12.794%	$1,637,176	3.25%	30	5.268%	$1,150,661					64%	873.7	559.2	$2,928	$2,058	
DEQ cost estimates	GP Toledo	EU-1 Lime Kiln	Formula 1	36	$789,879	$1,267,598	$158,169					3.25%	30	5.268%	$224,948		188	130	ppmvd @ 10% O2	31%	71.6	22.1		$10,184	$7,744
			Formula 2	36	$597,951	$896,927	$42,604					3.25%	30	5.268%	$89,856		188	130	ppmvd @ 10% O2	31%	71.6	22.1		$4,068	
			Formula 3	36	$943,668	$1,283,250	$130,744					3.25%	30	5.268%	$198,348		188	130	ppmvd @ 10% O2	31%	71.6	22.1		$8,979	
		EU-2 Lime Kiln	Formula 1	36	$789,879	$1,267,598	$158,169					3.25%	30	5.268%	$224,948		188	130	ppmvd @ 10% O2	31%	71.6	22.1		$10,184	$7,744
			Formula 2	36	$597,951	$896,927	$42,604					3.25%	30	5.268%	$89,856		188	130	ppmvd @ 10% O2	31%	71.6	22.1		$4,068	
			Formula 3	36	$943,668	$1,283,250	$130,744					3.25%	30	5.268%	$198,348		188	130	ppmvd @ 10% O2	31%	71.6	22.1		$8,979	
		EU-3 Lime Kiln	Formula 1	36	$789,879	$1,267,598	$158,169					3.25%	30	5.268%	$224,948		188	130	ppmvd @ 10% O2	31%	71.6	22.1		$10,184	$7,744
			Formula 2	36	$597,951	$896,927	$42,604					3.25%	30	5.268%	$89,856		188	130	ppmvd @ 10% O2	31%	71.6	22.1		$4,068	
			Formula 3	36	$943,668	$1,283,250	$130,744					3.25%	30	5.268%	$198,348		188	130	ppmvd @ 10% O2	31%	71.6	22.1		$8,979	
	GP Wauna	Lime Kiln	Formula 1	65	$1,125,970	$1,806,957	$225,469					3.25%	30	5.268%	$320,663	1.69		0.694	lb NOx / ton CaO	59%	88.8	52.3		$6,125	$5,355
			Formula 2	65	$1,079,634	$1,619,451	$76,924					3.25%	30	5.268%	$162,239	1.69		0.694	lb NOx / ton CaO	59%	88.8	52.3		$3,099	
			Formula 3	65	$1,703,844	$2,316,980	$236,066					3.25%	30	5.268%	$358,128	1.69		0.694	lb NOx / ton CaO	59%	88.8	52.3		$6,841	

approx conversion factors

	LNB cost per MMBTU/hr	Total capital cost / LNB cost	Annual cost / capital cost	
Formula 1	$8,952	1.60	0.12	from NWPPA 4FAs cost estimates for boilers
Formula 2	$16,610	1.50	0.0475	from GP Wauna 4FA for paper machines
Formula 3	$26,213	1.36	0.10	from 9/14/2020 GP Toledo Response letter

NOx concentration calculations for GP Wauna

PSELs for the Wauna lime kiln:

2010 PSEL:		2019 PSEL:		Achievable emissions rate, per Cascade Pacific Pulp Halsey	
358,227	ADTP/year	105,120	tons CaO / year	105,120	tons CaO / year
1	lb NOx / lb ADTP, NCA	1.69	lb NOx / ton CaO, NCASI TB1020	0.694	lb NOx / ton CaO, emission factor in 2020 permit
358,227	lb NOx / year	177,653	lb NOx / year	72,953	lb NOx / year
179.11	tons NOx / year	88.8	tons NOx / year	36.48	tons NOx / year

Emissions factors from Cascade Pacific Pulp Halsey permit issued in 2020:
https://www.deq.state.or.us/AQPermitsonline/22-3501-TV-01_P_2020.PDF

158.b. The emission factors for calculating pollutant emissions are as follows:

EU ID	Process/Device	Pollutant	Annual EF	Units
RFEU	All fuels	CO	See Condition 158.h	Tons
	All fuels	SO_2	See Condition 158.f	Tons
	All fuels	TRS	See Condition 158.g	Tons
	All fuels	H_2SO_4	0.02	lb/ pound SO_2
(461-128)	BLS & NCG combustion	NO_x	0.90	lb/ton BLS
	Oil combustion	NO_x	47	lb/Mgal oil
	Natural Gas Combustion	NO_x	280	lb/MM ft^3 nat. gas
	BLS & NCG combustion	PM/PM_{10}	0.416	lb/ton BLS
	BLS & NCG combustion	$PM_{2.5}$	0.374	lb/ton BLS
	Oil combustion	PM/PM_{10}	0.21/0.15	lb/Mgal oil
	Oil combustion	$PM_{2.5}$	0.12	lb/Mgal oil
	Natural Gas Combustion	PM/PM_{10}/ $PM_{2.5}$	2.5	lb/MM ft^3 nat. gas
	BLS & NCG combustion	VOC	0.0238	lb/ton BLS
	Oil combustion	VOC	0.76	lb/Mgal oil
	Natural Gas Combustion	VOC	5.5	lb/MM ft^3 nat. gas
LKEU	All fuels	CO	1.05	lb/ton CaO
(481-130)	All fuels	NO_x	0.694	lb/ton CaO
	All fuels	PM	0.698	lb/ton CaO
	All fuels	PM_{10}	0.663	lb/ton CaO
	All fuels	$PM_{2.5}$	0.650	lb/ton CaO
	Natural Gas Combustion	SO_2	0.013	lb/ton CaO
	Oil Combustion	SO_2	1.44	lb/Mgal
	NCG Combustion	SO_2	15.6	lb/hour
	All fuels	TRS	See Condition 158.e	tons
	All fuels	VOC	0.038	lb/ ton CaO
	Oil combustion	VOC	0.76	lb/Mgal oil
	Natural Gas Combustion	VOC	5.5	lb/MM ft^3 nat. gas
	NCG Combustion	H_2SO_4	91.8	lbs/ton SO_2
	Oil combustion	H_2SO_4	0.021	lb/ton CaO

Cascade Pacific Pulp Halsey, 2020 permit

Data used by GP Wauna, GP Toledo, Cascade Pacific Pulp and International Paper Springfield in their LNB cost estimates for boilers

Apparently this is from a 2001 quote for LNB on a
150 MMBTU/hr boiler.

Labor	Materials	Subcontracts	Equipment	total
$ 113,019	$ 102,100	$ 126,100	$ 865,800	$ 1,207,019

2001 CEPCI	394.3
2019 CEPCI	607.5

$$Capital\ Cost\ in\ 2001\ dollars = Quoted\ cost\ for\ 150\frac{MMBTU}{hr} boiler\ *\ (\frac{boiler\ size}{150\ MMBTU/hr})^{0.6}$$

$$Capital\ Cost\ in\ 2019\ dollars = Capital\ Cost\ in\ 2019\ dollars * (\frac{2019\ CEPCI}{2001\ CEPCI})$$

$340,500 "a recently obtained quote with the cost of installation of low-NOx burners on a tissue paper machine at another GP facility" as listed in GP Wauna's 4 Factor Analysis dated June 2020
20.5 MMBTU/hr

2.3.2. Low-NO_X Burners

A recently obtained vendor quote with the cost for installation of low-NO_X burners on a tissue paper machine at another GP facility was used as the basis for determining the total capital investment for burner replacements on each paper machine. The vendor data as well as the U.S. EPA's Control Cost Manual were used to estimate the direct and indirect operating costs. In addition, U.S. EPA's methodology was followed to determine the capital recovery cost and the annualized costs. The amount of pollutant removed by each low-NO_X burner was based on the vendor quote of outlet emissions of 0.026 lb/MMBtu for the new burners. As previously stated, while the burners themselves may achieve an outlet emission rate of 0.026 lb/MMBtu, it is important to note that NOx emissions in the burner stacks

Table A-16. Capital & Operating Cost Evaluation for a Low NO_X Burner Retrofit for GP Wauna Paper Machine 1

Cost Category	Value	Notes [1]
Total Capital Investment (TCI) =	$564,732	Based on previous quote of $340,500 for a 20.5 MMBtu/hr burner
Burner Emission Guarantee =	0.026	lb NO_X/MMBtu
Total Burner Heat Rating (MMBtu/hr) =	34	Q_B
Engineering Factor =	1.5	Accounts for costs of additional activities not included in vendor quote (ducting, engineering, utilities, etc.).
Total Capital Investment (TCI)	**$847,098**	Prorated from previous vendor quote × Engineering Factor

340500		16609.76
20.5	34	564731.7

Summary

Facility	Emissions Unit	Estimated $/ton of NOx reduced: Formula 1 (from NWPPA 4FAs cost estimates for boilers)	Formula 2 (from GP Wauna 4FA for paper machines)	Formula 3 (from 9/14/2020 GP Toledo Response letter)	Average of 3 formulas
EVRAZ	Reheat Furnace	$4,437	$4,910	$10,839	**$6,728**
GP Toledo	EU-1 Lime Kiln	$10,184	$4,068	$8,979	**$7,744**
	EU-2 Lime Kiln	$10,184	$4,068	$8,979	**$7,744**
	EU-3 Lime Kiln	$10,184	$4,068	$8,979	**$7,744**
GP Wauna	Lime Kiln	$6,952	$3,518	$7,765	**$6,078**

	Facility	Unit	estimate source	capacity (MMBTU /hr)	LNB Cost	Total Capital Cost	Annual Costs (all except capital recovery)	Capital Cost per MMBtu/hr	Annual Costs (all except capital recovery) per MMBtu/hr	As submitted: Interest Rate	As submitted: Lifetime of Control Device (years)	As submitted: Capital Recovery Factor	As submitted: Total Annual Costs	Adjusted: Interest Rate	Adjusted: Lifetime of Control Device (years)	Adjusted: Capital Recovery Factor	Adjusted: Total Annual Costs	current EF	current actual ER	target EF	Emissions Rate Units	control efficiency (%)	PSEL (tons/ year)	tons/year reduced at PSEL	$/ton at PSEL (as submitted)	$/ton at PSEL (adjusted)	
Cost Estimates Submitted	GP Toledo	#4 Hog Boiler (EU-11)	4FA	296.6	$2,799,508	$4,492,650	$560,297	$15,147.17	$1,889.07	4.75%	10	12.794%	$1,135,073	3.25%	30	5.268%	$796,978	107.5		50	ppm	53%	218.4	116.8	$9,717	$6,822	
			9/14/2020 letter	296.6	$5,925,900	$8,058,000	$850,994	$27,167.90	$2,869.16					3.25%	30	5.268%	$1,275,503	107.5		85	ppm	21%	218.4	45.7		$27,903	
		#1 Power Boiler (EU-13)	4FA	187.5	$2,126,081	$3,411,934	$402,234	$18,196.98	$2,145.25	4.75%	10	12.794%	$838,747	3.25%	30	5.268%	$581,981	234		50	ppm	79%	223.7	175.9	$4,768	$3,309	
			9/14/2020 letter	187.5	$5,925,900	$8,058,000	$809,583	$42,976.00	$4,317.78					3.25%	30	5.268%	$1,234,092	234		35	ppm	85%	223.7	190.2	$0	$6,487	
		#3 Power Boiler (EU-18)	4FA	156.3	$1,906,138	$3,058,970	$353,344	$19,571.15	$2,260.68	4.75%	10	12.794%	$744,700	3.25%	30	5.268%	$514,496	93.8		50	ppm	47%	107.6	50.2	$14,822	$10,240	
			9/14/2020 letter	156.3	$4,935,000	$6,711,600	$665,218	$42,940.50	$4,256.03					3.25%	30	5.268%	$1,018,797	93.8		23	ppm	75%	107.6	81.2	$0	$12,544	
	GP Wauna	Power Boiler (EU-33)	4FA	560	$4,099,131	$6,578,285	$897,930	$11,746.94	$1,603.45	4.75%	10	12.794%	$1,739,536	3.25%	30	5.268%	$1,244,486					64%	591.2	378.4	$4,597	$3,289	
	GP Wauna	Paper Machine 1	4FA	34	$564,732	$847,098	$40,237	$24,914.63	$1,183.45	4.75%	20	7.855%	$106,777	3.25%	30	5.268%	$84,864	13.6		3.87	tons/year	72%	13.6	9.7	$10,974	$8,722	
	GP Wauna	Paper Machine 2	4FA	34	$564,732	$847,098	$40,237	$24,914.63	$1,183.45	4.75%	20	7.855%	$106,777	3.25%	30	5.268%	$84,864	13.6		3.87	tons/year	72%	13.6	9.7	$10,974	$8,722	
	GP Wauna	Paper Machine 5	4FA	75	$1,245,732	$1,868,598	$88,758	$24,914.63	$1,183.45	4.75%	20	7.855%	$235,538	3.25%	30	5.268%	$187,199	29.99		8.54	tons/year	72%	29.99	21.5	$10,981	$8,727	
	GP Wauna	Paper Machine 6	4FA	196	$3,255,512	$4,883,268	$231,955	$24,914.63	$1,183.45	4.75%	20	7.855%	$615,538	3.25%	30	5.268%	$489,214	104.28		22.32	tons/year	79%	104.28	82.0	$7,510	$5,969	
	GP Wauna	Paper Machine 7	4FA	202	$3,355,171	$5,032,756	$239,056	$24,914.63	$1,183.45	4.75%	20	7.855%	$634,381	3.25%	30	5.268%	$504,190	108.53		23	tons/year	79%	108.53	85.5	$7,417	$5,895	
	Cascade Pacific Pulp	Power Boiler #1 PB1EU	4FA	236	$2,440,766	$3,916,942	$474,565	$16,597.21	$2,010.87	4.75%	10	12.794%	$975,687	3.25%	30	5.268%	$680,916	280		100	ppm?	64%	132.5	85.2	$11,455	$7,994	
	Cascade Pacific Pulp	Power Boiler #2 PB2EU	4FA	236	$2,440,766	$3,916,942	$474,565	$16,597.21	$2,010.87	4.75%	10	12.794%	$975,687	3.25%	30	5.268%	$680,916	280		100	ppm?	64%	75.1	48.3	$20,210	$14,104	
	International Paper Springfield	Power Boiler EU-150A	4FA	544	$4,028,453	$6,464,862	$810,081	$11,883.94	$1,489.12	4.75%	10	12.794%	$1,637,176	3.25%	30	5.268%	$1,150,661					64%	873.7	559.2	$2,928	$2,058	
DEQ cost estimates	EVRAZ	Reheat Furnace	Formula 1	460	$3,642,786	$5,845,943	$729,448	$12,708.57	$1,585.76					3.25%	30	5.268%	$1,037,422	0.196		0.08	lb/MMBTU	59%	395.1	233.8346939		$4,437	
			Formula 2	460	$7,640,488	$11,460,732	$544,385	$24,914.63	$1,183.45					3.25%	30	5.268%	$1,148,156	0.196		0.08	lb/MMBTU	59%	395.1	233.8346939		$4,910	$6,728
			Formula 3	460	$12,057,976	$16,397,089	$1,670,621	$35,645.85	$3,631.78					3.25%	30	5.268%	$2,534,448	0.196		0.08	lb/MMBTU	59%	395.1	233.8346939		$10,839	
	GP Toledo	EU-1 Lime Kiln	Formula 1	36	$789,879	$1,267,598	$158,169	$35,211.04	$4,393.58					3.25%	30	5.268%	$224,948		188	130	ppmvd @ 10% O2	31%	71.6	22.0893617		$10,184	
			Formula 2	36	$597,951	$896,927	$42,604	$24,914.63	$1,183.45					3.25%	30	5.268%	$89,856		188	130	ppmvd @ 10% O2	31%	71.6	22.0893617		$4,068	$7,744
			Formula 3	36	$943,668	$1,283,250	$130,744	$35,645.85	$3,631.78					3.25%	30	5.268%	$198,348		188	130	ppmvd @ 10% O2	31%	71.6	22.0893617		$8,979	
		EU-2 Lime Kiln	Formula 1	36	$789,879	$1,267,598	$158,169	$35,211.04	$4,393.58					3.25%	30	5.268%	$224,948		188	130	ppmvd @ 10% O2	31%	71.6	22.0893617		$10,184	
			Formula 2	36	$597,951	$896,927	$42,604	$24,914.63	$1,183.45					3.25%	30	5.268%	$89,856		188	130	ppmvd @ 10% O2	31%	71.6	22.0893617		$4,068	$7,744
			Formula 3	36	$943,668	$1,283,250	$130,744	$35,645.85	$3,631.78					3.25%	30	5.268%	$198,348		188	130	ppmvd @ 10% O2	31%	71.6	22.0893617		$8,979	
		EU-3 Lime Kiln	Formula 1	36	$789,879	$1,267,598	$158,169	$35,211.04	$4,393.58					3.25%	30	5.268%	$224,948		188	130	ppmvd @ 10% O2	31%	71.6	22.0893617		$10,184	
			Formula 2	36	$597,951	$896,927	$42,604	$24,914.63	$1,183.45					3.25%	30	5.268%	$89,856		188	130	ppmvd @ 10% O2	31%	71.6	22.0893617		$4,068	$7,744
			Formula 3	36	$943,668	$1,283,250	$130,744	$35,645.85	$3,631.78					3.25%	30	5.268%	$198,348		188	130	ppmvd @ 10% O2	31%	71.6	22.0893617		$8,979	
	GP Wauna	Lime Kiln	Formula 1	65	$1,125,970	$1,806,957	$225,469	$27,799.34	$3,468.76					3.25%	30	5.268%	$320,663	0.312		0.15	lb/MMBTU	52%	88.83	46.12326923		$6,952	
			Formula 2	65	$1,079,634	$1,619,451	$76,924	$24,914.63	$1,183.45					3.25%	30	5.268%	$162,239	0.312		0.15	lb/MMBTU	52%	88.83	46.12326923		$3,518	$6,078
			Formula 3	65	$1,703,844	$2,316,980	$236,066	$35,645.85	$3,631.78					3.25%	30	5.268%	$358,128	0.312		0.15	lb/MMBTU	52%	88.83	46.12326923		$7,765	
	Cascade Pacific Pulp	Lime Kiln	Formula 1	100	$1,458,072	$2,339,914	$291,971	$23,399.14	$2,919.71					3.25%	30	5.268%	$415,241	112	22.8	22.8	ppm @ 10% O2	0%		0		#DIV/0!	
			Formula 2	100	$1,660,976	$2,491,463	$118,345	$24,914.63	$1,183.45					3.25%	30	5.268%	$249,599	112	22.8	22.8	ppm @ 10% O2	0%		0		#DIV/0!	#DIV/0!
			Formula 3	100	$2,621,299	$3,564,585	$363,178	$35,645.85	$3,631.78					3.25%	30	5.268%	$550,967	112	22.8	22.8	ppm @ 10% O2	0%		0		#DIV/0!	
	International Paper Springfield	Lime Kiln #2	Formula 1	36	$789,879	$1,267,598	$158,169	$35,211.04	$4,393.58					3.25%	30	5.268%	$224,948	0.24	0.11		lb/MMBTU	30%	17.7	5.31		$42,363	
			Formula 2	36	$597,951	$896,927	$42,604	$24,914.63	$1,183.45					3.25%	30	5.268%	$89,856	0.24	0.11		lb/MMBTU	30%	17.7	5.31		$16,922	$32,213
			Formula 3	36	$943,668	$1,283,250	$130,744	$35,645.85	$3,631.78					3.25%	30	5.268%	$198,348	0.24	0.11		lb/MMBTU	30%	17.7	5.31		$37,354	
		Lime Kiln #3	Formula 1	100	$1,458,072	$2,339,914	$291,971	$23,399.14	$2,919.71					3.25%	30	5.268%	$415,241	0.24	0.11		lb/MMBTU	30%	45.9	13.77		$30,156	
			Formula 2	100	$1,660,976	$2,491,463	$118,345	$24,914.63	$1,183.45					3.25%	30	5.268%	$249,599	0.24	0.11		lb/MMBTU	30%	45.9	13.77		$18,126	$29,431
			Formula 3	100	$2,621,299	$3,564,585	$363,178	$35,645.85	$3,631.78					3.25%	30	5.268%	$550,967	0.24	0.11		lb/MMBTU	30%	45.9	13.77		$40,012	
	Willamette Falls Paper	Boiler 3	Formula 1	205	$2,243,010	$3,599,583	$449,150	$17,558.94	$2,190.98					3.25%	30	5.268%	$638,783	0.315	0.309	0.070	lb/MMBTU	77%	163.39	126.5094628		$5,049	
			Formula 2	205	$3,405,000	$5,107,500	$242,606	$24,914.63	$1,183.45					3.25%	30	5.268%	$511,678	0.315	0.309	0.070	lb/MMBTU	77%	163.39	126.5094628		$4,045	$6,007
			Formula 3	205	$5,373,663	$7,307,399	$744,516	$35,645.85	$3,631.78					3.25%	30	5.268%	$1,129,482	0.315	0.309	0.070	lb/MMBTU	77%	163.39	126.5094628		$8,928	
							min	$11,746.94	$1,183.45																		
							max	$42,976.00	$4,393.58																		

approx conversion factors

	LNB cost per MMBTU/hr	Total capital cost / LNB cost	Annual cost / capital cost	
Formula 1	$8,952*	1.60	0.12	from NWPPA 4FAs cost estimates for boilers
Formula 2	$16,610	1.50	0.0475	from GP Wauna 4FA for paper machines
Formula 3	$26,213	1.36	0.10	from 9/14/2020 GP Toledo Response letter

* see formula on quotes worksheet.

LNB calculations for EVRAZ:

RBLC ID	NOx Rate	Unit	Note
MI-0417	0.07	lb/mmscf	I think it's supposed to be 0.07 lb/mmbtu based on 260.7 MMBtu/hr furnace with 18.3 lb/hr limit
MI-0404	0.07	lb/mmscf	I think it's supposed to be 0.07 lb/mmbtu based on 260.7 MMBtu/hr furnace with 18.3 lb/hr limit
NJ-0087	0.1	lb/mmbtu	
	0.08	lb/mmbtu	Average BACT LNB rate for LNBs
	0.196	lb/mmbtu	Current Emission Rate
	59.18%	% Reduction	

Data used by GP Wauna, GP Toledo, Cascade Pacific Pulp and International Paper Springfield in their LNB cost estimates for boilers

Apparently this is from a 2001 quote for LNB on a
150 MMBTU/hr boiler.

Labor	Materials	Subcontracts	Equipment	total
$ 113,019	$ 102,100	$ 126,100	$ 865,800	$ 1,207,019

2001 CEPCI	394.3
2019 CEPCI	607.5

$$Capital\ Cost\ in\ 2001\ dollars = Quoted\ cost\ for\ 150\frac{MMBTU}{hr}boiler\ *\ \left(\frac{boiler\ size}{150\ MMBTU/hr}\right)^{0.6}$$

$$Capital\ Cost\ in\ 2019\ dollars = Capital\ Cost\ in\ 2019\ dollars * \left(\frac{2019\ CEPCI}{2001\ CEPCI}\right)$$

$340,500 "a recently obtained quote with the cost of installation of low-NOx burners on a tissue paper machine at another GP facility" as listed in GP Wauna's 4 Factor Analysis dated June 2020
20.5 MMBTU/hr

2.3.2. Low-NO_X Burners

A recently obtained vendor quote with the cost for installation of low-NO_X burners on a tissue paper machine at another GP facility was used as the basis for determining the total capital investment for burner replacements on each paper machine. The vendor data as well as the U.S. EPA's Control Cost Manual were used to estimate the direct and indirect operating costs. In addition, U.S. EPA's methodology was followed to determine the capital recovery cost and the annualized costs. The amount of pollutant removed by each low-NO_X burner was based on the vendor quote of outlet emissions of 0.026 lb/MMBtu for the new burners. As previously stated, while the burners themselves may achieve an outlet emission rate of 0.026 lb/MMBtu, it is important to note that NOx emissions in the burner stacks

Table A-16. Capital & Operating Cost Evaluation for a Low NO_X Burner Retrofit for GP Wauna Paper Machine 1

Cost Category	Value	Notes [1]
Total Capital Investment (TCI) =	$564,732	Based on previous quote of $340,500 for a 20.5 MMBtu/hr burner
Burner Emission Guarantee =	0.026	lb NO_X/MMBtu
Total Burner Heat Rating (MMBtu/hr) =	34	Q_B
Engineering Factor =	1.5	Accounts for costs of additional activities not included in vendor quote (ducting, engineering, utilities, etc.).
Total Capital Investment (TCI)	**$847,098**	Prorated from previous vendor quote × Engineering Factor

340500		16609.76
20.5	34	564731.7

Boiler 3	2012 Source Test	If retrofit with 50 ppm VPSSS Burner	If retrofit with 25 ppm VPSSS-SGB Burner
Date	4/4/12	--	--
Stack area, ft^2	33.183	33.183	33.183
Reference temperature, °F	68.00	68.00	68.00
Stack temperature, °F	314.0	314.0	314.0
Exhaust Moisture %	16.0	16.0	16.0
Gas Usage Mscfh	178	178	178
Steaming Rate (1000lb/hr)	152	152	152
Stack flow rate dscfm	39,600	39,600	39,600
O_2, % volume dry	4.90	4.90	4.90
CO_2, % volume dry	9.10	9.10	9.10
NO_X, ppm volume dry	198.0	44.7	22.3
NO_X, ppm dry @ 3% O_2	221.5	50.0	25.0
NO_X, lb/hr as NO_2	56.2	12.7	6.3
NO_X, lb/day (24 hours) as NO_2	1348.2	304.3	152.2
NO_X, lb/MMscf	315.6	71.2	35.6
NOx, lb/mmbtu	0.309	0.070	0.035
		77%	89%

Low NOx Burner/FGR Retrofit - GP Wauna PM1 and PM2 Yankee Burner

Burner Rating 31

CAPITAL COSTS				
	COST ITEM	FACTOR		COST ($)
Costs to Purchase and Install Equipment				
(a)	LNB and FGR Retrofit cost. Cost = 340,500 * (Rating/20.5)^0.6			***$436,397***
(b)	Instrumentation	0.10 × A		***$43,640***
(b)	Sales Tax	0.00 × A		***$0***
(b)	Freight	0.05 × A		***$21,820***
	Total Purchased Equipment Cost, B =	B		***$501,857***
	Total Direct Cost:		***TDC***	***$501,857***
Indirect Capital Costs				
(c)	Engineering	0.10 × B		***$50,186***
(c)	Contingencies	0.20 × B		***$100,371***
(c)	General Facilities	0.05 × B		***$25,093***
(b)	Testing	0.01 × B		***$5,019***
	Total Indirect Cost:		***TIC***	***$180,668***
	Total Capital Investment:		***TCI***	***$682,525***

ANNUALIZED COSTS					
	COST ITEM	COST FACTOR		UNIT COST	COST ($)
Annual Operating Costs - Direct Annual Costs					
(d)	Maintenance Costs	2.75%	of TCI		***$18,769***
Utilities					
(a)	Electricity	36	kW	$0.060 per kWh	***$19,118***
	Total Direct Annual Costs:			***DAC***	***$37,887***
Annual Operating Costs - Indirect Annual Costs					
(b)	Overhead	60%	of sum of operating & maintenance costs		***$11,262***
(b)	Administrative Charges	2%	of TCI		***$13,651***
(b)	Property Taxes	1%	of TCI		***$6,825***
(b)	Insurance	1%	of TCI		***$6,825***
	Total Indirect Annual Costs:			***IDAC***	***$38,563***
	Total Annual Costs:			***TAC***	***$76,450***
Cost Effectiveness					
(b)	Expected lifetime of equipment, years	30			
(b)	Interest rate, %/yr	3.25%			
(b)	Capital recovery factor	0.053			
(b)	Total Capital Investment Cost	$682,525			
	Annualized Capital Investment Cost:				***$35,957***
	Total Annualized Cost:				***$112,407***
(e)	NO_X Reduction	72%	Based on new burner rating of 0.026 lb/MMBtu		
(f)	Pre-retrofit NO_X	12.1	tons NO_X/yr		
	Post-retrofit NO_X using LNB	3.45	tons NO_X/yr		
	NO_X Removed	8.7	tons NO_X/yr		
	Annual Cost/Ton Removed:				***$12,989***

(a) Cost information obtained from Section 4.4 in document titled "Emission Control Study - Technology Cost Estimates" by BE&K Engineering for AF&PA, September 2001. The labor and equipment cost of installing LNB, FGR, new fan on a gas-fired boiler was scaled based on boiler capacity. The cost was adjusted from 2001 dollars to 2019 dollars using the Chemical Engineering Plant Cost Index (CEPCI). Electricity requirement ratioed based on boiler size.

(b) Cost information estimated using the U.S. EPA Air Pollution Control Cost Manual (6th edition) published in January 2002 by the OAQPS (Section 3.2, Chapter 2, "Thermal and Catalytic Incinerators"). The website for the manual is available at http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf.

(c) Indirect capital cost factors (i.e., engineering and office fees, contingencies, and general facilities) based on guidance from "Methods for Evaluating the Costs of Utility NO_X Control Technologies," Loan K. Tran and H. Christopher Frey, June 1996.

(d) Maintenance costs were estimated based on the U.S. EPA OAQPS Alternative Control Techniques Document - NO_X Emissions from Process Heaters (Revised), Document No. EPA-453/R-93-034 (September 1993).

(e) Control efficiency based on comparison of uncontrolled and controlled AP-42 factors.

(f) PSEL

Low NOx Burner/FGR Retrofit - GP Wauna PM1 and PM2 Yankee Burner
Using Methodology in Pages 300-304 of GP Wauna FFA

Burner Rating: 31

CAPITAL COSTS					
	COST ITEM	FACTOR			COST ($)
Costs to Purchase and Install Equipment					
(a)	LNB and FGR Retrofit cost. Cost = 340,500 * (Rating/20.5)^0.6				*$436,397*
(b)	Instrumentation	0.10	× A		*$43,640*
(b)	Sales Tax	0.00	× A		*$0*
(b)	Freight	0.05	× A		*$21,820*
	Total Purchased Equipment Cost, B =		B		*$501,857*
	Total Direct Cost:			*TDC*	*$501,857*
Indirect Capital Costs					
(c)	Engineering	0.10	× B		
(c)	Contingencies	0.20	× B		
(c)	General Facilities	0.05	× B		
(b)	Testing	0.01	× B		
	Total Indirect Cost:	0.5	x TDC	*TIC*	*$250,928*
	Total Capital Investment:			*TCI*	*$752,785*

ANNUALIZED COSTS						
	COST ITEM	COST FACTOR		UNIT COST		COST ($)
Annual Operating Costs - Direct Annual Costs						
(d)	Maintenance Costs	2.75%	of TCI			*$20,702*
Utilities						
(a)	Electricity	36	kW		per kWh	*$0*
	Total Direct Annual Costs:				*DAC*	*$20,702*
Annual Operating Costs - Indirect Annual Costs						
(b)	Overhead		of sum of operating & maintenance costs			*$0*
(b)	Administrative Charges	2%	of TCI			*$15,056*
(b)	Property Taxes		of TCI			*$0*
(b)	Insurance		of TCI			*$0*
	Total Indirect Annual Costs:				*IDAC*	*$15,056*
	Total Annual Costs:				*TAC*	*$35,757*
Cost Effectiveness						
(b)	Expected lifetime of equipment, years	30				
(b)	Interest rate, %/yr	3.25%				
(b)	Capital recovery factor	0.053				
(b)	Total Capital Investment Cost	$752,785				
	Annualized Capital Investment Cost:					*$39,658*
	Total Annualized Cost:					*$75,415*
(e)	NO_X Reduction	72%	Based on new burner rating of 0.026 lb/MMBtu			
(f)	Pre-retrofit NO_X	12.1	tons NO_X/yr			
	Post-retrofit NO_X using LNB	3.45	tons NO_X/yr			
	NO_X Removed	8.7	tons NO_X/yr			
	Annual Cost/Ton Removed:					*$8,714*

(a) Cost information obtained from Section 4.4 in document titled "Emission Control Study - Technology Cost Estimates" by BE&K Engineering for AF&PA, September 2001. The labor and equipment cost of installing LNB, FGR, new fan on a gas-fired boiler was scaled based on boiler capacity. The cost was adjusted from 2001 dollars to 2019 dollars using the Chemical Engineering Plant Cost Index (CEPCI). Electricity requirement ratioed based on boiler size.

(b) Cost information estimated using the U.S. EPA Air Pollution Control Cost Manual (6th edition) published in January 2002 by the OAQPS (Section 3.2, Chapter 2, "Thermal and Catalytic Incinerators"). The website for the manual is available at http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf.

(c) Indirect capital cost factors (i.e., engineering and office fees, contingencies, and general facilities) based on guidance from "Methods for Evaluating the Costs of Utility NO_X Control Technologies," Loan K. Tran and H. Christopher Frey, June 1996.

(d) Maintenance costs were estimated based on the U.S. EPA OAQPS Alternative Control Techniques Document - NO_X Emissions from Process Heaters (Revised), Document No. EPA-453/R-93-034 (September 1993).

(e) Control efficiency based on comparison of uncontrolled and controlled AP-42 factors.

(f) PSEL

Low NOx Burner/FGR Retrofit - GP Wauna PM5 Yankee Burner

Burner Rating
60

CAPITAL COSTS

	COST ITEM	FACTOR		COST ($)
Costs to Purchase and Install Equipment				
(a)	LNB and FGR Retrofit cost. Cost = 340,500 * (Rating/20.5)^0.6			***$648,568***
(b)	Instrumentation	0.10 × A		***$64,857***
(b)	Sales Tax	0.00 × A		***$0***
(b)	Freight	0.05 × A		***$32,428***
	Total Purchased Equipment Cost, B =	B		***$745,853***
	Total Direct Cost:		***TDC***	***$745,853***
Indirect Capital Costs				
(c)	Engineering	0.10 × B		***$74,585***
(c)	Contingencies	0.20 × B		***$149,171***
(c)	General Facilities	0.05 × B		***$37,293***
(b)	Testing	0.01 × B		***$7,459***
	Total Indirect Cost:		***TIC***	***$268,507***
	Total Capital Investment:		***TCI***	***$1,014,360***

ANNUALIZED COSTS

	COST ITEM	COST FACTOR		UNIT COST		COST ($)
Annual Operating Costs - Direct Annual Costs						
(d)	Maintenance Costs	2.75%	of TCI			***$27,895***
Utilities						
(a)	Electricity	70	kW	$0.060	per kWh	***$37,002***
	Total Direct Annual Costs:			***DAC***		***$64,897***
Annual Operating Costs - Indirect Annual Costs						
(b)	Overhead	60%	of sum of operating & maintenance costs			***$16,737***
(b)	Administrative Charges	2%	of TCI			***$20,287***
(b)	Property Taxes	1%	of TCI			***$10,144***
(b)	Insurance	1%	of TCI			***$10,144***
	Total Indirect Annual Costs:			***IDAC***		***$57,311***
	Total Annual Costs:			***TAC***		***$122,209***
Cost Effectiveness						
(b)	Expected lifetime of equipment, years	30				
(b)	Interest rate, %/yr	3.25%				
(b)	Capital recovery factor	0.053				
(b)	Total Capital Investment Cost	$1,014,360				
	Annualized Capital Investment Cost:					***$53,438***
	Total Annualized Cost:					***$175,647***
(e)	NO_X Reduction	72%	Based on new burner rating of 0.026 lb/MMBtu			
(f)	Pre-retrofit NO_X	24.0	tons NO_X/yr			
	Post-retrofit NO_X using LNB	6.83	tons NO_X/yr			
	NO_X Removed	17.2	tons NO_X/yr			
	Annual Cost/Ton Removed:					***$10,233***

(a) Cost information obtained from Section 4.4 in document titled "Emission Control Study - Technology Cost Estimates" by BE&K Engineering for AF&PA, September 2001. The labor and equipment cost of installing LNB, FGR, new fan on a gas-fired boiler was scaled based on boiler capacity. The cost was adjusted from 2001 dollars to 2019 dollars using the Chemical Engineering Plant Cost Index (CEPCI). Electricity requirement ratioed based on boiler size.

(b) Cost information estimated using the U.S. EPA Air Pollution Control Cost Manual (6th edition) published in January 2002 by the OAQPS (Section 3.2, Chapter 2, "Thermal and Catalytic Incinerators"). The website for the manual is available at http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf.

(c) Indirect capital cost factors (i.e., engineering and office fees, contingencies, and general facilities) based on guidance from "Methods for Evaluating the Costs of Utility NO_X Control Technologies," Loan K. Tran and H. Christopher Frey, June 1996.

(d) Maintenance costs were estimated based on the U.S. EPA OAQPS Alternative Control Techniques Document - NO_X Emissions from Process Heaters (Revised), Document No. EPA-453/R-93-034 (September 1993).

(e) Control efficiency based on comparison of uncontrolled and controlled AP-42 factors.

(f) PSEL

Low NOx Burner/FGR Retrofit - GP Wauna PM5 Yankee Burner
Using Methodology in Pages 300-304 of GP Wauna FFA

Burner Rating
60

CAPITAL COSTS				
	COST ITEM	**FACTOR**		**COST ($)**
Costs to Purchase and Install Equipment				
(a)	LNB and FGR Retrofit cost. Cost = 340,500 * (Rating/20.5)^0.6			***$648,568***
(b)	Instrumentation	0.10 × A		***$64,857***
(b)	Sales Tax	0.00 × A		***$0***
(b)	Freight	0.05 × A		***$32,428***
	Total Purchased Equipment Cost, B =	B		***$745,853***
	Total Direct Cost:		***TDC***	***$745,853***
Indirect Capital Costs				
(c)	Engineering	0.10 × B		
(c)	Contingencies	0.20 × B		
(c)	General Facilities	0.05 × B		
(b)	Testing	0.01 × B		
	Total Indirect Cost:	0.5 x TDC	***TIC***	***$372,927***
	Total Capital Investment:		***TCI***	***$1,118,780***

ANNUALIZED COSTS					
	COST ITEM	**COST FACTOR**		**UNIT COST**	**COST ($)**
Annual Operating Costs - Direct Annual Costs					
(d)	Maintenance Costs	2.75%	of TCI		***$30,766***
Utilities					
(a)	Electricity	70	kW	per kWh	***$0***
	Total Direct Annual Costs:			***DAC***	***$30,766***
Annual Operating Costs - Indirect Annual Costs					
(b)	Overhead		of sum of operating & maintenance costs		***$0***
(b)	Administrative Charges	2%	of TCI		***$22,376***
(b)	Property Taxes		of TCI		***$0***
(b)	Insurance		of TCI		***$0***
	Total Indirect Annual Costs:			***IDAC***	***$22,376***
	Total Annual Costs:			***TAC***	***$53,142***
Cost Effectiveness					
(b)	Expected lifetime of equipment, years	30			
(b)	Interest rate, %/yr	3.25%			
(b)	Capital recovery factor	0.053			
(b)	Total Capital Investment Cost	$1,118,780			
	Annualized Capital Investment Cost:				***$58,939***
	Total Annualized Cost:				***$112,081***
(e)	NO_X Reduction	72%	Based on new burner rating of 0.026 lb/MMBtu		
(f)	Pre-retrofit NO_X	24.0	tons NO_X/yr		
	Post-retrofit NO_X using LNB	6.83	tons NO_X/yr		
	NO_X Removed	17.2	tons NO_X/yr		
	Annual Cost/Ton Removed:				***$6,529***

(a) Cost information obtained from Section 4.4 in document titled "Emission Control Study - Technology Cost Estimates" by BE&K Engineering for AF&PA, September 2001. The labor and equipment cost of installing LNB, FGR, new fan on a gas-fired boiler was scaled based on boiler capacity. The cost was adjusted from 2001 dollars to 2019 dollars using the Chemical Engineering Plant Cost Index (CEPCI). Electricity requirement ratioed based on boiler size.

(b) Cost information estimated using the U.S. EPA Air Pollution Control Cost Manual (6th edition) published in January 2002 by the OAQPS (Section 3.2, Chapter 2, "Thermal and Catalytic Incinerators"). The website for the manual is available at http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf.

(c) Indirect capital cost factors (i.e., engineering and office fees, contingencies, and general facilities) based on guidance from "Methods for Evaluating the Costs of Utility NO_X Control Technologies," Loan K. Tran and H. Christopher Frey, June 1996.

(d) Maintenance costs were estimated based on the U.S. EPA OAQPS Alternative Control Techniques Document - NO_X Emissions from Process Heaters (Revised), Document No. EPA-453/R-93-034 (September 1993).

(e) Control efficiency based on comparison of uncontrolled and controlled AP-42 factors.

(f) PSEL

Low NOx Burner/FGR Retrofit - GP Wauna PM6 and PM7 Yankee Burner

Burner Rating: 9

CAPITAL COSTS

	COST ITEM	FACTOR		COST ($)
Costs to Purchase and Install Equipment				
(a)	LNB and FGR Retrofit cost. Cost = 340,500 * (Rating/20.5)^0.6			*$207,783*
(b)	Instrumentation	0.10 × A		*$20,778*
(b)	Sales Tax	0.00 × A		*$0*
(b)	Freight	0.05 × A		*$10,389*
	Total Purchased Equipment Cost, B =	B		*$238,951*
	Total Direct Cost:		*TDC*	*$238,951*
Indirect Capital Costs				
(c)	Engineering	0.10 × B		*$23,895*
(c)	Contingencies	0.20 × B		*$47,790*
(c)	General Facilities	0.05 × B		*$11,948*
(b)	Testing	0.01 × B		*$2,390*
	Total Indirect Cost:		*TIC*	*$86,022*
	Total Capital Investment:		*TCI*	*$324,973*

ANNUALIZED COSTS

	COST ITEM	COST FACTOR		UNIT COST		COST ($)
Annual Operating Costs - Direct Annual Costs						
(d)	Maintenance Costs	2.75%	of TCI			*$8,937*
Utilities						
(a)	Electricity	11	kW	$0.060	per kWh	*$5,550*
	Total Direct Annual Costs:			*DAC*		*$14,487*
Annual Operating Costs - Indirect Annual Costs						
(b)	Overhead	60%	of sum of operating & maintenance costs			*$5,362*
(b)	Administrative Charges	2%	of TCI			*$6,499*
(b)	Property Taxes	1%	of TCI			*$3,250*
(b)	Insurance	1%	of TCI			*$3,250*
	Total Indirect Annual Costs:			*IDAC*		*$18,361*
	Total Annual Costs:			*TAC*		*$32,848*
Cost Effectiveness						
(b)	Expected lifetime of equipment, years	30				
(b)	Interest rate, %/yr	3.25%				
(b)	Capital recovery factor	0.053				
(b)	Total Capital Investment Cost	$324,973				
	Annualized Capital Investment Cost:					*$17,120*
	Total Annualized Cost:					*$49,968*
(e)	NO_X Reduction	72%	Based on new burner rating of 0.026 lb/MMBtu			
(f)	Pre-retrofit NO_X	3.6	tons NO_X/yr			
	Post-retrofit NO_X using LNB	1.03	tons NO_X/yr			
	NO_X Removed	2.6	tons NO_X/yr			
	Annual Cost/Ton Removed:					*$19,407*

(a) Cost information obtained from Section 4.4 in document titled "Emission Control Study - Technology Cost Estimates" by BE&K Engineering for AF&PA, September 2001. The labor and equipment cost of installing LNB, FGR, new fan on a gas-fired boiler was scaled based on boiler capacity. The cost was adjusted from 2001 dollars to 2019 dollars using the Chemical Engineering Plant Cost Index (CEPCI). Electricity requirement ratioed based on boiler size.

(b) Cost information estimated using the U.S. EPA Air Pollution Control Cost Manual (6th edition) published in January 2002 by the OAQPS (Section 3.2, Chapter 2, "Thermal and Catalytic Incinerators"). The website for the manual is available at http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf.

(c) Indirect capital cost factors (i.e., engineering and office fees, contingencies, and general facilities) based on guidance from "Methods for Evaluating the Costs of Utility NO_X Control Technologies," Loan K. Tran and H. Christopher Frey, June 1996.

(d) Maintenance costs were estimated based on the U.S. EPA OAQPS Alternative Control Techniques Document - NO_X Emissions from Process Heaters (Revised), Document No. EPA-453/R-93-034 (September 1993).

(e) Control efficiency based on comparison of uncontrolled and controlled AP-42 factors.

(f) PSEL

Low NOx Burner/FGR Retrofit - GP Wauna PM6 and PM7 Yankee Burner
Using Methodology in Pages 300-304 of GP Wauna FFA

Burner Rating
9

CAPITAL COSTS				
	COST ITEM	FACTOR		COST ($)
Costs to Purchase and Install Equipment				
(a)	LNB and FGR Retrofit cost. Cost = 340,500 * (Rating/20.5)^0.6			***$207,783***
(b)	Instrumentation	0.10 × A		***$20,778***
(b)	Sales Tax	0.00 × A		***$0***
(b)	Freight	0.05 × A		***$10,389***
	Total Purchased Equipment Cost, B =	B		***$238,951***
	Total Direct Cost:		***TDC***	***$238,951***
Indirect Capital Costs				
(c)	Engineering	0.10 × B		
(c)	Contingencies	0.20 × B		
(c)	General Facilities	0.05 × B		
(b)	Testing	0.01 × B		
	Total Indirect Cost:	0.5 × TDC	***TIC***	***$119,475***
	Total Capital Investment:		***TCI***	***$358,426***

ANNUALIZED COSTS					
	COST ITEM	COST FACTOR		UNIT COST	COST ($)
Annual Operating Costs - Direct Annual Costs					
(d)	Maintenance Costs	2.75%	of TCI		***$9,857***
Utilities					
(a)	Electricity	11	kW	per kWh	***$0***
	Total Direct Annual Costs:			***DAC***	***$9,857***
Annual Operating Costs - Indirect Annual Costs					
(b)	Overhead		of sum of operating & maintenance costs		***$0***
(b)	Administrative Charges	2%	of TCI		***$7,169***
(b)	Property Taxes		of TCI		***$0***
(b)	Insurance		of TCI		***$0***
	Total Indirect Annual Costs:			***IDAC***	***$7,169***
	Total Annual Costs:			***TAC***	***$17,025***
Cost Effectiveness					
(b)	Expected lifetime of equipment, years	30			
(b)	Interest rate, %/yr	3.25%			
(b)	Capital recovery factor	0.053			
(b)	Total Capital Investment Cost	$358,426			
	Annualized Capital Investment Cost:				***$18,882***
	Total Annualized Cost:				***$35,908***
(e)	NO_X Reduction	72%	Based on new burner rating of 0.026 lb/MMBtu		
(f)	Pre-retrofit NO_X	3.6	tons NO_X/yr		
	Post-retrofit NO_X using LNB	1.03	tons NO_X/yr		
	NO_X Removed	2.6	tons NO_X/yr		
	Annual Cost/Ton Removed:				***$13,946***

(a) Cost information obtained from Section 4.4 in document titled "Emission Control Study - Technology Cost Estimates" by BE&K Engineering for AF&PA, September 2001. The labor and equipment cost of installing LNB, FGR, new fan on a gas-fired boiler was scaled based on boiler capacity. The cost was adjusted from 2001 dollars to 2019 dollars using the Chemical Engineering Plant Cost Index (CEPCI). Electricity requirement ratioed based on boiler size.

(b) Cost information estimated using the U.S. EPA Air Pollution Control Cost Manual (6th edition) published in January 2002 by the OAQPS (Section 3.2, Chapter 2, "Thermal and Catalytic Incinerators"). The website for the manual is available at http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf.

(c) Indirect capital cost factors (i.e., engineering and office fees, contingencies, and general facilities) based on guidance from "Methods for Evaluating the Costs of Utility NO_X Control Technologies," Loan K. Tran and H. Christopher Frey, June 1996.

(d) Maintenance costs were estimated based on the U.S. EPA OAQPS Alternative Control Techniques Document - NO_X Emissions from Process Heaters (Revised), Document No. EPA-453/R-93-034 (September 1993).

(e) Control efficiency based on comparison of uncontrolled and controlled AP-42 factors.

(f) PSEL

Low NOx Burner/FGR Retrofit - GP Wauna PM6 and PM7 TAD1 Burners

Burner Rating: 90

CAPITAL COSTS

	COST ITEM	FACTOR		COST ($)
Costs to Purchase and Install Equipment				
(a)	LNB and FGR Retrofit cost. Cost = 340,500 * (Rating/20.5)^0.6			***$827,200***
(b)	Instrumentation	0.10 × A		***$82,720***
(b)	Sales Tax	0.00 × A		***$0***
(b)	Freight	0.05 × A		***$41,360***
	Total Purchased Equipment Cost, B =	B		***$951,280***
	Total Direct Cost:		***TDC***	***$951,280***
Indirect Capital Costs				
(c)	Engineering	0.10 × B		***$95,128***
(c)	Contingencies	0.20 × B		***$190,256***
(c)	General Facilities	0.05 × B		***$47,564***
(b)	Testing	0.01 × B		***$9,513***
	Total Indirect Cost:		***TIC***	***$342,461***
	Total Capital Investment:		***TCI***	***$1,293,740***

ANNUALIZED COSTS

	COST ITEM	COST FACTOR	UNIT COST	COST ($)
Annual Operating Costs - Direct Annual Costs				
(d)	Maintenance Costs	2.75% of TCI		***$35,578***
Utilities				
(a)	Electricity	106 kW	$0.060 per kWh	***$55,503***
	Total Direct Annual Costs:		***DAC***	***$91,081***
Annual Operating Costs - Indirect Annual Costs				
(b)	Overhead	60% of sum of operating & maintenance costs		***$21,347***
(b)	Administrative Charges	2% of TCI		***$25,875***
(b)	Property Taxes	1% of TCI		***$12,937***
(b)	Insurance	1% of TCI		***$12,937***
	Total Indirect Annual Costs:		***IDAC***	***$73,096***
	Total Annual Costs:		***TAC***	***$164,178***
Cost Effectiveness				
(b)	Expected lifetime of equipment, years	30		
(b)	Interest rate, %/yr	3.25%		
(b)	Capital recovery factor	0.053		
(b)	Total Capital Investment Cost	$1,293,740		
	Annualized Capital Investment Cost:			***$68,156***
	Total Annualized Cost:			***$232,334***
(e)	NO_X Reduction	79% Based on new burner rating of 0.026 lb/MMBtu		
(f)	Pre-retrofit NO_X	49.9 tons NO_X/yr		
	Post-retrofit NO_X using LNB	10.26 tons NO_X/yr		
	NO_X Removed	39.6 tons NO_X/yr		
	Annual Cost/Ton Removed:			***$5,861***

(a) Cost information obtained from Section 4.4 in document titled "Emission Control Study - Technology Cost Estimates" by BE&K Engineering for AF&PA, September 2001. The labor and equipment cost of installing LNB, FGR, new fan on a gas-fired boiler was scaled based on boiler capacity. The cost was adjusted from 2001 dollars to 2019 dollars using the Chemical Engineering Plant Cost Index (CEPCI). Electricity requirement ratioed based on boiler size.

(b) Cost information estimated using the U.S. EPA Air Pollution Control Cost Manual (6th edition) published in January 2002 by the OAQPS (Section 3.2, Chapter 2, "Thermal and Catalytic Incinerators"). The website for the manual is available at http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf.

(c) Indirect capital cost factors (i.e., engineering and office fees, contingencies, and general facilities) based on guidance from "Methods for Evaluating the Costs of Utility NO_X Control Technologies," Loan K. Tran and H. Christopher Frey, June 1996.

(d) Maintenance costs were estimated based on the U.S. EPA OAQPS Alternative Control Techniques Document - NO_X Emissions from Process Heaters (Revised), Document No. EPA-453/R-93-034 (September 1993).

(e) Control efficiency based on comparison of uncontrolled and controlled AP-42 factors.

(f) PSEL

Low NOx Burner/FGR Retrofit - GP Wauna PM6 and PM7 TAD1 Burners
Using Methodology in Pages 300-304 of GP Wauna FFA

Burner Rating: 90

CAPITAL COSTS				
	COST ITEM	FACTOR		COST ($)
Costs to Purchase and Install Equipment				
(a)	LNB and FGR Retrofit cost. Cost = 340,500 * (Rating/20.5)^0.6			*$827,200*
(b)	Instrumentation	0.10 × A		*$82,720*
(b)	Sales Tax	0.00 × A		*$0*
(b)	Freight	0.05 × A		*$41,360*
	Total Purchased Equipment Cost, B =	B		*$951,280*
	Total Direct Cost:		*TDC*	*$951,280*
Indirect Capital Costs				
(c)	Engineering	0.10 × B		
(c)	Contingencies	0.20 × B		
(c)	General Facilities	0.05 × B		
(b)	Testing	0.01 × B		
	Total Indirect Cost:	0.5 x TDC	*TIC*	*$475,640*
	Total Capital Investment:		*TCI*	*$1,426,919*

ANNUALIZED COSTS					
	COST ITEM	COST FACTOR		UNIT COST	COST ($)
Annual Operating Costs - Direct Annual Costs					
(d)	Maintenance Costs	2.75%	of TCI		*$39,240*
Utilities					
(a)	Electricity	106	kW	per kWh	*$0*
	Total Direct Annual Costs:			*DAC*	*$39,240*
Annual Operating Costs - Indirect Annual Costs					
(b)	Overhead		of sum of operating & maintenance costs		*$0*
(b)	Administrative Charges	2%	of TCI		*$28,538*
(b)	Property Taxes		of TCI		*$0*
(b)	Insurance		of TCI		*$0*
	Total Indirect Annual Costs:			*IDAC*	*$28,538*
	Total Annual Costs:			*TAC*	*$67,779*
Cost Effectiveness					
(b)	Expected lifetime of equipment, years	30			
(b)	Interest rate, %/yr	3.25%			
(b)	Capital recovery factor	0.053			
(b)	Total Capital Investment Cost	$1,426,919			
	Annualized Capital Investment Cost:				*$75,173*
	Total Annualized Cost:				*$142,951*
(e)	NO_X Reduction	79%	Based on new burner rating of 0.026 lb/MMBtu		
(f)	Pre-retrofit NO_X	49.9	tons NO_X/yr		
	Post-retrofit NO_X using LNB	10.26	tons NO_X/yr		
	NO_X Removed	39.6	tons NO_X/yr		
	Annual Cost/Ton Removed:				*$3,606*

(a) Cost information obtained from Section 4.4 in document titled "Emission Control Study - Technology Cost Estimates" by BE&K Engineering for AF&PA, September 2001. The labor and equipment cost of installing LNB, FGR, new fan on a gas-fired boiler was scaled based on boiler capacity. The cost was adjusted from 2001 dollars to 2019 dollars using the Chemical Engineering Plant Cost Index (CEPCI). Electricity requirement ratioed based on boiler size.

(b) Cost information estimated using the U.S. EPA Air Pollution Control Cost Manual (6th edition) published in January 2002 by the OAQPS (Section 3.2, Chapter 2, "Thermal and Catalytic Incinerators"). The website for the manual is available at http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf.

(c) Indirect capital cost factors (i.e., engineering and office fees, contingencies, and general facilities) based on guidance from "Methods for Evaluating the Costs of Utility NO_X Control Technologies," Loan K. Tran and H. Christopher Frey, June 1996.

(d) Maintenance costs were estimated based on the U.S. EPA OAQPS Alternative Control Techniques Document - NO_X Emissions from Process Heaters (Revised), Document No. EPA-453/R-93-034 (September 1993).

(e) Control efficiency based on comparison of uncontrolled and controlled AP-42 factors.

(f) PSEL

Low NOx Burner/FGR Retrofit - GP Wauna PM6 and PM7 TAD2 Burners

Burner Rating
50

CAPITAL COSTS				
	COST ITEM	FACTOR		COST ($)
Costs to Purchase and Install Equipment				
(a)	LNB and FGR Retrofit cost. Cost = 340,500 * (Rating/20.5)^0.6			***$581,362***
(b)	Instrumentation	0.10 × A		***$58,136***
(b)	Sales Tax	0.00 × A		***$0***
(b)	Freight	0.05 × A		***$29,068***
	Total Purchased Equipment Cost, B =	B		***$668,567***
	Total Direct Cost:		***TDC***	***$668,567***
Indirect Capital Costs				
(c)	Engineering	0.10 × B		***$66,857***
(c)	Contingencies	0.20 × B		***$133,713***
(c)	General Facilities	0.05 × B		***$33,428***
(b)	Testing	0.01 × B		***$6,686***
	Total Indirect Cost:		***TIC***	***$240,684***
	Total Capital Investment:		***TCI***	***$909,251***

ANNUALIZED COSTS				
	COST ITEM	COST FACTOR	UNIT COST	COST ($)
Annual Operating Costs - Direct Annual Costs				
(d)	Maintenance Costs	2.75% of TCI		***$25,004***
Utilities				
(a)	Electricity	59 kW	$0.060 per kWh	***$30,835***
	Total Direct Annual Costs:		***DAC***	***$55,840***
Annual Operating Costs - Indirect Annual Costs				
(b)	Overhead	60% of sum of operating & maintenance costs		***$15,003***
(b)	Administrative Charges	2% of TCI		***$18,185***
(b)	Property Taxes	1% of TCI		***$9,093***
(b)	Insurance	1% of TCI		***$9,093***
	Total Indirect Annual Costs:		***IDAC***	***$51,373***
	Total Annual Costs:		***TAC***	***$107,212***
Cost Effectiveness				
(b)	Expected lifetime of equipment, years	30		
(b)	Interest rate, %/yr	3.25%		
(b)	Capital recovery factor	0.053		
(b)	Total Capital Investment Cost	$909,251		
	Annualized Capital Investment Cost:			***$47,901***
	Total Annualized Cost:			***$155,113***
(e)	NO_X Reduction	79% Based on new burner rating of 0.026 lb/MMBtu		
(f)	Pre-retrofit NO_X	27.7 tons NO_X/yr		
	Post-retrofit NO_X using LNB	5.69 tons NO_X/yr		
	NO_X Removed	22.0 tons NO_X/yr		
	Annual Cost/Ton Removed:			***$7,048***

(a) Cost information obtained from Section 4.4 in document titled "Emission Control Study - Technology Cost Estimates" by BE&K Engineering for AF&PA, September 2001. The labor and equipment cost of installing LNB, FGR, new fan on a gas-fired boiler was scaled based on boiler capacity. The cost was adjusted from 2001 dollars to 2019 dollars using the Chemical Engineering Plant Cost Index (CEPCI). Electricity requirement ratioed based on boiler size.

(b) Cost information estimated using the U.S. EPA Air Pollution Control Cost Manual (6th edition) published in January 2002 by the OAQPS (Section 3.2, Chapter 2, "Thermal and Catalytic Incinerators"). The website for the manual is available at http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf.

(c) Indirect capital cost factors (i.e., engineering and office fees, contingencies, and general facilities) based on guidance from "Methods for Evaluating the Costs of Utility NO_X Control Technologies," Loan K. Tran and H. Christopher Frey, June 1996.

(d) Maintenance costs were estimated based on the U.S. EPA OAQPS Alternative Control Techniques Document - NO_X Emissions from Process Heaters (Revised), Document No. EPA-453/R-93-034 (September 1993).

(e) Control efficiency based on comparison of uncontrolled and controlled AP-42 factors.

(f) PSEL

Low NOx Burner/FGR Retrofit - GP Wauna PM6 and PM7 TAD2 Burners
Using Methodology in Pages 300-304 of GP Wauna FFA

Burner Rating: 50

CAPITAL COSTS					
	COST ITEM	FACTOR			COST ($)
Costs to Purchase and Install Equipment					
(a)	LNB and FGR Retrofit cost. Cost = 340,500 * (Rating/20.5)^0.6				***$581,362***
(b)	Instrumentation	0.10	× A		***$58,136***
(b)	Sales Tax	0.00	× A		***$0***
(b)	Freight	0.05	× A		***$29,068***
	Total Purchased Equipment Cost, B =		B		
	Total Direct Cost:			***TDC***	***$668,567***
Indirect Capital Costs					
(c)	Engineering	0.10	× B		
(c)	Contingencies	0.20	× B		
(c)	General Facilities	0.05	× B		
(b)	Testing	0.01	× B		
	Total Indirect Cost:	0.5	x TDC	***TIC***	***$334,283***
	Total Capital Investment:			***TCI***	***$1,002,850***

ANNUALIZED COSTS					
	COST ITEM	COST FACTOR		UNIT COST	COST ($)
Annual Operating Costs - Direct Annual Costs					
(d)	Maintenance Costs	2.75%	of TCI		***$27,578***
Utilities					
(a)	Electricity	59	kW	per kWh	
	Total Direct Annual Costs:			***DAC***	***$27,578***
Annual Operating Costs - Indirect Annual Costs					
(b)	Overhead		of sum of operating & maintenance costs		***$0***
(b)	Administrative Charges	2%	of TCI		***$20,057***
(b)	Property Taxes		of TCI		***$0***
(b)	Insurance		of TCI		***$0***
	Total Indirect Annual Costs:			***IDAC***	***$20,057***
	Total Annual Costs:			***TAC***	***$47,635***
Cost Effectiveness					
(b)	Expected lifetime of equipment, years	30			
(b)	Interest rate, %/yr	3.25%			
(b)	Capital recovery factor	0.053			
(b)	Total Capital Investment Cost	$1,002,850			
	Annualized Capital Investment Cost:				***$52,832***
	Total Annualized Cost:				***$100,467***
(e)	NO_X Reduction	79%	Based on new burner rating of 0.026 lb/MMBtu		
(f)	Pre-retrofit NO_X	27.7	tons NO_X/yr		
	Post-retrofit NO_X using LNB	5.69	tons NO_X/yr		
	NO_X Removed	22.0	tons NO_X/yr		
	Annual Cost/Ton Removed:				***$4,565***

(a) Cost information obtained from Section 4.4 in document titled "Emission Control Study - Technology Cost Estimates" by BE&K Engineering for AF&PA, September 2001. The labor and equipment cost of installing LNB, FGR, new fan on a gas-fired boiler was scaled based on boiler capacity. The cost was adjusted from 2001 dollars to 2019 dollars using the Chemical Engineering Plant Cost Index (CEPCI). Electricity requirement ratioed based on boiler size.

(b) Cost information estimated using the U.S. EPA Air Pollution Control Cost Manual (6th edition) published in January 2002 by the OAQPS (Section 3.2, Chapter 2, "Thermal and Catalytic Incinerators"). The website for the manual is available at http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf.

(c) Indirect capital cost factors (i.e., engineering and office fees, contingencies, and general facilities) based on guidance from "Methods for Evaluating the Costs of Utility NO_X Control Technologies," Loan K. Tran and H. Christopher Frey, June 1996.

(d) Maintenance costs were estimated based on the U.S. EPA OAQPS Alternative Control Techniques Document - NO_X Emissions from Process Heaters (Revised), Document No. EPA-453/R-93-034 (September 1993).

(e) Control efficiency based on comparison of uncontrolled and controlled AP-42 factors.

(f) PSEL

Kate Brown, Governor

Department of Environmental Quality
Agency Headquarters
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TTY 711

January 21, 2021

Kimberly May
Kimberly.May@GAPAC.com
Georgia Pacific - Wauna Mill
92326 Taylorville Rd
Clatskanie, OR 97016-8264

Sent via EMAIL

Re: Round 2 Regional Haze Program, Preliminary Determination of Cost Effective Controls; Georgia Pacific - Wauna Mill, 04-0004

Dear Kimberly May:

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

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

Emissions Unit	Control Device	Target Pollutant
Paper Machine 1: Yankee Burner	LNB	NOx
Paper Machine 2: Yankee Burner	LNB	NOx
Paper Machine 5: Yankee Burner	LNB	NOx
21 - Lime Kiln	LNB	NOx
Paper Machine 6: TAD1 Burners	LNB	NOx
Paper Machine 7: TAD1 Burners	LNB	NOx
Paper Machine 6: TAD2 Burners	LNB	NOx
Paper Machine 7: TAD2 Burners	LNB	NOx
33 - Power Boiler	SCR	NOx

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

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

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

Sincerely,

Ali Mirzakhalili
Air Quality Division Administrator
Oregon Department of Environmental Quality

Cc: Karen Williams
Joe Westersund
Michael Orman
David Graiver
Steve Dietrich

Georgia-Pacific

Georgia-Pacific Consumer Operations LLC
92326 Taylorville Road
Clatskanie, Oregon 97016

Georgia-Pacific Toledo LLC
1400 SE Butler Bridge Rd
Toledo, Oregon 97391

April 30, 2021

Mr. Ali Mirzakhalili
Air Quality Division Administrator
Oregon Department of Environmental Quality
700 NE Multnomah Street
Suite 600
Portland, OR 97232-4100

Sent via EMAIL

Re: *Round 2 Regional Haze Program, Preliminary Determination of Cost-Effective Controls for Georgia-Pacific Consumer Operations LLC – Wauna Mill and Georgia-Pacific Toledo LLC Georgia-Pacific Proposals*

Dear Mr. Mirzakhalili:

The Georgia-Pacific Consumer Operations LLC – Wauna Mill (GP Wauna Mill) and Georgia-Pacific Toledo LLC (GP Toledo Mill) received the Department of Environmental Quality's (DEQ's) Regional Haze Preliminary Determination letters on Friday, January 22, 2021. By GP's calculations, the proposed controls to meet the Regional Haze Rule (RHR) requirements would necessitate about $50 million in capital expenditures and about $6 million in new annual operating costs across both facilities. GP submitted an initial response letter to DEQ on January 29, 2021 briefly summarizing several reasons we disagreed with the preliminary determination of controls and the process that DEQ had used to develop them. Among those reasons were the following, which we believe remain valid.

- DEQ has not provided a sufficient basis for requiring the proposed control devices and has not provided the corresponding emission rates believed to be achievable or necessary.
- DEQ arrived at its proposed control decisions in part by using a cost effectiveness threshold that is much higher than surrounding states ($10,000/ton) and has not provided any explanation as to why that cost threshold is appropriate or why it is necessary to impose a more stringent standard than neighboring states. We are concerned that, by using a much higher cost threshold than those used by other states in the area, DEQ is putting facilities in Oregon at a competitive disadvantage.
- DEQ has identified several sources where the proposed control device would provide an emissions reduction of less than 20 tons per year (tpy), which was identified in DEQ's August 14, 2020 letters to the facilities as a reason for ruling out a control device. In fact, some of these sources have Plant Site Emission Limit (PSEL) emission rates themselves that are lower than 20 tpy, as discussed in this letter.

- Perhaps most important, DEQ has not provided a regional-scale modeling analysis demonstrating that the controls identified for each facility will provide any measurable visibility benefit or are necessary to meet the state's regional haze reasonable progress goals for the second planning period. Nor has DEQ explained why the very steep expenditures that its proposed control decisions would require are justified by the insignificant amount of visibility improvements achieved by those controls. Based on GP's internal assessments described in more detail below, the proposed emissions reductions will have an insignificant impact on visibility at Class I areas.

CALPUFF Visibility Modeling

GP conducted a CALPUFF modeling analysis of each mill to gauge the impacts the facilities have on visibility in the nearest Class I areas. The assessments included all NO_X and SO_2 emission sources at the mills, considering the existing site configuration as a baseline scenario and a post-control scenario that includes all NO_X control measures identified by DEQ. Consistent with the Federal Land Managers' Air Quality Related Values Work Group (FLAG) Phase I Report[1] and the Environmental Protection Agency's (EPA's) Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations[2], neither source at current emissions levels contributes to visibility impairment at any Class I area given both sources demonstrated 98th percentile values of less than 0.5 deciview (dv) for each relevant Class I area. Notably, the post-control scenarios showed minimal visibility improvements as the differences in the 98th percentile values between the scenarios are less than 0.1 dv for all relevant Class I areas for each mill. Hence, the control measures proposed by DEQ that total over $50 million in capital investments across both mills would achieve an imperceptible change in visibility at the Class I areas closest to each mill.

In August 2019, EPA released a guidance document for states to assist with preparation of their state implementation plans (SIP) for the second planning period of the RHR.[3] While this guidance document does not require states to consider source-specific visibility impacts and improvements in making control measure determinations, it does make clear that it would be rational for states to do so; in fact, the section of the guidance on how to decide what control measures are necessary to make reasonable progress assumes that a state will consider the visibility benefits. The guidance goes on to state that "[b]ecause the goal of the regional haze program is to improve visibility, it is reasonable for a state to consider whether and by how much an emission control measure would help achieve that goal." In short, EPA states, "EPA interprets the CAA and the Regional Haze Rule to allow a state reasonable discretion to consider the anticipated visibility benefits of an emission control measure along with the other factors when determining whether a measure is necessary to make reasonable progress." And, when it comes to the required SIP contents, the regional haze rule requires states to document the technical basis, including modeling, for determining the emission reduction measures that are necessary to make reasonable progress at each Class I area.[4]

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[1] https://www.fws.gov/guidance/sites/default/files/documents/FLAG%20Air%20Quality%20Phase%201%20report.pdf
[2] https://www.govinfo.gov/content/pkg/FR-2005-07-06/pdf/05-12526.pdf
[3] https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf
[4] 40 CFR 51.308(f)(2)(iii)

GP Proposed PSEL Reductions and DEQ Proposed NO_X Control Measures

Each of the affected GP facilities is currently in the Title V Operating Permit renewal process and has recently proposed updated PSEL emission calculations that include considerable reductions in annual emission rates for both oxides of nitrogen (NO_X) and sulfur dioxide (SO_2) from the values in the current permits, which, along with 2017 actual emissions, were used as the basis for DEQ identifying sources needing to consider additional control measures. While DEQ's preliminary determination letters are focused on NO_X controls, GP believes the SO_2 reductions we have already proposed during our permit renewal process are particularly meaningful within the regional haze program. Each Mill has proposed over 400 tpy in SO_2 emission reductions with its latest PSEL calculations. Based on measured speciation data in Class I areas, sulfur compounds are the primary contributor to regional haze in most areas. GP's proposed SO_2 reductions are more likely to reduce regional haze than the controls proposed by DEQ, which are summarized in Tables 1 and 2. The reductions GP has already proposed to each mill's NO_X and SO_2 PSELs must be considered along with the various alternative options discussed in the remainder of this letter for the sources identified by DEQ.

TABLE 1. DEQ PROPOSED CONTROLS FOR THE GP TOLEDO MILL

Emissions Unit	Control Device	Target Pollutant
EU-118 Hardwood Chip Handling	Baghouse	PM_{10}
EU-1 Lime Kiln	LNB	NO_X
EU-2 Lime Kiln	LNB	NO_X
EU-3 Lime Kiln	LNB	NO_X
EU-11 No. 4 Boiler	SCR	NO_X
EU-13 No. 1 Boiler	SCR	NO_X
EU-18 No. 3 Boiler	SNCR	NO_X

TABLE 2. DEQ PROPOSED CONTROLS FOR THE GP WAUNA MILL

Emissions Unit	Control Device	Target Pollutant
Paper Machine 1: Yankee Burner	LNB	NO_X
Paper Machine 2: Yankee Burner	LNB	NO_X
Paper Machine 5: Yankee Burner	LNB	NO_X
21 – Lime Kiln	LNB	NO_X
Paper Machine 6: TAD1 Burners	LNB	NO_X
Paper Machine 7: TAD1 Burners	LNB	NO_X
Paper Machine 6: TAD2 Burners	LNB	NO_X
Paper Machine 7: TAD2 Burners	LNB	NO_X
33 – Power Boiler	SCR	NO_X

GP Toledo Hardwood Chip Handling Cyclone

GP conducted a stack test of the Hardwood Chip Handling Cyclone on April 21, 2021. Preliminary results indicate the mass of particulate matter (PM) collected during all three runs was less than the Oregon DEQ Method 8 minimum quantifiable limit (MQL) of 100 milligrams (mg). The volumetric flow rate was measured during this testing event as well as an earlier unsuccessful event and ranged from 5,767 to 5,826 dry standard cubic feet per minute (dscfm). Therefore, GP is assuming a maximum flow rate of 6,000 dscfm for the cyclone. Use of the MQL to determine the outlet concentration would result in a value of <0.0013 grains per dry standard cubic foot (gr/dscf) and a corresponding emission rate of <0.1 pounds per hour (lb/hr). For conservatism, GP reviewed stack test data from similar cyclones at another GP facility and chose the maximum outlet concentration and added two standard deviations. The resulting preliminary emission estimates are less than 5 tpy of PM, PM less than or equal to 10 microns in aerodynamic diameter (PM_{10}), and PM less than or equal to 2.5 microns in aerodynamic diameter ($PM_{2.5}$), which provides PSEL reductions of these pollutants of greater than 50 tpy, 40 tpy, and 20 tpy, respectively. Given these low estimates, no control measures should be required on the Hardwood Chip Cyclone.

GP Wauna Paper Machines

DEQ identified several paper machine burners as possible candidates for replacement with new low-NO_X burners (LNB). In a September 14, 2020 letter to DEQ, the GP Wauna Mill presented corrected burner heat input ratings for several of these burners, resulting in a reduction in total NO_X emissions within the PSEL of 58.9 tpy from the collection of paper machines. The resulting NO_X emission rates of the PM1 Yankee Burner and the PM2 Yankee Burner are less than 20 tpy, which was a threshold DEQ indicated it used for ruling out requiring additional control techniques. Since the potential emission rates of these burners are already less than that threshold, no changes are needed to these units.

GP has reviewed available data on the actual emission rates of the PM6 and PM7 TAD1 and TAD2 burners. Based on this data, GP is proposing to reduce the NO_X emission factor for each of these burners from 0.1265 lb/MMBtu to 0.06 lb/MMBtu, which would further reduce the permitted NO_X emission rates from each paper machine by 40.8 tpy.

GP is agreeing to replace the Yankee burner on PM5, at an estimated cost of $2.5 million. The Wauna Mill will also need to replace the Yankee hood and air system on the machine which will help increase the drying efficiency. GP expects to achieve a NO_X emission rate of 0.03 lb/MMBtu with a new burner, resulting in an additional reduction of 16.1 tpy of NO_X from PM5.

With the reduction in the NO_X emission factor for the PM6 and PM7 TAD1 and TAD2 burners and implementation of the Yankee hood and burner replacement project on PM5, the future expected NO_X emission rates from the paper machines are given in Table 3. The total future NO_X emission rate of 113.5 tpy from the collection of paper machines provides a reduction from the historic permitted NO_X emission rates of 156.5 tpy and from the corrected NO_X emission rates of 97.7 tpy. We believe these are sufficient reductions from the paper machines, to the extent any are necessary.

TABLE 3. FUTURE PAPER MACHINE BURNER NO_X EMISSION RATES

	Burner Heat Input Rating		Current NO_X	NO_X Emission Rates		Future NO_X	Future NO_X	NO_X Reductions from:	
Paper Machine Burner	Historic (MMBtu/hr)	Corrected (MMBtu/hr)	Emission Factor (lb/MMBtu)	Historic (tpy)	Corrected (tpy)	Emission Factor (lb/MMBtu)	Emission Rates (tpy)	Historic (tpy)	Corrected (tpy)
PM1 Yankee Burner	34	31	0.0913	13.6	12.4	0.0913	12.4	1.2	0.0
PM2 Yankee Burner	34	31	0.0913	13.6	12.4	0.0913	12.4	1.2	0.0
PM5 Yankee Burner	75	60	0.0913	30.0	24.0	0.03	7.9	22.1	16.1
PM6 Yankee Burner	28	9	0.0913	11.2	3.6	0.0913	3.6	7.6	0.0
PM6 TAD1 Burner	84	90	0.1265	46.5	49.9	0.06	23.7	22.9	26.2
PM6 TAD2 Burner	84	50	0.1265	46.5	27.7	0.06	13.1	33.4	14.6
PM7 Yankee Burner	22	9	0.0913	8.8	3.6	0.0913	3.6	5.2	0.0
PM7 TAD1 Burner	90	90	0.1265	49.9	49.9	0.06	23.7	26.2	26.2
PM7 TAD2 Burner	90	50	0.1265	49.9	27.7	0.06	13.1	36.7	14.6
Totals =	**541**	**420**		**270.0**	**211.1**		**113.5**	**156.5**	**97.7**

Lime Kilns

DEQ identified the three lime kilns at the GP Toledo Mill and the one lime kiln at the GP Wauna Mill as possible candidates for burner replacements with new LNBs. While burner replacement is feasible, it will not necessarily result in decreased annual NO_X emissions from the kilns due to the varying mechanisms for NO_X formation within the kilns, including[5]:

- Fuel NO_X – Formed by reaction of nitrogen bound in fuel with oxygen in combustion air
- Thermal NO_X – Formed by oxidation of nitrogen in air at sufficient time and temperature
- Prompt NO_X – Formed by reaction of atmospheric nitrogen and hydrocarbon radicals

All the kilns in operation at the GP Toledo and Wauna Mills use only natural gas as a fuel. Since natural gas has minimal nitrogen content, NO_X formation is dominated by the thermal NO_X pathway. As such, NO_X formation in the kilns is primarily related to peak flame temperature, with a secondary factor being oxygen availability in the combustion zone. Rotary kilns require very high temperatures throughout the vessel, therefore, peak flame temperatures in the "hot-end" of the kilns are very high (~3,000°F) and minor changes in temperature can have significant effects on thermal NO_X generation.[6]

In addition, many process inputs are required to manage kiln operation effectively and efficiently. Operators seek to achieve the lowest possible heat input per ton of lime produced while continuing to generate high quality lime. Often operators make changes at the wet end of the kiln and counter-changes at the dry end to achieve efficient operation. This can result in temperature oscillations and high variability in NO_X emissions from individual kilns over time. Differing kiln design (*e.g.,* kiln length and diameter, air flow rate, etc.) and operational characteristics (*e.g.,* production rate, dry solids rate, etc.) of each kiln also account for a wide range of NO_X emissions across different gas-fired kilns, as these differences affect peak temperatures, oxygen availability, and kiln residence time.

For the reasons described above, a burner replacement alone will not alter all the pathways to NO_X formation and will not necessarily result in a lower annual NO_X emission rate from an existing kiln.

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[5] Information from lime kiln burner vendor, Metso:Outotec, March 2021.
[6] NCASI Technical Bulletin No. 855, *Factors Affecting NO_X Emissions from Lime Kilns*, January 2003.

Therefore, GP is proposing no changes to the current lime kiln burners at the Toledo and Wauna Mills, as it is simply too speculative as to whether the costly proposed controls will verifiably reduce NO_X emissions by significant amounts.

Also, unique for the Toledo Mill and as DEQ has indicated, in 2018 GP reviewed a potential project for the caustic area of the Mill that included replacing the control system and burners for the three lime kilns and other process improvements. The Toledo Mill's caustic area does not have a distributed control system (DCS) and burner management system (BMS), rather it still relies on 1970s vintage single loop and programmable logic controllers. As included in the potential project, the Mill would have to replace the current control system with a new DCS and BMS in conjunction with any potential burner replacements. Based on the estimated capital cost of the complete project of roughly $9.7 million and the expected control efficiency of no more than 31% (reduction from current concentration of 188 ppm @ 10% O_2 to a vendor guarantee of 130 ppm @ 10% O_2), the cost effectiveness of replacing all three lime kiln burners is $17,557/ton of NO_X removed. Based on DEQ's cost effectiveness threshold of $10,000/ton of NO_X removed, these projects are not cost effective. Cost evaluation calculations for the Toledo Mill lime kilns are included in the attachment to this letter.

Power Boilers

DEQ proposed installation of selective catalytic reduction (SCR) for the Nos. 1 and 4 Power Boilers at the GP Toledo Mill and the Power Boiler at the GP Wauna Mill, and selective non-catalytic reduction (SNCR) for the No. 3 Power Boiler at the GP Toledo Mill. As detailed in the June 2020 Four-Factor Analysis (FFA) authored by All4, various negative environmental and energy impacts are associated with these add-on control devices that render them undesirable to the Mills. These impacts should also concern DEQ.

Potential adverse environmental impacts include the transport and handling, and eventual storage and use of additional chemicals onsite, which increases the chemical risk profile (e.g., risk to employees and risk of onsite and offsite release) of each Mill. Aqueous ammonia, which would be used in SCR devices, is a corrosive material that poses a potential health exposure and safety risk. Both systems also carry the risk of ammonia slip, which would potentially increase ammonia emissions from each Mill. The SNCR system proposed for the No. 3 Power Boiler at the Toledo Mill would require an increase in water usage that will also require treatment and disposal of the subsequent wastewater generated from the system.

Adverse impacts on energy are also a significant concern with each system, as both require more use of electricity and natural gas. In particular, the SCR systems in each of the three proposed applications would require an additional duct burner (size ranges from 20 MMBtu/hr to 50 MMBtu/hr) to reheat the exhaust gas to the optimal range for the catalyst, increasing natural gas use at each Mill and generating additional greenhouse gases (GHG). As the Oregon DEQ is currently undergoing rulemaking to reduce GHG emissions in the State, requiring facilities to install control techniques that would force additional natural gas consumption and generation of GHG emissions should be evaluated with respect to these goals. The drive for minimally effective regional haze control measures should not be pursued if it acts at cross-purposes with respect to the Department's GHG reduction goals.

For the reasons outlined above, GP is not agreeing to installation of SCR or SNCR on any of the identified power boilers. Alternatively, GP is proposing to use LNB and flue gas recirculation (FGR) technologies to achieve NO_X emissions reductions from the power boilers at each Mill, provided DEQ agrees to be flexible with respect to implementation deadlines.

Based on GP internal engineering experience and discussions with outside vendors, an outlet NO_X emission rate of 0.09 lb/MMBtu can be achieved in each relevant power boiler application. The GP Wauna Mill Power Boiler has a maximum heat input rating of 580 MMBtu/hr. Therefore, a burner replacement with a new LNB with FGR would achieve an outlet annual emission rate of 228.6 tpy, which corresponds to a reduction in the NO_X PSEL of 362.6 tpy.

The GP Toledo Mill has three affected power boilers (Nos. 1, 3, and 4 Power Boilers) and needs flexibility in determining if burners will be replaced in each unit or whether one or two new boilers will be constructed to replace these three units. Table 4 provides the current heat input rating, emission factors, and emission rates of the boilers as well as the potential future emission factors and emission rates. If the Mill decides to install one or two new units, GP proposes a total emission rate no greater than the sum of the future emission rates of the three existing units with the installation of LNB/FGR, or 252.4 tpy.

TABLE 4. GP TOLEDO MILL POWER BOILER NO_X EMISSION RATES FROM NATURAL GAS COMBUSTION

Emission Unit	Burner Heat Input Rating (MMBtu/hr)	Natural Gas Usage (MMscf/yr)	Current PSEL NO_X Emissions [1] Factor [2] (lb/MMscf)	(lb/MMBtu)	Annual Rate [3] (tpy)	Future NO_X Emissions Factor (lb/MMBtu)	Annual Rate [4] (tpy)	Total NO_X Reductions (tpy)
No. 1 Power Boiler (EU-13)	187.5	1,450	280	0.272	203.0	0.09	73.9	129.09
No. 4 Power Boiler (EU-11)	296.6	2,290	280	0.272	320.6	0.09	116.9	203.68
No. 3 Power Boiler (EU-18)	156.3	1,165	164.2	0.160	95.6	0.09	61.6	34.03
Totals =	**640.4**				**619.2**		**252.4**	**366.8**

1. The current PSEL NO_X emissions are based on the current permit.
2. Emission factor in lb/MMBtu is shown for comparison with the future emission factor.
It is calculated based on a natural gas heat content from actual mill data of: 1,028 Btu/ft^3
3. The current annual NO_X emission rate is calculated from natural gas usage in MMscf/yr and the emission factors in lb/MMscf.
4. The future annual NO_X emission rate is calculated from the burner heat input rating in MMBtu/hr and the emission factors in lb/MMBtu.

Steam supply is a significant operational consideration for any pulp and paper manufacturing facility. Each GP mill requires steam in the pulp production process as well as the papermaking process. As such, changes to steam producing assets require substantial consideration of and planning for the assets themselves as well as the entire pulp and paper manufacturing process to minimize disruptions to overall mill operations. Both mills will need sufficient time to plan the boiler projects with both internal and external engineering resources, and then implement the changes with as little interruption to mill operations as possible. Therefore, GP is requesting an extended timeframe for implementation of these boiler projects.

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GP maintains that there is no evidence that the proposed control measures will result in any measurable visibility benefits or have any impact on meeting reasonable further progress goals of relevant Class I areas. However, while we continue to have concerns over the process DEQ has followed for the regional haze second planning period as outlined in this letter and previous submittals, we are presenting alternative control strategies to reduce NO_X emissions by significant amounts, at significant cost, from various sources at both the GP Toledo and Wauna Mills. We believe that these alternative control measures are more than sufficient. If you have questions regarding this letter, please contact Calli Daly, (503) 931-5886 or calli.daly@kochps.com.

I, the undersigned, am the responsible official of the sources for which this document is being submitted. I hereby certify, based on the information and belief formed after reasonable inquiry, that the statements made, and the data contained in this document are true, accurate, and complete.

Sincerely,

Jeremy Ness
Vice-President – Manufacturing

Attachment

cc: Mr. Michael Orman, Oregon DEQ
Mr. Richard Whitman, Oregon DEQ
Ms. Calli Daly, Koch Companies Public Sector, LLC

ATTACHMENT
GP TOLEDO MILL COST EFFECTIVENESS CALCULATIONS FOR LIME KILN LNBS

Capital & Operating Cost Evaluation for Low NO_x Burner Retrofits for GP Toledo Lime Kiln Nos. 1, 2, and 3

Cost Category	Value	Notes [1]
Kiln Burners =	$2,749,000	
DCS & BMS Control Systems =	$5,580,000	
Kiln Grizzlies and Cameras =	$1,352,000	
Total Capital Investment (TCI)	**$9,681,000**	
Direct Operating Costs (DOC)		
Annual Maintenance Cost =	$266,228	A = 2.75% × TCI
Total Direct Operating Costs (DOC)	***$266,228***	***DOC = A***
Indirect Operating Costs (IOC)		
Administrative Charges (AC) =	$193,620	B = Assumed to be 2% of TCI
Property Taxes =	$96,810	C = Assumed to be 1% of TCI
Insurance =	$96,810	D = Assumed to be 1% of TCI
Capital Recovery Costs (CR) =	$510,012	E = TCI × CRF
Interest Rate (IR) =	3.25%	
Capital Recovery Factor (CRF) =	0.0527	CRF = 3.25% interest and 30-yr equipment life
Total Indirect Operating Costs (IOC)	***$897,252***	***IOC = B + C + D + E***
Total System Annualized Cost (AC) =	**$1,163,479**	***Sum of DOC and IOC***
Current NO_x Concentration =	188	ppm @ 10% O_2 - May 22, 2013 stack test result
Future NO_x Concentration =	130	ppm @ 10% O_2 - Expected vendor guarantee
% Control =	31%	
Current NO_x Emissions Rate (tpy) =	214.80	
Future NO_x Emissions Rate (tpy) =	148.53	
NO_x Removed (tpy) =	66.27	
Cost per ton of NO_x and PM Removed ($/ton)	**$17,557**	**$/ton = System AC / Pollutant Removed**

1. DOC and IOC factors and cost estimates reflect U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition), Section 1, Chapter 2, January 2002*.