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

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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:

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

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

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[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

[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

<u>LNB and FGR for Boiler NO_X Control</u>

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.

<u>Wet Electrostatic Precipitator for Additional PM_{10} Control</u>

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.

[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.

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[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-2
Cascade Pacific Pulp - Halsey
Low NOx Burner and FGR Retrofit - No. 1 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 236 MMBtu/hr boiler and 2019 dollars			***$2,440,766***
(b)	Instrumentation	0.10 × A		***$244,077***
(b)	Sales Tax	0.03 × A		***$73,223***
(b)	Freight	0.05 × A		***$122,038***
	Total Purchased Equipment Cost, B =	B		***$2,880,104***
	Total Direct Cost:		***TDC***	***$2,880,104***
Indirect Capital Costs				
(c)	Engineering	0.10 × B		***$288,010***
(c)	Contingencies	0.20 × B		***$576,021***
(c)	General Facilities	0.05 × B		***$144,005***
(b)	Testing	0.01 × B		***$28,801***
	Total Indirect Cost:		***TIC***	***$1,036,837***
	Total Capital Investment:		***TCI***	***$3,916,942***

ANNUALIZED COSTS				
	COST ITEM	**COST FACTOR**	**UNIT COST**	**COST ($)**
Annual Operating Costs - Direct Annual Costs				
(d)	Maintenance Costs	2.75% of TCI		***$107,716***
Utilities				
(a)	Electricity	277 kW	$0.060 per kWh	***$145,542***
	Total Direct Annual Costs:		***DAC***	***$253,258***
Annual Operating Costs - Indirect Annual Costs				
(b)	Overhead	60% of sum of operating & maintenance costs		***$64,630***
(b)	Administrative Charges	2% of TCI		***$78,339***
(b)	Property Taxes	1% of TCI		***$39,169***
(b)	Insurance	1% of TCI		***$39,169***
	Total Indirect Annual Costs:		***IDAC***	***$221,307***
	Total Annual Costs:		***TAC***	***$474,565***
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	$3,916,942		
	Annualized Capital Investment Cost:			***$501,122***
	Total Annualized Cost:			***$975,687***
(e)	NO_X Reduction	64%		
(f)	Pre-retrofit NO_X	132.5 tons NO_X/yr		
	Post-retrofit NO_X using LNB	47.32 tons NO_X/yr		
	NO_X Removed	85.18 tons NO_X/yr		
	Annual Cost/Ton Removed:			***$11,455***

(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 a comparison of AP-42 natural gas pre-NSPS uncontrolled and LNB/FGR emission factors.

(f) PSEL

Table A-2a
Cascade Pacific Pulp - Halsey
Low NOx Burner and FGR Retrofit - No. 1 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 236 MMBtu/hr boiler and 2019 dollars			***$2,440,766***
(b)	Instrumentation	0.10 × A		***$244,077***
(b)	Sales Tax	0.03 × A		***$73,223***
(b)	Freight	0.05 × A		***$122,038***
	Total Purchased Equipment Cost, B =	B		***$2,880,104***
	Total Direct Cost:		***TDC***	***$2,880,104***
Indirect Capital Costs				
(c)	Engineering	0.10 × B		***$288,010***
(c)	Contingencies	0.20 × B		***$576,021***
(c)	General Facilities	0.05 × B		***$144,005***
(b)	Testing	0.01 × B		***$28,801***
	Total Indirect Cost:		***TIC***	***$1,036,837***
	Total Capital Investment:		***TCI***	***$3,916,942***

ANNUALIZED COSTS				
	COST ITEM	**COST FACTOR**	**UNIT COST**	**COST ($)**
Annual Operating Costs - Direct Annual Costs				
(d)	Maintenance Costs	2.75% of TCI		***$107,716***
Utilities				
(a)	Electricity	277 kW	$0.060 per kWh	***$143,249***
	Total Direct Annual Costs:		***DAC***	***$250,965***
Annual Operating Costs - Indirect Annual Costs				
(b)	Overhead	60% of sum of operating & maintenance costs		***$64,630***
(b)	Administrative Charges	2% of TCI		***$78,339***
(b)	Property Taxes	1% of TCI		***$39,169***
(b)	Insurance	1% of TCI		***$39,169***
	Total Indirect Annual Costs:		***IDAC***	***$221,307***
	Total Annual Costs:		***TAC***	***$472,272***
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	$3,916,942		
	Annualized Capital Investment Cost:			***$501,122***
	Total Annualized Cost:			***$973,394***
(e)	NO_X Reduction	64%		
(f)	Pre-retrofit NO_X	52.9 tons NO_X/yr		
	Post-retrofit NO_X using LNB	18.89 tons NO_X/yr		
	NO_X Removed	34.01 tons NO_X/yr		
	Annual Cost/Ton Removed:			***$28,623***

(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 a comparison of AP-42 natural gas pre-NSPS uncontrolled and LNB/FGR emission factors.

(f) 2017 Actual Emissions

Table A-3
Cascade Pacific Pulp - Halsey
Low NOx Burner and FGR Retrofit - No. 2 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 236 MMBtu/hr boiler and 2019 dollars			***$2,440,766***
(b)	Instrumentation	0.10 × A		***$244,077***
(b)	Sales Tax	0.03 × A		***$73,223***
(b)	Freight	0.05 × A		***$122,038***
	Total Purchased Equipment Cost, B =	B		***$2,880,104***
	Total Direct Cost:		***TDC***	***$2,880,104***
Indirect Capital Costs				
(c)	Engineering	0.10 × B		***$288,010***
(c)	Contingencies	0.20 × B		***$576,021***
(c)	General Facilities	0.05 × B		***$144,005***
(b)	Testing	0.01 × B		***$28,801***
	Total Indirect Cost:		***TIC***	***$1,036,837***
	Total Capital Investment:		***TCI***	***$3,916,942***

ANNUALIZED COSTS						
	COST ITEM	**COST FACTOR**		**UNIT COST**		**COST ($)**
Annual Operating Costs - Direct Annual Costs						
(d)	Maintenance Costs	2.75%	of TCI			***$107,716***
Utilities						
(a)	Electricity	277	kW	$0.060	per kWh	***$145,542***
	Total Direct Annual Costs:			***DAC***		***$253,258***
Annual Operating Costs - Indirect Annual Costs						
(b)	Overhead	60%	of sum of operating & maintenance costs			***$64,630***
(b)	Administrative Charges	2%	of TCI			***$78,339***
(b)	Property Taxes	1%	of TCI			***$39,169***
(b)	Insurance	1%	of TCI			***$39,169***
	Total Indirect Annual Costs:			***IDAC***		***$221,307***
	Total Annual Costs:			***TAC***		***$474,565***
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	$3,916,942				
	Annualized Capital Investment Cost:					***$501,122***
	Total Annualized Cost:					***$975,687***
(e)	NO_X Reduction	64%				
(f)	Pre-retrofit NO_X	75.1	tons NO_X/yr			
	Post-retrofit NO_X using LNB	26.82	tons NO_X/yr			
	NO_X Removed	48.28	tons NO_X/yr			
	Annual Cost/Ton Removed:					***$20,210***

(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 a comparison of AP-42 natural gas pre-NSPS uncontrolled and LNB/FGR emission factors.

(f) PSEL

Table A-3a

Cascade Pacific Pulp - Halsey

Low NOx Burner and FGR Retrofit - No. 2 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 236 MMBtu/hr boiler and 2019 dollars			***$2,440,766***
(b)	Instrumentation	0.10 × A		***$244,077***
(b)	Sales Tax	0.03 × A		***$73,223***
(b)	Freight	0.05 × A		***$122,038***
	Total Purchased Equipment Cost, B =	B		***$2,880,104***
	Total Direct Cost:		***TDC***	***$2,880,104***
Indirect Capital Costs				
(c)	Engineering	0.10 × B		***$288,010***
(c)	Contingencies	0.20 × B		***$576,021***
(c)	General Facilities	0.05 × B		***$144,005***
(b)	Testing	0.01 × B		***$28,801***
	Total Indirect Cost:		***TIC***	***$1,036,837***
	Total Capital Investment:		***TCI***	***$3,916,942***

ANNUALIZED COSTS						
	COST ITEM	**COST FACTOR**		**UNIT COST**		**COST ($)**
Annual Operating Costs - Direct Annual Costs						
(d)	Maintenance Costs	2.75%	of TCI			***$107,716***
Utilities						
(a)	Electricity	277	kW	$0.060	per kWh	***$51,172***
	Total Direct Annual Costs:			***DAC***		***$158,888***
Annual Operating Costs - Indirect Annual Costs						
(b)	Overhead	60%	of sum of operating & maintenance costs			***$64,630***
(b)	Administrative Charges	2%	of TCI			***$78,339***
(b)	Property Taxes	1%	of TCI			***$39,169***
(b)	Insurance	1%	of TCI			***$39,169***
	Total Indirect Annual Costs:			***IDAC***		***$221,307***
	Total Annual Costs:			***TAC***		***$380,195***
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	$3,916,942				
	Annualized Capital Investment Cost:					***$501,122***
	Total Annualized Cost:					***$881,317***
(e)	NO_X Reduction	64%				
(f)	Pre-retrofit NO_X	5.6	tons NO_X/yr			
	Post-retrofit NO_X using LNB	2.00	tons NO_X/yr			
	NO_X Removed	3.60	tons NO_X/yr			
	Annual Cost/Ton Removed:					***$244,810***

(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 a comparison of AP-42 natural gas pre-NSPS uncontrolled and LNB/FGR emission factors.

(f) 2017 Actual Emissions

Table A-4
Low NOx Burner/FGR Retrofit - GP Toledo No. 4 Hog Fuel 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 296.6 MMBtu/hr boiler and 2019 dollars			***$2,799,508***
(b)	Instrumentation	0.10 × A		***$279,951***
(b)	Sales Tax	0.03 × A		***$83,985***
(b)	Freight	0.05 × A		***$139,975***
	Total Purchased Equipment Cost, B =	B		***$3,303,419***
	Total Direct Cost:		***TDC***	***$3,303,419***
Indirect Capital Costs				
(c)	Engineering	0.10 × B		***$330,342***
(c)	Contingencies	0.20 × B		***$660,684***
(c)	General Facilities	0.05 × B		***$165,171***
(b)	Testing	0.01 × B		***$33,034***
	Total Indirect Cost:		***TIC***	***$1,189,231***
	Total Capital Investment:		***TCI***	***$4,492,650***

ANNUALIZED COSTS				
	COST ITEM	COST FACTOR	UNIT COST	COST ($)
Annual Operating Costs - Direct Annual Costs				
(d)	Maintenance Costs	2.75% of TCI		***$123,548***
Utilities				
(a)	Electricity	348 kW	$0.060 per kWh	***$182,914***
	Total Direct Annual Costs:		***DAC***	***$306,462***
Annual Operating Costs - Indirect Annual Costs				
(b)	Overhead	60% of sum of operating & maintenance costs		***$74,129***
(b)	Administrative Charges	2% of TCI		***$89,853***
(b)	Property Taxes	1% of TCI		***$44,927***
(b)	Insurance	1% of TCI		***$44,927***
	Total Indirect Annual Costs:		***IDAC***	***$253,835***
	Total Annual Costs:		***TAC***	***$560,297***
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	$4,492,650		
	Annualized Capital Investment Cost:			***$574,776***
	Total Annualized Cost:			***$1,135,073***
(e)	NO_X Reduction	53%	107.5 ppm to	50 ppm
(f)	Pre-retrofit NO_X	218.4 tons NO_X/yr		
	Post-retrofit NO_X using LNB	101.58 tons NO_X/yr		
	NO_X Removed	116.82 tons NO_X/yr		
	Annual Cost/Ton Removed:			***$9,717***

(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

(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 a comparison of current actual ppm NOx at 3% O2 to post control 50 ppm.

(f) PSEL

Table A-4a
Low NOx Burner/FGR Retrofit - GP Toledo No. 4 Hog Fuel 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 296.6 MMBtu/hr boiler and 2019 dollars			***$2,799,508***
(b)	Instrumentation	0.10 × A		***$279,951***
(b)	Sales Tax	0.03 × A		***$83,985***
(b)	Freight	0.05 × A		***$139,975***
	Total Purchased Equipment Cost, B =	B		***$3,303,419***
	Total Direct Cost:		***TDC***	***$3,303,419***
Indirect Capital Costs				
(c)	Engineering	0.10 × B		***$330,342***
(c)	Contingencies	0.20 × B		***$660,684***
(c)	General Facilities	0.05 × B		***$165,171***
(b)	Testing	0.01 × B		***$33,034***
	Total Indirect Cost:		***TIC***	***$1,189,231***
	Total Capital Investment:		***TCI***	***$4,492,650***

ANNUALIZED COSTS					
	COST ITEM	**COST FACTOR**		**UNIT COST**	**COST ($)**
Annual Operating Costs - Direct Annual Costs					
(d)	Maintenance Costs	2.75%	of TCI		***$123,548***
Utilities					
(a)	Electricity	348	kW	$0.060 per kWh	***$178,989***
	Total Direct Annual Costs:			***DAC***	***$302,537***
Annual Operating Costs - Indirect Annual Costs					
(b)	Overhead	60%	of sum of operating & maintenance costs		***$74,129***
(b)	Administrative Charges	2%	of TCI		***$89,853***
(b)	Property Taxes	1%	of TCI		***$44,927***
(b)	Insurance	1%	of TCI		***$44,927***
	Total Indirect Annual Costs:			***IDAC***	***$253,835***
	Total Annual Costs:			***TAC***	***$556,371***
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	$4,492,650			
	Annualized Capital Investment Cost:				***$574,776***
	Total Annualized Cost:				***$1,131,148***
(e)	NO_X Reduction	53%		107.5 ppm to	50 ppm
(f)	Pre-retrofit NO_X	210.6	tons NO_X/yr		
	Post-retrofit NO_X using LNB	97.95	tons NO_X/yr		
	NO_X Removed	112.65	tons NO_X/yr		
	Annual Cost/Ton Removed:				***$10,042***

(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

(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 a comparison of current actual ppm NOx at 3% O2 to post control 50 ppm.

(f) 2017 Actual Emissions

Table A-5
Low NOx Burner/FGR Retrofit - GP Toledo No. 1 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 187.5 MMBtu/hr boiler and 2019 dollars			***$2,126,081***
(b)	Instrumentation	0.10 × A		***$212,608***
(b)	Sales Tax	0.03 × A		***$63,782***
(b)	Freight	0.05 × A		***$106,304***
	Total Purchased Equipment Cost, B =	B		***$2,508,775***
	Total Direct Cost:		***TDC***	***$2,508,775***
Indirect Capital Costs				
(c)	Engineering	0.10 × B		***$250,878***
(c)	Contingencies	0.20 × B		***$501,755***
(c)	General Facilities	0.05 × B		***$125,439***
(b)	Testing	0.01 × B		***$25,088***
	Total Indirect Cost:		***TIC***	***$903,159***
	Total Capital Investment:		***TCI***	***$3,411,934***

ANNUALIZED COSTS				
	COST ITEM	**COST FACTOR**	**UNIT COST**	**COST ($)**
Annual Operating Costs - Direct Annual Costs				
(d)	Maintenance Costs	2.75% of TCI		***$93,828***
Utilities				
(a)	Electricity	220 kW	$0.060 per kWh	***$115,632***
	Total Direct Annual Costs:		***DAC***	***$209,460***
Annual Operating Costs - Indirect Annual Costs				
(b)	Overhead	60% of sum of operating & maintenance costs		***$56,297***
(b)	Administrative Charges	2% of TCI		***$68,239***
(b)	Property Taxes	1% of TCI		***$34,119***
(b)	Insurance	1% of TCI		***$34,119***
	Total Indirect Annual Costs:		***IDAC***	***$192,774***
	Total Annual Costs:		***TAC***	***$402,234***
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	$3,411,934		
	Annualized Capital Investment Cost:			***$436,513***
	Total Annualized Cost:			***$838,747***
(e)	NO_X Reduction	79%	234 ppm to	50 ppm
(f)	Pre-retrofit NO_X	223.7 tons NO_X/yr		
	Post-retrofit NO_X using LNB	47.82 tons NO_X/yr		
	NO_X Removed	175.9 tons NO_X/yr		
	Annual Cost/Ton Removed:			***$4,769***

(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

(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 a comparison of current actual ppm NOx at 3% O2 to post control 50 ppm.

(f) PSEL

Table A-5a

Low NOx Burner/FGR Retrofit - GP Toledo No. 1 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 187.5 MMBtu/hr boiler and 2019 dollars			***$2,126,081***
(b)	Instrumentation	0.10 × A		***$212,608***
(b)	Sales Tax	0.03 × A		***$63,782***
(b)	Freight	0.05 × A		***$106,304***
	Total Purchased Equipment Cost, B =	B		***$2,508,775***
	Total Direct Cost:		***TDC***	***$2,508,775***
Indirect Capital Costs				
(c)	Engineering	0.10 × B		***$250,878***
(c)	Contingencies	0.20 × B		***$501,755***
(c)	General Facilities	0.05 × B		***$125,439***
(b)	Testing	0.01 × B		***$25,088***
	Total Indirect Cost:		***TIC***	***$903,159***
	Total Capital Investment:		***TCI***	***$3,411,934***

ANNUALIZED COSTS						
	COST ITEM	**COST FACTOR**		**UNIT COST**		**COST ($)**
Annual Operating Costs - Direct Annual Costs						
(d)	Maintenance Costs	2.75%	of TCI			***$93,828***
Utilities						
(a)	Electricity	220	kW	$0.060	per kWh	***$112,728***
	Total Direct Annual Costs:				***DAC***	***$206,556***
Annual Operating Costs - Indirect Annual Costs						
(b)	Overhead	60%	of sum of operating & maintenance costs			***$56,297***
(b)	Administrative Charges	2%	of TCI			***$68,239***
(b)	Property Taxes	1%	of TCI			***$34,119***
(b)	Insurance	1%	of TCI			***$34,119***
	Total Indirect Annual Costs:				***IDAC***	***$192,774***
	Total Annual Costs:				***TAC***	***$399,330***
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	$3,411,934				
	Annualized Capital Investment Cost:					***$436,513***
	Total Annualized Cost:					***$835,843***
(e)	NO_X Reduction	79%		234 ppm to		50 ppm
(f)	Pre-retrofit NO_X	150.1	tons NO_X/yr			
	Post-retrofit NO_X using LNB	32.09	tons NO_X/yr			
	NO_X Removed	118.0	tons NO_X/yr			
	Annual Cost/Ton Removed:					***$7,083***

(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

(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 a comparison of current actual ppm NOx at 3% O2 to post control 50 ppm.

(f) 2017 Actual Emissions

Table A-6
Low NOx Burner/FGR Retrofit - GP Toledo No. 3 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 156.3 MMBtu/hr boiler and 2019 dollars			***$1,906,138***
(b)	Instrumentation	0.10 × A		***$190,614***
(b)	Sales Tax	0.03 × A		***$57,184***
(b)	Freight	0.05 × A		***$95,307***
	Total Purchased Equipment Cost, B =	B		***$2,249,243***
	Total Direct Cost:		***TDC***	***$2,249,243***
Indirect Capital Costs				
(c)	Engineering	0.10 × B		***$224,924***
(c)	Contingencies	0.20 × B		***$449,849***
(c)	General Facilities	0.05 × B		***$112,462***
(b)	Testing	0.01 × B		***$22,492***
	Total Indirect Cost:		***TIC***	***$809,727***
	Total Capital Investment:		***TCI***	***$3,058,970***

ANNUALIZED COSTS						
	COST ITEM	COST FACTOR		UNIT COST		COST ($)
Annual Operating Costs - Direct Annual Costs						
(d)	Maintenance Costs	2.75%	of TCI			***$84,122***
Utilities						
(a)	Electricity	183	kW	$0.060	per kWh	***$96,391***
	Total Direct Annual Costs:			***DAC***		***$180,513***
Annual Operating Costs - Indirect Annual Costs						
(b)	Overhead	60%	of sum of operating & maintenance costs			***$50,473***
(b)	Administrative Charges	2%	of TCI			***$61,179***
(b)	Property Taxes	1%	of TCI			***$30,590***
(b)	Insurance	1%	of TCI			***$30,590***
	Total Indirect Annual Costs:			***IDAC***		***$172,832***
	Total Annual Costs:			***TAC***		***$353,344***
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	$3,058,970				
	Annualized Capital Investment Cost:					***$391,355***
	Total Annualized Cost:					***$744,700***
(e)	NO_X Reduction	47%		93.8 ppm to	50 ppm	
(f)	Pre-retrofit NO_X	107.6	tons NO_X/yr			
	Post-retrofit NO_X using LNB	57.36	tons NO_X/yr			
	NO_X Removed	50.2	tons NO_X/yr			
	Annual Cost/Ton Removed:					***$14,822***

(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 a comparison of current actual ppm NOx at 3% O2 to post control 50 ppm.

(f) PSEL

Table A-6a
Low NOx Burner/FGR Retrofit - GP Toledo No. 3 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 156.3 MMBtu/hr boiler and 2019 dollars			***$1,906,138***
(b)	Instrumentation	0.10 × A		***$190,614***
(b)	Sales Tax	0.03 × A		***$57,184***
(b)	Freight	0.05 × A		***$95,307***
	Total Purchased Equipment Cost, B =	B		***$2,249,243***
	Total Direct Cost:		***TDC***	***$2,249,243***
Indirect Capital Costs				
(c)	Engineering	0.10 × B		***$224,924***
(c)	Contingencies	0.20 × B		***$449,849***
(c)	General Facilities	0.05 × B		***$112,462***
(b)	Testing	0.01 × B		***$22,492***
	Total Indirect Cost:		***TIC***	***$809,727***
	Total Capital Investment:		***TCI***	***$3,058,970***

ANNUALIZED COSTS				
	COST ITEM	**COST FACTOR**	**UNIT COST**	**COST ($)**
Annual Operating Costs - Direct Annual Costs				
(d)	Maintenance Costs	2.75% of TCI		***$84,122***
Utilities				
(a)	Electricity	183 kW	$0.060 per kWh	***$93,871***
	Total Direct Annual Costs:		***DAC***	***$177,993***
Annual Operating Costs - Indirect Annual Costs				
(b)	Overhead	60% of sum of operating & maintenance costs		***$50,473***
(b)	Administrative Charges	2% of TCI		***$61,179***
(b)	Property Taxes	1% of TCI		***$30,590***
(b)	Insurance	1% of TCI		***$30,590***
	Total Indirect Annual Costs:		***IDAC***	***$172,832***
	Total Annual Costs:		***TAC***	***$350,825***
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	$3,058,970		
	Annualized Capital Investment Cost:			***$391,355***
	Total Annualized Cost:			***$742,180***
(e)	NO_X Reduction	47%	93.8 ppm to	50 ppm
(f)	Pre-retrofit NO_X	75.6 tons NO_X/yr		
	Post-retrofit NO_X using LNB	40.30 tons NO_X/yr		
	NO_X Removed	35.3 tons NO_X/yr		
	Annual Cost/Ton Removed:			***$21,024***

(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 a comparison of current actual ppm NOx at 3% O2 to post control 50 ppm.
(f) 2017 Actual Emissions

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

Table A-8
Low NOx Burner/FGR Retrofit - IP Springfield 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 544 MMBtu/hr boiler and 2019 dollars			***$4,028,453***
(b)	Instrumentation	0.10 × A		***$402,845***
(b)	Sales Tax	0.03 × A		***$120,854***
(b)	Freight	0.05 × A		***$201,423***
	Total Purchased Equipment Cost, B =	B		***$4,753,575***
	Total Direct Cost:		***TDC***	***$4,753,575***
Indirect Capital Costs				
(c)	Engineering	0.10 × B		***$475,357***
(c)	Contingencies	0.20 × B		***$950,715***
(c)	General Facilities	0.05 × B		***$237,679***
(b)	Testing	0.01 × B		***$47,536***
	Total Indirect Cost:		***TIC***	***$1,711,287***
	Total Capital Investment:		***TCI***	***$6,464,862***

ANNUALIZED COSTS				
	COST ITEM	**COST FACTOR**	**UNIT COST**	**COST ($)**
Annual Operating Costs - Direct Annual Costs				
(d)	Maintenance Costs	2.75% of TCI		***$177,784***
Utilities				
(a)	Electricity	508 kW	$0.060 per kWh	***$267,033***
	Total Direct Annual Costs:		***DAC***	***$444,817***
Annual Operating Costs - Indirect Annual Costs				
(b)	Overhead	60% of sum of operating & maintenance costs		***$106,670***
(b)	Administrative Charges	2% of TCI		***$129,297***
(b)	Property Taxes	1% of TCI		***$64,649***
(b)	Insurance	1% of TCI		***$64,649***
	Total Indirect Annual Costs:		***IDAC***	***$365,265***
	Total Annual Costs:		***TAC***	***$810,081***
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	$6,464,862		
	Annualized Capital Investment Cost:			***$827,095***
	Total Annualized Cost:			***$1,637,176***
(e)	NO_X Reduction	64%		
(f)	Pre-retrofit NO_X	873.7 tons NO_X/yr		
	Post-retrofit NO_X using LNB	314.5 tons NO_X/yr		
	NO_X Removed	559.2 tons NO_X/yr		
	Annual Cost/Ton Removed:			***$2,928***

(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 a comparison of AP-42 natural gas pre-NSPS uncontrolled and LNB/FGR emission factors.

(f) PSEL

Table A-8a

Low NOx Burner/FGR Retrofit - IP Springfield 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 544 MMBtu/hr boiler and 2019 dollars			***$4,028,453***
(b)	Instrumentation	0.10 × A		***$402,845***
(b)	Sales Tax	0.03 × A		***$120,854***
(b)	Freight	0.05 × A		***$201,423***
	Total Purchased Equipment Cost, B =	B		***$4,753,575***
	Total Direct Cost:		***TDC***	***$4,753,575***
Indirect Capital Costs				
(c)	Engineering	0.10 × B		***$475,357***
(c)	Contingencies	0.20 × B		***$950,715***
(c)	General Facilities	0.05 × B		***$237,679***
(b)	Testing	0.01 × B		***$47,536***
	Total Indirect Cost:		***TIC***	***$1,711,287***
	Total Capital Investment:		***TCI***	***$6,464,862***

ANNUALIZED COSTS

	COST ITEM	COST FACTOR		UNIT COST		COST ($)
Annual Operating Costs - Direct Annual Costs						
(d)	Maintenance Costs	2.75%	of TCI			***$177,784***
Utilities						
(a)	Electricity	508	kW	$0.060	per kWh	***$267,033***
	Total Direct Annual Costs:			***DAC***		***$444,817***
Annual Operating Costs - Indirect Annual Costs						
(b)	Overhead	60%	of sum of operating & maintenance costs			***$106,670***
(b)	Administrative Charges	2%	of TCI			***$129,297***
(b)	Property Taxes	1%	of TCI			***$64,649***
(b)	Insurance	1%	of TCI			***$64,649***
	Total Indirect Annual Costs:			***IDAC***		***$365,265***
	Total Annual Costs:			***TAC***		***$810,081***
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	$6,464,862				
	Annualized Capital Investment Cost:					***$827,095***
	Total Annualized Cost:					***$1,637,176***
(e)	NO_X Reduction	64%				
(f)	Pre-retrofit NO_X	140.3	tons NO_X/yr			
	Post-retrofit NO_X using LNB	50.5	tons NO_X/yr			
	NO_X Removed	89.8	tons NO_X/yr			
	Annual Cost/Ton Removed:					***$18,228***

(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 a comparison of AP-42 natural gas pre-NSPS uncontrolled and LNB/FGR emission 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)? 236 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,020 Btu/scf

What is the estimated actual annual fuel consumption? 856,000,000 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	0.276	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.152	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	2.04	
Concentration of reagent as stored (C_{stored})	50	Percent
Density of reagent as stored (ρ_{stored})	71	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years
Select the reagent used	Urea	

Plant Elevation: 278 Feet above sea level

*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019).

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}$)	1.66	$/gallon for a 50 percent solution of urea*		
Water ($Cost_{water}$)	0.0042	$/gallon*		
Electricity ($Cost_{elect}$)	0.0676	$/kWh*		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		$/ton		

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)	$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6, Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf.	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Fuel Cost ($/MMBtu)	2.87	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/.	1020 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 =	236	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	2,026,823,529	scf/Year	
Actual Annual fuel consumption (Mactual) =		856,000,000	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.00	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 =	29.36	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	59.63	tons/year	PSEL is 132.5 tpy
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 278 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.6	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

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

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x NSR x MW_R)/(MW_{NOx} x SR) = (whre SR = 1 for NH_3; 2 for Urea)	87	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	174	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	18.3	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	6,200	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 =	7.6	kW/hour	
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	83	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	0.70	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 ($SNCR_{cost}$) =	$932,866	in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$1,628,897	in 2019 dollars
Total Capital Investment (TCI) =	$3,330,291	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 ($SNCR_{cost}$) =	$932,866	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:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

Balance of Plant Costs (BOP_{cost}) =	$1,628,897	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$354,441	in 2019 dollars
Indirect Annual Costs (IDAC) =	$263,259	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$617,700	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 =	$49,954	in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$266,117	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$4,516	in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$3,041	in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$30,812	in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0	in 2019 dollars
Direct Annual Cost =		$354,441	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$1,499	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$261,761	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$263,259	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$617,700	per year in 2019 dollars
NOx Removed =	60	tons/year
Cost Effectiveness =	$10,360	per ton of NOx removed in 2019 dollars

Table A-9a - SNCR for CPP Halsey Power Boiler No. 1

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)? 236 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,020 Btu/scf

What is the estimated actual annual fuel consumption? 470,560,784 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-9a - SNCR for CPP Halsey Power Boiler No. 1

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	360	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.221	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.121	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	2.33	
Concentration of reagent as stored (C_{stored})	50	Percent
Density of reagent as stored (ρ_{stored})	71	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years
Select the reagent used	Urea	

Plant Elevation: 278 Feet above sea level

*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019).

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}$)	1.66	$/gallon for a 50 percent solution of urea*		
Water ($Cost_{water}$)	0.0042	$/gallon*		
Electricity ($Cost_{elect}$)	0.0676	$/kWh*		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		$/ton		

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-9a - SNCR for CPP Halsey Power Boiler No. 1

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6, Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf.	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Fuel Cost ($/MMBtu)	2.87	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/.	1020 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 =	236	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	2,026,823,529	scf/Year	
Actual Annual fuel consumption (Mactual) =		470,560,784	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.23	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	8622	hours	Based on 2017 Operating Hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	45	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	23.45	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	23.85	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 278 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.6	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

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

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea)	79	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	158	lb/hour
	$(m_{sol} \times 7.4805)$/Reagent Density =	16.7	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24$ hours/day)/Reagent Density =	5,700	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

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

Parameter	Equation	Calculated Value	Units	
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	6.9	kW/hour	
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x $((C_{stored}/C_{inj}) - 1)$ =	76	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$Hv \times m_{reagent} \times ((1/C_{inj})-1)$ =	0.64	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta fuel \times \%Ash \times 1x10^6)/HHV$ =	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 ($SNCR_{cost}$) =	$932,866	in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$1,585,574	in 2019 dollars
Total Capital Investment (TCI) =	$3,273,971	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 ($SNCR_{cost}$) =	$932,866	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:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

Balance of Plant Costs (BOP_{cost}) =	$1,585,574	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$322,190	in 2019 dollars
Indirect Annual Costs (IDAC) =	$258,807	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$580,997	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 =	$49,110	in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$238,669	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$4,051	in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$2,728	in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$27,634	in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0	in 2019 dollars
Direct Annual Cost =		$322,190	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$1,473	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$257,334	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$258,807	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$580,997	per year in 2019 dollars
NOx Removed =	24	tons/year
Cost Effectiveness =	$24,360	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 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)?	236	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,020	Btu/scf
What is the estimated actual annual fuel consumption?	525,000,000	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	0.280	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.154	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	2.02	
Concentration of reagent as stored (C_{stored})	50	Percent
Density of reagent as stored (ρ_{stored})	71	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years
Select the reagent used	Urea	

Plant Elevation: 278 Feet above sea level

*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019).

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 ($Cost_{reag}$)	1.66	\$/gallon for a 50 percent solution of urea*
Water ($Cost_{water}$)	0.0042	\$/gallon*
Electricity ($Cost_{elect}$)	0.0676	\$/kWh*
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		\$/ton

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)	$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6, Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf.	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Fuel Cost ($/MMBtu)	2.87	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/.	1020 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 =	236	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	2,026,823,529	scf/Year	
Actual Annual fuel consumption (Mactual) =		525,000,000	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.26	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 =	29.78	lb/hour	
Total NO_x removed per year =	$(NOx_{in}$ x EF x Q_B x $t_{op})/2000$ =	33.80	tons/year	PSEL is 75.1 tpy
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 278 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.6	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

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

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea)	87	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	175	lb/hour
	$(m_{sol} \times 7.4805)$/Reagent Density =	18.4	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24$ hours/day)/Reagent Density =	6,200	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

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

Parameter	Equation	Calculated Value	Units	
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	7.7	kW/hour	
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x $((C_{stored}/C_{inj}) - 1)$ =	84	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$Hv \times m_{reagent} \times ((1/C_{inj})-1)$ =	0.71	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta fuel \times \%Ash \times 1x10^6)/HHV$ =	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 ($SNCR_{cost}$) =	$932,866	in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$1,631,652	in 2019 dollars
Total Capital Investment (TCI) =	$3,333,873	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 ($SNCR_{cost}$) =	$932,866	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}) =	$1,631,652	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$356,401	in 2019 dollars
Indirect Annual Costs (IDAC) =	$263,543	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$619,943	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 =	$50,008	in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$267,783	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$4,545	in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$3,060	in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$31,005	in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0	in 2019 dollars
Direct Annual Cost =		$356,401	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$1,500	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$262,042	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$263,543	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$619,943	per year in 2019 dollars
NOx Removed =	34	tons/year
Cost Effectiveness =	$18,344	per ton of NOx removed in 2019 dollars

Table A-10a - SNCR for CPP Halsey Power Boiler No. 2

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)? 236 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,020 Btu/scf

What is the estimated actual annual fuel consumption? 60,689,216 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-10a - SNCR for CPP Halsey Power Boiler No. 2

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	129	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.181	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.100	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	2.64	
Concentration of reagent as stored (C_{stored})	50	Percent
Density of reagent as stored (ρ_{stored})	71	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years
Select the reagent used	Urea	

Plant Elevation	278	Feet above sea level

*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019).

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}$)	1.66	$/gallon for a 50 percent solution of urea*		
Water ($Cost_{water}$)	0.0042	$/gallon*		
Electricity ($Cost_{elect}$)	0.0676	$/kWh*		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		$/ton		

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-10a - SNCR for CPP Halsey Power Boiler No. 2

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6, Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf.	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Fuel Cost ($/MMBtu)	2.87	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/.	1020 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 =	236	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	2,026,823,529	scf/Year	
Actual Annual fuel consumption (Mactual) =		60,689,216	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.01	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	3080	hours	Based on 2017 Operating Hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	45	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	19.21	lb/hour	
Total NO_x removed per year =	$(NOx_{in}$ x EF x Q_B x $t_{op})/2000$ =	2.52	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 278 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.6	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

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

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea)	74	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	147	lb/hour
	$(m_{sol} \times 7.4805)$/Reagent Density =	15.5	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24$ hours/day)/Reagent Density =	5,300	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

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

Parameter	Equation	Calculated Value	Units	
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	6.5	kW/hour	
Water Usage: Water consumption (q_w) =	$(m_{sol}$/Density of water$) \times ((C_{stored}/C_{inj}) - 1)$ =	71	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$Hv \times m_{reagent} \times ((1/C_{inj})-1)$ =	0.60	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta fuel \times \%Ash \times 1x10^6)/HHV$ =	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 ($SNCR_{cost}$) =	$932,866	in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$1,548,091	in 2019 dollars
Total Capital Investment (TCI) =	$3,225,243	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 ($SNCR_{cost}$) =	$932,866	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:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

Balance of Plant Costs (BOP_{cost}) =	$1,548,091	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$139,108	in 2019 dollars
Indirect Annual Costs (IDAC) =	$254,955	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$394,064	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 =	$48,379	in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$79,297	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$1,346	in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$906	in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$9,181	in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0	in 2019 dollars
Direct Annual Cost =		$139,108	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$1,451	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$253,504	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$254,955	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$394,064	per year in 2019 dollars
NOx Removed =	3	tons/year
Cost Effectiveness =	$156,375	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 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)? 296.6 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,028 Btu/scf

What is the estimated actual annual fuel consumption? 2,527,400,000 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	0.168	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.092	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	2.77	
Concentration of reagent as stored (C_{stored})	50	Percent
Density of reagent as stored (ρ_{stored})	71	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years
Select the reagent used	Urea	

Plant Elevation: 180 Feet above sea level

*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019).

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 ($Cost_{reag}$)	1.66	\$/gallon for a 50 percent solution of urea*
Water ($Cost_{water}$)	0.0042	\$/gallon*
Electricity ($Cost_{elect}$)	0.0676	\$/kWh*
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		\$/ton

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)	$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf.	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Fuel Cost ($/MMBtu)	2.87	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 =	297	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	2,527,447,471	scf/Year	
Actual Annual fuel consumption (Mactual) =		2,527,400,000	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	1.00	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	8760	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	45	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	22.44	lb/hour	
Total NO_x removed per year =	$(NOx_{in}$ x EF x Q_B x $t_{op})/2000$ =	98.28	tons/year	Based on 218.4 tpy PSEL
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 180 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.6	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

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

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea)	90	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	181	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	19.0	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	6,400	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

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

Parameter	Equation	Calculated Value	Units	
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	7.9	kW/hour	
Water Usage: Water consumption (q_w) =	$(m_{sol}/\text{Density of water}) \times ((C_{stored}/C_{inj}) - 1)$ =	87	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$Hv \times m_{reagent} \times ((1/C_{inj})-1)$ =	0.73	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta fuel \times \%Ash \times 1x10^6)/HHV$ =	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 ($SNCR_{cost}$) =	$1,026,852	in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$1,700,726	in 2019 dollars
Total Capital Investment (TCI) =	$3,545,852	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 ($SNCR_{cost}$) =	$1,026,852	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:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

Balance of Plant Costs (BOP_{cost}) =	$1,700,726	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$369,671	in 2019 dollars
Indirect Annual Costs (IDAC) =	$280,300	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$649,971	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 =	$53,188	in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$276,602	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$4,694	in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$3,161	in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$32,026	in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0	in 2019 dollars
Direct Annual Cost =		$369,671	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$1,596	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$278,704	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$280,300	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$649,971	per year in 2019 dollars
NOx Removed =	98	tons/year
Cost Effectiveness =	$6,613	per ton of NOx removed in 2019 dollars

Table A-11a - SNCR for GP Toledo No. 4 Hog Fuel 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)? 296.6 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,028 Btu/scf

What is the estimated actual annual fuel consumption? 1,463,522,374 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-11a - SNCR for GP Toledo No. 4 Hog Fuel Boiler

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	358	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.280	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.154	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	2.03	

*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019).

Plant Elevation: 180 Feet above sea level

Concentration of reagent as stored (C_{stored})	50	Percent
Density of reagent as stored (ρ_{stored})	71	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years
Select the reagent used	Urea	

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

Enter the cost data for the proposed SNCR:

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}$)	1.66	$/gallon for a 50 percent solution of urea*		
Water ($Cost_{water}$)	0.0042	$/gallon*		
Electricity ($Cost_{elect}$)	0.0676	$/kWh*		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		$/ton		

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-11a - SNCR for GP Toledo No. 4 Hog Fuel 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)	$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf.	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Fuel Cost ($/MMBtu)	2.87	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 =	297	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	2,527,447,471	scf/Year	
Actual Annual fuel consumption (Mactual) =		1,463,522,374	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.57	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	8572	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	45	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	37.37	lb/hour	
Total NO_x removed per year =	$(NOx_{in}$ x EF x Q_B x $t_{op})/2000$ =	94.77	tons/year	Based on 2017 Annual 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 180 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.6	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

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

Reagent Data:

Type of reagent used: Urea

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

Density = 71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x NSR x MW_R)/(MW_{NOx} x SR) = (whre SR = 1 for NH_3; 2 for Urea)	110	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	220	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	23.1	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	7,800	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

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

Parameter	Equation	Calculated Value	Units	
Electricity Usage: Electricity Consumption (P) =	(0.47 x NOx_{in} x NSR x Q_B)/NPHR =	9.6	kW/hour	
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	105	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	0.89	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 ($SNCR_{cost}$) =	$1,026,852 in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0 in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$1,808,064 in 2019 dollars
Total Capital Investment (TCI) =	$3,685,391 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 ($SNCR_{cost}$) =	$1,026,852 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:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

Balance of Plant Costs (BOP_{cost}) =	$1,808,064 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	\$431,809 in 2019 dollars
Indirect Annual Costs (IDAC) =	\$291,330 in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	\$723,139 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 =	\$55,281 in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	\$329,080 in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	\$5,585 in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	\$3,761 in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	\$38,102 in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	\$0 in 2019 dollars
Direct Annual Cost =		\$431,809 in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	\$1,658 in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	\$289,672 in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	\$291,330 in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	\$723,139 per year in 2019 dollars
NOx Removed =	95 tons/year
Cost Effectiveness =	\$7,630 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 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)? 187.5 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,028 Btu/scf

What is the estimated actual annual fuel consumption? 1,597,800,000 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	0.271	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.149	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	2.06	
Concentration of reagent as stored (C_{stored})	50	Percent
Density of reagent as stored (ρ_{stored})	71	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years
Select the reagent used	Urea	

Plant Elevation: 180 Feet above sea level

*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019).

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}$)	1.66	$/gallon for a 50 percent solution of urea*		
Water ($Cost_{water}$)	0.0042	$/gallon*		
Electricity ($Cost_{elect}$)	0.0676	$/kWh*		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		$/ton		

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)	$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6, Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf.	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Fuel Cost ($/MMBtu)	2.87	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 =	188	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	1,597,762,646	scf/Year	
Actual Annual fuel consumption (Mactual) =		1,597,800,000	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	1.00	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	8760	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	45	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	22.87	lb/hour	
Total NO_x removed per year =	$(NOx_{in}$ x EF x Q_B x $t_{op})/2000$ =	100.67	tons/year	Based on PSEL of 223.7 tpy
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 180 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.6	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

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

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea)	68	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	137	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	14.4	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	4,900	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

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

Parameter	Equation	Calculated Value	Units	
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	6.0	kW/hour	
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	66	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x $((1/C_{inj})-1)$ =	0.55	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x 1×10^6)/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 ($SNCR_{cost}$) =	$846,948	in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$1,465,220	in 2019 dollars
Total Capital Investment (TCI) =	$3,005,818	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 ($SNCR_{cost}$) =	$846,948	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:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

Balance of Plant Costs (BOP_{cost}) =	$1,465,220	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$284,908	in 2019 dollars
Indirect Annual Costs (IDAC) =	$237,610	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$522,518	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 =	$45,087	in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$209,600	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$3,557	in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$2,395	in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$24,268	in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0	in 2019 dollars
Direct Annual Cost =		$284,908	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$1,353	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$236,257	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$237,610	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$522,518	per year in 2019 dollars
NOx Removed =	101	tons/year
Cost Effectiveness =	$5,191	per ton of NOx removed in 2019 dollars

Table A-12a - SNCR for GP Toledo No. 1 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)? 187.5 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,028 Btu/scf

What is the estimated actual annual fuel consumption? 1,043,080,739 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-12a - SNCR for GP Toledo No. 1 Power Boiler

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	356	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.280	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.154	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	2.03	

*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019).

Plant Elevation	180	Feet above sea level

Concentration of reagent as stored (C_{stored})	50	Percent
Density of reagent as stored (ρ_{stored})	71	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years
Select the reagent used	Urea	

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

Enter the cost data for the proposed SNCR:

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 ($Cost_{reag}$)	1.66	\$/gallon for a 50 percent solution of urea*
Water ($Cost_{water}$)	0.0042	\$/gallon*
Electricity ($Cost_{elect}$)	0.0676	\$/kWh*
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		\$/ton

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-12a - SNCR for GP Toledo No. 1 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)	$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6, Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf.	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Fuel Cost ($/MMBtu)	2.87	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 =	188	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	1,597,762,646	scf/Year	
Actual Annual fuel consumption (Mactual) =		1,043,080,739	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.64	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	8540	hours	Based on 2017 Operating Hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	45	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	23.62	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	67.55	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 180 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.6	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

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

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x NSR x MW_R)/(MW_{NOx} x SR) = (whre SR = 1 for NH_3; 2 for Urea)	69	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	139	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	14.6	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	5,000	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 =	6.1	kW/hour	
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	67	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	0.56	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 ($SNCR_{cost}$) =	$846,948	in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$1,470,916	in 2019 dollars
Total Capital Investment (TCI) =	$3,013,222	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 ($SNCR_{cost}$) =	$846,948	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:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

Balance of Plant Costs (BOP_{cost}) =	$1,470,916	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$282,338	in 2019 dollars
Indirect Annual Costs (IDAC) =	$238,195	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$520,534	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 =	$45,198	in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$207,257	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$3,517	in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$2,369	in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$23,997	in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0	in 2019 dollars
Direct Annual Cost =		$282,338	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$1,356	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$236,839	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$238,195	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$520,534	per year in 2019 dollars
NOx Removed =	68	tons/year
Cost Effectiveness =	$7,706	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 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)? 156.3 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,028 Btu/scf

What is the estimated actual annual fuel consumption? 1,310,600,000 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	0.160	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.088	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	2.87	
Concentration of reagent as stored (C_{stored})	50	Percent
Density of reagent as stored (ρ_{stored})	71	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years
Select the reagent used	Urea	

Plant Elevation: 180 Feet above sea level

*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019).

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}$)	1.66	$/gallon for a 50 percent solution of urea*		
Water ($Cost_{water}$)	0.0042	$/gallon*		
Electricity ($Cost_{elect}$)	0.0676	$/kWh*		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		$/ton		

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)	$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6, Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf.	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Fuel Cost ($/MMBtu)	2.87	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 =	156	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	1,331,894,942	scf/Year	
Actual Annual fuel consumption (Mactual) =		1,310,600,000	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.98	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 =	11.23	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	48.42	tons/year	Based on PSEL of 107.6 tpy
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 180 feet above sea level (P) =	2116x[(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.6	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

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

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x NSR x MW_R)/(MW_{NOx} x SR) = (whre SR = 1 for NH_3; 2 for Urea)	47	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	94	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	9.9	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	3,400	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 =	4.1	kW/hour	
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	45	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	0.38	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 ($SNCR_{cost}$) =	$784,619	in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$1,266,988	in 2019 dollars
Total Capital Investment (TCI) =	$2,667,089	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 ($SNCR_{cost}$) =	$784,619	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:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

Balance of Plant Costs (BOP_{cost}) =	$1,266,988	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$204,085	in 2019 dollars
Indirect Annual Costs (IDAC) =	$210,833	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$414,919	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 =	$40,006	in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$143,403	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$2,434	in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$1,639	in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$16,604	in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0	in 2019 dollars
Direct Annual Cost =		$204,085	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$1,200	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$209,633	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$210,833	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$414,919	per year in 2019 dollars
NOx Removed =	48	tons/year
Cost Effectiveness =	$8,569	per ton of NOx removed in 2019 dollars

Table A-13a - SNCR for GP Toledo No. 3 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)? 156.3 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,028 Btu/scf

What is the estimated actual annual fuel consumption? 895,734,436 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-13a - SNCR for GP Toledo No. 3 Power Boiler

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	356	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.164	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.090	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	2.82	

Plant Elevation: 180 Feet above sea level

*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019).

Concentration of reagent as stored (C_{stored})	50	Percent
Density of reagent as stored (ρ_{stored})	71	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years
Select the reagent used	Urea	

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

Enter the cost data for the proposed SNCR:

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 ($Cost_{reag}$)	1.66	\$/gallon for a 50 percent solution of urea*		
Water ($Cost_{water}$)	0.0042	\$/gallon*		
Electricity ($Cost_{elect}$)	0.0676	\$/kWh*		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		\$/ton		

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-13a - SNCR for GP Toledo No. 3 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)	$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6, Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf.	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Fuel Cost ($/MMBtu)	2.87	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 =	156	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	1,331,894,942	scf/Year	
Actual Annual fuel consumption (Mactual) =		895,734,436	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.66	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	8531	hours	Based on 2017 Operating Hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	45	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	11.55	lb/hour	
Total NO_x removed per year =	$(NOx_{in}$ x EF x Q_B x $t_{op})/2000$ =	34.02	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 180 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.6	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

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

Reagent Data:

Type of reagent used: Urea

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

Density = 71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea)	47	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	94	lb/hour
	$(m_{sol} \times 7.4805)$/Reagent Density =	9.9	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24$ hours/day)/Reagent Density =	3,400	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

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

Parameter	Equation	Calculated Value	Units	
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	4.1	kW/hour	
Water Usage: Water consumption (q_w) =	$(m_{sol}$/Density of water$) \times ((C_{stored}/C_{inj}) - 1)$ =	45	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$Hv \times m_{reagent} \times ((1/C_{inj})-1)$ =	0.38	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta fuel \times \%Ash \times 1\times10^6)/HHV$ =	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 ($SNCR_{cost}$) =	$784,619	in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$1,271,195	in 2019 dollars
Total Capital Investment (TCI) =	$2,672,559	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 ($SNCR_{cost}$) =	$784,619	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}) =	$1,271,195	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$201,277	in 2019 dollars
Indirect Annual Costs (IDAC) =	$211,266	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$412,543	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 =	$40,088	in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$140,877	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$2,391	in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$1,610	in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$16,311	in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0	in 2019 dollars
Direct Annual Cost =		$201,277	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$1,203	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$210,063	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$211,266	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$412,543	per year in 2019 dollars
NOx Removed =	34	tons/year
Cost Effectiveness =	$12,126	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 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)? 352.2 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,028 Btu/scf

What is the estimated actual annual fuel consumption? 3,001,200,000 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	0.058	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.032	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	6.33	

*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019).

Plant Elevation	180	Feet above sea level

Concentration of reagent as stored (C_{stored})	50	Percent
Density of reagent as stored (ρ_{stored})	71	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years

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

Select the reagent used: Urea

Enter the cost data for the proposed SNCR:

Desired dollar-year	2019			
CEPCI for 2019	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}$)	1.66	$/gallon for a 50 percent solution of urea*		
Water ($Cost_{water}$)	0.0042	$/gallon*		
Electricity ($Cost_{elect}$)	0.0676	$/kWh*		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		$/ton		

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)	$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6, Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf.	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Fuel Cost ($/MMBtu)	2.87	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 =	352	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	3,001,237,354	scf/Year	
Actual Annual fuel consumption (Mactual) =		3,001,200,000	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	1.00	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	8760	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	45	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	9.19	lb/hour	
Total NO_x removed per year =	$(NOx_{in}$ x EF x Q_B x $t_{op})/2000$ =	40.28	tons/year	Based on 89.5 tpy PSEL
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 180 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.6	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

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

Reagent Data:

Type of reagent used: Urea

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

Density = 71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea)	84	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	169	lb/hour
	$(m_{sol} \times 7.4805)$/Reagent Density =	17.8	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24$ hours/day)/Reagent Density =	6,000	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) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	7.4	kW/hour	
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x $((C_{stored}/C_{inj}) - 1)$ =	81	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$Hv \times m_{reagent} \times ((1/C_{inj})-1)$ =	0.68	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta fuel \times \%Ash \times 1x10^6)/HHV$ =	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 ($SNCR_{cost}$) =	$1,103,691 in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0 in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$1,617,156 in 2019 dollars
Total Capital Investment (TCI) =	$3,537,101 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 ($SNCR_{cost}$) =	$1,103,691 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}) =	$1,617,156 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$348,997	in 2019 dollars
Indirect Annual Costs (IDAC) =	$279,608	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$628,605	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 =	$53,057	in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$258,648	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$4,390	in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$2,956	in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$29,947	in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0	in 2019 dollars
Direct Annual Cost =		$348,997	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$1,592	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$278,016	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$279,608	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$628,605	per year in 2019 dollars
NOx Removed =	40	tons/year
Cost Effectiveness =	$15,608	per ton of NOx removed in 2019 dollars

Table A-14a - SNCR for GP Toledo No. 5 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)? 352.2 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,028 Btu/scf

What is the estimated actual annual fuel consumption? 1,662,626,459 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-14a - SNCR for GP Toledo No. 5 Power Boiler

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	358	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.045	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.025	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	7.90	
Concentration of reagent as stored (C_{stored})	50	Percent
Density of reagent as stored (ρ_{stored})	71	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years
Select the reagent used	Urea	

Plant Elevation: 180 Feet above sea level

*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019).

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}$)	1.66	$/gallon for a 50 percent solution of urea*		
Water ($Cost_{water}$)	0.0042	$/gallon*		
Electricity ($Cost_{elect}$)	0.0676	$/kWh*		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		$/ton		

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-14a - SNCR for GP Toledo No. 5 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)	$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6, Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf.	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Fuel Cost ($/MMBtu)	2.87	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 =	352	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	3,001,237,354	scf/Year	
Actual Annual fuel consumption (Mactual) =		1,662,626,459	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.54	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	8586	hours	Based on 2017 Operating Hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	45	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	7.13	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	17.15	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 180 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.6	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

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

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea)	82	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	163	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	17.2	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	5,800	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

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

Parameter	Equation	Calculated Value	Units	
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	7.2	kW/hour	
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	78	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x $((1/C_{inj})-1)$ =	0.66	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 ($SNCR_{cost}$) =	$1,103,691 in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0 in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$1,568,650 in 2019 dollars
Total Capital Investment (TCI) =	$3,474,043 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 ($SNCR_{cost}$) =	$1,103,691 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:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

Balance of Plant Costs (BOP_{cost}) =	$1,568,650 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$332,915	in 2019 dollars
Indirect Annual Costs (IDAC) =	$274,623	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$607,538	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 =	$52,111	in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$245,419	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$4,165	in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$2,805	in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$28,415	in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0	in 2019 dollars
Direct Annual Cost =		$332,915	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$1,563	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$273,060	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$274,623	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$607,538	per year in 2019 dollars
NOx Removed =	17	tons/year
Cost Effectiveness =	$35,435	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 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	
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

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:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

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 ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (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) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	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 1×10^6)/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:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

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 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)? 544 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,033 Btu/scf

*HHV value of 1033 Btu/scf is a default value. See below for data source. Enter actual HHV for fuel burned, if known.

What is the estimated actual annual fuel consumption? 3,677,506,292 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-16 - SNCR for IP Springfield Power Boiler

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	0.46	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.253	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	1.58	

Plant Elevation: 454 Feet above sea level

*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019).

Concentration of reagent as stored (C_{stored})	50	Percent
Density of reagent as stored (ρ_{stored})	71	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years
Select the reagent used	Urea	

Densities of typical SNCR reagents:

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

Enter the cost data for the proposed SNCR:

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 ($Cost_{reag}$)	1.66	\$/gallon for a 50 percent solution of urea*
Water ($Cost_{water}$)	0.0042	\$/gallon*
Electricity ($Cost_{elect}$)	0.0676	\$/kWh*
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		\$/ton

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)	$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6, Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf.	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Fuel Cost ($/MMBtu)	2.87	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/.	
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 =	544	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	4,613,204,259	scf/Year	
Actual Annual fuel consumption (Mactual) =		3,677,506,292	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.80	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	8760	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	45	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	89.77	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	393.18	tons/year	Based on PSEL of 873.74 tpy
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 454 feet above sea level (P) =	2116x[(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.5	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

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

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea)	259	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	518	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	54.5	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	18,400	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

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

Parameter	Equation	Calculated Value	Units	
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	22.7	kW/hour	
Water Usage: Water consumption (q_w) =	$(m_{sol}/\text{Density of water}) \times ((C_{stored}/C_{inj}) - 1)$ =	248	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$Hv \times m_{reagent} \times ((1/C_{inj})-1)$ =	2.10	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta fuel \times \%Ash \times 1\times10^6)/HHV$ =	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 ($SNCR_{cost}$) =	$1,324,792	in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$2,453,702	in 2019 dollars
Total Capital Investment (TCI) =	$4,912,042	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 ($SNCR_{cost}$) =	$1,324,792	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:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

Balance of Plant Costs (BOP_{cost}) =	$2,453,702	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$981,166	in 2019 dollars
Indirect Annual Costs (IDAC) =	$388,297	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$1,369,462	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 =	$73,681	in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$793,129	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$13,461	in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$9,064	in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$91,831	in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0	in 2019 dollars
Direct Annual Cost =		$981,166	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$2,210	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$386,086	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$388,297	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,369,462	per year in 2019 dollars
NOx Removed =	393	tons/year
Cost Effectiveness =	$3,483	per ton of NOx removed in 2019 dollars

Table A-16a - SNCR for IP Springfield 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)? 544 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,033 Btu/scf

*HHV value of 1033 Btu/scf is a default value. See below for data source. Enter actual HHV for fuel burned, if known.

What is the estimated actual annual fuel consumption? 1,237,783,524 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-16a - SNCR for IP Springfield Power Boiler

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	351	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.22	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.121	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	2.33	
Concentration of reagent as stored (C_{stored})	50	Percent
Density of reagent as stored (ρ_{stored})	71	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years
Select the reagent used	Urea	

Plant Elevation: 454 Feet above sea level

*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019).

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}$)	1.66	$/gallon for a 50 percent solution of urea*
Water ($Cost_{water}$)	0.0042	$/gallon*
Electricity ($Cost_{elect}$)	0.0676	$/kWh*
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		$/ton

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-16a - SNCR for IP Springfield 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)	$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6, Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf.	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Fuel Cost ($/MMBtu)	2.87	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/.	
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 =	544	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	4,613,204,259	scf/Year	
Actual Annual fuel consumption (Mactual) =		1,237,783,524	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.26	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	8424	hours	Based on 2017 Operating Hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	45	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	14.42	lb/hour	
Total NO_x removed per year =	$(NOx_{in}$ x EF x Q_B x $t_{op})/2000$ =	63.15	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 454 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.5	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

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

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea)	182	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	364	lb/hour
	$(m_{sol} \times 7.4805)$/Reagent Density =	38.4	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24$ hours/day)/Reagent Density =	12,900	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

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

Parameter	Equation	Calculated Value	Units	
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	16.0	kW/hour	
Water Usage: Water consumption (q_w) =	$(m_{sol}$/Density of water$) \times ((C_{stored}/C_{inj}) - 1)$ =	175	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$Hv \times m_{reagent} \times ((1/C_{inj})-1)$ =	1.48	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta fuel \times \%Ash \times 1x10^6)/HHV$ =	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 ($SNCR_{cost}$) =	$1,324,792	in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$1,970,234	in 2019 dollars
Total Capital Investment (TCI) =	$4,283,533	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 ($SNCR_{cost}$) =	$1,324,792	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:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

Balance of Plant Costs (BOP_{cost}) =	$1,970,234	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$678,359	in 2019 dollars
Indirect Annual Costs (IDAC) =	$338,613	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$1,016,973	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 =	$64,253	in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$536,720	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$9,109	in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$6,134	in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$62,143	in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0	in 2019 dollars
Direct Annual Cost =		$678,359	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$1,928	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$336,686	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$338,613	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,016,973	per year in 2019 dollars
NOx Removed =	63	tons/year
Cost Effectiveness =	$16,103	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 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)? 340 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,033 Btu/scf

*HHV value of 1033 Btu/scf is a default value. See below for data source. Enter actual HHV for fuel burned, if known.

What is the estimated actual annual fuel consumption? 2,883,252,662 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	0.2	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.11	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	2.48	
Concentration of reagent as stored (C_{stored})	50	Percent
Density of reagent as stored (ρ_{stored})	71	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years
Select the reagent used	Urea	

Plant Elevation	454	Feet above sea level

*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019).

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}$)	1.66	$/gallon for a 50 percent solution of urea*		
Water ($Cost_{water}$)	0.0042	$/gallon*		
Electricity ($Cost_{elect}$)	0.0676	$/kWh*		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		$/ton		

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)	$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6, Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf.	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Fuel Cost ($/MMBtu)	2.87	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/.	
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 =	340	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	2,883,252,662	scf/Year	
Actual Annual fuel consumption (Mactual) =		2,883,252,662	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	1.00	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 =	30.60	lb/hour	
Total NO_x removed per year =	$(NOx_{in}$ x EF x Q_B x $t_{op})/2000$ =	134.03	tons/year	Based on PSEL of 297.84 tpy
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 454 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.5	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

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

Reagent Data:

Type of reagent used: Urea

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

Density = 71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea)	110	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	220	lb/hour
	$(m_{sol} \times 7.4805)$/Reagent Density =	23.1	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24$ hours/day)/Reagent Density =	7,800	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

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

Parameter	Equation	Calculated Value	Units	
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	9.6	kW/hour	
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x $((C_{stored}/C_{inj}) - 1)$ =	105	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$Hv \times m_{reagent} \times ((1/C_{inj})-1)$ =	0.89	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta fuel \times \%Ash \times 1x10^6)/HHV$ =	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 ($SNCR_{cost}$) =	$1,087,470	in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$1,846,606	in 2019 dollars
Total Capital Investment (TCI) =	$3,814,299	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 ($SNCR_{cost}$) =	$1,087,470	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:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

Balance of Plant Costs (BOP_{cost}) =	$1,846,606	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$442,335	in 2019 dollars
Indirect Annual Costs (IDAC) =	$301,520	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$743,856	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 =	$57,214	in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$336,590	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$5,712	in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$3,847	in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$38,971	in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0	in 2019 dollars
Direct Annual Cost =		$442,335	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$1,716	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$299,804	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$301,520	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$743,856	per year in 2019 dollars
NOx Removed =	134	tons/year
Cost Effectiveness =	$5,550	per ton of NOx removed in 2019 dollars

Table A-17a - SNCR for IP Springfield Package 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)? 340 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,033 Btu/scf

*HHV value of 1033 Btu/scf is a default value. See below for data source. Enter actual HHV for fuel burned, if known.

What is the estimated actual annual fuel consumption? 38,813,069 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-17a - SNCR for IP Springfield Package Boiler

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	17	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.07	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.0385	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	5.40	
Concentration of reagent as stored (C_{stored})	50	Percent
Density of reagent as stored (ρ_{stored})	71	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years
Select the reagent used	Urea	

*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019).

Plant Elevation	454	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 ($Cost_{reag}$)	1.66	\$/gallon for a 50 percent solution of urea*		
Water ($Cost_{water}$)	0.0042	\$/gallon*		
Electricity ($Cost_{elect}$)	0.0676	\$/kWh*		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		\$/ton		

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-17a - SNCR for IP Springfield Package 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)	$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6, Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf.	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Fuel Cost ($/MMBtu)	2.87	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/.	
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 =	340	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	2,883,252,662	scf/Year	
Actual Annual fuel consumption (Mactual) =		38,813,069	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.00	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	394	hours	Based on 2017 Operating Hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	45	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	10.71	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	0.63	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 454 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.5	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

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

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea)	84	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	168	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	17.7	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	6,000	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) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	7.4	kW/hour	
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	80	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	0.68	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x 1×10^6)/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 ($SNCR_{cost}$) =	$1,087,470	in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$1,628,030	in 2019 dollars
Total Capital Investment (TCI) =	$3,530,150	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 ($SNCR_{cost}$) =	$1,087,470	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:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

Balance of Plant Costs (BOP_{cost}) =	$1,628,030	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$66,183 in 2019 dollars
Indirect Annual Costs (IDAC) =	$279,058 in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$345,241 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 =	$52,952 in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$11,564 in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$196 in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$132 in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$1,339 in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0 in 2019 dollars
Direct Annual Cost =		$66,183 in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$1,589 in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$277,470 in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$279,058 in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$345,241 per year in 2019 dollars
NOx Removed =	1 tons/year
Cost Effectiveness =	$548,002 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)? 236 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,020 Btu/scf

What is the estimated actual annual fuel consumption? 856,000,000 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 278 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	0.276	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.028	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	^oF
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
Annual Interest Rate (i)	4.75	Percent
Reagent ($Cost_{reag}$)	3.53	$/gallon for 29% ammonia
Electricity ($Cost_{elect}$)	0.0676	$/kWh
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst
Operator Labor Rate	60.00	$/hour (including benefits)*
Operator Hours/Day	4.00	hours/day*

CEPCI = Chemical Engineering Plant Cost Index

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

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

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

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

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.	
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/.	1020 is AP-42 default and used for 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
Natural gas cost, $/MMBtu	$5.00	eia.gov representative Oregon industrial natural gas price	

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 =	236	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	2,026,823,529	scf/Year	
Actual Annual fuel consumption (Mactual) =		856,000,000	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.422	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8760	hours	Based on 8760 hours (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 =	58.72	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	119.25	tons/year	Based on PSEL of 132.5 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} =	97,332	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	97.41	/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)* =	14.6	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})	999.22	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	101	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 $A_{catalyst}$	117	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	10.8	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 ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times EF \times SRF \times MW_R)/MW_{NOx}$ =	23	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	79	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	11	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	3,600	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.	121.35	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) =	$8,239,393	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,338,172	in 2019 dollars
Indirect Annual Costs (IDAC) =	$573,288	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$1,911,460	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 =		$41,197	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =		$325,071	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =		$71,861	in 2019 dollars
Annual Catalyst Replacement Cost =			$24,043	in 2019 dollars
Natural gas for duct burner to reheat stack gas, based on MMBtu/hr of:		20	$876,000	in 2019 dollars
	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF			
Direct Annual Cost =			$1,338,172	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) =	$3,122	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$570,166	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$573,288	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,911,460	per year in 2019 dollars
NOx Removed =	119	tons/year
Cost Effectiveness =	$16,029	per ton of NOx removed in 2019 dollars

Table A-18a - SCR for CPP Halsey No. 1 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 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)? 236 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,020 Btu/scf

What is the estimated actual annual fuel consumption? 470,560,784 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 278 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:

Table A-18a - SCR for CPP Halsey No. 1 Power Boiler

Number of days the SCR operates (t_{SCR})	360	days
Number of days the boiler operates (t_{plant})	360	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.221	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.022	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})	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-18a - SCR for CPP Halsey No. 1 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.	
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/.	1020 is AP-42 default and used for 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, pre-COVID prime rate
Natural gas cost, $/MMBtu	$5.00	eia.gov representative Oregon industrial natural gas price	

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 =	236	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	2,026,823,529	scf/Year	
Actual Annual fuel consumption (Mactual) =		470,560,784	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.232	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8622	hours	Based on 2017 Actual 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 =	46.91	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	47.70	tons/year	Based on 2017 Actual 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} =	97,332	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	99.29	/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)* =	14.6	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})	980.27	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	101	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 $A_{catalyst}$	117	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	10.8	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 ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times EF \times SRF \times MW_R)/MW_{NOx}$ =	18	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	63	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	8	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	2,900	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 $(\text{CoalF} \times \text{HRF})^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	121.35	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) =	$8,239,393	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,253,291	in 2019 dollars
Indirect Annual Costs (IDAC) =	$573,252	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$1,826,543	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 =		$41,197	in 2019 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =		$255,578	in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =		$70,729	in 2019 dollars
Annual Catalyst Replacement Cost =			$23,587	in 2019 dollars
Natural gas for duct burner to reheat stack gas, based on MMBtu/hr of:		20	$862,200	in 2019 dollars
	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$			
Direct Annual Cost =			$1,253,291	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) =	$3,086	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$570,166	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$573,252	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,826,543	per year in 2019 dollars
NOx Removed =	48	tons/year
Cost Effectiveness =	$38,292	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)? 236 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,020 Btu/scf

What is the estimated actual annual fuel consumption? 525,000,000 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 278 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	0.280	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.028	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	^oF
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
Annual Interest Rate (i)	4.75	Percent		
Reagent ($Cost_{reag}$)	3.53	$/gallon for 29% ammonia		
Electricity ($Cost_{elect}$)	0.0676	$/kWh		
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst		
Operator Labor Rate	60.00	$/hour (including benefits)*		
Operator Hours/Day	4.00	hours/day*		

CEPCI = Chemical Engineering Plant Cost Index

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

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

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

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

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.	
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/.	1020 is AP-42 default and used for 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, pre-COVID prime rate
Natural gas cost, $/MMBtu	$5.00	eia.gov representative Oregon industrial natural gas price	

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 =	236	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	2,026,823,529	scf/Year	
Actual Annual fuel consumption (Mactual) =		525,000,000	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.259	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8760	hours	Based on 8760 hours (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 =	59.56	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	67.59	tons/year	Based on 75.1 tpy PSEL
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} =	97,332	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	97.28	/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) =	$2116 \times [(59-(0.00356xh)+459.7)/518.6]^{5.256} \times (1/144)$* =	14.6	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})	1,000.56	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	101	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 $A_{catalyst}$	117	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	10.8	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} =	23	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	80	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	11	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	3,600	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.	121.35	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) =	$8,239,393	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,342,815	in 2019 dollars
Indirect Annual Costs (IDAC) =	$573,288	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$1,916,103	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 =		$41,197	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =		$329,682	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =		$71,861	in 2019 dollars
Annual Catalyst Replacement Cost =			$24,075	in 2019 dollars
Natural gas for duct burner to reheat stack gas, based on MMBtu/hr of:		20	$876,000	in 2019 dollars
	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF			
Direct Annual Cost =			$1,342,815	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) =	$3,122	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$570,166	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$573,288	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,916,103	per year in 2019 dollars
NOx Removed =	68	tons/year
Cost Effectiveness =	$28,349	per ton of NOx removed in 2019 dollars

Table A-19a - SCR for CPP Halsey No. 2 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 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)?	236	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,020	Btu/scf
What is the estimated actual annual fuel consumption?	60,689,216	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 278 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:

Table A-19a - SCR for CPP Halsey No. 2 Power Boiler

Number of days the SCR operates (t_{SCR})	129	days
Number of days the boiler operates (t_{plant})	129	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.181	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.018	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
Annual Interest Rate (i)	4.75	Percent		
Reagent ($Cost_{reag}$)	3.53	$/gallon for 29% ammonia		
Electricity ($Cost_{elect}$)	0.0676	$/kWh		
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst		
Operator Labor Rate	60.00	$/hour (including benefits)*		
Operator Hours/Day	4.00	hours/day*		

CEPCI = Chemical Engineering Plant Cost Index

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

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

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

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

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-19a - SCR for CPP Halsey No. 2 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.	
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/.	1020 is AP-42 default and used for 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
Natural gas cost, $/MMBtu	$5.00	eia.gov representative Oregon industrial natural gas price	

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 =	236	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	2,026,823,529	scf/Year	
Actual Annual fuel consumption (Mactual) =		60,689,216	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.030	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	3080	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 =	38.43	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	5.04	tons/year	Based on 2017 Actual 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} =	97,332	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	100.69	/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)* =	14.6	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	0.1057	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})	966.68	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	101	ft^2

Height of each catalyst layer (H_{layer}) =	$(Vol_{catalyst}/(R_{layer} \times A_{catalyst})) + 1$ (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	$1.15 \times A_{catalyst}$	117	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	10.8	feet
Reactor height =	$(R_{layer} + R_{empty}) \times (7ft + h_{layer}) + 9ft$	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} =	15	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	52	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	7	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	2,400	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.	121.35	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) =	$8,239,393	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$456,991	in 2019 dollars
Indirect Annual Costs (IDAC) =	$571,589	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$1,028,580	in 2019 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	$0.005 \times TCI =$		$41,197	in 2019 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op} =$		$74,797	in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op} =$		$25,266	in 2019 dollars
Annual Catalyst Replacement Cost =			$7,731	in 2019 dollars
Natural gas for duct burner to reheat stack gas, based on MMBtu/hr of:		20	$308,000	in 2019 dollars
	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$			
Direct Annual Cost =			$456,991	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) =	$1,423	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$570,166	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$571,589	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,028,580	per year in 2019 dollars
NOx Removed =	5	tons/year
Cost Effectiveness =	$204,083	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)?	296.6	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,028	Btu/scf
What is the estimated actual annual fuel consumption?	2,527,400,000	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	180	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 (selected)

Table A-20 - SCR for GP Toledo No. 4 Hog Fuel Boiler

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	0.168	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.017	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

50

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
Annual Interest Rate (i)	4.75	Percent	
Reagent ($Cost_{reag}$)	3.53	$/gallon for 29% ammonia	
Electricity ($Cost_{elect}$)	0.0676	$/kWh	
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	
Operator Labor Rate	60.00	$/hour (including benefits)*	
Operator Hours/Day	4.00	hours/day*	

CEPCI = Chemical Engineering Plant Cost Index

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

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

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

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

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	/gallon 50% urea so	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Mode	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 $5/MMBtu	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	1028 is basis of PSEL calcs
Catalyst Cost ($/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 =	297	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	2,527,447,471	scf/Year	
Actual Annual fuel consumption (Mactual) =		2,527,400,000	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	1.000	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8760	hours	Based on 8760 hours (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 =	44.88	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	196.56	tons/year	Based on 218.4 tpy PSEL
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} =	122,324	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	101.14	/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)* =	14.6	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})	1,209.41	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	127	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 $A_{catalyst}$	147	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	12.1	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} =	17	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	60	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	8	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	2,700	gallons (storage needed to store a 14 day reagent supply rounded to th

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.	152.51	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) =	$9,559,027	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,510,631	in 2019 dollars
Indirect Annual Costs (IDAC) =	$664,686	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$2,175,317	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 =		$47,795	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =		$248,422	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =		$90,313	in 2019 dollars
Annual Catalyst Replacement Cost =			$29,101	in 2019 dollars
Natural gas for duct burner to reheat stack gas, based on MMBtu/hr of:		25	$1,095,000	in 2019 dollars
	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF			
Direct Annual Cost =			$1,510,631	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) =	$3,202	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$661,485	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$664,686	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$2,175,317	per year in 2019 dollars
NOx Removed =	197	tons/year
Cost Effectiveness =	$11,067	per ton of NOx removed in 2019 dollars

Table A-20a - SCR for GP Toledo No. 4 Hog Fuel 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 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)?	296.6	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,028	Btu/scf
What is the estimated actual annual fuel consumption?	1,463,522,374	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 180 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-20a - SCR for GP Toledo No. 4 Hog Fuel Boiler

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	358	days
Number of days the boiler operates (t_{plant})	358	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.280	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.028	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	^oF
Base case fuel gas volumetric flow rate factor (Q_{fuel})	431	ft^3/min-MMBtu/hour

50

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
Annual Interest Rate (i)	4.75	Percent
Reagent ($Cost_{reag}$)	3.53	$/gallon for 29% ammonia
Electricity ($Cost_{elect}$)	0.0676	$/kWh
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst
Operator Labor Rate	60.00	$/hour (including benefits)*
Operator Hours/Day	4.00	hours/day*

CEPCI = Chemical Engineering Plant Cost Index

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

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

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

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

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-20a - SCR for GP Toledo No. 4 Hog Fuel 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	/gallon 50% urea so	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Mod	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 $5/MMBtu	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	1028 is basis of PSEL calcs
Catalyst Cost ($/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 =	297	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	2,527,447,471	scf/Year	
Actual Annual fuel consumption (Mactual) =		1,463,522,374	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.579	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8572	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 =	74.73	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	189.54	tons/year	Based on 2017 Actual 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} =	122,324	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	97.29	/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)* =	14.6	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})	1,257.29	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	127	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 $A_{catalyst}$	147	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	12.1	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} =	29	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	100	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	13	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	4,500	gallons (storage needed to store a 14 day reagent supply rounded to th

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.	152.51	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) =	$9,559,027	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,642,671	in 2019 dollars
Indirect Annual Costs (IDAC) =	$664,636	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$2,307,306	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 =		$47,795	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =		$404,802	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =		$88,371	in 2019 dollars
Annual Catalyst Replacement Cost =			$30,253	in 2019 dollars
Natural gas for duct burner to reheat stack gas, based on MMBtu/hr of:		25	$1,071,450	in 2019 dollars
	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF			
Direct Annual Cost =			$1,642,671	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) =	$3,151	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$661,485	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$664,636	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$2,307,306	per year in 2019 dollars
NOx Removed =	190	tons/year
Cost Effectiveness =	$12,173	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)? 187.5 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,028 Btu/scf

What is the estimated actual annual fuel consumption? 1,597,800,000 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 180 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	0.272	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.027	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	^oF
Base case fuel gas volumetric flow rate factor (Q_{fuel})	431	ft^3/min-MMBtu/hour

50

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
Annual Interest Rate (i)	4.75	Percent
Reagent ($Cost_{reag}$)	3.53	$/gallon for 29% ammonia
Electricity ($Cost_{elect}$)	0.0676	$/kWh
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst
Operator Labor Rate	60.00	$/hour (including benefits)*
Operator Hours/Day	4.00	hours/day*

CEPCI = Chemical Engineering Plant Cost Index

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

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

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

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

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	/gallon 50% urea so	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Mode	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 $5/MMBtu	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	1028 is basis of PSEL calcs
Catalyst Cost ($/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 =	188	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	1,597,762,646	scf/Year	
Actual Annual fuel consumption (Mactual) =		1,597,800,000	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	1.000	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8760	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 =	45.96	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	201.33	tons/year	Based on PSEL of 223.7 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} =	77,329	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	97.54	/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)* =	14.6	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})	792.76	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	81	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 $A_{catalyst}$	93	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	9.6	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} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	18	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	62	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	8	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	2,800	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 $(\text{CoalF x HRF})^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	96.41	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) =	$7,095,014	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,242,082	in 2019 dollars
Indirect Annual Costs (IDAC) =	$494,029	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$1,736,111	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 =		$35,475	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =		$254,439	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =		$57,093	in 2019 dollars
Annual Catalyst Replacement Cost =			$19,075	in 2019 dollars
Natural gas for duct burner to reheat stack gas, based on MMBtu/hr of:		20	$876,000	in 2019 dollars
	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF			
Direct Annual Cost =			$1,242,082	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) =	$3,054	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$490,975	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$494,029	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,736,111	per year in 2019 dollars
NOx Removed =	201	tons/year
Cost Effectiveness =	$8,623	per ton of NOx removed in 2019 dollars

Table A-21a - SCR for GP Toledo No. 1 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 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)?	187.5	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,028	Btu/scf
What is the estimated actual annual fuel consumption?	1,043,080,739	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	180	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-21a - SCR for GP Toledo No. 1 Power Boiler

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	356	days
Number of days the boiler operates (t_{plant})	356	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.280	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.028	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	^oF
Base case fuel gas volumetric flow rate factor (Q_{fuel})	431	ft^3/min-MMBtu/hour

50

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
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.

CEPCI = Chemical Engineering Plant Cost Index

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-21a - SCR for GP Toledo No. 1 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	/gallon 50% urea so	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Mode	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 $5/MMBtu	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	1028 is basis of PSEL calcs
Catalyst Cost ($/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 =	188	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	1,597,762,646	scf/Year	
Actual Annual fuel consumption (Mactual) =		1,043,080,739	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.653	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8540	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 =	47.24	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	135.09	tons/year	Based on 2017 Actual 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} =	77,329	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	97.29	/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) =	$2116 \times [(59-(0.00356xh)+459.7)/518.6]^{5.256} \times (1/144)$* =	14.6	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})	794.82	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	81	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 $A_{catalyst}$	93	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	9.6	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 ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times EF \times SRF \times MW_R)/MW_{NOx}$ =	18	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	63	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	8	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	2,900	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.	96.41	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) =	$7,095,014	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,219,164	in 2019 dollars
Indirect Annual Costs (IDAC) =	$493,964	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$1,713,128	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 =		$35,475	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =		$254,948	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =		$55,656	in 2019 dollars
Annual Catalyst Replacement Cost =			$19,125	in 2019 dollars
Natural gas for duct burner to reheat stack gas, based on MMBtu/hr of:		20	$853,960	in 2019 dollars
	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF			
Direct Annual Cost =			$1,219,164	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) =	$2,989	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$490,975	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$493,964	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,713,128	per year in 2019 dollars
NOx Removed =	135	tons/year
Cost Effectiveness =	$12,681	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)?	156.3	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,028	Btu/scf
What is the estimated actual annual fuel consumption?	1,310,600,000	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	180	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	0.160	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.016	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

50

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
Annual Interest Rate (i)	4.75	Percent
Reagent ($Cost_{reag}$)	3.53	$/gallon for 29% ammonia
Electricity ($Cost_{elect}$)	0.0676	$/kWh
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst
Operator Labor Rate	60.00	$/hour (including benefits)*
Operator Hours/Day	4.00	hours/day*

CEPCI = Chemical Engineering Plant Cost Index

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

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

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

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

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	/gallon 50% urea so	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Mode	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 $5/MMBtu	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	1028 is basis of PSEL calcs
Catalyst Cost ($/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 =	156	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	1,331,894,942	scf/Year	
Actual Annual fuel consumption (Mactual) =		1,310,600,000	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.984	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 =	22.47	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	96.84	tons/year	Based on PSEL of 107.6 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} =	64,462	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	101.44	/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)* =	14.6	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})	635.44	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	67	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 $A_{catalyst}$	77	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	8.8	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 $MW_R)/MW_{NOx}$ =	9	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	30	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	4	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	1,400	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.	80.37	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) =	$6,303,413	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$875,781	in 2019 dollars
Indirect Annual Costs (IDAC) =	$439,202	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$1,314,983	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 =		$31,517	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =		$124,382	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =		$47,592	in 2019 dollars
Annual Catalyst Replacement Cost =			$15,290	in 2019 dollars
Natural gas for duct burner to reheat stack gas, based on MMBtu/hr of:		15	$657,000	in 2019 dollars
	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF			
Direct Annual Cost =			$875,781	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) =	$3,006	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$436,196	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$439,202	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,314,983	per year in 2019 dollars
NOx Removed =	97	tons/year
Cost Effectiveness =	$13,579	per ton of NOx removed in 2019 dollars

Table A-22a - SCR for GP Toledo No. 3 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 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)? 156.3 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,028 Btu/scf

What is the estimated actual annual fuel consumption? 895,734,436 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 180 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-22a - SCR for GP Toledo No. 3 Power Boiler

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	356	days
Number of days the boiler operates (t_{plant})	356	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.164	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.016	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	^oF
Base case fuel gas volumetric flow rate factor (Q_{fuel})	431	ft^3/min-MMBtu/hour

50

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
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.

CEPCI = Chemical Engineering Plant Cost Index

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-22a - SCR for GP Toledo No. 3 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	/gallon 50% urea so	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Mode	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 $5/MMBtu	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	1028 is basis of PSEL calcs
Catalyst Cost ($/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 =	156	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	1,331,894,942	scf/Year	
Actual Annual fuel consumption (Mactual) =		895,734,436	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.673	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8531	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 =	15.95	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	68.04	tons/year	Based on 2017 Actual 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} =	64,462	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	101.28	/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)* =	14.6	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})	636.45	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	67	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 $A_{catalyst}$	77	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	8.8	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 $MW_R)/MW_{NOx}$ =	9	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	31	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	4	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	1,400	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.	80.37	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) =	$6,303,413	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$857,509	in 2019 dollars
Indirect Annual Costs (IDAC) =	$439,138	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$1,296,647	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 =		$31,517	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =		$124,521	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =		$46,347	in 2019 dollars
Annual Catalyst Replacement Cost =			$15,314	in 2019 dollars
Natural gas for duct burner to reheat stack gas, based on MMBtu/hr of:		15	$639,810	in 2019 dollars
	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF			
Direct Annual Cost =			$857,509	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) =	$2,941	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$436,196	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$439,138	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,296,647	per year in 2019 dollars
NOx Removed =	68	tons/year
Cost Effectiveness =	$19,057	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

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

What type of fuel does the unit burn? Natural Gas

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)?	352.2	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,028	Btu/scf
What is the estimated actual annual fuel consumption?	3,001,308,366	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	180	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	0.058	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.0058	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	^oF
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
Annual Interest Rate (i)	4.75	Percent
Reagent ($Cost_{reag}$)	3.53	$/gallon for 29% ammonia
Electricity ($Cost_{elect}$)	0.0676	$/kWh
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst
Operator Labor Rate	60.00	$/hour (including benefits)*
Operator Hours/Day	4.00	hours/day*

CEPCI = Chemical Engineering Plant Cost Index

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

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

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

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

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 $5/MMBtu	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	1028 is basis of PSEL calcs
Catalyst Cost ($/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 =	352	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	3,001,237,354	scf/Year	
Actual Annual fuel consumption (Mactual) =		3,001,308,366	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	1.000	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8760	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 =	18.38	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	80.55	tons/year	Based on 89.5 tpy PSEL
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} =	145,255	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	105.25	/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)* =	14.6	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})	1,380.15	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	151	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 $A_{catalyst}$	174	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	13.2	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 ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times EF \times SRF \times MW_R)/MW_{NOx}$ =	7	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/Csol$ =	25	lb/hour
	$(m_{sol} \times 7.4805)$/Reagent Density	3	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24)$/Reagent Density =	1,200	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) =	$A \times 1,000 \times 0.0056 \times (CoalF \times HRF)^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	181.10	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) =	$10,688,469	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,390,668	in 2019 dollars
Indirect Annual Costs (IDAC) =	$742,911	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$2,133,579	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 =		$53,442	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =		$101,774	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =		$107,243	in 2019 dollars
Annual Catalyst Replacement Cost =			$33,209	in 2019 dollars
Natural gas for duct burner to reheat stack gas, based on MMBtu/hr of:		25	$1,095,000	in 2019 dollars
	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF			
Direct Annual Cost =			$1,390,668	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) =	$3,269	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$739,642	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$742,911	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$2,133,579	per year in 2019 dollars
NOx Removed =	81	tons/year
Cost Effectiveness =	$26,488	per ton of NOx removed in 2019 dollars

Table A-23a - SCR for GP Toledo No. 5 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 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)?	352.2	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,028	Btu/scf
What is the estimated actual annual fuel consumption?	1,662,626,459	scf/Year
Enter the net plant heat input rate (NPHR)	8.2	MMBtu/MW
Plant Elevation	180	Feet above sea level

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

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-23a - SCR for GP Toledo No. 5 Power Boiler

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	358	days
Number of days the boiler operates (t_{plant})	358	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.045	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.0045	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	* $0.0676/kWh is a default value for electricity cost. User should enter actual value, if known.
Catalyst cost ($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-23a - SCR for GP Toledo No. 5 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 $5/MMBtu	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	1028 is basis of PSEL calcs
Catalyst Cost ($/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 =	352	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	3,001,237,354	scf/Year	
Actual Annual fuel consumption (Mactual) =		1,662,626,459	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.554	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8586	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 =	14.26	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	34.29	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} =	145,255	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	105.75	/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)* =	14.6	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})	1,373.55	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	151	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 $A_{catalyst}$	174	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	13.2	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} =	6	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	19	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	3	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	900	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.	181.10	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) =	$10,688,469	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,342,176	in 2019 dollars
Indirect Annual Costs (IDAC) =	$742,861	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$2,085,037	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 =		$53,442	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =		$77,389	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =		$105,107	in 2019 dollars
Annual Catalyst Replacement Cost =			$33,050	in 2019 dollars
Natural gas for duct burner to reheat stack gas, based on MMBtu/hr of:		25	$1,073,188	in 2019 dollars
	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF			
Direct Annual Cost =			$1,342,176	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) =	$3,219	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$739,642	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$742,861	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$2,085,037	per year in 2019 dollars
NOx Removed =	34	tons/year
Cost Effectiveness =	$60,806	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

Table A-24 - SCR for GP Wauna Power Boiler

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	^oF
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) =	$2116 \times [(59-(0.00356xh)+459.7)/518.6]^{5.256} \times (1/144)$* =	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})	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) =	$2116 \times [(59-(0.00356xh)+459.7)/518.6]^{5.256} \times (1/144)$* =	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	0.1819	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 ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times EF \times SRF \times MW_R)/MW_{NOx}$ =	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 $(CoalF \times HRF)^{0.43}$ = 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) =	$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	°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) =	$2116 \times [(59-(0.00356xh)+459.7)/518.6]^{5.256} \times (1/144)^*$ =	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})	1,012.46	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 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) =	$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:

- (selected) 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	^{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

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 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})	1,085.90	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 ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times EF \times SRF \times MW_R)/MW_{NOx}$ =	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 $(CoalF \times HRF)^{0.43}$ = 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) =	$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

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)? 544 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,033 Btu/scf

*HHV value of 1033 Btu/scf is a default value. See below for data source. Enter actual HHV for fuel burned, if known.

What is the estimated actual annual fuel consumption? 3,677,506,292 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 454 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:

Parameter	Value	Units
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	0.46	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.

Parameter	Value	Units
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

Parameter	Value	Units
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.

Parameter	Value	Units
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

50

Parameter	Value	Units
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	/gallon 50% urea so	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Mode	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.	
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/.	
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, pre-COVID prime rate
Natural gas cost, $/MMBtu	$5.00	eia.gov representative Oregon industrial natural gas price	

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 =	544	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	4,613,204,259	scf/Year	
Actual Annual fuel consumption (Mactual) =		3,677,506,292	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.797	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 =	225.22	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	786.37	tons/year	Based on PSEL of 873.74 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} =	224,358	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	91.67	/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) =	$2116 \times [(59-(0.00356xh)+459.7)/518.6]^{5.256} \times (1/144)$* =	14.5	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})	2,447.38	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	234	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 $A_{catalyst}$	269	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	16.4	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 ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times EF \times SRF \times MW_R)/MW_{NOx}$ =	88	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/Csol$ =	302	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	40	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	13,600	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.	279.72	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) =	$14,178,873	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$2,637,164	in 2019 dollars
Indirect Annual Costs (IDAC) =	$984,657	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$3,621,820	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 =		$70,894	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =		$1,246,736	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =		$165,645	in 2019 dollars
Annual Catalyst Replacement Cost =			$58,889	in 2019 dollars
Natural gas for duct burner to reheat stack gas, based on MMBtu/hr of:		25	$1,095,000	in 2019 dollars
	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF			
Direct Annual Cost =			$2,637,164	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) =	$3,479	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$981,178	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$984,657	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$3,621,820	per year in 2019 dollars
NOx Removed =	786	tons/year
Cost Effectiveness =	$4,606	per ton of NOx removed in 2019 dollars

Table A-26a - SCR for IP Springfield 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 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)?	544	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,033	Btu/scf
What is the estimated actual annual fuel consumption?	1,237,783,524	scf/Year
Enter the net plant heat input rate (NPHR)	8.2	MMBtu/MW
Plant Elevation	454	Feet above sea level

*HHV value of 1033 Btu/scf is a default value. See below for data source. Enter actual HHV for fuel burned, if known.

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

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-26a - SCR for IP Springfield Power Boiler

Enter the following design parameters for the proposed SCR:

Parameter	Value	Units
Number of days the SCR operates (t_{SCR})	351	days
Number of days the boiler operates (t_{plant})	351	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.22	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.022	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.

Parameter	Value	Units
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

Parameter	Value	Units
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.

50

Parameter	Value	Units
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

Parameter	Value	Units
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-26a - SCR for IP Springfield Power 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-26a - SCR for IP Springfield Power Boiler

Data Sources for Default Values Used in Calculations:

Data Element	/gallon 50% urea so	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Mod	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.	
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/.	
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, pre-COVID prime rate
Natural gas cost, $/MMBtu	$5.00	eia.gov representative Oregon industrial natural gas price	

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 =	544	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	4,613,204,259	scf/Year	
Actual Annual fuel consumption (Mactual) =		1,237,783,524	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.268	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8424	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 =	107.71	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	126.31	tons/year	Based on 2017 Actual 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} =	224,358	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	99.32	/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) =	$2116 \times [(59-(0.00356xh)+459.7)/518.6]^{5.256} \times (1/144)$* =	14.5	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})	2,258.95	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	234	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 $A_{catalyst}$	269	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	16.4	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} =	42	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	144	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	19	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	6,500	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 $(\text{CoalF x HRF})^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	279.72	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) =	$14,178,873	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)
TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,910,935	in 2019 dollars
Indirect Annual Costs (IDAC) =	$984,556	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$2,895,491	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 =		$70,894	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =		$573,394	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =		$159,291	in 2019 dollars
Annual Catalyst Replacement Cost =			$54,355	in 2019 dollars
Natural gas for duct burner to reheat stack gas, based on MMBtu/hr of:		25	$1,053,000	in 2019 dollars
	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF			
Direct Annual Cost =			$1,910,935	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) =	$3,378	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$981,178	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$984,556	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$2,895,491	per year in 2019 dollars
NOx Removed =	126	tons/year
Cost Effectiveness =	$22,924	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)? 340 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,033 Btu/scf

*HHV value of 1033 Btu/scf is a default value. See below for data source. Enter actual HHV for fuel burned, if known.

What is the estimated actual annual fuel consumption? 2,883,252,662 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 454 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:

Table A-27 - SCR for IP Springfield Package 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	0.2	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.02	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})	431	ft^3/min-MMBtu/hour

50

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
Annual Interest Rate (i)	4.75	Percent		
Reagent ($Cost_{reag}$)	3.53	$/gallon for 29% ammonia		
Electricity ($Cost_{elect}$)	0.0676	$/kWh		
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst		
Operator Labor Rate	60.00	$/hour (including benefits)*		
Operator Hours/Day	4.00	hours/day*		

CEPCI = Chemical Engineering Plant Cost Index

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

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

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

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

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	/gallon 50% urea so	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Mod	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.	
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/.	
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, pre-COVID prime rate
Natural gas cost, $/MMBtu	$5.00	eia.gov representative Oregon industrial natural gas price	

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 =	340	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	2,883,252,662	scf/Year	
Actual Annual fuel consumption (Mactual) =		2,883,252,662	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	1.000	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 =	61.20	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	268.06	tons/year	Based on PSEL of 297.84 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} =	140,224	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	100.01	/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)* =	14.5	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})	1,402.03	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	146	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 $A_{catalyst}$	168	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	13.0	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 $MW_R)/MW_{NOx}$ =	24	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	82	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	11	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	3,700	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 $(\text{CoalF x HRF})^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	174.83	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) =	$10,446,329	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)
TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,404,282	in 2019 dollars
Indirect Annual Costs (IDAC) =	$726,141	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$2,130,423	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 =		$52,232	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =		$338,787	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =		$103,528	in 2019 dollars
Annual Catalyst Replacement Cost =			$33,736	in 2019 dollars
Natural gas for duct burner to reheat stack gas, based on MMBtu/hr of:		20	$876,000	in 2019 dollars
	n_{scr} x Vol_{cat} x $(CC_{replace}/R_{layer})$ x FWF			
Direct Annual Cost =			$1,404,282	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) =	$3,255	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$722,886	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$726,141	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$2,130,423	per year in 2019 dollars
NOx Removed =	268	tons/year
Cost Effectiveness =	$7,948	per ton of NOx removed in 2019 dollars

Table A-27a - SCR for IP Springfield Package Boiler

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

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

What type of fuel does the unit burn? Natural Gas

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)? 340 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,033 Btu/scf

*HHV value of 1033 Btu/scf is a default value. See below for data source. Enter actual HHV for fuel burned, if known.

What is the estimated actual annual fuel consumption? 38,813,069 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 454 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:

Table A-27a - SCR for IP Springfield Package Boiler

Number of days the SCR operates (t_{SCR})	17	days
Number of days the boiler operates (t_{plant})	17	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.07	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.007	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

50

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-27a - SCR for IP Springfield Package 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	/gallon 50% urea so	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Mod	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.	
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/.	
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, pre-COVID prime rate
Natural gas cost, $/MMBtu	$5.00	eia.gov representative Oregon industrial natural gas price	

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 =	340	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	2,883,252,662	scf/Year	
Actual Annual fuel consumption (Mactual) =		38,813,069	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.013	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	394	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 =	21.42	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	1.26	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} =	140,224	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	104.78	/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) =	$2116 \times [(59-(0.00356xh)+459.7)/518.6]^{5.256} \times (1/144)$* =	14.5	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	0.0033	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})	1,338.24	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	146	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 $A_{catalyst}$	168	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	13.0	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} =	8	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	29	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	4	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	1,300	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.	174.83	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) =	$10,446,329	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$101,968	in 2019 dollars
Indirect Annual Costs (IDAC) =	$723,635	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$825,603	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 =		$52,232	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =		$5,335	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =		$4,658	in 2019 dollars
Annual Catalyst Replacement Cost =			$334	in 2019 dollars
Natural gas for duct burner to reheat stack gas, based on MMBtu/hr of:		20	$39,410	in 2019 dollars
	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF			
Direct Annual Cost =			$101,968	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) =	$749	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$722,886	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$723,635	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$825,603	per year in 2019 dollars
NOx Removed =	1	tons/year
Cost Effectiveness =	$655,241	per ton of NOx removed in 2019 dollars

Table A-28

Cascade Pacific Pulp - Halsey

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 rebuild		$4,617,030
(b)		Instrumentation	0.10 A	$461,703
(b)		Sales Tax	0.03 A	$138,511
(b)		Freight	0.05 A	$230,851
	B	***Total Purchased Equipment Cost***		***$5,448,095***
	Direct Installation Costs			
(b)		Foundations and Supports[c]	0.04 B	$0
(b)		Handling and Erection	0.50 B	$2,724,047
(b)		Electrical	0.08 B	$435,848
(b)		Piping	0.01 B	$54,481
(b)		Insulation	0.02 B	$108,962
(b)		Painting	0.02 B	$108,962
		Direct Installation Cost		***$3,432,300***
	Total Direct Costs			***$8,880,395***
Indirect Costs				
(b)		Engineering	0.20 B	$1,089,619
(b)		Construction Management	0.20 B	$1,089,619
(b)		Contractor fees	0.10 B	$544,809
(b)		Start-up	0.01 B	$54,481
(b)		Performance test	0.01 B	$54,481
(b)		Model Study	0.02 B	$108,962
(b)		Contingencies	0.03 B	$163,443
	Total Indirect Costs			***$3,105,414***
Total Capital Investment (TCI)[a]				***$11,985,809***

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]				
	Additional Electricity	299	kW	$0.060 per kWh[b]	$156,937
	Total Direct Annual Costs				***$156,937***
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		$119,858
(b)	Insurance	1%	of TCI		$119,858
(b)	Capital recovery	0.079	x TCI		$941,491
	Life of the control:		20 years at	4.75% interest	
	Total Indirect Annual Costs				***$1,181,207***
Total Annual Costs					***$1,338,144***
Cost Effectiveness ($/ton)					
	PM_{10} Control Efficiency[f]:	99.5%	(assumes improvement from 99 to 99.5% control with the rebuild)		
	PM_{10} Emissions[g]:	107.4	tpy	Total Annual Costs/Controlled PM_{10} Emissions:	
	Controlled PM_{10} Emissions[h]:	53.7	additional tons of PM_{10} removed annually		***$24,919***

[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 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-28a

Cascade Pacific Pulp - Halsey

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 rebuild		$4,617,030	(b)	Operator	hours/shift	$31.00 per hour[d]	$0
(b)	Instrumentation	0.10 A	$461,703	(b)	Supervisor	of operator labor		$0
(b)	Sales Tax	0.03 A	$138,511	(b)	Coordinator	of operator labor		$0
(b)	Freight	0.05 A	$230,851		***Maintenance[c]***			
	B Total Purchased Equipment Cost		***$5,448,095***	(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		Additional Electricity	299 kW	$0.060 per kWh[b]	$151,938
(b)	Handling and Erection	0.50 B	$2,724,047					
(b)	Electrical	0.08 B	$435,848		***Total Direct Annual Costs***			***$151,938***
(b)	Piping	0.01 B	$54,481					
(b)	Insulation	0.02 B	$108,962					
(b)	Painting	0.02 B	$108,962		***Indirect Annual Costs***			
	Direct Installation Cost		***$3,432,300***	(c)	Overhead	60% Labor and Material Costs		$0
	Total Direct Costs		***$8,880,395***	(c)	General and administrative	2% of TCI		$0
				(b)	Property taxes	1% of TCI		$119,858
	Indirect Costs			(b)	Insurance	1% of TCI		$119,858
(b)	Engineering	0.20 B	$1,089,619	(b)	Capital recovery	0.079 x TCI		$941,491
(b)	Construction Management	0.20 B	$1,089,619		Life of the control:	20 years at	4.75% interest	
(b)	Contractor fees	0.10 B	$544,809					
(b)	Start-up	0.01 B	$54,481		***Total Indirect Annual Costs***			***$1,181,207***
(b)	Performance test	0.01 B	$54,481					
(b)	Model Study	0.02 B	$108,962		***Total Annual Costs***			***$1,333,145***
(b)	Contingencies	0.03 B	$163,443					
	Total Indirect Costs		***$3,105,414***		***Cost Effectiveness ($/ton)***			
					PM_{10} Control Efficiency[f]:	99.5% (assumes improvement from 99 to 99.5% control with the rebuild)		
	Total Capital Investment (TCI)[a]		***$11,985,809***		PM_{10} Emissions[g]:	172.6 tpy	Total Annual Costs/Controlled PM_{10} Emissions:	
					Controlled PM_{10} Emissions[h]:	86.3 additional tons of PM_{10} removed annually		***$15,448***

[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 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-29

Georgia-Pacific Toledo LLC

Capital and Annual Costs Associated with ESP Upgrade for No. 1 Recovery Furnace

CAPITAL COSTS[(a)]

		COST ITEM	COST FACTOR	COST ($)
Direct Costs				
	Purchased Equipment Costs			
(a)	***A***	ESP		$3,148,314
(b)		Instrumentation	0.10 A	$314,831
(b)		Sales Tax	0.03 A	$94,449
(b)		Freight	0.05 A	$157,416
	B	***Total Purchased Equipment Cost***		***$3,715,011***
	Direct Installation Costs			
(b)		Foundations and Supports[(c)]	0.04 B	$0
(b)		Handling and Erection	0.50 B	$1,857,506
(b)		Electrical	0.08 B	$297,201
(b)		Piping	0.01 B	$37,150
(b)		Insulation	0.02 B	$74,300
(b)		Painting	0.02 B	$74,300
		Direct Installation Cost		***$2,340,457***
	Total Direct Costs			***$6,055,468***
Indirect Costs				
(b)		Engineering	0.20 B	$743,002
(b)		Construction Management	0.20 B	$743,002
(b)		Contractor fees	0.10 B	$371,501
(b)		Start-up	0.01 B	$37,150
(b)		Performance test	0.01 B	$37,150
(b)		Model Study	0.02 B	$74,300
(b)		Contingencies	0.03 B	$111,450
	Total Indirect Costs			***$2,117,556***
Total Capital Investment (TCI)[(a)]				***$8,173,024***

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	158	kW	$0.060 per kWh[(b)]	$82,906
	Total Direct Annual Costs				***$82,906***
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		$81,730
(b)	Insurance	1%	of TCI		$81,730
(b)	Capital recovery	0.079	x TCI		$641,995
	Life of the control:		20 years at	4.75% interest	
	Total Indirect Annual Costs				***$805,455***
Total Annual Costs					***$888,361***
Cost Effectiveness ($/ton)					
	PM_{10} Control Efficiency[(f)]:	99.5%			
	PM_{10} Emissions[(g)]:	29	tpy	Total Annual Costs/Controlled PM_{10} Emissions:	
	Controlled PM_{10} Emissions[(h)]:	14.5	tons of additional PM_{10} removed annually		***$61,266***

[(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-29a

Georgia-Pacific Toledo LLC

Capital and Annual Costs Associated with ESP Upgrade for No. 1 Recovery Furnace

CAPITAL COSTS[a]

		COST ITEM	COST FACTOR	COST ($)
		Direct Costs		
		Purchased Equipment Costs		
(a)	*A*	ESP		$3,148,314
(b)		Instrumentation	0.10 A	$314,831
(b)		Sales Tax	0.03 A	$94,449
(b)		Freight	0.05 A	$157,416
	B	***Total Purchased Equipment Cost***		***$3,715,011***
		Direct Installation Costs		
(b)		Foundations and Supports[c]	0.04 B	$0
(b)		Handling and Erection	0.50 B	$1,857,506
(b)		Electrical	0.08 B	$297,201
(b)		Piping	0.01 B	$37,150
(b)		Insulation	0.02 B	$74,300
(b)		Painting	0.02 B	$74,300
		Direct Installation Cost		***$2,340,457***
		Total Direct Costs		***$6,055,468***
		Indirect Costs		
(b)		Engineering	0.20 B	$743,002
(b)		Construction Management	0.20 B	$743,002
(b)		Contractor fees	0.10 B	$371,501
(b)		Start-up	0.01 B	$37,150
(b)		Performance test	0.01 B	$37,150
(b)		Model Study	0.02 B	$74,300
(b)		Contingencies	0.03 B	$111,450
		Total Indirect Costs		***$2,117,556***
		Total Capital Investment (TCI)[a]		***$8,173,024***

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	158	kW	$0.060	per kWh[b]	$76,934
	Total Direct Annual Costs					***$76,934***
	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			$81,730
(b)	Insurance	1%	of TCI			$81,730
(b)	Capital recovery	0.079	x TCI			$641,995
	Life of the control:		20 years at	4.75%	interest	
	Total Indirect Annual Costs					***$805,455***
	Total Annual Costs					***$882,389***
	Cost Effectiveness ($/ton)					
	PM_{10} Control Efficiency[f]:	99.5%				
	PM_{10} Emissions[g]:	26.4	tpy		Total Annual Costs/Controlled PM_{10} Emissions:	
	Controlled PM_{10} Emissions[h]:	13.2	tons of additional PM_{10} removed annually			***$66,848***

[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-30

Georgia-Pacific Toledo LLC

Capital and Annual Costs Associated with ESP Upgrade for No. 2 Recovery Furnace

CAPITAL COSTS[a]

		COST ITEM	COST FACTOR	COST ($)
		Direct Costs		
		Purchased Equipment Costs		
(a)	***A***	ESP		$3,148,314
(b)		Instrumentation	0.10 A	$314,831
(b)		Sales Tax	0.03 A	$94,449
(b)		Freight	0.05 A	$157,416
	B	***Total Purchased Equipment Cost***		***$3,715,011***
		Direct Installation Costs		
(b)		Foundations and Supports[c]	0.04 B	$0
(b)		Handling and Erection	0.50 B	$1,857,506
(b)		Electrical	0.08 B	$297,201
(b)		Piping	0.01 B	$37,150
(b)		Insulation	0.02 B	$74,300
(b)		Painting	0.02 B	$74,300
		Direct Installation Cost		***$2,340,457***
		Total Direct Costs		***$6,055,468***
		Indirect Costs		
(b)		Engineering	0.20 B	$743,002
(b)		Construction Management	0.20 B	$743,002
(b)		Contractor fees	0.10 B	$371,501
(b)		Start-up	0.01 B	$37,150
(b)		Performance test	0.01 B	$37,150
(b)		Model Study	0.02 B	$74,300
(b)		Contingencies	0.03 B	$111,450
		Total Indirect Costs		***$2,117,556***
		Total Capital Investment (TCI)[a]		***$8,173,024***

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	158	kW	$0.060	per kWh[b]	$82,906
	Total Direct Annual Costs					***$82,906***
	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			$81,730
(b)	Insurance	1%	of TCI			$81,730
(b)	Capital recovery	0.079	x TCI			$641,995
	Life of the control:	20	years at	4.75%	interest	
	Total Indirect Annual Costs					***$805,455***
	Total Annual Costs					***$888,361***
	Cost Effectiveness ($/ton)					
	PM_{10} Control Efficiency[f]:	99.5%				
	PM_{10} Emissions[g]:	29	tpy	Total Annual Costs/Controlled PM_{10} Emissions:		
	Controlled PM_{10} Emissions[h]:	14.5	tons of additional PM_{10} removed annually			***$61,266***

[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-30a

Georgia-Pacific Toledo LLC

Capital and Annual Costs Associated with ESP Upgrade for No. 2 Recovery Furnace

CAPITAL COSTS[a]

		COST ITEM	COST FACTOR	COST ($)
		Direct Costs		
		Purchased Equipment Costs		
(a)	***A***	ESP		$3,148,314
(b)		Instrumentation	0.10 A	$314,831
(b)		Sales Tax	0.03 A	$94,449
(b)		Freight	0.05 A	$157,416
	B	***Total Purchased Equipment Cost***		***$3,715,011***
		Direct Installation Costs		
(b)		Foundations and Supports[c]	0.04 B	$0
(b)		Handling and Erection	0.50 B	$1,857,506
(b)		Electrical	0.08 B	$297,201
(b)		Piping	0.01 B	$37,150
(b)		Insulation	0.02 B	$74,300
(b)		Painting	0.02 B	$74,300
		Direct Installation Cost		***$2,340,457***
		Total Direct Costs		***$6,055,468***
		Indirect Costs		
(b)		Engineering	0.20 B	$743,002
(b)		Construction Management	0.20 B	$743,002
(b)		Contractor fees	0.10 B	$371,501
(b)		Start-up	0.01 B	$37,150
(b)		Performance test	0.01 B	$37,150
(b)		Model Study	0.02 B	$74,300
(b)		Contingencies	0.03 B	$111,450
		Total Indirect Costs		***$2,117,556***
		Total Capital Investment (TCI)[a]		***$8,173,024***

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	158	kW	$0.060 per kWh[b]	$76,934
	Total Direct Annual Costs				***$76,934***
	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		$81,730
(b)	Insurance	1%	of TCI		$81,730
(b)	Capital recovery	0.079	x TCI		$641,995
	Life of the control:		20 years at	4.75% interest	
	Total Indirect Annual Costs				***$805,455***
	Total Annual Costs				***$882,389***
	Cost Effectiveness ($/ton)				
	PM_{10} Control Efficiency[f]:	99.5%			
	PM_{10} Emissions[g]:	26.8	tpy	Total Annual Costs/Controlled PM_{10} Emissions:	
	Controlled PM_{10} Emissions[h]:	13.4	tons of additional PM_{10} removed annually		***$65,850***

[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-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]

		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]	$192,572
	Total Direct Annual Costs				***$192,572***
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					***$1,600,077***
Cost Effectiveness ($/ton)					
	PM_{10} Control Efficiency[f]:	99.5%			
	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-32

International Paper Springfield

Capital and Annual Costs Associated with ESP Upgrade for No. 4 Recovery Furnace

CAPITAL COSTS[a]

	COST ITEM	COST FACTOR	COST ($)
	Direct Costs		
	Purchased Equipment Costs		
(a)	***A*** ESP		$5,395,375
(b)	Instrumentation	0.10 A	$539,538
(b)	Sales Tax	0.03 A	$161,861
(b)	Freight	0.05 A	$269,769
	B Total Purchased Equipment Cost		***$6,366,543***
	Direct Installation Costs		
(b)	Foundations and Supports[c]	0.04 B	$0
(b)	Handling and Erection	0.50 B	$3,183,271
(b)	Electrical	0.08 B	$509,323
(b)	Piping	0.01 B	$63,665
(b)	Insulation	0.02 B	$127,331
(b)	Painting	0.02 B	$127,331
	Direct Installation Cost		***$4,010,922***
	Total Direct Costs		***$10,377,464***
	Indirect Costs		
(b)	Engineering	0.20 B	$1,273,309
(b)	Construction Management	0.20 B	$1,273,309
(b)	Contractor fees	0.10 B	$636,654
(b)	Start-up	0.01 B	$63,665
(b)	Performance test	0.01 B	$63,665
(b)	Model Study	0.02 B	$127,331
(b)	Contingencies	0.03 B	$190,996
	Total Indirect Costs		***$3,628,929***
	Total Capital Investment (TCI)[a]		***$14,006,394***

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	387	kW	$0.060 per kWh[b]	$203,465
	Total Direct Annual Costs				***$203,465***
	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		$140,064
(b)	Insurance	1%	of TCI		$140,064
(b)	Capital recovery	0.079	x TCI		$1,100,209
	Life of the control:		20 years at	4.75% interest	
	Total Indirect Annual Costs				***$1,380,337***
	Total Annual Costs				***$1,583,802***
	Cost Effectiveness ($/ton)				
	PM_{10} Control Efficiency[f]:	99.5%			
	PM_{10} Emissions[g]:	145.75	tpy	Total Annual Costs/Controlled PM_{10} Emissions:	
	Controlled PM_{10} Emissions[h]:	72.9	tons of additional PM_{10} removed annually		***$21,733***

[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-32a

International Paper Springfield

Capital and Annual Costs Associated with ESP Upgrade for No. 4 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		$5,395,375	(b)	Operator		hours/shift	$31.00 per hour[d]	$0
(b)	Instrumentation	0.10 A	$539,538	(b)	Supervisor		of operator labor		$0
(b)	Sales Tax	0.03 A	$161,861	(b)	Coordinator		of operator labor		$0
(b)	Freight	0.05 A	$269,769		***Maintenance*** [c]				
	B Total Purchased Equipment Cost		***$6,366,543***	(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	387	kW	$0.060 per kWh[b]	$201,653
(b)	Handling and Erection	0.50 B	$3,183,271						
(b)	Electrical	0.08 B	$509,323		***Total Direct Annual Costs***				***$201,653***
(b)	Piping	0.01 B	$63,665						
(b)	Insulation	0.02 B	$127,331						
(b)	Painting	0.02 B	$127,331		***Indirect Annual Costs***				
	Direct Installation Cost		***$4,010,922***	(c)	Overhead	60%	Labor and Material Costs		$0
	Total Direct Costs		***$10,377,464***	(c)	General and administrative	2%	of TCI		$0
				(b)	Property taxes	1%	of TCI		$140,064
	Indirect Costs			(b)	Insurance	1%	of TCI		$140,064
(b)	Engineering	0.20 B	$1,273,309	(b)	Capital recovery	0.079	x TCI		$1,100,209
(b)	Construction Management	0.20 B	$1,273,309		Life of the control:		20 years at	4.75% interest	
(b)	Contractor fees	0.10 B	$636,654						
(b)	Start-up	0.01 B	$63,665		***Total Indirect Annual Costs***				***$1,380,337***
(b)	Performance test	0.01 B	$63,665						
(b)	Model Study	0.02 B	$127,331		***Total Annual Costs***				***$1,581,990***
(b)	Contingencies	0.03 B	$190,996						
	Total Indirect Costs		***$3,628,929***		***Cost Effectiveness ($/ton)***				
					PM_{10} Control Efficiency[f]:	99.5%			
	Total Capital Investment (TCI) [a]		***$14,006,394***		PM_{10} Emissions[g]:	120.22	tpy	Total Annual Costs/Controlled PM_{10} Emissions:	
					Controlled PM_{10} Emissions [h]:	60.1	tons of additional PM_{10} removed annually		***$26,318***

[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-33

Cascade Pacific Pulp - Halsey

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		$3,669,186
(b)		Instrumentation and controls	0.10 A	$366,919
(b)		Sales Tax	0.03 A	$110,076
(b)		Freight	0.05 A	$183,459
	B	***Total Purchased Equipment Cost***		***$4,329,639***
		Direct Installation Costs		
(b)		Foundations and Supports	0.04 B	$173,186
(b)		Handling and Erection	0.50 B	$2,164,820
(b)		Electrical	0.08 B	$346,371
(b)		Piping	0.01 B	$43,296
(b)		Insulation for Ductwork	0.02 B	$86,593
(b)		Painting	0.02 B	$86,593
		Direct Installation Cost		***$2,900,858***
		Total Direct Costs		***$7,230,497***
Indirect Costs				
(b)		Engineering	0.20 B	$865,928
(b)		Construction and Field Expenses	0.20 B	$865,928
(b)		Contractor fees	0.10 B	$432,964
(b)		Start-up	0.01 B	$43,296
(b)		Performance test	0.01 B	$43,296
(b)		Model Study	0.02 B	$86,593
(b)		Contingencies	0.03 B	$129,889
		Total Indirect Costs		***$2,467,894***
Total Capital Investment (TCI)				***$9,698,392***

ANNUALIZED COSTS

	COST ITEM	COST FACTOR		RATE		COST ($)
Direct Annual Costs						
	Operating Labor					
(b)	Operator[c]	1	hours/shift	$31.00	per hour[d]	$33,945
(b)	Supervisor	15%	of operator labor			$5,091.75
(b)	Coordinator	33%	of operator labor			$11,201.85
	Maintenance					
(b)	Maintenance labor[c]	0.5	hours/shift	$34.00	per hour[d]	$18,615
(b)	Maintenance materials	1%	of purchased equipment costs			$43,296
	Utilities [c)(e]					
	Electricity	215	kW	$0.060	per kWh[d]	$112,785
	Water	10,000	gal/day	$0.01	per gal	$36,500
	Total Direct Annual Costs					***$261,435***
Indirect Annual Costs						
(b)	Overhead	60%	Labor and Material Costs			$67,289.99
(b)	General and administrative	2%	of TCI			$193,968
(b)	Property taxes	1%	of TCI			$96,984
(b)	Insurance	1%	of TCI			$96,984
(b)	Capital recovery	0.079	x TCI			$761,813
	Life of the control:		20 years at	4.75%	interest	
	Total Indirect Annual Costs					***$1,217,039***
Total Annual Costs						***$1,478,474***
Cost Effectiveness ($/ton)						
	Addl PM_{10} Control [f]:	80%				
	PM_{10} Emissions[g]:	107.4	tpy		Total Annual Costs/Controlled PM_{10} Emissions:	
	Controlled PM_{10} Emissions:	85.9	tons of PM_{10} removed annually			***$17,208***

[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-33a

Cascade Pacific Pulp - Halsey

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		$3,669,186
(b)		Instrumentation and controls	0.10 A	$366,919
(b)		Sales Tax	0.03 A	$110,076
(b)		Freight	0.05 A	$183,459
	B	***Total Purchased Equipment Cost***		***$4,329,639***
	Direct Installation Costs			
(b)		Foundations and Supports	0.04 B	$173,186
(b)		Handling and Erection	0.50 B	$2,164,820
(b)		Electrical	0.08 B	$346,371
(b)		Piping	0.01 B	$43,296
(b)		Insulation for Ductwork	0.02 B	$86,593
(b)		Painting	0.02 B	$86,593
		Direct Installation Cost		***$2,900,858***
	Total Direct Costs			***$7,230,497***
Indirect Costs				
(b)		Engineering	0.20 B	$865,928
(b)		Construction and Field Expenses	0.20 B	$865,928
(b)		Contractor fees	0.10 B	$432,964
(b)		Start-up	0.01 B	$43,296
(b)		Performance test	0.01 B	$43,296
(b)		Model Study	0.02 B	$86,593
(b)		Contingencies	0.03 B	$129,889
	Total Indirect Costs			***$2,467,894***
Total Capital Investment (TCI)				***$9,698,392***

ANNUALIZED COSTS

	COST ITEM	COST FACTOR		RATE		COST ($)
Direct Annual Costs						
	Operating Labor					
(b)	Operator[c]	1	hours/shift	$31.00	per hour[d]	$32,864
(b)	Supervisor	15%	of operator labor			$4,929.58
(b)	Coordinator	33%	of operator labor			$10,845.08
	Maintenance					
(b)	Maintenance labor[c]	0.5	hours/shift	$34.00	per hour[d]	$18,022
(b)	Maintenance materials	1%	of purchased equipment costs			$43,296
	Utilities [c][e]					
	Electricity	215	kW	$0.060	per kWh[d]	$109,193
	Water	10,000	gal/day	$0.01	per gal	$36,500
	Total Direct Annual Costs					***$255,650***
Indirect Annual Costs						
(b)	Overhead	60%	Labor and Material Costs			$65,974.23
(b)	General and administrative	2%	of TCI			$193,968
(b)	Property taxes	1%	of TCI			$96,984
(b)	Insurance	1%	of TCI			$96,984
(b)	Capital recovery	0.079	x TCI			$761,813
	Life of the control:		20 years at	4.75%	interest	
	Total Indirect Annual Costs					***$1,215,723***
Total Annual Costs						***$1,471,373***
Cost Effectiveness ($/ton)						
	Addl PM_{10} Control [f]:	80%				
	PM_{10} Emissions[g]:	171.6	tpy		Total Annual Costs/Controlled PM_{10} Emissions:	
	Controlled PM_{10} Emissions:	137.3	tons of PM_{10} removed annually			***$10,716***

[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 8481 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-34

Georgia-Pacific - Toledo

Capital and Annual Costs Associated with WESP for No. 1 Recovery Furnace

CAPITAL COSTS

		COST ITEM	COST FACTOR	COST ($)
		Direct Costs		
		Purchased Equipment Costs		
(a)	***A***	WESP		$1,938,335
(b)		Instrumentation and controls	0.10 A	$193,833
(b)		Sales Tax	0.03 A	$58,150
(b)		Freight	0.05 A	$96,917
	B	***Total Purchased Equipment Cost***		***$2,287,235***
		Direct Installation Costs		
(b)		Foundations and Supports	0.04 B	$91,489
(b)		Handling and Erection	0.50 B	$1,143,617
(b)		Electrical	0.08 B	$182,979
(b)		Piping	0.01 B	$22,872
(b)		Insulation for Ductwork	0.02 B	$45,745
(b)		Painting	0.02 B	$45,745
		Direct Installation Cost		***$1,532,447***
		Total Direct Costs		***$3,819,682***
		Indirect Costs		
(b)		Engineering	0.20 B	$457,447
(b)		Construction and Field Expenses	0.20 B	$457,447
(b)		Contractor fees	0.10 B	$228,723
(b)		Start-up	0.01 B	$22,872
(b)		Performance test	0.01 B	$22,872
(b)		Model Study	0.02 B	$45,745
(b)		Contingencies	0.03 B	$68,617
		Total Indirect Costs		***$1,303,724***
		Total Capital Investment (TCI)		***$5,123,406***

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			$22,872
	Utilities [c)(e]					
	Electricity	215	kW	$0.060	per kWh	$112,785
	Water	10,000	gal/day	$0.01	per gal	$876,000
	Total Direct Annual Costs					***$1,072,341***
	Indirect Annual Costs					
(b)	Overhead	60%	Labor and Material Costs			$50,133.56
(b)	General and administrative	2%	of TCI			$102,468
(b)	Property taxes	1%	of TCI			$51,234
(b)	Insurance	1%	of TCI			$51,234
(b)	Capital recovery	0.079	x TCI			$402,446
	Life of the control:	20 years at		4.75%	interest	
	Total Indirect Annual Costs					***$657,516***
	Total Annual Costs					***$1,729,857***
	Cost Effectiveness ($/ton)					
	PM_{10} Control Efficiency[f]:	80%				
	2017 PM_{10} Emissions[g]:	29	tpy		Total Annual Costs/Controlled PM_{10} Emissions:	
	Controlled PM_{10} Emissions:	23.2	tons of PM_{10} removed annually			***$74,563***

[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-34a

Georgia-Pacific - Toledo

Capital and Annual Costs Associated with WESP for No. 1 Recovery Furnace

CAPITAL COSTS

		COST ITEM	COST FACTOR	COST ($)
		Direct Costs		
		Purchased Equipment Costs		
(a)	***A***	WESP		$1,938,335
(b)		Instrumentation and controls	0.10 A	$193,833
(b)		Sales Tax	0.03 A	$58,150
(b)		Freight	0.05 A	$96,917
	B	***Total Purchased Equipment Cost***		***$2,287,235***
		Direct Installation Costs		
(b)		Foundations and Supports	0.04 B	$91,489
(b)		Handling and Erection	0.50 B	$1,143,617
(b)		Electrical	0.08 B	$182,979
(b)		Piping	0.01 B	$22,872
(b)		Insulation for Ductwork	0.02 B	$45,745
(b)		Painting	0.02 B	$45,745
		Direct Installation Cost		***$1,532,447***
		Total Direct Costs		***$3,819,682***
		Indirect Costs		
(b)		Engineering	0.20 B	$457,447
(b)		Construction and Field Expenses	0.20 B	$457,447
(b)		Contractor fees	0.10 B	$228,723
(b)		Start-up	0.01 B	$22,872
(b)		Performance test	0.01 B	$22,872
(b)		Model Study	0.02 B	$45,745
(b)		Contingencies	0.03 B	$68,617
		Total Indirect Costs		***$1,303,724***
		Total Capital Investment (TCI)		***$5,123,406***

ANNUALIZED COSTS

	COST ITEM	COST FACTOR		RATE		COST ($)
	Direct Annual Costs					
	Operating Labor					
(b)	Operator[c]	1	hours/shift	$29.06	per hour[d]	$29,529
(b)	Supervisor	15%	of operator labor			$4,429.29
(b)	Coordinator	33%	of operator labor			$9,744.44
	Maintenance					
(b)	Maintenance labor[c]	0.5	hours/shift	$24.82	per hour[d]	$12,610
(b)	Maintenance materials	1%	of purchased equipment costs			$22,872
	Utilities [c](e)					
	Electricity	215	kW	$0.060	per kWh	$104,661
	Water	10,000	gal/day	$0.01	per gal	$812,900
	Total Direct Annual Costs					***$996,746***
	Indirect Annual Costs					
(b)	Overhead	60%	Labor and Material Costs			$47,510.87
(b)	General and administrative	2%	of TCI			$102,468
(b)	Property taxes	1%	of TCI			$51,234
(b)	Insurance	1%	of TCI			$51,234
(b)	Capital recovery	0.079	x TCI			$402,446
	Life of the control:	20	years at	4.75%	interest	
	Total Indirect Annual Costs					***$654,893***
	Total Annual Costs					***$1,651,639***

Cost Effectiveness ($/ton)

PM_{10} Control Efficiency[f]:	80%		
2017 PM_{10} Emissions[g]:	26.4	tpy	Total Annual Costs/Controlled PM_{10} Emissions:
Controlled PM_{10} Emissions:	21.1	tons of PM_{10} removed annually	***$78,203***

[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 8129 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-35

Georgia-Pacific - Toledo

Capital and Annual Costs Associated with WESP for No. 2 Recovery Furnace

CAPITAL COSTS

		COST ITEM	COST FACTOR	COST ($)
		Direct Costs		
		Purchased Equipment Costs		
(a)	*A*	WESP		$1,938,335
(b)		Instrumentation and controls	0.10 A	$193,833
(b)		Sales Tax	0.03 A	$58,150
(b)		Freight	0.05 A	$96,917
	B	***Total Purchased Equipment Cost***		***$2,287,235***
		Direct Installation Costs		
(b)		Foundations and Supports	0.04 B	$91,489
(b)		Handling and Erection	0.50 B	$1,143,617
(b)		Electrical	0.08 B	$182,979
(b)		Piping	0.01 B	$22,872
(b)		Insulation for Ductwork	0.02 B	$45,745
(b)		Painting	0.02 B	$45,745
		Direct Installation Cost		***$1,532,447***
		Total Direct Costs		***$3,819,682***
		Indirect Costs		
(b)		Engineering	0.20 B	$457,447
(b)		Construction and Field Expenses	0.20 B	$457,447
(b)		Contractor fees	0.10 B	$228,723
(b)		Start-up	0.01 B	$22,872
(b)		Performance test	0.01 B	$22,872
(b)		Model Study	0.02 B	$45,745
(b)		Contingencies	0.03 B	$68,617
		Total Indirect Costs		***$1,303,724***
		Total Capital Investment (TCI)		***$5,123,406***

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			$22,872
	Utilities [c][e]					
	Electricity	215	kW	$0.060	per kWh	$112,785
	Water	10,000	gal/day	$0.01	per gal	$876,000
	Total Direct Annual Costs					***$1,072,341***
	Indirect Annual Costs					
(b)	Overhead	60%	Labor and Material Costs			$50,133.56
(b)	General and administrative	2%	of TCI			$102,468
(b)	Property taxes	1%	of TCI			$51,234
(b)	Insurance	1%	of TCI			$51,234
(b)	Capital recovery	0.079	x TCI			$402,446
	Life of the control:	20	years at	4.75%	interest	
	Total Indirect Annual Costs					***$657,516***
	Total Annual Costs					***$1,729,857***
	Cost Effectiveness ($/ton)					
	PM_{10} Control Efficiency[f]:	80%				
	2017 PM_{10} Emissions[g]:	29	tpy		Total Annual Costs/Controlled PM_{10} Emissions:	
	Controlled PM_{10} Emissions:	23.2	tons of PM_{10} removed annually			***$74,563***

[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-35a

Georgia-Pacific - Toledo

Capital and Annual Costs Associated with WESP for No. 2 Recovery Furnace

CAPITAL COSTS

	COST ITEM	COST FACTOR	COST ($)
	Direct Costs		
	Purchased Equipment Costs		
(a)	***A*** WESP		$1,938,335
(b)	Instrumentation and controls	0.10 A	$193,833
(b)	Sales Tax	0.03 A	$58,150
(b)	Freight	0.05 A	$96,917
	B Total Purchased Equipment Cost		***$2,287,235***
	Direct Installation Costs		
(b)	Foundations and Supports	0.04 B	$91,489
(b)	Handling and Erection	0.50 B	$1,143,617
(b)	Electrical	0.08 B	$182,979
(b)	Piping	0.01 B	$22,872
(b)	Insulation for Ductwork	0.02 B	$45,745
(b)	Painting	0.02 B	$45,745
	Direct Installation Cost		***$1,532,447***
	Total Direct Costs		***$3,819,682***
	Indirect Costs		
(b)	Engineering	0.20 B	$457,447
(b)	Construction and Field Expenses	0.20 B	$457,447
(b)	Contractor fees	0.10 B	$228,723
(b)	Start-up	0.01 B	$22,872
(b)	Performance test	0.01 B	$22,872
(b)	Model Study	0.02 B	$45,745
(b)	Contingencies	0.03 B	$68,617
	Total Indirect Costs		***$1,303,724***
	Total Capital Investment (TCI)		***$5,123,406***

ANNUALIZED COSTS

	COST ITEM	COST FACTOR		RATE		COST ($)
	Direct Annual Costs					
	Operating Labor					
(b)	Operator[c]	1	hours/shift	$29.06	per hour[d]	$29,529
(b)	Supervisor	15%	of operator labor			$4,429.29
(b)	Coordinator	33%	of operator labor			$9,744.44
	Maintenance					
(b)	Maintenance labor[c]	0.5	hours/shift	$24.82	per hour[d]	$12,610
(b)	Maintenance materials	1%	of purchased equipment costs			$22,872
	Utilities [(c)(e)]					
	Electricity	215	kW	$0.060	per kWh	$104,661
	Water	10,000	gal/day	$0.01	per gal	$812,900
	Total Direct Annual Costs					***$996,746***
	Indirect Annual Costs					
(b)	Overhead	60%	Labor and Material Costs			$47,510.87
(b)	General and administrative	2%	of TCI			$102,468
(b)	Property taxes	1%	of TCI			$51,234
(b)	Insurance	1%	of TCI			$51,234
(b)	Capital recovery	0.079	x TCI			$402,446
	Life of the control:	20	years at	4.75%	interest	
	Total Indirect Annual Costs					***$654,893***
	Total Annual Costs					***$1,651,639***
	Cost Effectiveness ($/ton)					
	PM_{10} Control Efficiency[f]:	80%				
	2017 PM_{10} Emissions[g]:	26.8	tpy		Total Annual Costs/Controlled PM_{10} Emissions:	
	Controlled PM_{10} Emissions:	21.4	tons of PM_{10} removed annually			***$77,035***

[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 8129 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-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-37
International Paper - Springfield
Capital and Annual Costs Associated with WESP for No. 4 Recovery Furnace

CAPITAL COSTS

		COST ITEM	COST FACTOR	COST ($)
Direct Costs				
	Purchased Equipment Costs			
(a)	***A***	WESP		$4,757,017
(b)		Instrumentation and controls	0.10 A	$475,702
(b)		Sales Tax	0.03 A	$142,711
(b)		Freight	0.05 A	$237,851
	B	***Total Purchased Equipment Cost***		***$5,613,280***
	Direct Installation Costs			
(b)		Foundations and Supports	0.04 B	$224,531
(b)		Handling and Erection	0.50 B	$2,806,640
(b)		Electrical	0.08 B	$449,062
(b)		Piping	0.01 B	$56,133
(b)		Insulation for Ductwork	0.02 B	$112,266
(b)		Painting	0.02 B	$112,266
		Direct Installation Cost		***$3,760,897***
	Total Direct Costs			***$9,374,177***
Indirect Costs				
(b)		Engineering	0.20 B	$1,122,656
(b)		Construction and Field Expenses	0.20 B	$1,122,656
(b)		Contractor fees	0.10 B	$561,328
(b)		Start-up	0.01 B	$56,133
(b)		Performance test	0.01 B	$56,133
(b)		Model Study	0.02 B	$112,266
(b)		Contingencies	0.03 B	$168,398
	Total Indirect Costs			***$3,199,569***
Total Capital Investment (TCI)				***$12,573,747***

ANNUALIZED COSTS

	COST ITEM	COST FACTOR		RATE		COST ($)
Direct Annual Costs						
	Operating Labor					
(b)	Operator[c]	1	hours/shift	$31.00	per hour[d]	$33,945
(b)	Supervisor	15%	of operator labor			$5,091.75
(b)	Coordinator	33%	of operator labor			$11,201.85
	Maintenance					
(b)	Maintenance labor[c]	0.5	hours/shift	$34.00	per hour[d]	$18,615
(b)	Maintenance materials	1%	of purchased equipment costs			$56,133
	Utilities [c][e]					
	Electricity	215	kW	$0.060	per kWh	$112,785
	Water	10,000	gal/day	$0.01	per gal	$876,000
	Total Direct Annual Costs					***$1,113,771***
Indirect Annual Costs						
(b)	Overhead	60%	Labor and Material Costs			$74,991.84
(b)	General and administrative	2%	of TCI			$251,475
(b)	Property taxes	1%	of TCI			$125,737
(b)	Insurance	1%	of TCI			$125,737
(b)	Capital recovery	0.079	x TCI			$987,674
		Life of the control:	20 years at	4.75%	interest	
	Total Indirect Annual Costs					***$1,565,615***
Total Annual Costs						***$2,679,387***
Cost Effectiveness ($/ton)						
	PM_{10} Control Efficiency[f]:	80%				
	PM_{10} Emissions[g]:	145.8	tpy	Total Annual Costs/Controlled PM_{10} Emissions:		
	Controlled PM_{10} Emissions:	116.6	tons of PM_{10} removed annually			***$22,979***

[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 Chapter 6, Section 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-37a

International Paper - Springfield

Capital and Annual Costs Associated with WESP for No. 4 Recovery Furnace

CAPITAL COSTS

		COST ITEM	COST FACTOR	COST ($)
		Direct Costs		
		Purchased Equipment Costs		
(a)	*A*	WESP		$4,757,017
(b)		Instrumentation and controls	0.10 A	$475,702
(b)		Sales Tax	0.03 A	$142,711
(b)		Freight	0.05 A	$237,851
	B	***Total Purchased Equipment Cost***		***$5,613,280***
		Direct Installation Costs		
(b)		Foundations and Supports	0.04 B	$224,531
(b)		Handling and Erection	0.50 B	$2,806,640
(b)		Electrical	0.08 B	$449,062
(b)		Piping	0.01 B	$56,133
(b)		Insulation for Ductwork	0.02 B	$112,266
(b)		Painting	0.02 B	$112,266
		Direct Installation Cost		***$3,760,897***
		Total Direct Costs		***$9,374,177***
		Indirect Costs		
(b)		Engineering	0.20 B	$1,122,656
(b)		Construction and Field Expenses	0.20 B	$1,122,656
(b)		Contractor fees	0.10 B	$561,328
(b)		Start-up	0.01 B	$56,133
(b)		Performance test	0.01 B	$56,133
(b)		Model Study	0.02 B	$112,266
(b)		Contingencies	0.03 B	$168,398
		Total Indirect Costs		***$3,199,569***
		Total Capital Investment (TCI)		***$12,573,747***

ANNUALIZED COSTS

	COST ITEM	COST FACTOR		RATE		COST ($)
	Direct Annual Costs					
	Operating Labor					
(b)	Operator[c]	1	hours/shift	$31.00	per hour[d]	$33,643
(b)	Supervisor	15%	of operator labor			$5,046.41
(b)	Coordinator	33%	of operator labor			$11,102.11
	Maintenance					
(b)	Maintenance labor[c]	0.5	hours/shift	$34.00	per hour[d]	$18,449
(b)	Maintenance materials	1%	of purchased equipment costs			$56,133
	Utilities [c][e]					
	Electricity	215	kW	$0.060	per kWh	$111,781
	Water	10,000	gal/day	$0.01	per gal	$868,200
	Total Direct Annual Costs					***$1,104,354***
	Indirect Annual Costs					
(b)	Overhead	60%	Labor and Material Costs			$74,623.99
(b)	General and administrative	2%	of TCI			$251,475
(b)	Property taxes	1%	of TCI			$125,737
(b)	Insurance	1%	of TCI			$125,737
(b)	Capital recovery	0.079	x TCI			$987,674
	Life of the control:		20 years at	4.75%	interest	
	Total Indirect Annual Costs					***$1,565,248***
	Total Annual Costs					***$2,669,602***
	Cost Effectiveness ($/ton)					
	PM_{10} Control Efficiency[f]:	80%				
	PM_{10} Emissions[g]:	120.2	tpy		Total Annual Costs/Controlled PM_{10} Emissions:	
	Controlled PM_{10} Emissions:	96.2	tons of PM_{10} removed annually			***$27,757***

[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 Chapter 6, Section 2.

[c] Based on 8682 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-38

Cascade Pacific Pulp - Halsey

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		***$7,276,846***
(b)		Instrumentation	0.10 A	$727,685
(b)		Sales Tax	0.03 A	$218,305
(b)		Freight	0.05 A	$363,842
	B	***Total Purchased Equipment Cost***		***$8,586,678***
		Direct Installation Costs		
(b)		Foundations and Supports	0.12 B	$1,030,401
(b)		Handling and erection	0.40 B	$3,434,671
(b)		Electrical	0.01 B	$85,867
(b)		Piping	0.30 B	$2,576,003
(b)		Insulation for ductwork	0.01 B	$85,867
(b)		Painting	0.01 B	$85,867
		Direct Installation Cost		***$7,298,676***
		Total Direct Costs		***$15,885,354***
Indirect Costs				
(b)		Engineering	0.10 B	$858,668
(b)		Construction Management	0.10 B	$858,668
(b)		Contractor fees	0.10 B	$858,668
(b)		Start-up	0.01 B	$85,867
(b)		Performance test	0.01 B	$85,867
(b)		Contingencies	0.03 B	$257,600
		Total Indirect Costs		***$3,005,337***
Total Capital Investment (TCI)				***$18,890,691***

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	1,185	kW	$0.060	per kWh[b]	$622,783
	Chemicals	829	lb/hr NaOH	$0.25	per lb NaOH[d]	$1,815,197
	Fresh water usage	108	gpm	$0.20	per 1000 gallon[b]	$11,303
	Wastewater disposal	10.90	gpm	$3.80	per 1000 gallon[b]	$21,765
	Total Direct Annual Costs					***$2,527,796***
Indirect Annual Costs						
	Overhead	60%	Labor and Material Costs			$34,049
	General and administrative	2%	of TCI			$377,814
	Property taxes	1%	of TCI			$188,907
	Insurance	1%	of TCI			$188,907
	Capital recovery	0.095	x TCI			$1,789,348
	Life of the control:	15	years at	4.75%	interest	
	Total Indirect Annual Costs					***$2,579,024***
Total Annual Costs						***$5,106,821***
Cost Effectiveness ($/ton)						
	SO_2 Control Efficiency[f]:	98%				
	SO_2 Emissions[g]:	453.3	tpy	Total Annual Costs/Controlled SO_2 Emissions:		
	Controlled SO_2 Emissions:	444.2	tons of SO_2 removed annually			***$11,496***

[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 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, 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-38a

Cascade Pacific Pulp - Halsey

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		***$7,276,846***
(b)		Instrumentation	0.10 A	$727,685
(b)		Sales Tax	0.03 A	$218,305
(b)		Freight	0.05 A	$363,842
	B	***Total Purchased Equipment Cost***		***$8,586,678***
	Direct Installation Costs			
(b)		Foundations and Supports	0.12 B	$1,030,401
(b)		Handling and erection	0.40 B	$3,434,671
(b)		Electrical	0.01 B	$85,867
(b)		Piping	0.30 B	$2,576,003
(b)		Insulation for ductwork	0.01 B	$85,867
(b)		Painting	0.01 B	$85,867
		Direct Installation Cost		***$7,298,676***
	Total Direct Costs			***$15,885,354***
Indirect Costs				
(b)		Engineering	0.10 B	$858,668
(b)		Construction Management	0.10 B	$858,668
(b)		Contractor fees	0.10 B	$858,668
(b)		Start-up	0.01 B	$85,867
(b)		Performance test	0.01 B	$85,867
(b)		Contingencies	0.03 B	$257,600
	Total Indirect Costs			***$3,005,337***
Total Capital Investment (TCI)				***$18,890,691***

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]	$16,432
(b)	Supervisor	15%	of operator labor			$2,465
	Maintenance					
(b)	Maintenance labor[c]	0.5	hours/shift	$34.00	per hour[d]	$18,022
(b)	Maintenance materials	100%	of maintenance labor			$18,022
	Utilities [e]					
	Electricity	1,185	kW	$0.060	per kWh[b]	$602,948
	Chemicals	829	lb/hr NaOH	$0.25	per lb NaOH[d]	$1,757,384
	Fresh water usage	108	gpm	$0.20	per 1000 gallon[b]	$10,943
	Wastewater disposal	10.90	gpm	$3.80	per 1000 gallon[b]	$21,072
	Total Direct Annual Costs					***$2,447,288***
Indirect Annual Costs						
	Overhead	60%	Labor and Material Costs			$32,965
	General and administrative	2%	of TCI			$377,814
	Property taxes	1%	of TCI			$188,907
	Insurance	1%	of TCI			$188,907
	Capital recovery	0.095	x TCI			$1,789,348
	Life of the control:	15	years at	4.75%	interest	
	Total Indirect Annual Costs					***$2,577,940***
Total Annual Costs						***$5,025,227***
Cost Effectiveness ($/ton)						
	SO_2 Control Efficiency[f]:	98%				
	SO_2 Emissions[g]:	45.2	tpy	Total Annual Costs/Controlled SO_2 Emissions:		
	Controlled SO_2 Emissions:	44.3	tons of SO_2 removed annually			***$113,447***

[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 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 8481 operating hours.

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

[e] Utility cost represents the electrical consumption, 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-39

Georgia-Pacific - Toledo

Capital and Annual Costs Associated with Wet Scrubbing for Recovery Furnace No. 1

CAPITAL COSTS[(a)]

		COST ITEM	COST FACTOR	COST ($)
		Direct Costs		
		Purchased Equipment Costs		
(a)	***A***	Equipment Costs		***$4,962,021***
(b)		Instrumentation	0.10 A	$496,202
(b)		Sales Tax	0.03 A	$148,861
(b)		Freight	0.05 A	$248,101
	B	***Total Purchased Equipment Cost***		***$5,855,185***
		Direct Installation Costs		
(b)		Foundations and Supports	0.12 B	$702,622
(b)		Handling and erection	0.40 B	$2,342,074
(b)		Electrical	0.01 B	$58,552
(b)		Piping	0.30 B	$1,756,555
(b)		Insulation for ductwork	0.01 B	$58,552
(b)		Painting	0.01 B	$58,552
		Direct Installation Cost		***$4,976,907***
		Total Direct Costs		***$10,832,092***
		Indirect Costs		
(b)		Engineering	0.10 B	$585,518
(b)		Construction Management	0.10 B	$585,518
(b)		Contractor fees	0.10 B	$585,518
(b)		Start-up	0.01 B	$58,552
(b)		Performance test	0.01 B	$58,552
(b)		Contingencies	0.03 B	$175,656
		Total Indirect Costs		***$2,049,315***
		Total Capital Investment (TCI)		***$12,881,407***

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	626	kW	$0.060	per kWh[(b)]	$329,000
	Chemicals	438	lb/hr NaOH	$0.25	per lb NaOH[(d)]	$958,921
	Fresh water usage	57	gpm	$0.20	per 1000 gallon[(b)]	$5,971
	Wastewater disposal	5.76	gpm	$3.80	per 1000 gallon[(b)]	$11,498
	Total Direct Annual Costs					***$1,362,138***
	Indirect Annual Costs					
	Overhead	60%	Labor and Material Costs			$34,049
	General and administrative	2%	of TCI			$257,628
	Property taxes	1%	of TCI			$128,814
	Insurance	1%	of TCI			$128,814
	Capital recovery	0.095	x TCI			$1,220,141
		Life of the control:	15 years at	4.75%	interest	
	Total Indirect Annual Costs					***$1,769,447***
	Total Annual Costs					***$3,131,585***

Cost Effectiveness ($/ton)			
SO_2 Control Efficiency[(f)]:	98%		
SO_2 Emissions[(g)]:	10.9 tpy	Total Annual Costs/Controlled SO_2 Emissions:	
Controlled SO_2 Emissions:	10.7 tons of SO_2 removed annually		***$293,165***

[(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-39a

Georgia-Pacific - Toledo

Capital and Annual Costs Associated with Wet Scrubbing for Recovery Furnace No. 1

CAPITAL COSTS[a]

	COST ITEM	COST FACTOR	COST ($)
	Direct Costs		
	Purchased Equipment Costs		
(a)	***A*** Equipment Costs		***$4,962,021***
(b)	Instrumentation	0.10 A	$496,202
(b)	Sales Tax	0.03 A	$148,861
(b)	Freight	0.05 A	$248,101
	B Total Purchased Equipment Cost		***$5,855,185***
	Direct Installation Costs		
(b)	Foundations and Supports	0.12 B	$702,622
(b)	Handling and erection	0.40 B	$2,342,074
(b)	Electrical	0.01 B	$58,552
(b)	Piping	0.30 B	$1,756,555
(b)	Insulation for ductwork	0.01 B	$58,552
(b)	Painting	0.01 B	$58,552
	Direct Installation Cost		***$4,976,907***
	Total Direct Costs		***$10,832,092***
	Indirect Costs		
(b)	Engineering	0.10 B	$585,518
(b)	Construction Management	0.10 B	$585,518
(b)	Contractor fees	0.10 B	$585,518
(b)	Start-up	0.01 B	$58,552
(b)	Performance test	0.01 B	$58,552
(b)	Contingencies	0.03 B	$175,656
	Total Indirect Costs		***$2,049,315***
	Total Capital Investment (TCI)		***$12,881,407***

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]	$15,750
(b)	Supervisor	15%	of operator labor			$2,362
	Maintenance					
(b)	Maintenance labor[c]	0.5	hours/shift	$34.00	per hour[d]	$17,274
(b)	Maintenance materials	100%	of maintenance labor			$17,274
	Utilities[e]					
	Electricity	626	kW	$0.060	per kWh[b]	$305,302
	Chemicals	438	lb/hr NaOH	$0.25	per lb NaOH[d]	$889,848
	Fresh water usage	57	gpm	$0.20	per 1000 gallon[b]	$5,541
	Wastewater disposal	5.76	gpm	$3.80	per 1000 gallon[b]	$10,670
	Total Direct Annual Costs					***$1,264,021***
	Indirect Annual Costs					
	Overhead	60%	Labor and Material Costs			$31,596
	General and administrative	2%	of TCI			$257,628
	Property taxes	1%	of TCI			$128,814
	Insurance	1%	of TCI			$128,814
	Capital recovery	0.095	x TCI			$1,220,141
	Life of the control:		15 years at	4.75%	interest	
	Total Indirect Annual Costs					***$1,766,994***
	Total Annual Costs					***$3,031,015***
	Cost Effectiveness ($/ton)					
	SO_2 Control Efficiency[f]:	98%				
	SO_2 Emissions[g]:	2.9	tpy	Total Annual Costs/Controlled SO_2 Emissions:		
	Controlled SO_2 Emissions:	2.8	tons of SO_2 removed annually			***$1,066,508***

[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 8129 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-40

Georgia-Pacific - Toledo

Capital and Annual Costs Associated with Wet Scrubbing for Recovery Furnace No. 2

CAPITAL COSTS[a]

		COST ITEM	COST FACTOR	COST ($)
		Direct Costs		
		Purchased Equipment Costs		
(a)	***A***	Equipment Costs		***$4,962,021***
(b)		Instrumentation	0.10 A	$496,202
(b)		Sales Tax	0.03 A	$148,861
(b)		Freight	0.05 A	$248,101
	B	***Total Purchased Equipment Cost***		***$5,855,185***
		Direct Installation Costs		
(b)		Foundations and Supports	0.12 B	$702,622
(b)		Handling and erection	0.40 B	$2,342,074
(b)		Electrical	0.01 B	$58,552
(b)		Piping	0.30 B	$1,756,555
(b)		Insulation for ductwork	0.01 B	$58,552
(b)		Painting	0.01 B	$58,552
		Direct Installation Cost		***$4,976,907***
		Total Direct Costs		***$10,832,092***
		Indirect Costs		
(b)		Engineering	0.10 B	$585,518
(b)		Construction Management	0.10 B	$585,518
(b)		Contractor fees	0.10 B	$585,518
(b)		Start-up	0.01 B	$58,552
(b)		Performance test	0.01 B	$58,552
(b)		Contingencies	0.03 B	$175,656
		Total Indirect Costs		***$2,049,315***
		Total Capital Investment (TCI)		***$12,881,407***

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	626	kW	$0.060	per kWh[b]	$329,000
	Chemicals	438	lb/hr NaOH	$0.25	per lb NaOH[d]	$958,921
	Fresh water usage	57	gpm	$0.20	per 1000 gallon[b]	$5,971
	Wastewater disposal	5.76	gpm	$3.80	per 1000 gallon[b]	$11,498
	Total Direct Annual Costs					***$1,362,138***
	Indirect Annual Costs					
	Overhead	60%	Labor and Material Costs			$34,049
	General and administrative	2%	of TCI			$257,628
	Property taxes	1%	of TCI			$128,814
	Insurance	1%	of TCI			$128,814
	Capital recovery	0.095	x TCI			$1,220,141
	Life of the control:	15	years at	4.75%	interest	
	Total Indirect Annual Costs					***$1,769,447***
	Total Annual Costs					***$3,131,585***
	Cost Effectiveness ($/ton)					
	SO_2 Control Efficiency[f]:	98%				
	SO_2 Emissions[g]:	6.3	tpy	Total Annual Costs/Controlled SO_2 Emissions:		
	Controlled SO_2 Emissions:	6.2	tons of SO_2 removed annually			***$507,221***

[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-40a

Georgia-Pacific - Toledo

Capital and Annual Costs Associated with Wet Scrubbing for Recovery Furnace No. 2

CAPITAL COSTS[a]

		COST ITEM	COST FACTOR	COST ($)
		Direct Costs		
		Purchased Equipment Costs		
(a)	***A***	Equipment Costs		***$4,962,021***
(b)		Instrumentation	0.10 A	$496,202
(b)		Sales Tax	0.03 A	$148,861
(b)		Freight	0.05 A	$248,101
	B	***Total Purchased Equipment Cost***		***$5,855,185***
		Direct Installation Costs		
(b)		Foundations and Supports	0.12 B	$702,622
(b)		Handling and erection	0.40 B	$2,342,074
(b)		Electrical	0.01 B	$58,552
(b)		Piping	0.30 B	$1,756,555
(b)		Insulation for ductwork	0.01 B	$58,552
(b)		Painting	0.01 B	$58,552
		Direct Installation Cost		***$4,976,907***
		Total Direct Costs		***$10,832,092***
		Indirect Costs		
(b)		Engineering	0.10 B	$585,518
(b)		Construction Management	0.10 B	$585,518
(b)		Contractor fees	0.10 B	$585,518
(b)		Start-up	0.01 B	$58,552
(b)		Performance test	0.01 B	$58,552
(b)		Contingencies	0.03 B	$175,656
		Total Indirect Costs		***$2,049,315***
		Total Capital Investment (TCI)		***$12,881,407***

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]	$15,750
(b)	Supervisor	15%	of operator labor			$2,362
	Maintenance					
(b)	Maintenance labor[c]	0.5	hours/shift	$34.00	per hour[d]	$17,274
(b)	Maintenance materials	100%	of maintenance labor			$17,274
	Utilities[e]					
	Electricity	626	kW	$0.060	per kWh[b]	$305,302
	Chemicals	438	lb/hr NaOH	$0.25	per lb NaOH[d]	$889,848
	Fresh water usage	57	gpm	$0.20	per 1000 gallon[b]	$5,541
	Wastewater disposal	5.76	gpm	$3.80	per 1000 gallon[b]	$10,670
	Total Direct Annual Costs					***$1,264,021***
	Indirect Annual Costs					
	Overhead	60%	Labor and Material Costs			$31,596
	General and administrative	2%	of TCI			$257,628
	Property taxes	1%	of TCI			$128,814
	Insurance	1%	of TCI			$128,814
	Capital recovery	0.095	x TCI			$1,220,141
	Life of the control:	15	years at	4.75%	interest	
	Total Indirect Annual Costs					***$1,766,994***
	Total Annual Costs					***$3,031,015***
	Cost Effectiveness ($/ton)					
	SO_2 Control Efficiency[f]:	98%				
	SO_2 Emissions[g]:	5.0	tpy	Total Annual Costs/Controlled SO_2 Emissions:		
	Controlled SO_2 Emissions:	4.9	tons of SO_2 removed annually			***$618,574***

[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 8129 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-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-42

International Paper - Springfield

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		***$8,503,587***
(b)		Instrumentation	0.10 A	$850,359
(b)		Sales Tax	0.03 A	$255,108
(b)		Freight	0.05 A	$425,179
	B	***Total Purchased Equipment Cost***		***$10,034,232***
		Direct Installation Costs		
(b)		Foundations and Supports	0.12 B	$1,204,108
(b)		Handling and erection	0.40 B	$4,013,693
(b)		Electrical	0.01 B	$100,342
(b)		Piping	0.30 B	$3,010,270
(b)		Insulation for ductwork	0.01 B	$100,342
(b)		Painting	0.01 B	$100,342
		Direct Installation Cost		***$8,529,098***
		Total Direct Costs		***$18,563,330***
		Indirect Costs		
(b)		Engineering	0.10 B	$1,003,423
(b)		Construction Management	0.10 B	$1,003,423
(b)		Contractor fees	0.10 B	$1,003,423
(b)		Start-up	0.01 B	$100,342
(b)		Performance test	0.01 B	$100,342
(b)		Contingencies	0.03 B	$301,027
		Total Indirect Costs		***$3,511,981***
		Total Capital Investment (TCI)		***$22,075,311***

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	1,536	kW	$0.060	per kWh[b]	$807,424
	Chemicals	1,075	lb/hr NaOH	$0.25	per lb NaOH[d]	$2,353,362
	Fresh water usage	139	gpm	$0.20	per 1000 gallon[b]	$14,653
	Wastewater disposal	14.13	gpm	$3.80	per 1000 gallon[b]	$28,218
	Total Direct Annual Costs					***$3,260,406***
	Indirect Annual Costs					
(b)	Overhead	60%	Labor and Material Costs			$34,049
(b)	General and administrative	2%	of TCI			$441,506
(b)	Property taxes	1%	of TCI			$220,753
(b)	Insurance	1%	of TCI			$220,753
(b)	Capital recovery	0.095	x TCI			$2,090,999
	Life of the control:	15	years at	4.75%	interest	
	Total Indirect Annual Costs					***$3,008,060***
	Total Annual Costs					***$6,268,466***

Cost Effectiveness ($/ton)

SO_2 Control Efficiency[f]:	98%		
SO_2 Emissions[g]:	84.1 tpy	Total Annual Costs/Controlled SO_2 Emissions:	
Controlled SO_2 Emissions:	82.4 tons of SO_2 removed annually		***$76,075***

[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 consumption, 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-42a

International Paper - Springfield

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		***$8,503,587***
(b)		Instrumentation	0.10 A	$850,359
(b)		Sales Tax	0.03 A	$255,108
(b)		Freight	0.05 A	$425,179
	B	***Total Purchased Equipment Cost***		***$10,034,232***
	Direct Installation Costs			
(b)		Foundations and Supports	0.12 B	$1,204,108
(b)		Handling and erection	0.40 B	$4,013,693
(b)		Electrical	0.01 B	$100,342
(b)		Piping	0.30 B	$3,010,270
(b)		Insulation for ductwork	0.01 B	$100,342
(b)		Painting	0.01 B	$100,342
		Direct Installation Cost		***$8,529,098***
	Total Direct Costs			***$18,563,330***
Indirect Costs				
(b)		Engineering	0.10 B	$1,003,423
(b)		Construction Management	0.10 B	$1,003,423
(b)		Contractor fees	0.10 B	$1,003,423
(b)		Start-up	0.01 B	$100,342
(b)		Performance test	0.01 B	$100,342
(b)		Contingencies	0.03 B	$301,027
	Total Indirect Costs			***$3,511,981***
Total Capital Investment (TCI)				***$22,075,311***

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]	$16,821
(b)	Supervisor	15%	of operator labor			$2,523
	Maintenance					
(b)	Maintenance labor[c]	0.5	hours/shift	$34.00	per hour[d]	$18,449
(b)	Maintenance materials	100%	of maintenance labor			$18,449
	Utilities [e]					
	Electricity	1,536	kW	$0.060	per kWh[b]	$800,235
	Chemicals	1,075	lb/hr NaOH	$0.25	per lb NaOH[d]	$2,332,408
	Fresh water usage	139	gpm	$0.20	per 1000 gallon[b]	$14,523
	Wastewater disposal	14.13	gpm	$3.80	per 1000 gallon[b]	$27,967
	Total Direct Annual Costs					***$3,231,375***
Indirect Annual Costs						
(b)	Overhead	60%	Labor and Material Costs			$33,746
(b)	General and administrative	2%	of TCI			$441,506
(b)	Property taxes	1%	of TCI			$220,753
(b)	Insurance	1%	of TCI			$220,753
(b)	Capital recovery	0.095	x TCI			$2,090,999
	Life of the control:	15	years at	4.75%	interest	
	Total Indirect Annual Costs					***$3,007,757***
Total Annual Costs						***$6,239,132***
Cost Effectiveness ($/ton)						
	SO_2 Control Efficiency[f]:	98%				
	SO_2 Emissions[g]:	2.74	tpy	Total Annual Costs/Controlled SO_2 Emissions:		
	Controlled SO_2 Emissions:	2.69	tons of SO_2 removed annually			***$2,323,526***

[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 8682 operating hours.

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

[e] Utility cost represents the electrical consumption, 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-43

Cascade Pacific Pulp - Halsey

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		$2,704,709
(b)	Instrumentation	0.10 A	$270,471
(b)	Sales Tax	0.03 A	$81,141
(b)	Freight	0.05 A	$135,235
	B Total Purchased Equipment Cost		***$3,191,557***
	Direct Installation Costs		
(b)	Foundations and Supports	0.04 B	$127,662
(b)	Handling and Erection	0.50 B	$1,595,778
(b)	Electrical	0.08 B	$255,325
(b)	Piping	0.01 B	$31,916
(b)	Insulation	0.02 B	$63,831
(b)	Painting	0.02 B	$63,831
	Direct Installation Cost		***$2,138,343***
	Total Direct Costs		***$5,329,900***
	Indirect Costs		
(b)	Engineering	0.20 B	$638,311
(b)	Construction Management	0.20 B	$638,311
(b)	Contractor fees	0.10 B	$319,156
(b)	Start-up	0.01 B	$31,916
(b)	Performance test	0.01 B	$31,916
(b)	Model Study	0.02 B	$63,831
(b)	Contingencies	0.03 B	$95,747
	Total Indirect Costs		***$1,819,187***
	Total Capital Investment (TCI)[a]		***$7,149,088***

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		$31,916
	Utilities				
	Additional Electricity	208	kW	$0.060 per kWh[b]	$109,491
	Total Direct Annual Costs				***$200,953***
	Indirect Annual Costs				
(b)	Overhead	60%	Labor and Material Costs		$54,877
(b)	General and administrative	2%	of TCI		$142,982
(b)	Property taxes	1%	of TCI		$71,491
(b)	Insurance	1%	of TCI		$71,491
(b)	Capital recovery	0.079	x TCI		$561,564
	Life of the control:		20 years at	4.75% interest	
	Total Indirect Annual Costs				***$902,405***
	Total Annual Costs				***$1,103,358***
	Cost Effectiveness ($/ton)				
	PM_{10} Control Improvement[f]:	90%			
	PM_{10} Emissions[g]:	26	tpy	Total Annual Costs/Controlled PM_{10} Emissions:	
	Reduction in PM_{10} Emissions [h]:	23.4	tpy		***$47,152***

[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-43a

Cascade Pacific Pulp - Halsey

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		$2,704,709
(b)	Instrumentation	0.10 A	$270,471
(b)	Sales Tax	0.03 A	$81,141
(b)	Freight	0.05 A	$135,235
	B Total Purchased Equipment Cost		***$3,191,557***
	Direct Installation Costs		
(b)	Foundations and Supports	0.04 B	$127,662
(b)	Handling and Erection	0.50 B	$1,595,778
(b)	Electrical	0.08 B	$255,325
(b)	Piping	0.01 B	$31,916
(b)	Insulation	0.02 B	$63,831
(b)	Painting	0.02 B	$63,831
	Direct Installation Cost		***$2,138,343***
	Total Direct Costs		***$5,329,900***
	Indirect Costs		
(b)	Engineering	0.20 B	$638,311
(b)	Construction Management	0.20 B	$638,311
(b)	Contractor fees	0.10 B	$319,156
(b)	Start-up	0.01 B	$31,916
(b)	Performance test	0.01 B	$31,916
(b)	Model Study	0.02 B	$63,831
(b)	Contingencies	0.03 B	$95,747
	Total Indirect Costs		***$1,819,187***
	Total Capital Investment (TCI)[(a)]		***$7,149,088***

ANNUALIZED COSTS

	COST ITEM	COST FACTOR	RATE	COST ($)
	Direct Annual Costs[(c)]			
	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		$31,916
	Utilities			
	Additional Electricity	208 kW[(e)]	$0.060 per kWh[(b)]	$105,317
	Total Direct Annual Costs			***$196,778***
	Indirect Annual Costs			
(b)	Overhead	60% Labor and Material Costs		$54,877
(b)	General and administrative	2% of TCI		$142,982
(b)	Property taxes	1% of TCI		$71,491
(b)	Insurance	1% of TCI		$71,491
(b)	Capital recovery	0.079 x TCI		$561,564
	Life of the control:	20 years at	4.75% interest	
	Total Indirect Annual Costs			***$902,405***
	Total Annual Costs			***$1,099,183***
	Cost Effectiveness ($/ton)			
	PM_{10} Control Improvement[(f)]:	90%		
	PM_{10} Emissions[(g)]:	28.2 tpy	Total Annual Costs/Controlled PM_{10} Emissions:	
	Reduction in PM_{10} Emissions[(h)]:	25.4 tpy		***$43,309***

[(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)] Based on 2017 actual operating hours.

[(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-44

GP Toledo

Capital and Annual Costs Associated with New ESP for Lime Kilns 1-3

	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		$3,794,723	(b)	Operator	1	hours/shift	$31.00	per hour[d]	$33,945
(b)	Instrumentation	0.10 A	$379,472	(b)	Supervisor	15%	of operator labor			$5,092
(b)	Sales Tax	0.03 A	$113,842	(b)	Coordinator	33%	of operator labor			$11,202
(b)	Freight	0.05 A	$189,736		***Maintenance***					
	B Total Purchased Equipment Cost		***$4,477,773***	(b)	Maintenance labor	0.25	hours/shift	$34.00	per hour[d]	$9,308
				(b)	Maintenance materials	1%	of purchased equipment costs			$44,778
	Direct Installation Costs				***Utilities***					
(b)	Foundations and Supports	0.04 B	$179,111		Electricity	366	kW	$0.060	per kWh[b]	$192,521
(b)	Handling and Erection	0.50 B	$2,238,886							
(b)	Electrical	0.08 B	$358,222		***Total Direct Annual Costs***					***$296,845***
(b)	Piping	0.01 B	$44,778							
(b)	Insulation	0.02 B	$89,555							
(b)	Painting	0.02 B	$89,555		***Indirect Annual Costs***					
	Direct Installation Cost		***$3,000,108***	(b)	Overhead	60%	Labor and Material Costs			$62,594
	Total Direct Costs		***$7,477,881***	(b)	General and administrative	2%	of TCI			$200,604
				(b)	Property taxes	1%	of TCI			$100,302
	Indirect Costs			(b)	Insurance	1%	of TCI			$100,302
(b)	Engineering	0.20 B	$895,555	(b)	Capital recovery	0.079	x TCI			$787,878
(b)	Construction Management	0.20 B	$895,555		Life of the control:		20 years at	4.75%	interest	
(b)	Contractor fees	0.10 B	$447,777							
(b)	Start-up	0.01 B	$44,778		***Total Indirect Annual Costs***					***$1,251,681***
(b)	Performance test	0.01 B	$44,778							
(b)	Model Study	0.02 B	$89,555		***Total Annual Costs***					***$1,548,526***
(b)	Contingencies	0.03 B	$134,333							
	Total Indirect Costs		***$2,552,331***		***Cost Effectiveness ($/ton)***					
					PM_{10} Control Improvement[f]:	90.0%				
	Total Capital Investment (TCI)[a]		***$10,030,211***		PM_{10} Emissions[g]:	107	tpy		Total Annual Costs/Controlled PM_{10} Emissions:	
					Reduction in PM_{10} Emissions [h]:	96.1	tpy			***$16,110***

[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-44a

GP Toledo

Capital and Annual Costs Associated with New ESP for Lime Kilns 1-3

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		$3,794,723	(b)	Operator	1	hours/shift	$31.00 per hour[d]	$33,945
(b)	Instrumentation	0.10 A	$379,472	(b)	Supervisor	15%	of operator labor		$5,092
(b)	Sales Tax	0.03 A	$113,842	(b)	Coordinator	33%	of operator labor		$11,202
(b)	Freight	0.05 A	$189,736		***Maintenance***				
	B Total Purchased Equipment Cost		***$4,477,773***	(b)	Maintenance labor	0.25	hours/shift	$34.00 per hour[d]	$9,308
				(b)	Maintenance materials	1%	of purchased equipment costs		$44,778
	Direct Installation Costs				***Utilities***				
(b)	Foundations and Supports	0.04 B	$179,111		Electricity	366	kW	$0.060 per kWh[b]	$180,214
(b)	Handling and Erection	0.50 B	$2,238,886						
(b)	Electrical	0.08 B	$358,222		***Total Direct Annual Costs***				***$284,538***
(b)	Piping	0.01 B	$44,778						
(b)	Insulation	0.02 B	$89,555						
(b)	Painting	0.02 B	$89,555		***Indirect Annual Costs***				
	Direct Installation Cost		***$3,000,108***	(b)	Overhead	60%	Labor and Material Costs		$62,594
	Total Direct Costs		***$7,477,881***	(b)	General and administrative	2%	of TCI		$200,604
				(b)	Property taxes	1%	of TCI		$100,302
	Indirect Costs			(b)	Insurance	1%	of TCI		$100,302
(b)	Engineering	0.20 B	$895,555	(b)	Capital recovery	0.079	x TCI		$787,878
(b)	Construction Management	0.20 B	$895,555		Life of the control:	20	years at	4.75% interest	
(b)	Contractor fees	0.10 B	$447,777						
(b)	Start-up	0.01 B	$44,778		***Total Indirect Annual Costs***				***$1,251,681***
(b)	Performance test	0.01 B	$44,778						
(b)	Model Study	0.02 B	$89,555		***Total Annual Costs***				***$1,536,218***
(b)	Contingencies	0.03 B	$134,333						
	Total Indirect Costs		***$2,552,331***		***Cost Effectiveness ($/ton)***				
					PM_{10} Control Improvement[f]:	90.0%			
	Total Capital Investment (TCI)[a]		***$10,030,211***		PM_{10} Emissions[g]:	70.3	tpy	Total Annual Costs/Controlled PM_{10} Emissions:	
					Reduction in PM_{10} Emissions[h]:	63.3	tpy		***$24,280***

[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-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]

		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]	$132,044
	Total Direct Annual Costs				***$229,669***
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					***$1,299,455***
Cost Effectiveness ($/ton)					
	PM_{10} Control Improvement[f]:	90.0%			
	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-46

International Paper Springfield

Capital and Annual Costs Associated with ESP Upgrade for the Lime Kilns

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		$1,392,690	(b)	Operator		hours/shift	$31.00 per hour[d]	$0
(b)	Instrumentation	0.10 A	$139,269	(b)	Supervisor		of operator labor		$0
(b)	Sales Tax	0.03 A	$41,781	(b)	Coordinator		of operator labor		$0
(b)	Freight	0.05 A	$69,634		***Maintenance*** [c]				
	B Total Purchased Equipment Cost		***$1,643,374***	(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	108	kW	$0.060 per kWh[b]	$57,000
(b)	Handling and Erection	0.50 B	$821,687						
(b)	Electrical	0.08 B	$131,470		***Total Direct Annual Costs***				***$57,000***
(b)	Piping	0.01 B	$16,434						
(b)	Insulation	0.02 B	$32,867						
(b)	Painting	0.02 B	$32,867		***Indirect Annual Costs***				
	Direct Installation Cost		***$1,035,326***	(c)	Overhead	60%	Labor and Material Costs		$0
	Total Direct Costs		***$2,678,699***	(c)	General and administrative	2%	of TCI		$0
				(b)	Property taxes	1%	of TCI		$36,154
	Indirect Costs			(b)	Insurance	1%	of TCI		$36,154
(b)	Engineering	0.20 B	$328,675	(b)	Capital recovery	0.079	x TCI		$283,993
(b)	Construction Management	0.20 B	$328,675		Life of the control:		20 years at	4.75% interest	
(b)	Contractor fees	0.10 B	$164,337						
(b)	Start-up	0.01 B	$16,434		***Total Indirect Annual Costs***				***$356,302***
(b)	Performance test	0.01 B	$16,434						
(b)	Model Study	0.02 B	$32,867		***Total Annual Costs***				***$413,302***
(b)	Contingencies	0.03 B	$49,301						
	Total Indirect Costs		***$936,723***		***Cost Effectiveness ($/ton)***				
					PM_{10} Control Efficiency[f]:	99.5%			
	Total Capital Investment (TCI) [a]		***$3,615,422***		PM_{10} Emissions[g]:	19.08	tpy	Total Annual Costs/Controlled PM_{10} Emissions:	
					Controlled PM_{10} Emissions [h]:	9.5	tons of additional PM_{10} removed annually		***$43,323***

[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 rebuilding an ESP on a lime kiln was scaled based on CaO 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 kiln 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-46a

International Paper Springfield

Capital and Annual Costs Associated with ESP Upgrade for the Lime Kilns

CAPITAL COSTS[a]

		COST ITEM	COST FACTOR	COST ($)
		Direct Costs		
		Purchased Equipment Costs		
(a)	***A***	ESP		$1,392,690
(b)		Instrumentation	0.10 A	$139,269
(b)		Sales Tax	0.03 A	$41,781
(b)		Freight	0.05 A	$69,634
	B	***Total Purchased Equipment Cost***		***$1,643,374***
		Direct Installation Costs		
(b)		Foundations and Supports[c]	0.04 B	$0
(b)		Handling and Erection	0.50 B	$821,687
(b)		Electrical	0.08 B	$131,470
(b)		Piping	0.01 B	$16,434
(b)		Insulation	0.02 B	$32,867
(b)		Painting	0.02 B	$32,867
		Direct Installation Cost		***$1,035,326***
		Total Direct Costs		***$2,678,699***
		Indirect Costs		
(b)		Engineering	0.20 B	$328,675
(b)		Construction Management	0.20 B	$328,675
(b)		Contractor fees	0.10 B	$164,337
(b)		Start-up	0.01 B	$16,434
(b)		Performance test	0.01 B	$16,434
(b)		Model Study	0.02 B	$32,867
(b)		Contingencies	0.03 B	$49,301
		Total Indirect Costs		***$936,723***
		Total Capital Investment (TCI)[a]		***$3,615,422***

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	108	kW	$0.060	per kWh[b]	$56,675
	Total Direct Annual Costs					***$56,675***
	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			$36,154
(b)	Insurance	1%	of TCI			$36,154
(b)	Capital recovery	0.079	x TCI			$283,993
	Life of the control:		20 years at	4.75%	interest	
	Total Indirect Annual Costs					***$356,302***
	Total Annual Costs					***$412,976***
	Cost Effectiveness ($/ton)					
	PM_{10} Control Efficiency[f]:	99.5%				
	PM_{10} Emissions[g]:	15.74	tpy	Total Annual Costs/Controlled PM_{10} Emissions:		
	Controlled PM_{10} Emissions[h]:	7.9	tons of additional PM_{10} removed annually			***$52,475***

[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 rebuilding an ESP on a lime kiln was scaled based on CaO 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 kiln 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-47

International Paper - Springfield

Capital and Annual Costs Associated with Wet Scrubbing for Lime Kiln

CAPITAL COSTS[a]

	COST ITEM	COST FACTOR	COST ($)
	Direct Costs		
	Purchased Equipment Costs		
(a)	***A*** Equipment Costs		***$4,153,832***
(b)	Instrumentation	0.10 A	$415,383
(b)	Sales Tax	0.03 A	$124,615
(b)	Freight	0.05 A	$207,692
	B Total Purchased Equipment Cost		***$4,901,522***
	Direct Installation Costs		
(b)	Foundations and Supports	0.12 B	$588,183
(b)	Handling and erection	0.40 B	$1,960,609
(b)	Electrical	0.01 B	$49,015
(b)	Piping	0.30 B	$1,470,456
(b)	Insulation for ductwork	0.01 B	$49,015
(b)	Painting	0.01 B	$49,015
	Direct Installation Cost		***$4,166,293***
	Total Direct Costs		***$9,067,815***
	Indirect Costs		
(b)	Engineering	0.10 B	$490,152
(b)	Construction Management	0.10 B	$490,152
(b)	Contractor fees	0.10 B	$490,152
(b)	Start-up	0.01 B	$49,015
(b)	Performance test	0.01 B	$49,015
(b)	Contingencies	0.03 B	$147,046
	Total Indirect Costs		***$1,715,533***
	Total Capital Investment (TCI)		***$10,783,348***

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	465 kW	$0.060 per kWh[b]	$244,632
	Chemicals	326 lb/hr NaOH	$0.25 per lb NaOH[d]	$713,017
	Fresh water usage	42 gpm	$0.20 per 1000 gallon[b]	$4,440
	Wastewater disposal	4.28 gpm	$3.80 per 1000 gallon[b]	$8,549
	Total Direct Annual Costs			***$1,027,387***
	Indirect Annual Costs			
(b)	Overhead	60% Labor and Material Costs		$34,049
(b)	General and administrative	2% of TCI		$215,667
(b)	Property taxes	1% of TCI		$107,833
(b)	Insurance	1% of TCI		$107,833
(b)	Capital recovery	0.095 x TCI		$1,021,411
		Life of the control: 15 years at	4.8% interest	
	Total Indirect Annual Costs			***$1,486,794***
	Total Annual Costs			***$2,514,180***
	Cost Effectiveness ($/ton)			
	SO_2 Control Efficiency[f]:	98%		
	SO_2 Emissions[g]:	151.9 tpy	Total Annual Costs/Controlled SO_2 Emissions:	
	Controlled SO_2 Emissions:	148.8 tons of SO_2 removed annually		***$16,895***

[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 a comparison of furnace exhaust flow to lime kiln exhaust flow. 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, water consumption, and wastewater disposal of a wet scrubber system, based on the document cited in footnote (a) and scaled based on the exhaust flow rate.

[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-47a

International Paper - Springfield

Capital and Annual Costs Associated with Wet Scrubbing for Lime Kiln

CAPITAL COSTS[a]

		COST ITEM	COST FACTOR	COST ($)
Direct Costs				
	Purchased Equipment Costs			
(a)	***A***	Equipment Costs		***$4,153,832***
(b)		Instrumentation	0.10 A	$415,383
(b)		Sales Tax	0.03 A	$124,615
(b)		Freight	0.05 A	$207,692
	B	***Total Purchased Equipment Cost***		***$4,901,522***
	Direct Installation Costs			
(b)		Foundations and Supports	0.12 B	$588,183
(b)		Handling and erection	0.40 B	$1,960,609
(b)		Electrical	0.01 B	$49,015
(b)		Piping	0.30 B	$1,470,456
(b)		Insulation for ductwork	0.01 B	$49,015
(b)		Painting	0.01 B	$49,015
		Direct Installation Cost		***$4,166,293***
	Total Direct Costs			***$9,067,815***
Indirect Costs				
(b)		Engineering	0.10 B	$490,152
(b)		Construction Management	0.10 B	$490,152
(b)		Contractor fees	0.10 B	$490,152
(b)		Start-up	0.01 B	$49,015
(b)		Performance test	0.01 B	$49,015
(b)		Contingencies	0.03 B	$147,046
	Total Indirect Costs			***$1,715,533***
Total Capital Investment (TCI)				***$10,783,348***

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]	$16,876
(b)	Supervisor	15%	of operator labor			$2,531
	Maintenance					
(b)	Maintenance labor[c]	0.5	hours/shift	$34.00	per hour[d]	$18,509
(b)	Maintenance materials	100%	of maintenance labor			$18,509
	Utilities[e]					
	Electricity	465	kW	$0.060	per kWh[b]	$243,236
	Chemicals	326	lb/hr NaOH	$0.25	per lb NaOH[d]	$708,948
	Fresh water usage	42	gpm	$0.20	per 1000 gallon[b]	$4,414
	Wastewater disposal	4.28	gpm	$3.80	per 1000 gallon[b]	$8,501
	Total Direct Annual Costs					***$1,021,523***
Indirect Annual Costs						
(b)	Overhead	60%	Labor and Material Costs			$33,855
(b)	General and administrative	2%	of TCI			$215,667
(b)	Property taxes	1%	of TCI			$107,833
(b)	Insurance	1%	of TCI			$107,833
(b)	Capital recovery	0.095	x TCI			$1,021,411
	Life of the control:		15 years at	4.8%	interest	
	Total Indirect Annual Costs					***$1,486,599***
Total Annual Costs						***$2,508,122***
Cost Effectiveness ($/ton)						
	SO_2 Control Efficiency[f]:	98%				
	SO_2 Emissions[g]:	49.1	tpy	Total Annual Costs/Controlled SO_2 Emissions:		
	Controlled SO_2 Emissions:	48.1	tons of SO_2 removed annually			***$52,124***

[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 a comparison of furnace exhaust flow to lime kiln exhaust flow. 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 8710 operating hours.

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

[e] Utility cost represents the electrical consumption, water consumption, and wastewater disposal of a wet scrubber system, based on the document cited in footnote (a) and scaled based on the exhaust flow rate.

[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-48

Cascade Pacific Pulp - Halsey

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		***$829,793***
(b)		Instrumentation	0.10 A	$82,979
(b)		Sales Tax	0.03 A	$24,894
(b)		Freight	0.05 A	$41,490
	B	***Total Purchased Equipment Cost***		***$979,156***
		Direct Installation Costs		
(b)		Foundations and Supports	0.12 B	$117,499
(b)		Handling and erection	0.40 B	$391,662
(b)		Electrical	0.01 B	$9,792
(b)		Piping	0.30 B	$293,747
(b)		Insulation for ductwork	0.01 B	$9,792
(b)		Painting	0.01 B	$9,792
		Direct Installation Cost		***$832,283***
		Total Direct Costs		***$1,811,439***
		Indirect Costs		
(b)		Engineering	0.10 B	$97,916
(b)		Construction Management	0.10 B	$97,916
(b)		Contractor fees	0.10 B	$97,916
(b)		Start-up	0.01 B	$9,792
(b)		Performance test	0.01 B	$9,792
(b)		Contingencies	0.03 B	$29,375
		Total Indirect Costs		***$342,705***
		Total Capital Investment (TCI)		***$2,154,144***

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	229 kW	$0.060 per kWh[b]	$120,280
	Total Direct Annual Costs			***$120,280***
	Indirect Annual Costs			
	Overhead	60% Labor and Material Costs		$0
	General and administrative	2% of TCI		$43,083
	Property taxes	1% of TCI		$21,541
	Insurance	1% of TCI		$21,541
	Capital recovery	0.095 x TCI		$204,043
	Life of the control:	15 years at	4.75% interest	
	Total Indirect Annual Costs			***$290,209***
	Total Annual Costs			***$410,489***
	Cost Effectiveness ($/ton)			
	Additional PM10 Control Efficiency[f]:	50%		
	PM10 Emissions[g]:	24.4 tpy	Total Annual Costs/Controlled PM10 Emissions:	
	Reduced PM10 Emissions:	12.2 tons of additional PM10 removed annually		***$33,647***

[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-48a

Cascade Pacific Pulp - Halsey

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		***$829,793***
(b)		Instrumentation	0.10 A	$82,979
(b)		Sales Tax	0.03 A	$24,894
(b)		Freight	0.05 A	$41,490
	B	***Total Purchased Equipment Cost***		***$979,156***
		Direct Installation Costs		
(b)		Foundations and Supports	0.12 B	$117,499
(b)		Handling and erection	0.40 B	$391,662
(b)		Electrical	0.01 B	$9,792
(b)		Piping	0.30 B	$293,747
(b)		Insulation for ductwork	0.01 B	$9,792
(b)		Painting	0.01 B	$9,792
		Direct Installation Cost		***$832,283***
		Total Direct Costs		***$1,811,439***
Indirect Costs				
(b)		Engineering	0.10 B	$97,916
(b)		Construction Management	0.10 B	$97,916
(b)		Contractor fees	0.10 B	$97,916
(b)		Start-up	0.01 B	$9,792
(b)		Performance test	0.01 B	$9,792
(b)		Contingencies	0.03 B	$29,375
		Total Indirect Costs		***$342,705***
Total Capital Investment (TCI)				***$2,154,144***

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	229	kW	$0.060	per kWh[b]	$116,765
	Total Direct Annual Costs					***$116,765***
	Indirect Annual Costs					
	Overhead	60%	Labor and Material Costs			$0
	General and administrative	2%	of TCI			$43,083
	Property taxes	1%	of TCI			$21,541
	Insurance	1%	of TCI			$21,541
	Capital recovery	0.095	x TCI			$204,043
	Life of the control:		15 years at	4.75%	interest	
	Total Indirect Annual Costs					***$290,209***
	Total Annual Costs					***$406,974***
	Cost Effectiveness ($/ton)					
	Additional PM10 Control Efficiency[f]:	50%				
	PM10 Emissions[g]:	21.5	tpy	Total Annual Costs/Controlled PM10 Emissions:		
	Reduced PM10 Emissions:	10.8	tons of additional PM10 removed annually			***$37,858***

[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 8504 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

Table A-49

Georgia-Pacific - Toledo

Capital and Annual Costs Associated with Replacing the No. 1 Smelt Dissolving Tank Wet Scrubber

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***	Equipment Costs		***$565,829***	(b)	Operator[(c)]		hours/shift	$31.00 per hour[(d)]	$0
(b)		Instrumentation	0.10 A	$56,583	(b)	Supervisor	15%	of operator labor		$0
(b)		Sales Tax	0.03 A	$16,975		***Maintenance***				
(b)		Freight	0.05 A	$28,291	(b)	Maintenance labor[(c)]		hours/shift	$34.00 per hour[(d)]	$0
	B	***Total Purchased Equipment Cost***		***$667,679***	(b)	Maintenance materials	100%	of maintenance labor		$0
						Utilities [(e)]				
		Direct Installation Costs				Electricity	121	kW	$0.060 per kWh[(b)]	$63,541
(b)		Foundations and Supports	0.12 B	$80,121						
(b)		Handling and erection	0.40 B	$267,071						
(b)		Electrical	0.01 B	$6,677						
(b)		Piping	0.30 B	$200,304		***Total Direct Annual Costs***				***$63,541***
(b)		Insulation for ductwork	0.01 B	$6,677						
(b)		Painting	0.01 B	$6,677		***Indirect Annual Costs***				
		Direct Installation Cost		***$567,527***		Overhead	60%	Labor and Material Costs		$0
		Total Direct Costs		***$1,235,205***		General and administrative	2%	of TCI		$29,378
						Property taxes	1%	of TCI		$14,689
		Indirect Costs				Insurance	1%	of TCI		$14,689
(b)		Engineering	0.10 B	$66,768		Capital recovery	0.095	x TCI		$139,135
(b)		Construction Management	0.10 B	$66,768		Life of the control:		15 years at	4.75% interest	
(b)		Contractor fees	0.10 B	$66,768						
(b)		Start-up	0.01 B	$6,677		***Total Indirect Annual Costs***				***$197,891***
(b)		Performance test	0.01 B	$6,677						
(b)		Contingencies	0.03 B	$20,030		***Total Annual Costs***				***$261,432***
		Total Indirect Costs		***$233,687***		***Cost Effectiveness ($/ton)***				
						Additional PM10 Control Efficiency[(f)]:	50%			
		Total Capital Investment (TCI)		***$1,468,893***		PM10 Emissions[(g)]:	21.8	tpy	Total Annual Costs/Controlled PM10 Emissions:	
						Reduced PM10 Emissions:	10.9	tons of additional PM10 removed annually		***$23,985***

[(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-49a

Georgia-Pacific - Toledo

Capital and Annual Costs Associated with Replacing the No. 1 Smelt Dissolving Tank Wet Scrubber

		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***	Equipment Costs		***$565,829***	(b)	Operator[c]		hours/shift	$31.00 per hour[d]	$0
(b)		Instrumentation	0.10 A	$56,583	(b)	Supervisor	15%	of operator labor		$0
(b)		Sales Tax	0.03 A	$16,975		***Maintenance***				
(b)		Freight	0.05 A	$28,291	(b)	Maintenance labor[c]		hours/shift	$34.00 per hour[d]	$0
	B	***Total Purchased Equipment Cost***		***$667,679***	(b)	Maintenance materials	100%	of maintenance labor		$0
						Utilities [e]				
		Direct Installation Costs				Electricity	121	kW	$0.060 per kWh[b]	$58,964
(b)		Foundations and Supports	0.12 B	$80,121						
(b)		Handling and erection	0.40 B	$267,071						
(b)		Electrical	0.01 B	$6,677						
(b)		Piping	0.30 B	$200,304		***Total Direct Annual Costs***				***$58,964***
(b)		Insulation for ductwork	0.01 B	$6,677						
(b)		Painting	0.01 B	$6,677		***Indirect Annual Costs***				
		Direct Installation Cost		***$567,527***		Overhead	60%	Labor and Material Costs		$0
		Total Direct Costs		***$1,235,205***		General and administrative	2%	of TCI		$29,378
						Property taxes	1%	of TCI		$14,689
		Indirect Costs				Insurance	1%	of TCI		$14,689
(b)		Engineering	0.10 B	$66,768		Capital recovery	0.095	x TCI		$139,135
(b)		Construction Management	0.10 B	$66,768		Life of the control:		15 years at	4.75% interest	
(b)		Contractor fees	0.10 B	$66,768						
(b)		Start-up	0.01 B	$6,677		***Total Indirect Annual Costs***				***$197,891***
(b)		Performance test	0.01 B	$6,677						
(b)		Contingencies	0.03 B	$20,030		***Total Annual Costs***				***$256,855***
		Total Indirect Costs		***$233,687***		***Cost Effectiveness ($/ton)***				
						Additional PM10 Control Efficiency[f]:	50%			
		Total Capital Investment (TCI)		***$1,468,893***		PM10 Emissions[g]:	19.0	tpy	Total Annual Costs/Controlled PM10 Emissions:	
						Reduced PM10 Emissions:	9.5	tons of additional PM10 removed annually		***$27,037***

[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 8129 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

Table A-50

Georgia-Pacific - Toledo

Capital and Annual Costs Associated with Replacing the No. 2 Smelt Dissolving Tank Wet Scrubber

CAPITAL COSTS[a]

		COST ITEM	COST FACTOR	COST ($)
Direct Costs				
	Purchased Equipment Costs			
(a)	***A***	Equipment Costs		***$565,829***
(b)		Instrumentation	0.10 A	$56,583
(b)		Sales Tax	0.03 A	$16,975
(b)		Freight	0.05 A	$28,291
	B	***Total Purchased Equipment Cost***		***$667,679***
	Direct Installation Costs			
(b)		Foundations and Supports	0.12 B	$80,121
(b)		Handling and erection	0.40 B	$267,071
(b)		Electrical	0.01 B	$6,677
(b)		Piping	0.30 B	$200,304
(b)		Insulation for ductwork	0.01 B	$6,677
(b)		Painting	0.01 B	$6,677
		Direct Installation Cost		***$567,527***
	Total Direct Costs			***$1,235,205***
Indirect Costs				
(b)		Engineering	0.10 B	$66,768
(b)		Construction Management	0.10 B	$66,768
(b)		Contractor fees	0.10 B	$66,768
(b)		Start-up	0.01 B	$6,677
(b)		Performance test	0.01 B	$6,677
(b)		Contingencies	0.03 B	$20,030
	Total Indirect Costs			***$233,687***
Total Capital Investment (TCI)				***$1,468,893***

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	121	kW	$0.060	per kWh[b]	$63,541
	Total Direct Annual Costs					***$63,541***
Indirect Annual Costs						
	Overhead	60%	Labor and Material Costs			$0
	General and administrative	2%	of TCI			$29,378
	Property taxes	1%	of TCI			$14,689
	Insurance	1%	of TCI			$14,689
	Capital recovery	0.095	x TCI			$139,135
	Life of the control:		15 years at	4.75%	interest	
	Total Indirect Annual Costs					***$197,891***
Total Annual Costs						***$261,432***
Cost Effectiveness ($/ton)						
	Additional PM10 Control Efficiency[f]:	50%				
	PM10 Emissions[g]:	15.0	tpy		Total Annual Costs/Controlled PM10 Emissions:	
	Reduced PM10 Emissions:	7.5	tons of additional PM10 removed annually			***$34,858***

[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-50a

Georgia-Pacific - Toledo

Capital and Annual Costs Associated with Replacing the No. 2 Smelt Dissolving Tank Wet Scrubber

CAPITAL COSTS[a]

	COST ITEM	COST FACTOR	COST ($)
	Direct Costs		
	Purchased Equipment Costs		
(a)	***A*** Equipment Costs		***$565,829***
(b)	Instrumentation	0.10 A	$56,583
(b)	Sales Tax	0.03 A	$16,975
(b)	Freight	0.05 A	$28,291
	B Total Purchased Equipment Cost		***$667,679***
	Direct Installation Costs		
(b)	Foundations and Supports	0.12 B	$80,121
(b)	Handling and erection	0.40 B	$267,071
(b)	Electrical	0.01 B	$6,677
(b)	Piping	0.30 B	$200,304
(b)	Insulation for ductwork	0.01 B	$6,677
(b)	Painting	0.01 B	$6,677
	Direct Installation Cost		***$567,527***
	Total Direct Costs		***$1,235,205***
	Indirect Costs		
(b)	Engineering	0.10 B	$66,768
(b)	Construction Management	0.10 B	$66,768
(b)	Contractor fees	0.10 B	$66,768
(b)	Start-up	0.01 B	$6,677
(b)	Performance test	0.01 B	$6,677
(b)	Contingencies	0.03 B	$20,030
	Total Indirect Costs		***$233,687***
	Total Capital Investment (TCI)		***$1,468,893***

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	121	kW	$0.060 per kWh[b]	$59,479
	Total Direct Annual Costs				***$59,479***
	Indirect Annual Costs				
	Overhead	60%	Labor and Material Costs		$0
	General and administrative	2%	of TCI		$29,378
	Property taxes	1%	of TCI		$14,689
	Insurance	1%	of TCI		$14,689
	Capital recovery	0.095	x TCI		$139,135
	Life of the control:		15 years at	4.75% interest	
	Total Indirect Annual Costs				***$197,891***
	Total Annual Costs				***$257,370***
	Cost Effectiveness ($/ton)				
	Additional PM10 Control Efficiency[f]:	50%			
	PM10 Emissions[g]:	13.1	tpy	Total Annual Costs/Controlled PM10 Emissions:	
	Reduced PM10 Emissions:	6.6	tons of additional PM10 removed annually		***$39,293***

[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 8200 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

Table A-51

Georgia-Pacific - Wauna

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

		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***	Equipment Costs		***$988,767***	(b)	Operator[c]		hours/shift	$31.00 per hour[d]	$0
(b)		Instrumentation	0.10 A	$98,877	(b)	Supervisor	15%	of operator labor		$0
(b)		Sales Tax	0.03 A	$29,663		***Maintenance***				
(b)		Freight	0.05 A	$49,438	(b)	Maintenance labor[c]		hours/shift	$34.00 per hour[d]	$0
	B	***Total Purchased Equipment Cost***		***$1,166,745***	(b)	Maintenance materials	100%	of maintenance labor		$0
						Utilities [e]				
	Direct Installation Costs					Electricity	306	kW	$0.060 per kWh[b]	$161,089
(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		***Total Direct Annual Costs***				***$161,089***
(b)		Insulation for ductwork	0.01 B	$11,667						
(b)		Painting	0.01 B	$11,667	***Indirect Annual Costs***					
		Direct Installation Cost		***$991,733***		Overhead	60%	Labor and Material Costs		$0
	Total Direct Costs			***$2,158,478***		General and administrative	2%	of TCI		$51,337
						Property taxes	1%	of TCI		$25,668
Indirect Costs						Insurance	1%	of TCI		$25,668
(b)		Engineering	0.10 B	$116,674		Capital recovery	0.095	x TCI		$243,134
(b)		Construction Management	0.10 B	$116,674			Life of the control:	15 years at	4.75% interest	
(b)		Contractor fees	0.10 B	$116,674						
(b)		Start-up	0.01 B	$11,667		***Total Indirect Annual Costs***				***$345,807***
(b)		Performance test	0.01 B	$11,667						
(b)		Contingencies	0.03 B	$35,002	***Total Annual Costs***					***$506,897***
	Total Indirect Costs			***$408,361***	***Cost Effectiveness ($/ton)***					
						Additional PM10 Control Efficiency[f]:	50%			
Total Capital Investment (TCI)				***$2,566,839***		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

Table A-52

IP Springfield

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		***$969,681***
(b)		Instrumentation	0.10 A	$96,968
(b)		Sales Tax	0.03 A	$29,090
(b)		Freight	0.05 A	$48,484
	B	***Total Purchased Equipment Cost***		***$1,144,224***
		Direct Installation Costs		
(b)		Foundations and Supports	0.12 B	$137,307
(b)		Handling and erection	0.40 B	$457,690
(b)		Electrical	0.01 B	$11,442
(b)		Piping	0.30 B	$343,267
(b)		Insulation for ductwork	0.01 B	$11,442
(b)		Painting	0.01 B	$11,442
		Direct Installation Cost		***$972,590***
		Total Direct Costs		***$2,116,814***
		Indirect Costs		
(b)		Engineering	0.10 B	$114,422
(b)		Construction Management	0.10 B	$114,422
(b)		Contractor fees	0.10 B	$114,422
(b)		Start-up	0.01 B	$11,442
(b)		Performance test	0.01 B	$11,442
(b)		Contingencies	0.03 B	$34,327
		Total Indirect Costs		***$400,478***
		Total Capital Investment (TCI)		***$2,517,292***

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	297	kW	$0.060	per kWh[(b)]	$155,940
	Total Direct Annual Costs					***$155,940***
	Indirect Annual Costs					
	Overhead	60%	Labor and Material Costs			$0
	General and administrative	2%	of TCI			$0
(b)	Property taxes	1%	of TCI			$25,173
(b)	Insurance	1%	of TCI			$25,173
(b)	Capital recovery	0.095	x TCI			$238,441
	Life of the control:	15	years at	4.75%	interest	
	Total Indirect Annual Costs					***$288,787***
	Total Annual Costs					***$444,727***
	Cost Effectiveness ($/ton)					
	Additional PM10 Control Efficiency[(f)]:	50%				
	PM10 Emissions[(g)]:	42.4	tpy	Total Annual Costs/Controlled PM10 Emissions:		
	Reduced PM10 Emissions:	21.2	tons of additional PM10 removed annually			***$20,978***

[(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. No additional labor, maintenance, or overhead costed for the replacement scrubber.

[(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-52a

IP Springfield

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		***$969,681***
(b)		Instrumentation	0.10 A	$96,968
(b)		Sales Tax	0.03 A	$29,090
(b)		Freight	0.05 A	$48,484
	B	***Total Purchased Equipment Cost***		***$1,144,224***
		Direct Installation Costs		
(b)		Foundations and Supports	0.12 B	$137,307
(b)		Handling and erection	0.40 B	$457,690
(b)		Electrical	0.01 B	$11,442
(b)		Piping	0.30 B	$343,267
(b)		Insulation for ductwork	0.01 B	$11,442
(b)		Painting	0.01 B	$11,442
		Direct Installation Cost		***$972,590***
		Total Direct Costs		***$2,116,814***
Indirect Costs				
(b)		Engineering	0.10 B	$114,422
(b)		Construction Management	0.10 B	$114,422
(b)		Contractor fees	0.10 B	$114,422
(b)		Start-up	0.01 B	$11,442
(b)		Performance test	0.01 B	$11,442
(b)		Contingencies	0.03 B	$34,327
		Total Indirect Costs		***$400,478***
Total Capital Investment (TCI)				***$2,517,292***

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	297	kW	$0.060	per kWh[b]	$152,327
	Total Direct Annual Costs					***$152,327***
Indirect Annual Costs						
	Overhead	60%	Labor and Material Costs			$0
	General and administrative	2%	of TCI			$0
(b)	Property taxes	1%	of TCI			$25,173
(b)	Insurance	1%	of TCI			$25,173
(b)	Capital recovery	0.095	x TCI			$238,441
	Life of the control:		15 years at	4.75%	interest	
	Total Indirect Annual Costs					***$288,787***
Total Annual Costs						***$441,113***
Cost Effectiveness ($/ton)						
	Additional PM10 Control Efficiency[f]:	50%				
	PM10 Emissions[g]:	34.97	tpy		Total Annual Costs/Controlled PM10 Emissions:	
	Reduced PM10 Emissions:	17.5	tons of additional PM10 removed annually			***$25,228***

[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 8557 operating hours. No additional labor, maintenance, or overhead costed for the replacement scrubber.

[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

Sargent & Lundy LLC

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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.

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

Item		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)	$	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

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)	$	14,762,000	Base module for unmilled sorbent includes all equipment from unloading to injection, including dehumification 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

		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)	$ 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

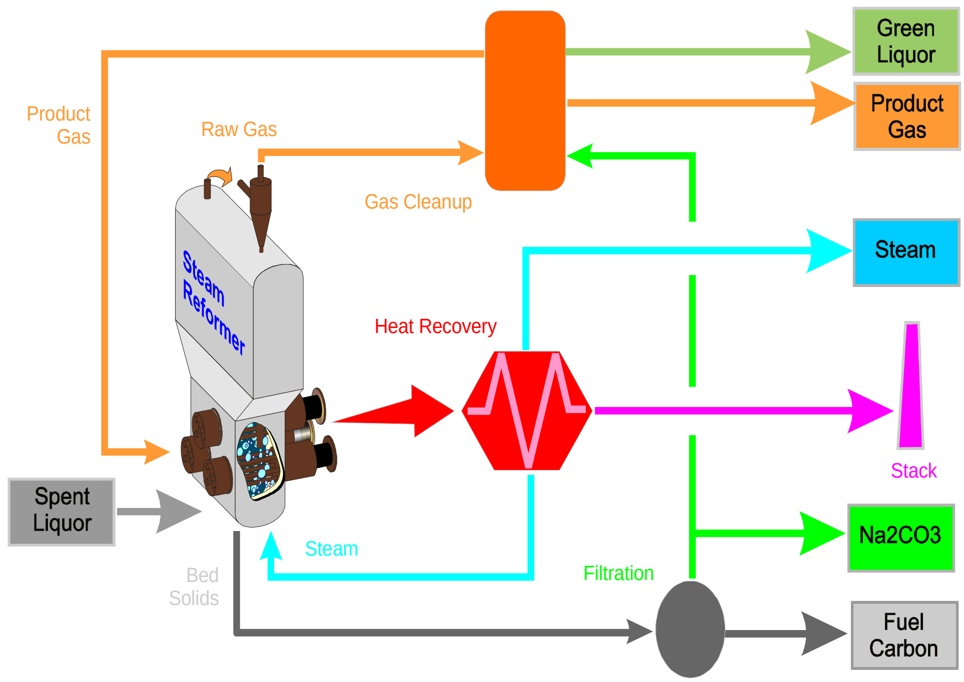
- ✓ Maintenance labor & materials: 3.5% of TIC
- ✓ Power: 22 kw
- ✓ Power usage factor: 70%
- ✓ Workhours: 2.25 hours per day

- ✓ 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.

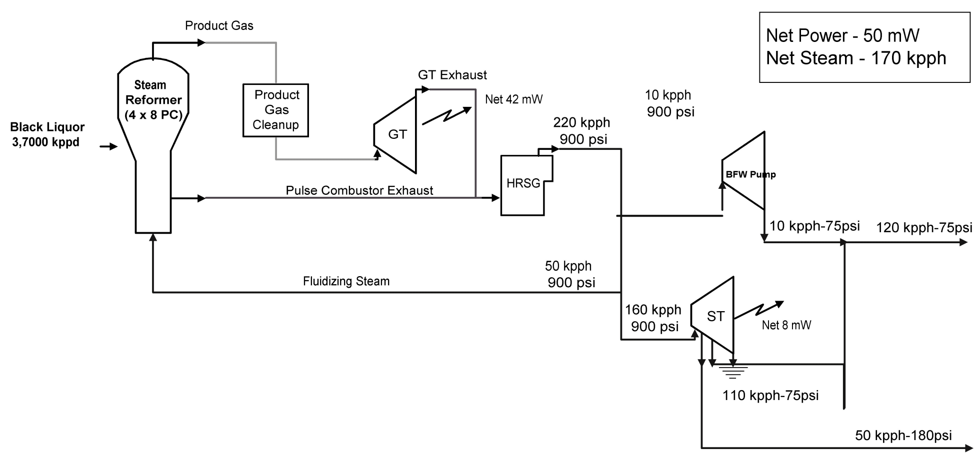
Dissolving, washing, and filtering the bed solids produce a “clear” alkali carbonate solution. The filter cake contains any unreacted carbon as well as insoluble non-process elements such as calcium and silicon. The carbon cake can be used as an activated charcoal for color or odor removal, mixed on 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



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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

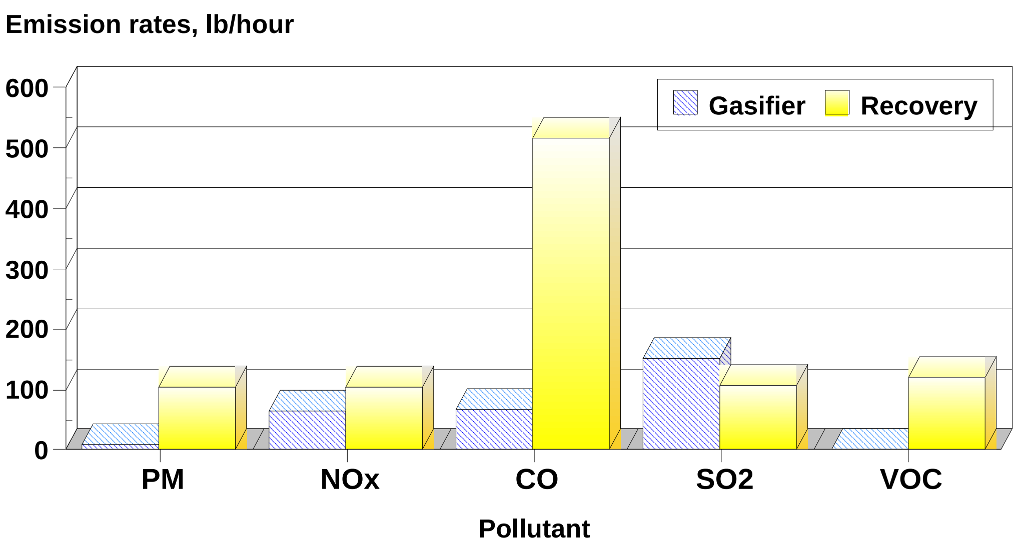
Recovery Boiler & Smelt Dissolver Emission Estimates

	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

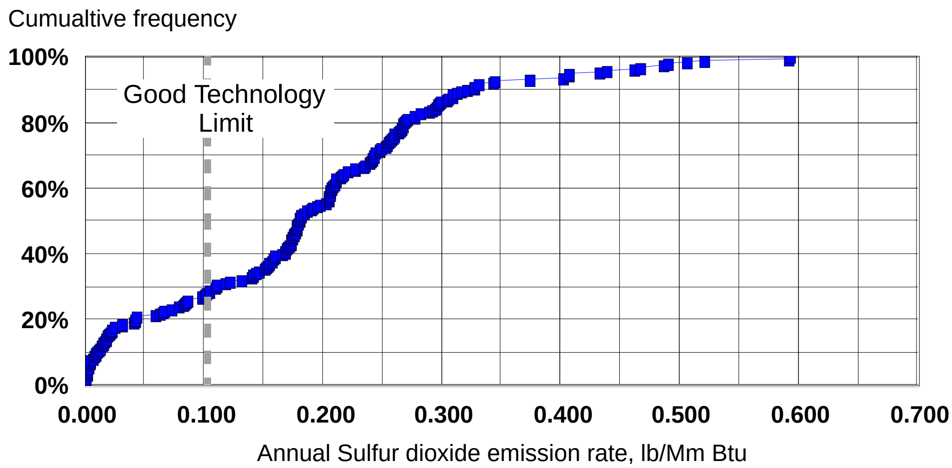
17.3.3. SO_2 Control Technology

- ✓ 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 (**these are the same as what was estimated for good controls for NO_x**) 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.
- ✓ <u>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.</u>

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

AF&PA Detail Installed
Cost Summary and Operating Cost Assumptions

															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	