



Oregon

Kate Brown, Governor

Department of Environmental Quality

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December 23, 2019

Lisa Scott
Cascade Pacific Pulp, LLC
Environmental Supervisor
PO Box 400
Halsey, OR 97348-0400

Re: Regional Haze Four Factor Analysis; Halsey Pulp Mill

Dear Lisa Scott:

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

Background

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

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

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

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

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

DEQ has identified your facility as a significant source of regional haze precursor emissions. Based on the information in the table below, DEQ selected your facility to provide additional information about emissions and current and potential controls based on a screening evaluation of haze-causing emissions relative to distance to Class I Areas in Oregon.

DEQ Facility ID:	22-3501
Federal Facility ID:	7394911
Facility name:	Halsey Pulp Mill
Facility Address	30480 AMERICAN DR
Facility City, State, Zip	HALSEY, OR 97348-9750

Facility 2017 Emissions³

Actual (tons per year)				Potential to Emit (tons per year)			
NOx	SO ₂	PM-10	Total Q	NOx	SO ₂	PM-10	Total Q
352.1	80.9	278.8	711.8	687	851	366	1904

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

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

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

prepared using the EPA guidance referenced above as well as EPA's Air Pollution Control Cost Manual⁴ and EPA's Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM2.5, and Regional Haze.⁵ Please complete the analysis for every emission point at your facility. If a unit is too small to control, please demonstrate that.

If you fail to submit your four factor analysis to DEQ by May 31, 2020, you may be subject to enforcement, including civil penalties.

Four Factor Analysis

Based on our evaluation, your facility warrants an analysis to be included in DEQ's SIP submittal, which could mean that additional emission controls will be required. As outlined in 40 CFR 51.308(f)(2), DEQ must evaluate four factors to determine whether specific control measures for your facility are reasonable and should be included in an updated long-term strategy. By this letter, DEQ is requiring you to provide information and analysis of the four factors. These four factors are:

- 1) The costs of compliance.
- 2) The time necessary for compliance.
- 3) The energy and non-air quality environmental impacts of compliance.
- 4) The remaining useful life of any potentially affected major or minor stationary source or group of sources.

DEQ looks forward to your submittal of a four factor analysis for these emission units and pollutants as soon as practicable, but no later than May 31, 2020. We encourage you to share drafts with us for comments and we are prepared to engage in consultation to ensure an approvable submittal before the deadline.

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

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

Contact

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

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

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

Sincerely,

Ali Mirzakhali
Air Quality Division Administrator

Cc:

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



June 15, 2020

Department of Environmental Quality
ATTN: D Pei Wu
700 NE Multnomah Street, Suite 600
Portland, OR 97232

Dear Ms. Wu,

Attached is the Four Factor Analysis for Cascade Pacific Pulp, (Halsey Pulp Mill) as requested by DEQ in December 2019. The Four Factor Analysis is used to determine if additional emission control measures are necessary to make reasonable progress toward natural visibility conditions at Class I areas. The analysis consists of the 1) cost of compliance, 2) the time necessary for compliance, 3) the energy and non-air quality environmental impacts of compliance, and 4) the remaining useful life of any potentially affected major or minor stationary source or group of sources. The Four Factor Analysis Report is for the Oregon pulp and paper mills in conjunction with Northwest Pulp and Paper Association.

The report focuses on the significant sources of SO₂, NO_x and PM₁₀ emissions. For Cascade Pacific Pulp, the report uses the emissions from the Plant Site Emission Limits (PSEL) and the actual emissions from 2017 for the four-factor analysis. The PSEL for Cascade Pacific Pulp used in this report are the PSEL from the Title V Permit that is out on public notice for renewal.

The Four Factor Analysis Report indicates that additional emission controls for SO₂, NO_x, and PM₁₀ are either not feasible or not cost effective to implement.

If you have any further questions, please contact me at 541-369-1752 or Toby Smith at 541-369-1196.

Sincerely,

Lisa Scott

c. Toby Smith-Cascade Pacific Pulp

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

JUNE 2020

Submitted by:



Northwest Pulp & Paper
ASSOCIATION

Northwest Pulp and Paper Association
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Olympia, WA 98501-1302

Submitted to:



Oregon Department of Environmental Quality
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1. INTRODUCTION

The Oregon Department of Environmental Quality (DEQ) Air Quality Division is in the process of developing a State Implementation Plan (SIP) revision for the second planning period under the 1999 Regional Haze Rule (RHR) at 40 CFR Part 51, Subpart P. The RHR focuses on improving visibility in federal Class I areas by reducing emissions of visibility impairing pollutants. DEQ is required to update the SIP by July 2021 to address further controls that could be applied to reduce emissions of sulfur dioxide (SO₂), nitrogen oxides (NO_x), and particulate matter less than 10 microns in aerodynamic diameter (PM₁₀) 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 SO₂ 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 SO₂, NO_x, and PM₁₀ 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 SO₂, NO_x, and PM₁₀ emissions from boilers, recovery furnaces, and lime kilns located at the four mills. These source groups comprise the majority of the total SO₂, NO_x, and PM₁₀ 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 SO₂, NO_x, and PM₁₀ 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 PM₁₀ 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

Northwest Pulp and Paper Association
Four Factor Analysis

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	

Northwest Pulp and Paper Association
Four Factor Analysis

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, SO₂, and PM₁₀ from all BART-era emission units at the same facility.

MACT standards that limit visibility-impairing pollutants were determined to meet the requirements for BART unless there were new cost-effective control technologies available. Per Section IV of 40 CFR Part 51, Appendix Y, Guidelines for BART Determinations under the Regional Haze Rules: “Unless there are new technologies subsequent to the MACT standards which would lead to cost-effective increases in the level of control, [state agencies] may rely on the MACT standards for purposes of BART.” 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 SO₂ emissions. Fuel oil is fired in the No. 1 Power Boiler only when natural gas is curtailed, resulting in lower PM₁₀ and SO₂ 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 PM₁₀ and SO₂ 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 PM₁₀ and SO₂ 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, PM₁₀, and SO₂ 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 PM₁₀ and SO₂ emissions. The Mill no longer fires pet coke in the lime kiln, resulting in lower SO₂ emissions. The Mill is already subject to a Federally enforceable permit limit on SO₂ and NO_x emissions that was implemented in the 2008 Oregon Regional Haze Plan to reduce the visibility impact of the BART-eligible units (including the Power Boiler).

1.4 DOCUMENT ORGANIZATION

The document is organized as follows:

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

2. FOUR-FACTOR ANALYSIS FOR BOILERS

This section of the report presents the results of the FFA for PM₁₀, SO₂, 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 database² 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 PM₁₀ Control Technologies

The potentially feasible control technologies for reducing emissions of PM₁₀ 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 PM₁₀ removal efficiencies as high as those achieved by fabric filters. Two ESP designs are common: dry electrostatic precipitators and wet electrostatic precipitators. The systems are similar except that wet electrostatic precipitators use water to flush the captured particles from the collector plates.

Fabric Filters

Various types of fabric filters or bag houses have been successfully used for PM control on solid fuel-fired boilers. A fabric filter utilizes 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 PM₁₀ reduction obtained by fabric filters and ESPs without being operated at extremely high energy input levels. In addition, wet scrubber systems often require higher levels of maintenance and generate a wastewater stream that must be treated.

2.1.2 Available SO₂ Control Technologies

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 SO₂ emissions and are not evaluated in this report for further SO₂ emissions control. The potentially feasible add-on control technologies for reducing emissions of SO₂ 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 SO₂ control, the absorption process is chemical-based and uses an alkali solution (*i.e.*, sodium hydroxide, sodium carbonate, sodium bicarbonate, calcium hydroxide, etc.) as a sorbent or reagent in combination with water. Removal efficiencies are affected by the chemistry of the absorbing solution as it reacts with the pollutant. Wet scrubbers may take the form of a variety of different configurations, including 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 SO₂, 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 (N₂), water (H₂O), and carbon dioxide (CO₂). SNCR involves injecting ammonia or urea into a combustion chamber or the flue gas stream, which must be between approximately 1,600 and 2,000 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 N₂ and H₂O. SCR employs a metal-based catalyst, such as vanadium or titanium, to increase the rate of the NO_x reduction reaction⁴. 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°F⁵. 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.

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/ttn/catc1/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.

PM₁₀ Emissions

The Nos. 1 and 2 Power Boilers at the CPP Halsey Mill fire natural gas and have minimal PM₁₀ 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 PM₁₀ 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 PM₁₀ emissions. No PM₁₀ 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 PM₁₀.

SO₂ 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 SO₂ 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 SO₂ controls beyond burning natural gas as the primary fuel and limiting fuel oil firing to periods of curtailment are feasible for these boilers.

NO_x Emissions

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

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

⁶ *Unit designed to burn gas 1 subcategory* includes any boiler or process heater that burns only natural gas, refinery gas, and/or other gas 1 fuels. Gaseous fuel boilers and process heaters that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this definition. Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply interruptions of any duration are also included in this definition.

Period of gas curtailment or supply interruption means a period of time during which the supply of gaseous fuel to an affected boiler or process heater is restricted or halted for reasons beyond the control of the facility. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas due to normal market fluctuations not during periods of supplier delivery restriction does not constitute a period of natural gas curtailment or supply interruption. On-site gaseous fuel system emergencies or equipment failures qualify as periods of supply interruption when the emergency or failure is beyond the control of the facility.

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

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

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

The variability of the SNCR temperature window is a critical issue, because of the consequences of ammonia injection outside this window. Below the temperature window, ammonia slip will occur due to incomplete reactions of the injected chemicals with the NO_x. Above the temperature

window, the reducing chemicals could be combusted to form additional NO_x. Multiple injection levels must sometimes be installed to accommodate firebox temperature variability.

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

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

The natural gas boilers evaluated in this report have air heaters and/or economizers. There is not adequate space to install an SCR reactor on these boilers prior to the air heater or economizer and

the exhaust gas temperature following the air heater or economizer is typically less than 450°F. Therefore, a duct burner would be necessary for an SCR to be effective at reducing NO_x emissions from the boilers evaluated in this report. Despite the challenges of implementing SCR, it is considered technically feasible.

2.3 COST OF TECHNICALLY FEASIBLE CONTROL TECHNOLOGIES

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

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

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

Source Emissions Unit	Fuels Fired	Existing Control Technology			Additional Control Technology Costed		
		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 Emissions Unit	Fuels Fired	Existing Control Technology			Additional Control Technology Costed		
		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 rule⁷, 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 PM₁₀ Economic Impacts

As stated above, all of the industrial boilers evaluated in this report are already well controlled for PM₁₀. However, for purposes of this report, and because the PM₁₀ 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 PM₁₀ 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 PM₁₀ 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 PM₁₀ PSEL, the approximate cost would be \$10,684/ton of PM₁₀ removed, which is not cost effective.

2.3.3 SO₂ 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% SO₂ 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

¹⁰ <https://www3.epa.gov/ttn/catc/dir1/fwespwpi.pdf>

¹¹ Sargent & Lundy LLC. 2017. *Dry Sorbent Injection for SO₂/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 SO₂ PSEL and the 2017 actual emissions.

**Table 2-3
Trona Injection System Cost Summary**

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

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

2.3.4 NO_x Economic Impacts

LNB and FGR for Boiler NO_x Control

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

Where current NO_x 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/snscr/>, <https://www.cecenviro.com/selective-non-catalytic-reduction-snscr-cca-combustion-systems>, <https://www.ftek.com/en-US/products/productssubapc/urea-snscr>

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 SO₂ 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 PM₁₀, SO₂, 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 PM₁₀ Control Technologies

The following control technologies were identified as potentially available for reducing emissions of PM₁₀ 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 PM₁₀ removal efficiencies as high as those achieved by fabric filters. Two ESP designs are common: dry electrostatic precipitators and wet electrostatic precipitators. The systems are similar except that wet electrostatic precipitators use water to flush the captured particles from the collector plates. 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 PM₁₀ reduction obtained by fabric filters and ESPs without being operated at extremely high energy input levels. In addition, wet scrubber systems often require higher levels of maintenance and generate a wastewater stream that must be treated.

3.1.2 Available SO₂ 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 SO₂ 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 SO₂ emissions. A well-operated recovery furnace can have very low SO₂ emissions.

The following add-on control technologies were identified as potentially feasible for reducing emissions of SO₂ 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 SO₂ control, the absorption process is chemical-based and uses an alkali solution (*i.e.*, sodium hydroxide, sodium carbonate, sodium bicarbonate, calcium hydroxide, etc.) as a sorbent or reagent in combination

with water. Removal efficiencies are affected by the chemistry of the absorbing solution as it reacts with the pollutant. Wet scrubbers may take the form of a variety of different configurations, including plate or tray columns, spray chambers, and venturi scrubbers.

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 an 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.

PM₁₀ Emissions

All the recovery furnaces included in this FFA are equipped with dry ESPs for PM₁₀ control. While fabric filters can also achieve high levels of PM₁₀ control, the exhaust gas stream from a recovery furnace has a relatively high moisture content that causes the PM to be hygroscopic in nature and would cause the filter bags to blind and plug. Therefore, fabric filters are not a feasible PM₁₀ control technology for recovery furnaces. Installation of a wet scrubber following the ESP was not evaluated for PM₁₀ because scrubbers are not expected to further control PM₁₀ that is not already controlled by the ESP. Wet scrubbers use water droplets to capture dust particles and have higher control efficiencies for larger particles¹³; therefore, scrubbers are not suited to control additional PM₁₀ after an ESP.

Two additional PM₁₀ control options were evaluated for each recovery furnace: (1) upgrading the existing ESP to increase PM₁₀ control (the emissions reduction was calculated assuming a change from 99% to 99.5% PM₁₀ control), and (2) installing a WESP following the dry ESP to achieve an estimated additional 80% reduction in controlled PM₁₀ 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 PM₁₀ 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 PM₁₀ control, assuming space were available.

SO₂ Emissions

The recovery furnaces in this FFA are not equipped with add-on SO₂ control technology. Although SO₂ emissions from recovery furnaces can be inherently low, addition of a wet scrubber to further reduce SO₂ 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 PM₁₀ 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 SO₂ 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 PM₁₀ 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 PM₁₀ 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 PM₁₀ 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 PM₁₀ PSEL levels assigned to each recovery furnace and 2017 actual emissions. The reduction in PM₁₀ was estimated to be 50% of current levels (e.g., an increase from 99 to 99.5% PM₁₀ control with the upgrade).

**Table 3-3
ESP Upgrade Cost Summary**

Emissions Unit Description	Capital Cost (\$)	Annual Cost (\$/yr)	Cost Effectiveness of Controls (\$/Ton PM₁₀)
Based on PSEL			
CPP Halsey Recovery Furnace (RFEU)	\$11,985,809	\$1,338,144	\$24,919

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

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

Wet Electrostatic Precipitator for Additional PM₁₀ Control

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

¹⁴ <https://www3.epa.gov/ttn/catc/dir1/fwespwpi.pdf>

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

Table 3-4 summarizes the capital cost, annual cost, and cost effectiveness of implementing this control technology, based on operating data and both the portion of the PM₁₀ 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 PM₁₀)
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 SO₂ Economic Impacts

Wet Scrubber for SO₂ 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 SO₂ 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 PM₁₀ 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 SO₂)
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 SO₂ 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 PM₁₀, SO₂, 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 PM₁₀ Control Technologies

The following control technologies were identified as potentially available for reducing emissions of PM₁₀ 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 PM₁₀ removal efficiencies as high as those achieved by fabric filters. Two ESP designs are common: dry electrostatic precipitators and wet electrostatic precipitators. The systems are similar except that wet electrostatic precipitators use water to flush the captured particles from the collector plates.

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 PM₁₀ 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 PM₁₀ reduction obtained by fabric filters and ESPs without being operated at extremely high energy input levels. In addition, wet scrubber systems often require higher levels of maintenance and generate a wastewater stream that must be treated.

4.1.2 Available SO₂ Control Technologies

The purpose of a lime kiln is to calcine lime mud (CaCO₃) to produce lime product (CaO). Typically, SO₂ 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 SO₂ 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 SO₂ control, the absorption process is chemical-based and uses an alkali solution (*i.e.*, sodium hydroxide, sodium carbonate, sodium bicarbonate, calcium hydroxide, etc.) as a sorbent or reagent in combination with water. Removal efficiencies are affected by the chemistry of the absorbing solution as it reacts with the pollutant. Wet scrubbers may take the form of a variety of different configurations including plate or tray columns, spray chambers, and venturi scrubbers.

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 N₂, H₂O, and CO₂. 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 N₂ and H₂O. SCR employs a metal-based catalyst, such as vanadium or titanium, to increase the rate of the NO_x reduction reaction¹⁶. 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°F¹⁷. 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/ttnatc1/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.

PM₁₀ 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 PM₁₀ 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 PM₁₀ control is considered technically feasible.

SO₂ Emissions

The lime kilns provide inherent control of SO₂ 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 SO₂ 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 SO₂ emissions at the GP Toledo mill are less than 1 tpy and the portion of the SO₂ PSEL assigned to the lime kilns at GP Wauna and GP Toledo is less than 5 tpy, so no additional SO₂ controls are necessary for these kilns.

The CPP Halsey lime kiln's portion of the SO₂ 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 SO₂ 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 SO₂ emissions from this kiln was evaluated (rather than replacing the venturi scrubber with a caustic wet scrubber and potentially decreasing the PM₁₀ control efficiency). Addition of a wet scrubber with caustic addition (following the ESP) for additional SO₂ 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°F¹⁸) 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.

¹⁸Air Pollution Control Technology Fact Sheet. EPA-452/F-03-032. <https://www3.epa.gov/ttn/catc1/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 PM₁₀ 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 PM₁₀ 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 PM₁₀ 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 PM₁₀)
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 PM₁₀ is estimated to result from upgrading the ESP (*e.g.*, an improvement from 99% PM₁₀ 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 SO₂ Economic Impacts

The U.S. EPA's fact sheet on packed bed scrubbers¹⁹ 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 SO₂ 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 SO₂ 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/ttnecat1/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 SO₂)
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 PM₁₀, NO_x, and SO₂ 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 PM₁₀, NO_x, and SO₂ emissions at the mills.

Lime slakers emit small amounts of PM₁₀ 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 PM₁₀. 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 PM₁₀ 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 SO₂ 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 SO₂ 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 PM₁₀ was performed.

The cost of installing a replacement wet scrubber to improve PM₁₀ 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 PM₁₀ 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 PM₁₀)
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 SO₂.

Concentrations of PM are very low in each paper machine vent, as discussed in NCASI Technical Bulletin No. 942, "Measurement of PM, PM₁₀, 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 PM₁₀ 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 PM₁₀ EMISSIONS FROM MATERIAL HANDLING SOURCES

Table 5-2 shows the material handling type sources that emit PM₁₀ at each mill. The current PM₁₀ control technique, assigned portion of the PM₁₀ PSEL, and additional control evaluated are shown.

Note that IP Springfield has eliminated the New Fiber Line emission unit (EU-402), which had a PM₁₀ 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 PM₁₀ 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 sheet²⁰, 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 PM₁₀ is at least \$20,000/ton of PM₁₀ reduced, which is not cost effective.

Data on PM₁₀ 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 PM₁₀ fractions were less than 1.5 pounds of PM₁₀ per million pounds of bark or chips and less than 3 percent of total suspended PM. Potential filterable PM₁₀ emission factors developed as a result of the NCASI study are much lower than emission factors historically used, so actual PM₁₀ emissions from chip and wood handling are likely much lower than PSEL emissions.

²⁰ <https://www3.epa.gov/ttn/catc/dir1/ff-revar.pdf>

**Table 5-2
Material Handling Sources**

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

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Emissions Unit Description	PM₁₀ Control Technique	PM₁₀ PSEL, tpy	Additional PM₁₀ 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 SO₂, NO_x, and PM₁₀ 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 SO₂, NO_x, and PM₁₀ 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 PM₁₀.
- 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 PM₁₀ and SO₂ 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 = $0.208e^{(0.0281 \cdot H)}$
Sorbent Feed Rate	M	ton/hr	0.21	$\text{Trona} = (1.2011 \cdot 10^{-06}) \cdot K \cdot A \cdot C \cdot D$
Estimated HCl Removal	V	%	98.85	Milled or Unmilled Trona w/ FF = $84.598 \cdot H^{0.0346}$
Sorbent Waste Rate	N	ton/hr	0.17	$\text{Trona} = (0.7387 + 0.00185 \cdot H / K) \cdot M$
Fly Ash Waste Rate	P	ton/hr	2.90	Ash in Bark = 0.05; Boiler Ash Removal = 0.2; HHV = 4600 $(A \cdot C) \cdot \text{Ash} \cdot (1 - \text{Boiler Ash Removal}) / (2 \cdot \text{HHV})$
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 $(M > 25, 820000 \cdot B \cdot M, 8300000 \cdot B \cdot (M^{0.284}))$
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/SO₂ Emissions			\$	111,494

^(a)Cost information based on the April 2017 "Dry Sorbent Injection for SO₂/HCl Control Cost Development Methodology" study by Sargent & Lundy for a milled Trona system. 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 = $0.208e^{(0.0281 \cdot H)}$
Sorbent Feed Rate	M	ton/hr	0.21	$\text{Trona} = (1.2011 \cdot 10^{-06}) \cdot K \cdot A \cdot C \cdot D$
Estimated HCl Removal	V	%	98.85	Milled or Unmilled Trona w/ FF = $84.598 \cdot H^{0.0346}$
Sorbent Waste Rate	N	ton/hr	0.17	$\text{Trona} = (0.7387 + 0.00185 \cdot H / K) \cdot M$
Fly Ash Waste Rate	P	ton/hr	2.90	Ash in Bark = 0.05; Boiler Ash Removal = 0.2; HHV = 4600 $(A \cdot C) \cdot \text{Ash} \cdot (1 - \text{Boiler Ash Removal}) / (2 \cdot \text{HHV})$
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

SO₂ Control Efficiency:	90%
2017 Actual Emissions, tpy	25.1
Controlled SO₂ Emissions:	22.6

Capital Costs				
Direct Costs				
BM (Base Module) scaled to 2019 dollars		\$	\$	5,966,395 Milled Trona if $(M > 25, 820000 \cdot B \cdot M, 8300000 \cdot B \cdot (M^{0.284}))$
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/SO₂ Emissions			\$	122,475

^(a)Cost information based on the April 2017 "Dry Sorbent Injection for SO₂/HCl Control Cost Development Methodology" study by Sargent & Lundy for a milled Trona system. 2016 costs scaled to 2019 costs using the CEPCI.

Table A-2
Cascade Pacific Pulp - Halsey
Low NO_x 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 NO_x 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 NO_x 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 NO_x 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 NO_x 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 NO_x at 3% O₂ to post control 50 ppm.
- (f) 2017 Actual Emissions

Table A-5
Low NO_x 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 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 NO_x at 3% O₂ to post control 50 ppm.
- (f) PSEL

Table A-5a
Low NO_x 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 Technologies," Loan K. Tran and H. Christopher Frey, June 1996.
- (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 NO_x at 3% O₂ to post control 50 ppm.
- (f) 2017 Actual Emissions

Table A-6
Low NO_x 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 NO_x at 3% O₂ to post control 50 ppm.
- (f) PSEL

Table A-6a
Low NO_x 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 NO_x at 3% O₂ to post control 50 ppm.
- (f) 2017 Actual Emissions

Table A-7
Low NO_x 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 NO_x 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 NO_x 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 NO_x 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 SO₂ emission rate:

Not Applicable ▼

Ash content (%Ash):

percent by weight

Not applicable to units burning 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-9 - 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})

365 days

Plant Elevation

278 Feet above sea level

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

0.276 lb/MMBtu

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

0.152 lb/MMBtu

Estimated Normalized Stoichiometric Ratio (NSR)

2.04

*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/ft³Concentration 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/ft³29.4% aqueous NH_3 56 lbs/ft³

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

CEPCI = Chemical Engineering Plant Cost Index

Annual Interest Rate (i)

4.75 Percent

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

5.00 \$/MMBtu

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

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

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

0.0042 \$/gallon*

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

0.0676 \$/kWh*

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

\$/ton

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

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

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =

0.015

Administrative Charges Factor (ACF) =

0.03

Table A-9 - 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) =	$(Q_B \times 1.0E6 \text{ Btu/MMBtu} \times 8760) / \text{HHV} =$	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}) =	$(\text{Mactual} / \text{Mfuel}) \times (\text{tSNCR} / 365) =$	0.00	fraction	
Total operating time for the SNCR (t_{op}) =	$CF_{\text{total}} \times 8760 =$	8760	hours	Based on 8760 (PTE)
NOx Removal Efficiency (EF) =	$(\text{NOx}_{\text{in}} - \text{NOx}_{\text{out}}) / \text{NOx}_{\text{in}} =$	45	percent	
NOx removed per hour =	$\text{NOx}_{\text{in}} \times \text{EF} \times Q_B =$	29.36	lb/hour	
Total NO _x removed per year =	$(\text{NOx}_{\text{in}} \times \text{EF} \times Q_B \times t_{\text{op}}) / 2000 =$	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 =	$(\%S/100) \times (64/32) \times (1 \times 10^6) / \text{HHV} =$			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEV _F) =	14.7 psia/P =			Not applicable; elevation factor does not
Atmospheric pressure at 278 feet above sea level (P) =	$2116 \times [(59 - (0.00356 \times h)) + 459.7] / 518.6^{5.256} \times (1/144)^* =$	14.6	psia	apply to plants located at elevations below 500 feet.
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

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

Reagent Data:

Type of reagent used

Urea

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

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NOx}_{\text{in}} \times Q_{\text{B}} \times \text{NSR} \times \text{MW}_{\text{R}}) / (\text{MW}_{\text{NOx}} \times \text{SR}) =$ (whre SR = 1 for NH_3 ; 2 for Urea)	87	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}} / C_{\text{sol}} =$	174	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density} =$	18.3	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24 \text{ hours/day}) / \text{Reagent Density} =$	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) =	$(0.47 \times \text{NOx}_{\text{in}} \times \text{NSR} \times Q_{\text{B}}) / \text{NPHR} =$	7.6	kW/hour
Water Usage: Water consumption (q_{w}) =	$(m_{\text{sol}} / \text{Density of water}) \times ((C_{\text{stored}} / C_{\text{inj}}) - 1) =$	83	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$H_v \times m_{\text{reagent}} \times ((1/C_{\text{inj}}) - 1) =$	0.70	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta \text{fuel} \times \% \text{Ash} \times 1 \times 10^6) / \text{HHV} =$	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
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Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

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

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

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

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

Total Annual Cost (TAC)

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

Direct Annual Costs (DAC) =	\$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)

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

Annual Maintenance Cost =	$0.015 \times \text{TCI} =$	\$49,954 in 2019 dollars
Annual Reagent Cost =	$q_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$266,117 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$4,516 in 2019 dollars
Annual Water Cost =	$q_{\text{water}} \times \text{Cost}_{\text{water}} \times t_{\text{op}} =$	\$3,041 in 2019 dollars
Additional Fuel Cost =	$\Delta \text{Fuel} \times \text{Cost}_{\text{fuel}} \times t_{\text{op}} =$	\$30,812 in 2019 dollars
Additional Ash Cost =	$\Delta \text{Ash} \times \text{Cost}_{\text{ash}} \times t_{\text{op}} \times (1/2000) =$	\$0 in 2019 dollars
Direct Annual Cost =		\$354,441 in 2019 dollars

Indirect Annual Cost (IDAC)

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

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

Cost Effectiveness

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

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 SO₂ emission rate:

Not Applicable ▼

Ash content (%Ash):

percent by weight

Not applicable to units burning 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

Plant Elevation

278 Feet above sea level

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

0.221 lb/MMBtu

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

0.121 lb/MMBtu

Estimated Normalized Stoichiometric Ratio (NSR)

2.33

*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).

Concentration of reagent as stored (C_{stored})

50 Percent

Density of reagent as stored (ρ_{stored})71 lb/ft³Concentration 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/ft³29.4% aqueous NH_3 56 lbs/ft³

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

CEPCI = Chemical Engineering Plant Cost Index

Annual Interest Rate (i)

4.75 Percent

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

5.00 \$/MMBtu

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

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

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

0.0042 \$/gallon*

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

0.0676 \$/kWh*

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

\$/ton

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

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

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =

0.015

Administrative Charges Factor (ACF) =

0.03

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) =	$(Q_B \times 1.0E6 \text{ Btu/MMBtu} \times 8760)/\text{HHV} =$	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}) =	$(\text{Mactual}/\text{Mfuel}) \times (\text{tSNCR}/365) =$	0.23	fraction	
Total operating time for the SNCR (t_{op}) =	$CF_{\text{total}} \times 8760 =$	8622	hours	Based on 2017 Operating Hours
NOx Removal Efficiency (EF) =	$(\text{NOx}_{\text{in}} - \text{NOx}_{\text{out}})/\text{NOx}_{\text{in}} =$	45	percent	
NOx removed per hour =	$\text{NOx}_{\text{in}} \times \text{EF} \times Q_B =$	23.45	lb/hour	
Total NO _x removed per year =	$(\text{NOx}_{\text{in}} \times \text{EF} \times Q_B \times t_{\text{op}})/2000 =$	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 =	$(\%S/100) \times (64/32) \times (1 \times 10^6)/\text{HHV} =$			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEV _F) =	14.7 psia/P =			Not applicable; elevation factor does not
Atmospheric pressure at 278 feet above sea level (P) =	$2116 \times [(59 - (0.00356 \times h)) + 459.7]/518.6^{5.256} \times (1/144)^* =$	14.6	psia	apply to plants located at elevations below 500 feet.
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

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

Reagent Data:

Type of reagent used

Urea

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

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NOx}_{\text{in}} \times Q_{\text{B}} \times \text{NSR} \times \text{MW}_{\text{R}}) / (\text{MW}_{\text{NOx}} \times \text{SR}) =$ (whre SR = 1 for NH_3 ; 2 for Urea)	79	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}} / C_{\text{sol}} =$	158	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density} =$	16.7	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24 \text{ hours/day}) / \text{Reagent Density} =$	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) =	$(0.47 \times \text{NOx}_{\text{in}} \times \text{NSR} \times Q_{\text{B}}) / \text{NPHR} =$	6.9	kW/hour
Water Usage: Water consumption (q_{w}) =	$(m_{\text{sol}} / \text{Density of water}) \times ((C_{\text{stored}} / C_{\text{inj}}) - 1) =$	76	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$\text{Hv} \times m_{\text{reagent}} \times ((1/C_{\text{inj}}) - 1) =$	0.64	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta \text{fuel} \times \% \text{Ash} \times 1 \times 10^6) / \text{HHV} =$	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
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Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

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

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

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

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

Total Annual Cost (TAC)

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

Direct Annual Costs (DAC) =	\$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)

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

Annual Maintenance Cost =	$0.015 \times \text{TCI} =$	\$49,110 in 2019 dollars
Annual Reagent Cost =	$q_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$238,669 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$4,051 in 2019 dollars
Annual Water Cost =	$q_{\text{water}} \times \text{Cost}_{\text{water}} \times t_{\text{op}} =$	\$2,728 in 2019 dollars
Additional Fuel Cost =	$\Delta \text{Fuel} \times \text{Cost}_{\text{fuel}} \times t_{\text{op}} =$	\$27,634 in 2019 dollars
Additional Ash Cost =	$\Delta \text{Ash} \times \text{Cost}_{\text{ash}} \times t_{\text{op}} \times (1/2000) =$	\$0 in 2019 dollars
Direct Annual Cost =		\$322,190 in 2019 dollars

Indirect Annual Cost (IDAC)

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

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

Cost Effectiveness

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

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 SO₂ emission rate:

Not Applicable ▼

Ash content (%Ash):

percent by weight

Not applicable to units burning 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-10 - 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})

365 days

Plant Elevation

278 Feet above sea level

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

0.280 lb/MMBtu

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

0.154 lb/MMBtu

Estimated Normalized Stoichiometric Ratio (NSR)

2.02

*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/ft³Concentration 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/ft³29.4% aqueous NH_3 56 lbs/ft³

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

CEPCI = Chemical Engineering Plant Cost Index

Annual Interest Rate (i)

4.75 Percent

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

5.00 \$/MMBtu

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

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

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

0.0042 \$/gallon*

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

0.0676 \$/kWh*

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

\$/ton

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

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

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =

0.015

Administrative Charges Factor (ACF) =

0.03

Table A-10 - 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) =	$(Q_B \times 1.0E6 \text{ Btu/MMBtu} \times 8760) / \text{HHV} =$	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}) =	$(\text{Mactual} / \text{Mfuel}) \times (\text{tSNCR} / 365) =$	0.26	fraction	
Total operating time for the SNCR (t_{op}) =	$CF_{\text{total}} \times 8760 =$	8760	hours	Based on 8760 (PTE)
NOx Removal Efficiency (EF) =	$(\text{NOx}_{\text{in}} - \text{NOx}_{\text{out}}) / \text{NOx}_{\text{in}} =$	45	percent	
NOx removed per hour =	$\text{NOx}_{\text{in}} \times \text{EF} \times Q_B =$	29.78	lb/hour	
Total NO _x removed per year =	$(\text{NOx}_{\text{in}} \times \text{EF} \times Q_B \times t_{\text{op}}) / 2000 =$	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 =	$(\%S/100) \times (64/32) \times (1 \times 10^6) / \text{HHV} =$			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEV _F) =	14.7 psia/P =			Not applicable; elevation factor does not
Atmospheric pressure at 278 feet above sea level (P) =	$2116 \times [(59 - (0.00356 \times h)) + 459.7] / 518.6^{5.256} \times (1/144)^* =$	14.6	psia	apply to plants located at elevations below 500 feet.
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

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

Reagent Data:

Type of reagent used

Urea

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

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NOx}_{\text{in}} \times Q_{\text{B}} \times \text{NSR} \times \text{MW}_{\text{R}}) / (\text{MW}_{\text{NOx}} \times \text{SR}) =$ (whre SR = 1 for NH_3 ; 2 for Urea)	87	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}} / C_{\text{sol}} =$	175	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density} =$	18.4	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24 \text{ hours/day}) / \text{Reagent Density} =$	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) =	$(0.47 \times \text{NOx}_{\text{in}} \times \text{NSR} \times Q_{\text{B}}) / \text{NPHR} =$	7.7	kW/hour
Water Usage: Water consumption (q_{w}) =	$(m_{\text{sol}} / \text{Density of water}) \times ((C_{\text{stored}} / C_{\text{inj}}) - 1) =$	84	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$H_v \times m_{\text{reagent}} \times ((1/C_{\text{inj}}) - 1) =$	0.71	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta \text{fuel} \times \% \text{Ash} \times 1 \times 10^6) / \text{HHV} =$	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
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Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

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

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

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

Balance of Plant Costs (BOP_{cost}) =	\$1,631,652 in 2019 dollars
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Annual Costs

Total Annual Cost (TAC)

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

Direct Annual Costs (DAC) =	\$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)

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

Annual Maintenance Cost =	$0.015 \times \text{TCI} =$	\$50,008 in 2019 dollars
Annual Reagent Cost =	$q_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$267,783 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$4,545 in 2019 dollars
Annual Water Cost =	$q_{\text{water}} \times \text{Cost}_{\text{water}} \times t_{\text{op}} =$	\$3,060 in 2019 dollars
Additional Fuel Cost =	$\Delta \text{Fuel} \times \text{Cost}_{\text{fuel}} \times t_{\text{op}} =$	\$31,005 in 2019 dollars
Additional Ash Cost =	$\Delta \text{Ash} \times \text{Cost}_{\text{ash}} \times t_{\text{op}} \times (1/2000) =$	\$0 in 2019 dollars
Direct Annual Cost =		\$356,401 in 2019 dollars

Indirect Annual Cost (IDAC)

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

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

Cost Effectiveness

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

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 SO₂ emission rate:

Not Applicable ▼

Ash content (%Ash):

percent by weight

Not applicable to units burning 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

Plant Elevation

278 Feet above sea level

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

0.181 lb/MMBtu

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

0.100 lb/MMBtu

Estimated Normalized Stoichiometric Ratio (NSR)

2.64

*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/ft³Concentration 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/ft³29.4% aqueous NH_3 56 lbs/ft³

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

CEPCI = Chemical Engineering Plant Cost Index

Annual Interest Rate (i)

4.75 Percent

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

5.00 \$/MMBtu

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

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

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

0.0042 \$/gallon*

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

0.0676 \$/kWh*

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

\$/ton

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

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

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =

0.015

Administrative Charges Factor (ACF) =

0.03

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) =	$(Q_B \times 1.0E6 \text{ Btu/MMBtu} \times 8760)/\text{HHV} =$	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}) =	$(\text{Mactual}/\text{Mfuel}) \times (\text{tSNCR}/365) =$	0.01	fraction	
Total operating time for the SNCR (t_{op}) =	$CF_{\text{total}} \times 8760 =$	3080	hours	Based on 2017 Operating Hours
NOx Removal Efficiency (EF) =	$(\text{NOx}_{\text{in}} - \text{NOx}_{\text{out}})/\text{NOx}_{\text{in}} =$	45	percent	
NOx removed per hour =	$\text{NOx}_{\text{in}} \times \text{EF} \times Q_B =$	19.21	lb/hour	
Total NO _x removed per year =	$(\text{NOx}_{\text{in}} \times \text{EF} \times Q_B \times t_{\text{op}})/2000 =$	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 =	$(\%S/100) \times (64/32) \times (1 \times 10^6)/\text{HHV} =$			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEV _F) =	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) =	$2116 \times [(59 - (0.00356 \times h)) + 459.7]/518.6]^{5.256} \times (1/144)^* =$	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>.

Reagent Data:

Type of reagent used

Urea

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

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NOx}_{\text{in}} \times Q_{\text{B}} \times \text{NSR} \times \text{MW}_{\text{R}}) / (\text{MW}_{\text{NOx}} \times \text{SR}) =$ (whre SR = 1 for NH_3 ; 2 for Urea)	74	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}} / C_{\text{sol}} =$	147	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density} =$	15.5	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24 \text{ hours/day}) / \text{Reagent Density} =$	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) =	$(0.47 \times \text{NOx}_{\text{in}} \times \text{NSR} \times Q_{\text{B}}) / \text{NPHR} =$	6.5	kW/hour
Water Usage: Water consumption (q_{w}) =	$(m_{\text{sol}} / \text{Density of water}) \times ((C_{\text{stored}} / C_{\text{inj}}) - 1) =$	71	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$H_v \times m_{\text{reagent}} \times ((1/C_{\text{inj}}) - 1) =$	0.60	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta \text{fuel} \times \% \text{Ash} \times 1 \times 10^6) / \text{HHV} =$	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
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Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

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

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:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

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

Total Annual Cost (TAC)

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

Direct Annual Costs (DAC) =	\$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)

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

Annual Maintenance Cost =	$0.015 \times \text{TCI} =$	\$48,379 in 2019 dollars
Annual Reagent Cost =	$q_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$79,297 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$1,346 in 2019 dollars
Annual Water Cost =	$q_{\text{water}} \times \text{Cost}_{\text{water}} \times t_{\text{op}} =$	\$906 in 2019 dollars
Additional Fuel Cost =	$\Delta \text{Fuel} \times \text{Cost}_{\text{fuel}} \times t_{\text{op}} =$	\$9,181 in 2019 dollars
Additional Ash Cost =	$\Delta \text{Ash} \times \text{Cost}_{\text{ash}} \times t_{\text{op}} \times (1/2000) =$	\$0 in 2019 dollars
Direct Annual Cost =		\$139,108 in 2019 dollars

Indirect Annual Cost (IDAC)

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

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

Cost Effectiveness

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

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 SO₂ emission rate:

Not Applicable ▼

Ash content (%Ash):

percent by weight

Not applicable to units burning 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-11 - 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})

365 days

Plant Elevation

180 Feet above sea level

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

0.168 lb/MMBtu

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

0.092 lb/MMBtu

Estimated Normalized Stoichiometric Ratio (NSR)

2.77

*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/ft³Concentration 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/ft³29.4% aqueous NH_3 56 lbs/ft³

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

CEPCI = Chemical Engineering Plant Cost Index

Annual Interest Rate (i)

4.75 Percent

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

5.00 \$/MMBtu

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

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

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

0.0042 \$/gallon*

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

0.0676 \$/kWh*

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

\$/ton

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

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

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =

0.015

Administrative Charges Factor (ACF) =

0.03

Table A-11 - 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) =	$(Q_B \times 1.0E6 \text{ Btu/MMBtu} \times 8760)/\text{HHV} =$	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}) =	$(\text{Mactual}/\text{Mfuel}) \times (\text{tSNCR}/365) =$	1.00	fraction	
Total operating time for the SNCR (t_{op}) =	$CF_{\text{total}} \times 8760 =$	8760	hours	
NOx Removal Efficiency (EF) =	$(\text{NO}_{x_{\text{in}}} - \text{NO}_{x_{\text{out}}})/\text{NO}_{x_{\text{in}}} =$	45	percent	
NOx removed per hour =	$\text{NO}_{x_{\text{in}}} \times \text{EF} \times Q_B =$	22.44	lb/hour	
Total NO _x removed per year =	$(\text{NO}_{x_{\text{in}}} \times \text{EF} \times Q_B \times t_{\text{op}})/2000 =$	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 =	$(\%S/100) \times (64/32) \times (1 \times 10^6)/\text{HHV} =$			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEV _F) =	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) =	$2116 \times [(59 - (0.00356 \times h)) + 459.7]/518.6]^{5.256} \times (1/144)^* =$	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>.

Reagent Data:

Type of reagent used

Urea

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

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NOx}_{\text{in}} \times Q_{\text{B}} \times \text{NSR} \times \text{MW}_{\text{R}}) / (\text{MW}_{\text{NOx}} \times \text{SR}) =$ (whre SR = 1 for NH_3 ; 2 for Urea)	90	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}} / C_{\text{sol}} =$	181	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density} =$	19.0	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24 \text{ hours/day}) / \text{Reagent Density} =$	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) =	$(0.47 \times \text{NOx}_{\text{in}} \times \text{NSR} \times Q_{\text{B}}) / \text{NPHR} =$	7.9	kW/hour
Water Usage: Water consumption (q_{w}) =	$(m_{\text{sol}} / \text{Density of water}) \times ((C_{\text{stored}} / C_{\text{inj}}) - 1) =$	87	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$H_v \times m_{\text{reagent}} \times ((1/C_{\text{inj}}) - 1) =$	0.73	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta \text{fuel} \times \% \text{Ash} \times 1 \times 10^6) / \text{HHV} =$	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
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Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

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

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

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

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

Total Annual Cost (TAC)

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

Direct Annual Costs (DAC) =	\$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)

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

Annual Maintenance Cost =	$0.015 \times \text{TCI} =$	\$53,188 in 2019 dollars
Annual Reagent Cost =	$q_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$276,602 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$4,694 in 2019 dollars
Annual Water Cost =	$q_{\text{water}} \times \text{Cost}_{\text{water}} \times t_{\text{op}} =$	\$3,161 in 2019 dollars
Additional Fuel Cost =	$\Delta \text{Fuel} \times \text{Cost}_{\text{fuel}} \times t_{\text{op}} =$	\$32,026 in 2019 dollars
Additional Ash Cost =	$\Delta \text{Ash} \times \text{Cost}_{\text{ash}} \times t_{\text{op}} \times (1/2000) =$	\$0 in 2019 dollars
Direct Annual Cost =		\$369,671 in 2019 dollars

Indirect Annual Cost (IDAC)

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

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

Cost Effectiveness

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

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 SO₂ emission rate:

Not Applicable ▼

Ash content (%Ash):

percent by weight

Not applicable to units burning 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

Plant Elevation

180 Feet above sea level

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

0.280 lb/MMBtu

Outlet NO_x Emissions ($\text{NO}_{x,\text{out}}$) 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).

Concentration of reagent as stored (C_{stored})

50 Percent

Density of reagent as stored (ρ_{stored})71 lb/ft³Concentration 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/ft³29.4% aqueous NH_3 56 lbs/ft³

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

CEPCI = Chemical Engineering Plant Cost Index

Annual Interest Rate (i)

4.75 Percent

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

5.00 \$/MMBtu

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

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

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

0.0042 \$/gallon*

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

0.0676 \$/kWh*

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

\$/ton

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

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

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =

0.015

Administrative Charges Factor (ACF) =

0.03

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) =	$(Q_B \times 1.0E6 \text{ Btu/MMBtu} \times 8760) / \text{HHV} =$	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}) =	$(\text{Mactual} / \text{Mfuel}) \times (\text{tSNCR} / 365) =$	0.57	fraction	
Total operating time for the SNCR (t_{op}) =	$CF_{\text{total}} \times 8760 =$	8572	hours	
NOx Removal Efficiency (EF) =	$(\text{NO}_{x_{\text{in}}} - \text{NO}_{x_{\text{out}}}) / \text{NO}_{x_{\text{in}}} =$	45	percent	
NOx removed per hour =	$\text{NO}_{x_{\text{in}}} \times \text{EF} \times Q_B =$	37.37	lb/hour	
Total NO _x removed per year =	$(\text{NO}_{x_{\text{in}}} \times \text{EF} \times Q_B \times t_{\text{op}}) / 2000 =$	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 =	$(\%S/100) \times (64/32) \times (1 \times 10^6) / \text{HHV} =$			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEV _F) =	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) =	$2116 \times [(59 - (0.00356 \times h)) + 459.7] / 518.6^{5.256} \times (1/144)^* =$	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>.

Reagent Data:

Type of reagent used

Urea

Molecular Weight of Reagent (MW) =

60.06 g/mole

Density =

71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NOx}_{\text{in}} \times Q_{\text{B}} \times \text{NSR} \times \text{MW}_{\text{R}}) / (\text{MW}_{\text{NOx}} \times \text{SR}) =$ (whre SR = 1 for NH_3 ; 2 for Urea)	110	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}} / C_{\text{sol}} =$	220	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density} =$	23.1	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24 \text{ hours/day}) / \text{Reagent Density} =$	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) =	$(0.47 \times \text{NOx}_{\text{in}} \times \text{NSR} \times Q_{\text{B}}) / \text{NPHR} =$	9.6	kW/hour
Water Usage: Water consumption (q_{w}) =	$(m_{\text{sol}} / \text{Density of water}) \times ((C_{\text{stored}} / C_{\text{inj}}) - 1) =$	105	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$H_v \times m_{\text{reagent}} \times ((1/C_{\text{inj}}) - 1) =$	0.89	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta \text{fuel} \times \% \text{Ash} \times 1 \times 10^6) / \text{HHV} =$	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
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Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

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

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

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

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

Total Annual Cost (TAC)

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

Direct Annual Costs (DAC) =	\$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)

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

Annual Maintenance Cost =	$0.015 \times \text{TCI} =$	\$55,281 in 2019 dollars
Annual Reagent Cost =	$q_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$329,080 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$5,585 in 2019 dollars
Annual Water Cost =	$q_{\text{water}} \times \text{Cost}_{\text{water}} \times t_{\text{op}} =$	\$3,761 in 2019 dollars
Additional Fuel Cost =	$\Delta \text{Fuel} \times \text{Cost}_{\text{fuel}} \times t_{\text{op}} =$	\$38,102 in 2019 dollars
Additional Ash Cost =	$\Delta \text{Ash} \times \text{Cost}_{\text{ash}} \times t_{\text{op}} \times (1/2000) =$	\$0 in 2019 dollars
Direct Annual Cost =		\$431,809 in 2019 dollars

Indirect Annual Cost (IDAC)

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

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

Cost Effectiveness

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

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 SO₂ emission rate:

Not Applicable ▼

Ash content (%Ash):

percent by weight

Not applicable to units burning 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

Plant Elevation

180 Feet above sea level

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

0.271 lb/MMBtu

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

0.149 lb/MMBtu

Estimated Normalized Stoichiometric Ratio (NSR)

2.06

*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/ft³Concentration 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/ft³29.4% aqueous NH_3 56 lbs/ft³

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

CEPCI = Chemical Engineering Plant Cost Index

Annual Interest Rate (i)

4.75 Percent

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

5.00 \$/MMBtu

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

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

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

0.0042 \$/gallon*

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

0.0676 \$/kWh*

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

\$/ton

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

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

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =

0.015

Administrative Charges Factor (ACF) =

0.03

Table A-12 - 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) =	$(Q_B \times 1.0E6 \text{ Btu/MMBtu} \times 8760)/\text{HHV} =$	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}) =	$(\text{Mactual}/\text{Mfuel}) \times (\text{tSNCR}/365) =$	1.00	fraction	
Total operating time for the SNCR (t_{op}) =	$CF_{\text{total}} \times 8760 =$	8760	hours	
NOx Removal Efficiency (EF) =	$(\text{NO}_{x_{\text{in}}} - \text{NO}_{x_{\text{out}}})/\text{NO}_{x_{\text{in}}} =$	45	percent	
NOx removed per hour =	$\text{NO}_{x_{\text{in}}} \times \text{EF} \times Q_B =$	22.87	lb/hour	
Total NO _x removed per year =	$(\text{NO}_{x_{\text{in}}} \times \text{EF} \times Q_B \times t_{\text{op}})/2000 =$	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 =	$(\%S/100) \times (64/32) \times (1 \times 10^6)/\text{HHV} =$			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEV _F) =	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) =	$2116 \times [(59 - (0.00356 \times h)) + 459.7]/518.6]^{5.256} \times (1/144)^* =$	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>.

Reagent Data:

Type of reagent used

Urea

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

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NOx}_{\text{in}} \times Q_{\text{B}} \times \text{NSR} \times \text{MW}_{\text{R}}) / (\text{MW}_{\text{NOx}} \times \text{SR}) =$ (whre SR = 1 for NH_3 ; 2 for Urea)	68	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}} / C_{\text{sol}} =$	137	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density} =$	14.4	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24 \text{ hours/day}) / \text{Reagent Density} =$	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) =	$(0.47 \times \text{NOx}_{\text{in}} \times \text{NSR} \times Q_{\text{B}}) / \text{NPHR} =$	6.0	kW/hour
Water Usage: Water consumption (q_{w}) =	$(m_{\text{sol}} / \text{Density of water}) \times ((C_{\text{stored}} / C_{\text{inj}}) - 1) =$	66	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$H_v \times m_{\text{reagent}} \times ((1/C_{\text{inj}}) - 1) =$	0.55	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta \text{fuel} \times \% \text{Ash} \times 1 \times 10^6) / \text{HHV} =$	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
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Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

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

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

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

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

Total Annual Cost (TAC)

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

Direct Annual Costs (DAC) =	\$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)

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

Annual Maintenance Cost =	$0.015 \times \text{TCI} =$	\$45,087 in 2019 dollars
Annual Reagent Cost =	$q_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$209,600 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$3,557 in 2019 dollars
Annual Water Cost =	$q_{\text{water}} \times \text{Cost}_{\text{water}} \times t_{\text{op}} =$	\$2,395 in 2019 dollars
Additional Fuel Cost =	$\Delta \text{Fuel} \times \text{Cost}_{\text{fuel}} \times t_{\text{op}} =$	\$24,268 in 2019 dollars
Additional Ash Cost =	$\Delta \text{Ash} \times \text{Cost}_{\text{ash}} \times t_{\text{op}} \times (1/2000) =$	\$0 in 2019 dollars
Direct Annual Cost =		\$284,908 in 2019 dollars

Indirect Annual Cost (IDAC)

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

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

Cost Effectiveness

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

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 SO₂ emission rate:

Not Applicable ▼

Ash content (%Ash):

percent by weight

Not applicable to units burning 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

Plant Elevation

180 Feet above sea level

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

0.280 lb/MMBtu

Outlet NO_x Emissions ($\text{NO}_{x,\text{out}}$) 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).

Concentration of reagent as stored (C_{stored})

50 Percent

Density of reagent as stored (ρ_{stored})71 lb/ft³Concentration 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/ft³29.4% aqueous NH_3 56 lbs/ft³

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

CEPCI = Chemical Engineering Plant Cost Index

Annual Interest Rate (i)

4.75 Percent

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

5.00 \$/MMBtu

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

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

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

0.0042 \$/gallon*

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

0.0676 \$/kWh*

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

\$/ton

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

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

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =

0.015

Administrative Charges Factor (ACF) =

0.03

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) =	$(Q_B \times 1.0E6 \text{ Btu/MMBtu} \times 8760)/\text{HHV} =$	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}) =	$(\text{Mactual}/\text{Mfuel}) \times (\text{tSNCR}/365) =$	0.64	fraction	
Total operating time for the SNCR (t_{op}) =	$CF_{\text{total}} \times 8760 =$	8540	hours	Based on 2017 Operating Hours
NOx Removal Efficiency (EF) =	$(\text{NO}_{x_{\text{in}}} - \text{NO}_{x_{\text{out}}})/\text{NO}_{x_{\text{in}}} =$	45	percent	
NOx removed per hour =	$\text{NO}_{x_{\text{in}}} \times \text{EF} \times Q_B =$	23.62	lb/hour	
Total NO _x removed per year =	$(\text{NO}_{x_{\text{in}}} \times \text{EF} \times Q_B \times t_{\text{op}})/2000 =$	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 =	$(\%S/100) \times (64/32) \times (1 \times 10^6)/\text{HHV} =$			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEV _F) =	14.7 psia/P =			Not applicable; elevation factor does not
Atmospheric pressure at 180 feet above sea level (P) =	$2116 \times [(59 - (0.00356 \times h)) + 459.7]/518.6^{5.256} \times (1/144)^* =$	14.6	psia	apply to plants located at elevations below 500 feet.
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

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

Reagent Data:

Type of reagent used

Urea

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

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NOx}_{\text{in}} \times Q_{\text{B}} \times \text{NSR} \times \text{MW}_{\text{R}}) / (\text{MW}_{\text{NOx}} \times \text{SR}) =$ (whre SR = 1 for NH_3 ; 2 for Urea)	69	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}} / C_{\text{sol}} =$	139	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density} =$	14.6	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24 \text{ hours/day}) / \text{Reagent Density} =$	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) =	$(0.47 \times \text{NOx}_{\text{in}} \times \text{NSR} \times Q_{\text{B}}) / \text{NPHR} =$	6.1	kW/hour
Water Usage: Water consumption (q_{w}) =	$(m_{\text{sol}} / \text{Density of water}) \times ((C_{\text{stored}} / C_{\text{inj}}) - 1) =$	67	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$H_v \times m_{\text{reagent}} \times ((1/C_{\text{inj}}) - 1) =$	0.56	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta \text{fuel} \times \% \text{Ash} \times 1 \times 10^6) / \text{HHV} =$	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
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Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

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

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

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

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

Total Annual Cost (TAC)

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

Direct Annual Costs (DAC) =	\$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)

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

Annual Maintenance Cost =	$0.015 \times \text{TCI} =$	\$45,198 in 2019 dollars
Annual Reagent Cost =	$q_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$207,257 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$3,517 in 2019 dollars
Annual Water Cost =	$q_{\text{water}} \times \text{Cost}_{\text{water}} \times t_{\text{op}} =$	\$2,369 in 2019 dollars
Additional Fuel Cost =	$\Delta \text{Fuel} \times \text{Cost}_{\text{fuel}} \times t_{\text{op}} =$	\$23,997 in 2019 dollars
Additional Ash Cost =	$\Delta \text{Ash} \times \text{Cost}_{\text{ash}} \times t_{\text{op}} \times (1/2000) =$	\$0 in 2019 dollars
Direct Annual Cost =		\$282,338 in 2019 dollars

Indirect Annual Cost (IDAC)

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

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

Cost Effectiveness

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

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 SO₂ emission rate:

Not Applicable ▼

Ash content (%Ash):

percent by weight

Not applicable to units burning 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

Plant Elevation

180 Feet above sea level

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

0.160 lb/MMBtu

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

0.088 lb/MMBtu

Estimated Normalized Stoichiometric Ratio (NSR)

2.87

*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/ft³Concentration 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/ft³29.4% aqueous NH_3 56 lbs/ft³

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

CEPCI = Chemical Engineering Plant Cost Index

Annual Interest Rate (i)

4.75 Percent

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

5.00 \$/MMBtu

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

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

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

0.0042 \$/gallon*

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

0.0676 \$/kWh*

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

\$/ton

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

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

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =

0.015

Administrative Charges Factor (ACF) =

0.03

Table A-13 - 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) =	$(Q_B \times 1.0E6 \text{ Btu/MMBtu} \times 8760)/\text{HHV} =$	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}) =	$(\text{Mactual}/\text{Mfuel}) \times (\text{tSNCR}/365) =$	0.98	fraction	
Total operating time for the SNCR (t_{op}) =	$CF_{\text{total}} \times 8760 =$	8760	hours	Based on 8760 (PTE)
NOx Removal Efficiency (EF) =	$(\text{NO}_{x_{\text{in}}} - \text{NO}_{x_{\text{out}}})/\text{NO}_{x_{\text{in}}} =$	45	percent	
NOx removed per hour =	$\text{NO}_{x_{\text{in}}} \times \text{EF} \times Q_B =$	11.23	lb/hour	
Total NO _x removed per year =	$(\text{NO}_{x_{\text{in}}} \times \text{EF} \times Q_B \times t_{\text{op}})/2000 =$	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 =	$(\%S/100) \times (64/32) \times (1 \times 10^6)/\text{HHV} =$			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEV _F) =	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) =	$2116 \times [(59 - (0.00356 \times h)) + 459.7]/518.6]^{5.256} \times (1/144)^* =$	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>.

Reagent Data:

Type of reagent used

Urea

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

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NOx}_{\text{in}} \times Q_{\text{B}} \times \text{NSR} \times \text{MW}_{\text{R}}) / (\text{MW}_{\text{NOx}} \times \text{SR}) =$ (whre SR = 1 for NH_3 ; 2 for Urea)	47	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}} / C_{\text{sol}} =$	94	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density} =$	9.9	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24 \text{ hours/day}) / \text{Reagent Density} =$	3,400	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) =	$(0.47 \times \text{NOx}_{\text{in}} \times \text{NSR} \times Q_{\text{B}}) / \text{NPHR} =$	4.1	kW/hour
Water Usage: Water consumption (q_{w}) =	$(m_{\text{sol}} / \text{Density of water}) \times ((C_{\text{stored}} / C_{\text{inj}}) - 1) =$	45	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$H_v \times m_{\text{reagent}} \times ((1/C_{\text{inj}}) - 1) =$	0.38	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta \text{fuel} \times \% \text{Ash} \times 1 \times 10^6) / \text{HHV} =$	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
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Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

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

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

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

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

Total Annual Cost (TAC)

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

Direct Annual Costs (DAC) =	\$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)

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

Annual Maintenance Cost =	$0.015 \times \text{TCI} =$	\$40,006 in 2019 dollars
Annual Reagent Cost =	$q_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$143,403 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$2,434 in 2019 dollars
Annual Water Cost =	$q_{\text{water}} \times \text{Cost}_{\text{water}} \times t_{\text{op}} =$	\$1,639 in 2019 dollars
Additional Fuel Cost =	$\Delta \text{Fuel} \times \text{Cost}_{\text{fuel}} \times t_{\text{op}} =$	\$16,604 in 2019 dollars
Additional Ash Cost =	$\Delta \text{Ash} \times \text{Cost}_{\text{ash}} \times t_{\text{op}} \times (1/2000) =$	\$0 in 2019 dollars
Direct Annual Cost =		\$204,085 in 2019 dollars

Indirect Annual Cost (IDAC)

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

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

Cost Effectiveness

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

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 SO₂ emission rate:

Not Applicable ▼

Ash content (%Ash):

percent by weight

Not applicable to units burning 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

Plant Elevation

180 Feet above sea level

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

0.164 lb/MMBtu

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

0.090 lb/MMBtu

Estimated Normalized Stoichiometric Ratio (NSR)

2.82

*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/ft³Concentration 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/ft³29.4% aqueous NH_3 56 lbs/ft³

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

CEPCI = Chemical Engineering Plant Cost Index

Annual Interest Rate (i)

4.75 Percent

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

5.00 \$/MMBtu

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

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

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

0.0042 \$/gallon*

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

0.0676 \$/kWh*

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

\$/ton

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

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

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =

0.015

Administrative Charges Factor (ACF) =

0.03

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) =	$(Q_B \times 1.0E6 \text{ Btu/MMBtu} \times 8760)/\text{HHV} =$	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}) =	$(\text{Mactual}/\text{Mfuel}) \times (\text{tSNCR}/365) =$	0.66	fraction	
Total operating time for the SNCR (t_{op}) =	$CF_{\text{total}} \times 8760 =$	8531	hours	Based on 2017 Operating Hours
NOx Removal Efficiency (EF) =	$(\text{NOx}_{\text{in}} - \text{NOx}_{\text{out}})/\text{NOx}_{\text{in}} =$	45	percent	
NOx removed per hour =	$\text{NOx}_{\text{in}} \times \text{EF} \times Q_B =$	11.55	lb/hour	
Total NO _x removed per year =	$(\text{NOx}_{\text{in}} \times \text{EF} \times Q_B \times t_{\text{op}})/2000 =$	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 =	$(\%S/100) \times (64/32) \times (1 \times 10^6)/\text{HHV} =$			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEV _F) =	14.7 psia/P =			Not applicable; elevation factor does not
Atmospheric pressure at 180 feet above sea level (P) =	$2116 \times [(59 - (0.00356 \times h)) + 459.7]/518.6^{5.256} \times (1/144)^* =$	14.6	psia	apply to plants located at elevations below 500 feet.
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

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

Reagent Data:

Type of reagent used

Urea

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

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NOx}_{\text{in}} \times Q_{\text{B}} \times \text{NSR} \times \text{MW}_{\text{R}}) / (\text{MW}_{\text{NOx}} \times \text{SR}) =$ (whre SR = 1 for NH_3 ; 2 for Urea)	47	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}} / C_{\text{sol}} =$	94	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density} =$	9.9	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24 \text{ hours/day}) / \text{Reagent Density} =$	3,400	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) =	$(0.47 \times \text{NOx}_{\text{in}} \times \text{NSR} \times Q_{\text{B}}) / \text{NPHR} =$	4.1	kW/hour
Water Usage: Water consumption (q_{w}) =	$(m_{\text{sol}} / \text{Density of water}) \times ((C_{\text{stored}} / C_{\text{inj}}) - 1) =$	45	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$H_v \times m_{\text{reagent}} \times ((1/C_{\text{inj}}) - 1) =$	0.38	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta \text{fuel} \times \% \text{Ash} \times 1 \times 10^6) / \text{HHV} =$	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
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Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

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

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

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

Balance of Plant Costs (BOP_{cost}) =	\$1,271,195 in 2019 dollars
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Annual Costs

Total Annual Cost (TAC)

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

Direct Annual Costs (DAC) =	\$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)

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

Annual Maintenance Cost =	$0.015 \times \text{TCI} =$	\$40,088 in 2019 dollars
Annual Reagent Cost =	$q_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$140,877 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$2,391 in 2019 dollars
Annual Water Cost =	$q_{\text{water}} \times \text{Cost}_{\text{water}} \times t_{\text{op}} =$	\$1,610 in 2019 dollars
Additional Fuel Cost =	$\Delta \text{Fuel} \times \text{Cost}_{\text{fuel}} \times t_{\text{op}} =$	\$16,311 in 2019 dollars
Additional Ash Cost =	$\Delta \text{Ash} \times \text{Cost}_{\text{ash}} \times t_{\text{op}} \times (1/2000) =$	\$0 in 2019 dollars
Direct Annual Cost =		\$201,277 in 2019 dollars

Indirect Annual Cost (IDAC)

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

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

Cost Effectiveness

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

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 SO₂ emission rate:

Not Applicable ▼

Ash content (%Ash):

percent by weight

Not applicable to units burning 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 ($\text{NO}_{x,\text{in}}$) to SNCR

0.058 lb/MMBtu

Outlet NO_x Emissions ($\text{NO}_{x,\text{out}}$) 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).

Concentration of reagent as stored (C_{stored})

50 Percent

Density of reagent as stored (ρ_{stored})71 lb/ft³Concentration of reagent injected (C_{inj})

10 percent

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

14 days

Estimated equipment life

20 Years

Plant Elevation

180 Feet above sea level

Select the reagent used

Urea

Densities of typical SNCR reagents:

50% urea solution

71 lbs/ft³29.4% aqueous NH_3 56 lbs/ft³

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

CEPCI = Chemical Engineering Plant Cost Index

Annual Interest Rate (i)

4.75 Percent

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

5.00 \$/MMBtu

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

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

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

0.0042 \$/gallon*

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

0.0676 \$/kWh*

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

\$/ton

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

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

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =

0.015

Administrative Charges Factor (ACF) =

0.03

Table A-14 - 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) =	$(Q_B \times 1.0E6 \text{ Btu/MMBtu} \times 8760)/\text{HHV} =$	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}) =	$(\text{Mactual}/\text{Mfuel}) \times (\text{tSNCR}/365) =$	1.00	fraction	
Total operating time for the SNCR (t_{op}) =	$CF_{\text{total}} \times 8760 =$	8760	hours	
NOx Removal Efficiency (EF) =	$(\text{NO}_{x_{\text{in}}} - \text{NO}_{x_{\text{out}}})/\text{NO}_{x_{\text{in}}} =$	45	percent	
NOx removed per hour =	$\text{NO}_{x_{\text{in}}} \times \text{EF} \times Q_B =$	9.19	lb/hour	
Total NO _x removed per year =	$(\text{NO}_{x_{\text{in}}} \times \text{EF} \times Q_B \times t_{\text{op}})/2000 =$	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 =	$(\%S/100) \times (64/32) \times (1 \times 10^6)/\text{HHV} =$			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEV _F) =	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) =	$2116 \times [(59 - (0.00356 \times h)) + 459.7]/518.6]^{5.256} \times (1/144)^* =$	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>.

Reagent Data:

Type of reagent used

Urea

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

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NOx}_{\text{in}} \times Q_{\text{B}} \times \text{NSR} \times \text{MW}_{\text{R}}) / (\text{MW}_{\text{NOx}} \times \text{SR}) =$ (whre SR = 1 for NH_3 ; 2 for Urea)	84	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}} / C_{\text{sol}} =$	169	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density} =$	17.8	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24 \text{ hours/day}) / \text{Reagent Density} =$	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) =	$(0.47 \times \text{NOx}_{\text{in}} \times \text{NSR} \times Q_{\text{B}}) / \text{NPHR} =$	7.4	kW/hour
Water Usage: Water consumption (q_{w}) =	$(m_{\text{sol}} / \text{Density of water}) \times ((C_{\text{stored}} / C_{\text{inj}}) - 1) =$	81	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$H_v \times m_{\text{reagent}} \times ((1/C_{\text{inj}}) - 1) =$	0.68	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta \text{fuel} \times \% \text{Ash} \times 1 \times 10^6) / \text{HHV} =$	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
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Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

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

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

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

Balance of Plant Costs (BOP_{cost}) =	\$1,617,156 in 2019 dollars
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Annual Costs

Total Annual Cost (TAC)

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

Direct Annual Costs (DAC) =	\$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)

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

Annual Maintenance Cost =	$0.015 \times \text{TCI} =$	\$53,057 in 2019 dollars
Annual Reagent Cost =	$q_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$258,648 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$4,390 in 2019 dollars
Annual Water Cost =	$q_{\text{water}} \times \text{Cost}_{\text{water}} \times t_{\text{op}} =$	\$2,956 in 2019 dollars
Additional Fuel Cost =	$\Delta \text{Fuel} \times \text{Cost}_{\text{fuel}} \times t_{\text{op}} =$	\$29,947 in 2019 dollars
Additional Ash Cost =	$\Delta \text{Ash} \times \text{Cost}_{\text{ash}} \times t_{\text{op}} \times (1/2000) =$	\$0 in 2019 dollars
Direct Annual Cost =		\$348,997 in 2019 dollars

Indirect Annual Cost (IDAC)

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

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

Cost Effectiveness

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

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 SO₂ emission rate:

Not Applicable ▼

Ash content (%Ash):

percent by weight

Not applicable to units burning 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

Plant Elevation

180 Feet above sea level

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

0.045 lb/MMBtu

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

0.025 lb/MMBtu

Estimated Normalized Stoichiometric Ratio (NSR)

7.90

*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/ft³Concentration 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/ft³29.4% aqueous NH_3 56 lbs/ft³

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

CEPCI = Chemical Engineering Plant Cost Index

Annual Interest Rate (i)

4.75 Percent

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

5.00 \$/MMBtu

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

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

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

0.0042 \$/gallon*

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

0.0676 \$/kWh*

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

\$/ton

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

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

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =

0.015

Administrative Charges Factor (ACF) =

0.03

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) =	$(Q_B \times 1.0E6 \text{ Btu/MMBtu} \times 8760)/\text{HHV} =$	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}) =	$(\text{Mactual}/\text{Mfuel}) \times (\text{tSNCR}/365) =$	0.54	fraction	
Total operating time for the SNCR (t_{op}) =	$CF_{\text{total}} \times 8760 =$	8586	hours	Based on 2017 Operating Hours
NOx Removal Efficiency (EF) =	$(\text{NOx}_{\text{in}} - \text{NOx}_{\text{out}})/\text{NOx}_{\text{in}} =$	45	percent	
NOx removed per hour =	$\text{NOx}_{\text{in}} \times \text{EF} \times Q_B =$	7.13	lb/hour	
Total NO _x removed per year =	$(\text{NOx}_{\text{in}} \times \text{EF} \times Q_B \times t_{\text{op}})/2000 =$	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 =	$(\%S/100) \times (64/32) \times (1 \times 10^6)/\text{HHV} =$			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEV _F) =	14.7 psia/P =			Not applicable; elevation factor does not
Atmospheric pressure at 180 feet above sea level (P) =	$2116 \times [(59 - (0.00356 \times h)) + 459.7]/518.6]^{5.256} \times (1/144)^* =$	14.6	psia	apply to plants located at elevations below 500 feet.
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

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

Reagent Data:

Type of reagent used

Urea

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

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NOx}_{\text{in}} \times Q_{\text{B}} \times \text{NSR} \times \text{MW}_{\text{R}}) / (\text{MW}_{\text{NOx}} \times \text{SR}) =$ (whre SR = 1 for NH_3 ; 2 for Urea)	82	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}} / C_{\text{sol}} =$	163	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density} =$	17.2	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24 \text{ hours/day}) / \text{Reagent Density} =$	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) =	$(0.47 \times \text{NOx}_{\text{in}} \times \text{NSR} \times Q_{\text{B}}) / \text{NPHR} =$	7.2	kW/hour
Water Usage: Water consumption (q_{w}) =	$(m_{\text{sol}} / \text{Density of water}) \times ((C_{\text{stored}} / C_{\text{inj}}) - 1) =$	78	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$H_v \times m_{\text{reagent}} \times ((1/C_{\text{inj}}) - 1) =$	0.66	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta \text{fuel} \times \% \text{Ash} \times 1 \times 10^6) / \text{HHV} =$	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
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Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

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

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

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

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

Total Annual Cost (TAC)

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

Direct Annual Costs (DAC) =	\$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)

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

Annual Maintenance Cost =	$0.015 \times \text{TCI} =$	\$52,111 in 2019 dollars
Annual Reagent Cost =	$q_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$245,419 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$4,165 in 2019 dollars
Annual Water Cost =	$q_{\text{water}} \times \text{Cost}_{\text{water}} \times t_{\text{op}} =$	\$2,805 in 2019 dollars
Additional Fuel Cost =	$\Delta \text{Fuel} \times \text{Cost}_{\text{fuel}} \times t_{\text{op}} =$	\$28,415 in 2019 dollars
Additional Ash Cost =	$\Delta \text{Ash} \times \text{Cost}_{\text{ash}} \times t_{\text{op}} \times (1/2000) =$	\$0 in 2019 dollars
Direct Annual Cost =		\$332,915 in 2019 dollars

Indirect Annual Cost (IDAC)

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

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

Cost Effectiveness

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

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 SO₂ emission rate:

Not Applicable ▼

Ash content (%Ash):

percent by weight

Not applicable to units burning 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-15 - SNCR for GP Wauna Power Boiler

Enter the following design parameters for the proposed SNCR:

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

365 days

Plant Elevation

20 Feet above sea level

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

0.341 lb/MMBtu

Outlet NO_x Emissions ($\text{NO}_{x,\text{out}}$) 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/ft³Concentration 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/ft³29.4% aqueous NH_3 56 lbs/ft³

Select the reagent used

Ammonia

(The Wauna FBB uses ammonia in its SNCR system)

Enter the cost data for the proposed SNCR:

Desired dollar-year

2019

CEPCI for 2019

607.5 Enter the CEPCI value for 2019

541.7

2016 CEPCI

CEPCI = Chemical Engineering Plant Cost Index

Annual Interest Rate (i)

4.75 Percent

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

5.00 \$/MMBtu

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

3.53 \$/gallon for a 29 percent solution of ammonia

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

0.0042 \$/gallon*

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

0.0676 \$/kWh*

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

\$/ton

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

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

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =

0.015

Administrative Charges Factor (ACF) =

0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost (\$/gallon)	\$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. $0.47/\text{lb} * 56 \text{ lb}/\text{ft}^3 * 0.134 \text{ ft}^3/\text{gal} = \$3.53/\text{gal}$
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) =	$(Q_B \times 1.0E6 \text{ Btu/MMBtu} \times 8760)/\text{HHV} =$	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}) =	$(\text{Mactual}/\text{Mfuel}) \times (\text{tSNCR}/365) =$	0.72	fraction	
Total operating time for the SNCR (t_{op}) =	$CF_{\text{total}} \times 8760 =$	8760	hours	Based on 8760 (PTE)
NOx Removal Efficiency (EF) =	$(\text{NO}_{x_{\text{in}}} - \text{NO}_{x_{\text{out}}})/\text{NO}_{x_{\text{in}}} =$	45	percent	
NOx removed per hour =	$\text{NO}_{x_{\text{in}}} \times \text{EF} \times Q_B =$	85.83	lb/hour	
Total NO _x removed per year =	$(\text{NO}_{x_{\text{in}}} \times \text{EF} \times Q_B \times t_{\text{op}})/2000 =$	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 =	$(\%S/100) \times (64/32) \times (1 \times 10^6)/\text{HHV} =$			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEV _F) =	14.7 psia/P =			Not applicable; elevation factor does not
Atmospheric pressure at 20 feet above sea level (P) =	$2116 \times [(59 - (0.00356 \times h)) + 459.7]/518.6^{5.256} \times (1/144)^* =$	14.7	psia	apply to plants located at elevations below 500 feet.
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}) =	$(\text{NOx}_{\text{in}} \times Q_{\text{B}} \times \text{NSR} \times \text{MW}_{\text{R}}) / (\text{MW}_{\text{NOx}} \times \text{SR}) =$ (whre SR = 1 for NH_3 ; 2 for Urea)	129	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}} / C_{\text{sol}} =$	444	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density} =$	59.3	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24 \text{ hours/day}) / \text{Reagent Density} =$	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) =	$(0.47 \times \text{NOx}_{\text{in}} \times \text{NSR} \times Q_{\text{B}}) / \text{NPHR} =$	19.9	kW/hour
Water Usage: Water consumption (q_{w}) =	$(m_{\text{sol}} / \text{Density of water}) \times ((C_{\text{stored}} / C_{\text{inj}}) - 1) =$	101	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$H_v \times m_{\text{reagent}} \times ((1/C_{\text{inj}}) - 1) =$	1.04	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta \text{fuel} \times \% \text{Ash} \times 1 \times 10^6) / \text{HHV} =$	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
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Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

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

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

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

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

Total Annual Cost (TAC)

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

Direct Annual Costs (DAC) =	\$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)

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

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

Indirect Annual Cost (IDAC)

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

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

Cost Effectiveness

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

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) =

or

Select the appropriate SO₂ emission rate:

Not Applicable

Ash content (%Ash):

percent by weight

Not applicable to units burning 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

Plant Elevation

20 Feet above sea level

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

0.465 lb/MMBtu

Outlet NO_x Emissions ($\text{NO}_{x,\text{out}}$) 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/ft³Concentration 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/ft³29.4% aqueous NH_3 56 lbs/ft³

Select the reagent used

Ammonia

(The Wauna FBB uses ammonia in its SNCR system)

Enter the cost data for the proposed SNCR:

Desired dollar-year

2019

CEPCI for 2019

607.5 Enter the CEPCI value for 2019

541.7

2016 CEPCI

CEPCI = Chemical Engineering Plant Cost Index

Annual Interest Rate (i)

4.75 Percent

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

5.00 \$/MMBtu

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

3.53 \$/gallon for a 29 percent solution of ammonia

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

0.0042 \$/gallon*

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

0.0676 \$/kWh*

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

\$/ton

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

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

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =

0.015

Administrative Charges Factor (ACF) =

0.03

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. $0.47/\text{lb} * 56 \text{ lb}/\text{ft}^3 * 0.134 \text{ ft}^3/\text{gal} = \$3.53/\text{gal}$
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) =	$(Q_B \times 1.0E6 \text{ Btu/MMBtu} \times 8760) / \text{HHV} =$	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}) =	$(\text{Mactual} / \text{Mfuel}) \times (\text{tSNCR} / 365) =$	0.12	fraction	
Total operating time for the SNCR (t_{op}) =	$CF_{\text{total}} \times 8760 =$	4392	hours	
NOx Removal Efficiency (EF) =	$(\text{NOx}_{\text{in}} - \text{NOx}_{\text{out}}) / \text{NOx}_{\text{in}} =$	45	percent	
NOx removed per hour =	$\text{NOx}_{\text{in}} \times \text{EF} \times Q_B =$	117.12	lb/hour	
Total NO _x removed per year =	$(\text{NOx}_{\text{in}} \times \text{EF} \times Q_B \times t_{\text{op}}) / 2000 =$	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 =	$(\%S/100) \times (64/32) \times (1 \times 10^6) / \text{HHV} =$			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEV _F) =	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) =	$2116 \times [(59 - (0.00356 \times h)) + 459.7] / 518.6^{5.256} \times (1/144)^* =$	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>.

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}) =	$(\text{NOx}_{\text{in}} \times Q_{\text{B}} \times \text{NSR} \times \text{MW}_{\text{R}}) / (\text{MW}_{\text{NOx}} \times \text{SR}) =$ (whre SR = 1 for NH_3 ; 2 for Urea)	152	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}} / C_{\text{sol}} =$	524	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density} =$	70.0	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24 \text{ hours/day}) / \text{Reagent Density} =$	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) =	$(0.47 \times \text{NOx}_{\text{in}} \times \text{NSR} \times Q_{\text{B}}) / \text{NPHR} =$	23.5	kW/hour
Water Usage: Water consumption (q_{w}) =	$(m_{\text{sol}} / \text{Density of water}) \times ((C_{\text{stored}} / C_{\text{inj}}) - 1) =$	119	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$H_v \times m_{\text{reagent}} \times ((1/C_{\text{inj}}) - 1) =$	1.23	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta \text{fuel} \times \% \text{Ash} \times 1 \times 10^6) / \text{HHV} =$	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
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Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

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

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

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

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

Total Annual Cost (TAC)

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

Direct Annual Costs (DAC) =	\$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)

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

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

Indirect Annual Cost (IDAC)

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

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

Cost Effectiveness

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

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 SO₂ emission rate:

Not Applicable ▼

Ash content (%Ash):

percent by weight

Not applicable to units burning 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

Plant Elevation

454 Feet above sea level

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

0.46 lb/MMBtu

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

0.253 lb/MMBtu

Estimated Normalized Stoichiometric Ratio (NSR)

1.58

*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/ft³Concentration 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/ft³29.4% aqueous NH_3 56 lbs/ft³

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

CEPCI = Chemical Engineering Plant Cost Index

Annual Interest Rate (i)

4.75 Percent

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

5.00 \$/MMBtu

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

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

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

0.0042 \$/gallon*

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

0.0676 \$/kWh*

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

\$/ton

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

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

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =

0.015

Administrative Charges Factor (ACF) =

0.03

Table A-16 - 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) =	$(Q_B \times 1.0E6 \text{ Btu/MMBtu} \times 8760) / \text{HHV} =$	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}) =	$(\text{Mactual} / \text{Mfuel}) \times (\text{tSNCR} / 365) =$	0.80	fraction	
Total operating time for the SNCR (t_{op}) =	$CF_{\text{total}} \times 8760 =$	8760	hours	
NOx Removal Efficiency (EF) =	$(\text{NO}_{x_{\text{in}}} - \text{NO}_{x_{\text{out}}}) / \text{NO}_{x_{\text{in}}} =$	45	percent	
NOx removed per hour =	$\text{NO}_{x_{\text{in}}} \times \text{EF} \times Q_B =$	89.77	lb/hour	
Total NO _x removed per year =	$(\text{NO}_{x_{\text{in}}} \times \text{EF} \times Q_B \times t_{\text{op}}) / 2000 =$	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 =	$(\%S/100) \times (64/32) \times (1 \times 10^6) / \text{HHV} =$			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEV _F) =	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) =	$2116 \times [(59 - (0.00356 \times h)) + 459.7] / 518.6^{5.256} \times (1/144)^* =$	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>.

Reagent Data:

Type of reagent used

Urea

Molecular Weight of Reagent (MW) =

60.06 g/mole

Density =

71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NOx}_{\text{in}} \times Q_{\text{B}} \times \text{NSR} \times \text{MW}_{\text{R}}) / (\text{MW}_{\text{NOx}} \times \text{SR}) =$ (whre SR = 1 for NH_3 ; 2 for Urea)	259	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}} / C_{\text{sol}} =$	518	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density} =$	54.5	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24 \text{ hours/day}) / \text{Reagent Density} =$	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) =	$(0.47 \times \text{NOx}_{\text{in}} \times \text{NSR} \times Q_{\text{B}}) / \text{NPHR} =$	22.7	kW/hour
Water Usage: Water consumption (q_{w}) =	$(m_{\text{sol}} / \text{Density of water}) \times ((C_{\text{stored}} / C_{\text{inj}}) - 1) =$	248	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$H_v \times m_{\text{reagent}} \times ((1/C_{\text{inj}}) - 1) =$	2.10	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta \text{fuel} \times \% \text{Ash} \times 1 \times 10^6) / \text{HHV} =$	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
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Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

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

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

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

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

Total Annual Cost (TAC)

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

Direct Annual Costs (DAC) =	\$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)

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

Annual Maintenance Cost =	$0.015 \times \text{TCI} =$	\$73,681 in 2019 dollars
Annual Reagent Cost =	$q_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$793,129 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$13,461 in 2019 dollars
Annual Water Cost =	$q_{\text{water}} \times \text{Cost}_{\text{water}} \times t_{\text{op}} =$	\$9,064 in 2019 dollars
Additional Fuel Cost =	$\Delta \text{Fuel} \times \text{Cost}_{\text{fuel}} \times t_{\text{op}} =$	\$91,831 in 2019 dollars
Additional Ash Cost =	$\Delta \text{Ash} \times \text{Cost}_{\text{ash}} \times t_{\text{op}} \times (1/2000) =$	\$0 in 2019 dollars
Direct Annual Cost =		\$981,166 in 2019 dollars

Indirect Annual Cost (IDAC)

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

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

Cost Effectiveness

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

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 SO₂ emission rate:

Not Applicable

Ash content (%Ash):

percent by weight

Not applicable to units burning 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

Plant Elevation

454 Feet above sea level

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

0.22 lb/MMBtu

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

0.121 lb/MMBtu

Estimated Normalized Stoichiometric Ratio (NSR)

2.33

*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).

Concentration of reagent as stored (C_{stored})

50 Percent

Density of reagent as stored (ρ_{stored})71 lb/ft³Concentration 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/ft³29.4% aqueous NH_3 56 lbs/ft³

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

CEPCI = Chemical Engineering Plant Cost Index

Annual Interest Rate (i)

4.75 Percent

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

5.00 \$/MMBtu

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

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

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

0.0042 \$/gallon*

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

0.0676 \$/kWh*

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

\$/ton

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

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

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =

0.015

Administrative Charges Factor (ACF) =

0.03

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) =	$(Q_B \times 1.0E6 \text{ Btu/MMBtu} \times 8760)/\text{HHV} =$	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}) =	$(\text{Mactual}/\text{Mfuel}) \times (\text{tSNCR}/365) =$	0.26	fraction	
Total operating time for the SNCR (t_{op}) =	$CF_{\text{total}} \times 8760 =$	8424	hours	Based on 2017 Operating Hours
NOx Removal Efficiency (EF) =	$(\text{NO}_{x_{\text{in}}} - \text{NO}_{x_{\text{out}}})/\text{NO}_{x_{\text{in}}} =$	45	percent	
NOx removed per hour =	$\text{NO}_{x_{\text{in}}} \times \text{EF} \times Q_B =$	14.42	lb/hour	
Total NO _x removed per year =	$(\text{NO}_{x_{\text{in}}} \times \text{EF} \times Q_B \times t_{\text{op}})/2000 =$	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 =	$(\%S/100) \times (64/32) \times (1 \times 10^6)/\text{HHV} =$			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEV _F) =	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) =	$2116 \times [(59 - (0.00356 \times h)) + 459.7]/518.6]^{5.256} \times (1/144)^* =$	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>.

Reagent Data:

Type of reagent used

Urea

Molecular Weight of Reagent (MW) =

60.06 g/mole

Density =

71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NOx}_{\text{in}} \times Q_{\text{B}} \times \text{NSR} \times \text{MW}_{\text{R}}) / (\text{MW}_{\text{NOx}} \times \text{SR}) =$ (whre SR = 1 for NH_3 ; 2 for Urea)	182	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}} / C_{\text{sol}} =$	364	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density} =$	38.4	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24 \text{ hours/day}) / \text{Reagent Density} =$	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) =	$(0.47 \times \text{NOx}_{\text{in}} \times \text{NSR} \times Q_{\text{B}}) / \text{NPHR} =$	16.0	kW/hour
Water Usage: Water consumption (q_{w}) =	$(m_{\text{sol}} / \text{Density of water}) \times ((C_{\text{stored}} / C_{\text{inj}}) - 1) =$	175	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$H_v \times m_{\text{reagent}} \times ((1/C_{\text{inj}}) - 1) =$	1.48	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta \text{fuel} \times \% \text{Ash} \times 1 \times 10^6) / \text{HHV} =$	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
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Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

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

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

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

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

Total Annual Cost (TAC)

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

Direct Annual Costs (DAC) =	\$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)

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

Annual Maintenance Cost =	$0.015 \times \text{TCI} =$	\$64,253 in 2019 dollars
Annual Reagent Cost =	$q_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$536,720 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$9,109 in 2019 dollars
Annual Water Cost =	$q_{\text{water}} \times \text{Cost}_{\text{water}} \times t_{\text{op}} =$	\$6,134 in 2019 dollars
Additional Fuel Cost =	$\Delta \text{Fuel} \times \text{Cost}_{\text{fuel}} \times t_{\text{op}} =$	\$62,143 in 2019 dollars
Additional Ash Cost =	$\Delta \text{Ash} \times \text{Cost}_{\text{ash}} \times t_{\text{op}} \times (1/2000) =$	\$0 in 2019 dollars
Direct Annual Cost =		\$678,359 in 2019 dollars

Indirect Annual Cost (IDAC)

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

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

Cost Effectiveness

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

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 SO₂ emission rate:

Not Applicable

Ash content (%Ash):

percent by weight

Not applicable to units burning 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-17 - SNCR for IP Springfield Package Boiler

Enter the following design parameters for the proposed SNCR:

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

365 days

Plant Elevation

454 Feet above sea level

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

0.2 lb/MMBtu

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

0.11 lb/MMBtu

Estimated Normalized Stoichiometric Ratio (NSR)

2.48

*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/ft³Concentration 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/ft³29.4% aqueous NH_3 56 lbs/ft³

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

CEPCI = Chemical Engineering Plant Cost Index

Annual Interest Rate (i)

4.75 Percent

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

5.00 \$/MMBtu

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

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

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

0.0042 \$/gallon*

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

0.0676 \$/kWh*

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

\$/ton

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

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

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =

0.015

Administrative Charges Factor (ACF) =

0.03

Table A-17 - 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) =	$(Q_B \times 1.0E6 \text{ Btu/MMBtu} \times 8760)/\text{HHV} =$	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}) =	$(\text{Mactual}/\text{Mfuel}) \times (\text{tSNCR}/365) =$	1.00	fraction	
Total operating time for the SNCR (t_{op}) =	$CF_{\text{total}} \times 8760 =$	8760	hours	Based on 8760 (PTE)
NOx Removal Efficiency (EF) =	$(\text{NOx}_{\text{in}} - \text{NOx}_{\text{out}})/\text{NOx}_{\text{in}} =$	45	percent	
NOx removed per hour =	$\text{NOx}_{\text{in}} \times \text{EF} \times Q_B =$	30.60	lb/hour	
Total NO _x removed per year =	$(\text{NOx}_{\text{in}} \times \text{EF} \times Q_B \times t_{\text{op}})/2000 =$	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 =	$(\%S/100) \times (64/32) \times (1 \times 10^6)/\text{HHV} =$			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEV _F) =	14.7 psia/P =			Not applicable; elevation factor does not
Atmospheric pressure at 454 feet above sea level (P) =	$2116 \times [(59 - (0.00356 \times h)) + 459.7]/518.6^{5.256} \times (1/144)^* =$	14.5	psia	apply to plants located at elevations below 500 feet.
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

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

Reagent Data:

Type of reagent used

Urea

Molecular Weight of Reagent (MW) =

60.06 g/mole

Density =

71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NOx}_{\text{in}} \times Q_{\text{B}} \times \text{NSR} \times \text{MW}_{\text{R}}) / (\text{MW}_{\text{NOx}} \times \text{SR}) =$ (whre SR = 1 for NH_3 ; 2 for Urea)	110	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}} / C_{\text{sol}} =$	220	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density} =$	23.1	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24 \text{ hours/day}) / \text{Reagent Density} =$	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) =	$(0.47 \times \text{NOx}_{\text{in}} \times \text{NSR} \times Q_{\text{B}}) / \text{NPHR} =$	9.6	kW/hour
Water Usage: Water consumption (q_{w}) =	$(m_{\text{sol}} / \text{Density of water}) \times ((C_{\text{stored}} / C_{\text{inj}}) - 1) =$	105	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$H_v \times m_{\text{reagent}} \times ((1/C_{\text{inj}}) - 1) =$	0.89	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta \text{fuel} \times \% \text{Ash} \times 1 \times 10^6) / \text{HHV} =$	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
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Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

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

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

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

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

Total Annual Cost (TAC)

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

Direct Annual Costs (DAC) =	\$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)

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

Annual Maintenance Cost =	$0.015 \times \text{TCI} =$	\$57,214 in 2019 dollars
Annual Reagent Cost =	$q_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$336,590 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$5,712 in 2019 dollars
Annual Water Cost =	$q_{\text{water}} \times \text{Cost}_{\text{water}} \times t_{\text{op}} =$	\$3,847 in 2019 dollars
Additional Fuel Cost =	$\Delta \text{Fuel} \times \text{Cost}_{\text{fuel}} \times t_{\text{op}} =$	\$38,971 in 2019 dollars
Additional Ash Cost =	$\Delta \text{Ash} \times \text{Cost}_{\text{ash}} \times t_{\text{op}} \times (1/2000) =$	\$0 in 2019 dollars
Direct Annual Cost =		\$442,335 in 2019 dollars

Indirect Annual Cost (IDAC)

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

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

Cost Effectiveness

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

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 SO₂ emission rate:

Not Applicable ▼

Ash content (%Ash):

percent by weight

Not applicable to units burning 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

Plant Elevation

454 Feet above sea level

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

0.07 lb/MMBtu

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

0.0385 lb/MMBtu

Estimated Normalized Stoichiometric Ratio (NSR)

5.40

*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/ft³Concentration 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/ft³29.4% aqueous NH_3 56 lbs/ft³

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

CEPCI = Chemical Engineering Plant Cost Index

Annual Interest Rate (i)

4.75 Percent

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

5.00 \$/MMBtu

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

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

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

0.0042 \$/gallon*

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

0.0676 \$/kWh*

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

\$/ton

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

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

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =

0.015

Administrative Charges Factor (ACF) =

0.03

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) =	$(Q_B \times 1.0E6 \text{ Btu/MMBtu} \times 8760)/\text{HHV} =$	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}) =	$(\text{Mactual}/\text{Mfuel}) \times (\text{tSNCR}/365) =$	0.00	fraction	
Total operating time for the SNCR (t_{op}) =	$CF_{\text{total}} \times 8760 =$	394	hours	Based on 2017 Operating Hours
NOx Removal Efficiency (EF) =	$(\text{NOx}_{\text{in}} - \text{NOx}_{\text{out}})/\text{NOx}_{\text{in}} =$	45	percent	
NOx removed per hour =	$\text{NOx}_{\text{in}} \times \text{EF} \times Q_B =$	10.71	lb/hour	
Total NO _x removed per year =	$(\text{NOx}_{\text{in}} \times \text{EF} \times Q_B \times t_{\text{op}})/2000 =$	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 =	$(\%S/100) \times (64/32) \times (1 \times 10^6)/\text{HHV} =$			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEV _F) =	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) =	$2116 \times [(59 - (0.00356 \times h)) + 459.7]/518.6]^{5.256} \times (1/144)^*$ =	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>.

Reagent Data:

Type of reagent used

Urea

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

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NOx}_{\text{in}} \times Q_{\text{B}} \times \text{NSR} \times \text{MW}_{\text{R}}) / (\text{MW}_{\text{NOx}} \times \text{SR}) =$ (whre SR = 1 for NH_3 ; 2 for Urea)	84	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}} / C_{\text{sol}} =$	168	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density} =$	17.7	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24 \text{ hours/day}) / \text{Reagent Density} =$	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) =	$(0.47 \times \text{NOx}_{\text{in}} \times \text{NSR} \times Q_{\text{B}}) / \text{NPHR} =$	7.4	kW/hour
Water Usage: Water consumption (q_{w}) =	$(m_{\text{sol}} / \text{Density of water}) \times ((C_{\text{stored}} / C_{\text{inj}}) - 1) =$	80	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$H_v \times m_{\text{reagent}} \times ((1/C_{\text{inj}}) - 1) =$	0.68	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta \text{fuel} \times \% \text{Ash} \times 1 \times 10^6) / \text{HHV} =$	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
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Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

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

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

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

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

Total Annual Cost (TAC)

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

Direct Annual Costs (DAC) =	\$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)

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

Annual Maintenance Cost =	$0.015 \times \text{TCI} =$	\$52,952 in 2019 dollars
Annual Reagent Cost =	$q_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$11,564 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$196 in 2019 dollars
Annual Water Cost =	$q_{\text{water}} \times \text{Cost}_{\text{water}} \times t_{\text{op}} =$	\$132 in 2019 dollars
Additional Fuel Cost =	$\Delta \text{Fuel} \times \text{Cost}_{\text{fuel}} \times t_{\text{op}} =$	\$1,339 in 2019 dollars
Additional Ash Cost =	$\Delta \text{Ash} \times \text{Cost}_{\text{ash}} \times t_{\text{op}} \times (1/2000) =$	\$0 in 2019 dollars
Direct Annual Cost =		\$66,183 in 2019 dollars

Indirect Annual Cost (IDAC)

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

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

Cost Effectiveness

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

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 burning 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-18 - SCR for CPP Halsey No. 1 Power Boiler

Number of days the SCR operates (t_{SCR})	365 days	Number of SCR reactor chambers (n_{scr})	1
Number of days the boiler operates (t_{plant})	365 days	Number of catalyst layers (R_{layer})	3
Inlet NO_x Emissions ($NO_{x,in}$) to SCR	0.276 lb/MMBtu	Number of empty catalyst layers (R_{empty})	1
Outlet NO_x Emissions ($NO_{x,out}$) from SCR	0.028 lb/MMBtu	Ammonia Slip (Slip) provided by vendor	2 ppm
Stoichiometric Ratio Factor (SRF)	1.050	Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
*The SRF value of 1.05 is a default value. User should enter actual value, if known.		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	Gas temperature at the SCR inlet (T)	650 °F
Estimated SCR equipment life	25 Years*	Base case fuel gas volumetric flow rate factor (Q_{fuel})	431 ft ³ /min-MMBtu/hour
* For industrial boilers, the typical equipment life is between 20 and 25 years.			

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

Select the reagent used
Ammonia

Densities of typical SCR reagents:
50% urea solution 71 lbs/ft³
29.4% aqueous NH₃ 56 lbs/ft³

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.

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/ft ³ * 0.134 ft ³ /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) =	$(Q_B \times 1.0E6 \times 8760)/HHV =$	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}) =	$(Mactual/Mfuel) \times (tscr/tplant) =$	0.422	fraction	
Total operating time for the SCR (t_{op}) =	$CF_{total} \times 8760 =$	8760	hours	Based on 8760 hours (PTE)
NOx Removal Efficiency (EF) =	$(NO_{x_{in}} - NO_{x_{out}})/NO_{x_{in}} =$	90.0	percent	
NOx removed per hour =	$NO_{x_{in}} \times EF \times Q_B =$	58.72	lb/hour	
Total NO _x removed per year =	$(NO_{x_{in}} \times EF \times Q_B \times t_{op})/2000 =$	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 ($q_{flue\ gas}$) =	$Q_{fuel} \times Q_B \times (460 + T)/(460 + 700)n_{scr} =$	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 =	$(\%S/100) \times (64/32) \times 1 \times 10^6 / HHV =$			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) =	$2116 \times [(59 - (0.00356 \times h)) + 459.7] / 518.6^{5.256} \times (1/144)^* =$	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) =	$(\text{interest rate})(1/((1 + \text{interest rate})^Y - 1))$, where $Y = H_{\text{catalysts}}/(t_{\text{SCR}} \times 24 \text{ hours})$ rounded to the nearest integer	0.3180	Fraction
Catalyst volume ($\text{Vol}_{\text{catalyst}}$) =	$2.81 \times Q_B \times EF_{\text{adj}} \times \text{Slip}_{\text{adj}} \times \text{NOx}_{\text{adj}} \times S_{\text{adj}} \times (T_{\text{adj}}/N_{\text{scr}})$	999.22	Cubic feet
Cross sectional area of the catalyst (A_{catalyst}) =	$q_{\text{flue gas}} / (16\text{ft/sec} \times 60 \text{ sec/min})$	101	ft^2
Height of each catalyst layer (H_{layer}) =	$(\text{Vol}_{\text{catalyst}} / (R_{\text{layer}} \times A_{\text{catalyst}})) + 1$ (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	$1.15 \times A_{\text{catalyst}}$	117	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{\text{SCR}})^{0.5}$	10.8	feet
Reactor height =	$(R_{\text{layer}} + R_{\text{empty}}) \times (7\text{ft} + h_{\text{layer}}) + 9\text{ft}$	54	feet

Reagent Data:

Type of reagent used

Ammonia

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

Density = 56 lb/ft³

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NOx}_{\text{in}} \times Q_{\text{g}} \times \text{EF} \times \text{SRF} \times \text{MW}_{\text{R}}) / \text{MW}_{\text{NOx}} =$	23	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}} / \text{CSol} =$	79	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density}$	11	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24) / \text{Reagent Density} =$	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) =	$A \times 1,000 \times 0.0056 \times (\text{CoalF} \times \text{HRF})^{0.43} =$ 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) =

\$1,338,172 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 =

$$0.005 \times TCI =$$

\$41,197 in 2019 dollars

Annual Reagent Cost =

$$m_{sol} \times \text{Cost}_{reag} \times t_{op} =$$

\$325,071 in 2019 dollars

Annual Electricity Cost =

$$P \times \text{Cost}_{elect} \times t_{op} =$$

\$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

$$n_{scr} \times \text{Vol}_{cat} \times (CC_{replace}/R_{layer}) \times FWF$$

Direct Annual Cost =

\$1,338,172 in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =

$$0.03 \times (\text{Operator Cost} + 0.4 \times \text{Annual Maintenance Cost}) =$$

\$3,122 in 2019 dollars

Capital Recovery Costs (CR)=

$$CRF \times TCI =$$

\$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 burning 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 SCR reactor chambers (n_{scr})	1
Number of days the boiler operates (t_{plant})	360 days	Number of catalyst layers (R_{layer})	3
Inlet NO_x Emissions ($NO_{x,in}$) to SCR	0.221 lb/MMBtu	Number of empty catalyst layers (R_{empty})	1
Outlet NO_x Emissions ($NO_{x,out}$) from SCR	0.022 lb/MMBtu	Ammonia Slip (Slip) provided by vendor	2 ppm
Stoichiometric Ratio Factor (SRF)	1.050	Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
*The SRF value of 1.05 is a default value. User should enter actual value, if known.		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	Gas temperature at the SCR inlet (T)	650 °F
Estimated SCR equipment life	25 Years*	Base case fuel gas volumetric flow rate factor (Q_{fuel})	431 ft ³ /min-MMBtu/hour
* For industrial boilers, the typical equipment life is between 20 and 25 years.			

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

Select the reagent used
Ammonia

Densities of typical SCR reagents:
50% urea solution 71 lbs/ft³
29.4% aqueous NH₃ 56 lbs/ft³

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-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) =	$(Q_B \times 1.0E6 \times 8760)/HHV =$	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}) =	$(Mactual/Mfuel) \times (tscr/tplant) =$	0.232	fraction	
Total operating time for the SCR (t_{op}) =	$CF_{total} \times 8760 =$	8622	hours	Based on 2017 Actual Hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in} =$	90.0	percent	
NOx removed per hour =	$NOx_{in} \times EF \times Q_B =$	46.91	lb/hour	
Total NO _x removed per year =	$(NOx_{in} \times EF \times Q_B \times t_{op})/2000 =$	47.70	tons/year	Based on 2017 Actual Emissions
NO _x removal factor (NRF) =	EF/80 =	1.13		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	$Q_{fuel} \times Q_B \times (460 + T)/(460 + 700)n_{scr} =$	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 =	$(\%S/100) \times (64/32) \times 1 \times 10^6 / HHV =$			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) =	$2116 \times [(59 - (0.00356 \times h)) + 459.7] / 518.6^{5.256} \times (1/144)^* =$	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) =	$(\text{interest rate})(1/((1 + \text{interest rate})^Y - 1))$, where $Y = H_{\text{catalysts}}/(t_{\text{SCR}} \times 24 \text{ hours})$ rounded to the nearest integer	0.3180	Fraction
Catalyst volume ($\text{Vol}_{\text{catalyst}}$) =	$2.81 \times Q_B \times EF_{\text{adj}} \times \text{Slip}_{\text{adj}} \times \text{NOx}_{\text{adj}} \times S_{\text{adj}} \times (T_{\text{adj}}/N_{\text{scr}})$	980.27	Cubic feet
Cross sectional area of the catalyst (A_{catalyst}) =	$q_{\text{flue gas}}/(16\text{ft/sec} \times 60 \text{ sec/min})$	101	ft^2
Height of each catalyst layer (H_{layer}) =	$(\text{Vol}_{\text{catalyst}}/(R_{\text{layer}} \times A_{\text{catalyst}})) + 1$ (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	$1.15 \times A_{\text{catalyst}}$	117	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{\text{SCR}})^{0.5}$	10.8	feet
Reactor height =	$(R_{\text{layer}} + R_{\text{empty}}) \times (7\text{ft} + h_{\text{layer}}) + 9\text{ft}$	54	feet

Reagent Data:

Type of reagent used

Ammonia

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

Density = 56 lb/ft³

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NOx}_{\text{in}} \times Q_{\text{g}} \times \text{EF} \times \text{SRF} \times \text{MW}_{\text{R}}) / \text{MW}_{\text{NOx}} =$	18	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}} / \text{C}_{\text{sol}} =$	63	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density}$	8	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24) / \text{Reagent Density} =$	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) =	$A \times 1,000 \times 0.0056 \times (\text{CoalF} \times \text{HRF})^{0.43} =$ 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 =

$$0.005 \times TCI =$$

\$41,197 in 2019 dollars

Annual Reagent Cost =

$$m_{sol} \times \text{Cost}_{reag} \times t_{op} =$$

\$255,578 in 2019 dollars

Annual Electricity Cost =

$$P \times \text{Cost}_{elect} \times t_{op} =$$

\$70,729 in 2019 dollars

Annual Catalyst Replacement Cost =

$$n_{scr} \times \text{Vol}_{cat} \times (CC_{replace}/R_{layer}) \times FWF$$

\$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

Direct Annual Cost =

\$1,253,291 in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =

$$0.03 \times (\text{Operator Cost} + 0.4 \times \text{Annual Maintenance Cost}) =$$

\$3,086 in 2019 dollars

Capital Recovery Costs (CR)=

$$CRF \times TCI =$$

\$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 burning 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-19 - SCR for CPP Halsey No. 2 Power Boiler

Number of days the SCR operates (t_{SCR})	365 days	Number of SCR reactor chambers (n_{SCR})	1
Number of days the boiler operates (t_{plant})	365 days	Number of catalyst layers (R_{layer})	3
Inlet NO_x Emissions ($NO_{x,in}$) to SCR	0.280 lb/MMBtu	Number of empty catalyst layers (R_{empty})	1
Outlet NO_x Emissions ($NO_{x,out}$) from SCR	0.028 lb/MMBtu	Ammonia Slip (Slip) provided by vendor	2 ppm
Stoichiometric Ratio Factor (SRF)	1.050	Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
*The SRF value of 1.05 is a default value. User should enter actual value, if known.		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	Gas temperature at the SCR inlet (T)	650 °F
Estimated SCR equipment life	25 Years*	Base case fuel gas volumetric flow rate factor (Q_{fuel})	431 ft ³ /min-MMBtu/hour
* For industrial boilers, the typical equipment life is between 20 and 25 years.			

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

Select the reagent used	Ammonia
-------------------------	---------

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

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 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-19 - 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, 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) =	$(Q_B \times 1.0E6 \times 8760)/HHV =$	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}) =	$(Mactual/Mfuel) \times (tscr/tplant) =$	0.259	fraction	
Total operating time for the SCR (t_{op}) =	$CF_{total} \times 8760 =$	8760	hours	Based on 8760 hours (PTE)
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in} =$	90.0	percent	
NOx removed per hour =	$NOx_{in} \times EF \times Q_B =$	59.56	lb/hour	
Total NO _x removed per year =	$(NOx_{in} \times EF \times Q_B \times t_{op})/2000 =$	67.59	tons/year	Based on 75.1 tpy PSEL
NO _x removal factor (NRF) =	EF/80 =	1.13		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	$Q_{fuel} \times Q_B \times (460 + T)/(460 + 700)n_{scr} =$	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 =	$(\%S/100) \times (64/32) \times 1 \times 10^6 / HHV =$			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) =	$2116 \times [(59 - (0.00356 \times h)) + 459.7] / 518.6^{5.256} \times (1/144)^* =$	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) =	$(\text{interest rate}) / (1 / ((1 + \text{interest rate})^Y - 1))$, where $Y = H_{catalysts} / (t_{SCR} \times 24 \text{ hours})$ rounded to the nearest integer	0.3180	Fraction
Catalyst volume ($Vol_{catalyst}$) =	$2.81 \times Q_B \times EF_{adj} \times Slip_{adj} \times NOx_{adj} \times S_{adj} \times (T_{adj}/N_{scr})$	1,000.56	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas} / (16 \text{ ft/sec} \times 60 \text{ sec/min})$	101	ft ²

Height of each catalyst layer (H_{layer}) =	$(\text{Vol}_{\text{catalyst}} / (R_{\text{layer}} \times A_{\text{catalyst}})) + 1$ (rounded to next highest integer)	4	feet
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SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	$1.15 \times A_{\text{catalyst}}$	117	ft ²
Reactor length and width dimensions for a square reactor =	$(A_{\text{SCR}})^{0.5}$	10.8	feet
Reactor height =	$(R_{\text{layer}} + R_{\text{empty}}) \times (7\text{ft} + h_{\text{layer}}) + 9\text{ft}$	54	feet

Reagent Data:

Type of reagent used

Ammonia

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

Density = 56 lb/ft³

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NOx}_{\text{in}} \times Q_{\text{g}} \times \text{EF} \times \text{SRF} \times \text{MW}_{\text{R}}) / \text{MW}_{\text{NOx}} =$	23	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}} / \text{CSol} =$	80	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density}$	11	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24) / \text{Reagent Density} =$	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) =	$A \times 1,000 \times 0.0056 \times (\text{CoalF} \times \text{HRF})^{0.43} =$ 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) =

\$1,342,815 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 =

$$0.005 \times TCI =$$

\$41,197 in 2019 dollars

Annual Reagent Cost =

$$m_{sol} \times \text{Cost}_{reag} \times t_{op} =$$

\$329,682 in 2019 dollars

Annual Electricity Cost =

$$P \times \text{Cost}_{elect} \times t_{op} =$$

\$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

$$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$$

Direct Annual Cost =

\$1,342,815 in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =

$$0.03 \times (\text{Operator Cost} + 0.4 \times \text{Annual Maintenance Cost}) =$$

\$3,122 in 2019 dollars

Capital Recovery Costs (CR)=

$$CRF \times TCI =$$

\$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 burning 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 SCR reactor chambers (n_{SCR})	1
Number of days the boiler operates (t_{plant})	129 days	Number of catalyst layers (R_{layer})	3
Inlet NO_x Emissions ($NO_{x,in}$) to SCR	0.181 lb/MMBtu	Number of empty catalyst layers (R_{empty})	1
Outlet NO_x Emissions ($NO_{x,out}$) from SCR	0.018 lb/MMBtu	Ammonia Slip (Slip) provided by vendor	2 ppm
Stoichiometric Ratio Factor (SRF)	1.050	Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
*The SRF value of 1.05 is a default value. User should enter actual value, if known.		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	Gas temperature at the SCR inlet (T)	650 °F
Estimated SCR equipment life	25 Years*	Base case fuel gas volumetric flow rate factor (Q_{fuel})	431 ft ³ /min-MMBtu/hour
* For industrial boilers, the typical equipment life is between 20 and 25 years.			

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

Select the reagent used	Ammonia
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Densities of typical SCR reagents:	
50% urea solution	71 lbs/ft ³
29.4% aqueous NH ₃	56 lbs/ft ³

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 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-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/ft ³ * 0.134 ft ³ /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) =	$(Q_B \times 1.0E6 \times 8760)/HHV =$	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}) =	$(Mactual/Mfuel) \times (tscr/tplant) =$	0.030	fraction	
Total operating time for the SCR (t_{op}) =	$CF_{total} \times 8760 =$	3080	hours	Based on 2017 Operating Hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in} =$	90.0	percent	
NOx removed per hour =	$NOx_{in} \times EF \times Q_B =$	38.43	lb/hour	
Total NO _x removed per year =	$(NOx_{in} \times EF \times Q_B \times t_{op})/2000 =$	5.04	tons/year	Based on 2017 Actual Emissions
NO _x removal factor (NRF) =	EF/80 =	1.13		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	$Q_{fuel} \times Q_B \times (460 + T)/(460 + 700)n_{scr} =$	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 =	$(\%S/100) \times (64/32) \times 1 \times 10^6 / HHV =$			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) =	$2116 \times [(59 - (0.00356 \times h)) + 459.7] / 518.6^{5.256} \times (1/144)^* =$	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) =	$(\text{interest rate}) / (1 / ((1 + \text{interest rate})^Y - 1))$, where $Y = H_{catalysts} / (t_{SCR} \times 24 \text{ hours})$ rounded to the nearest integer	0.1057	Fraction
Catalyst volume ($Vol_{catalyst}$) =	$2.81 \times Q_B \times EF_{adj} \times Slip_{adj} \times NOx_{adj} \times S_{adj} \times (T_{adj}/N_{scr})$	966.68	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas} / (16 \text{ ft/sec} \times 60 \text{ sec/min})$	101	ft ²

Height of each catalyst layer (H_{layer}) =	$(\text{Vol}_{\text{catalyst}} / (R_{\text{layer}} \times A_{\text{catalyst}})) + 1$ (rounded to next highest integer)	4	feet
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SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	$1.15 \times A_{\text{catalyst}}$	117	ft ²
Reactor length and width dimensions for a square reactor =	$(A_{\text{SCR}})^{0.5}$	10.8	feet
Reactor height =	$(R_{\text{layer}} + R_{\text{empty}}) \times (7\text{ft} + h_{\text{layer}}) + 9\text{ft}$	54	feet

Reagent Data:

Type of reagent used

Ammonia

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

Density = 56 lb/ft³

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NOx}_{\text{in}} \times Q_{\text{g}} \times \text{EF} \times \text{SRF} \times \text{MW}_{\text{R}}) / \text{MW}_{\text{NOx}} =$	15	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}} / \text{CSol} =$	52	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density}$	7	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24) / \text{Reagent Density} =$	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) =	$A \times 1,000 \times 0.0056 \times (\text{CoalF} \times \text{HRF})^{0.43} =$ 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:

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

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

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

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

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

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

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

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

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

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

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

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 =

$$m_{sol} \times \text{Cost}_{reag} \times t_{op} =$$

\$74,797 in 2019 dollars

Annual Electricity Cost =

$$P \times \text{Cost}_{elect} \times t_{op} =$$

\$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) =

$$0.03 \times (\text{Operator Cost} + 0.4 \times \text{Annual Maintenance Cost}) =$$

\$1,423 in 2019 dollars

Capital Recovery Costs (CR)=

$$CRF \times TCI =$$

\$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 burning 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-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 SCR reactor chambers (n_{SCR})	1
Number of days the boiler operates (t_{plant})	365 days	Number of catalyst layers (R_{layer})	3
Inlet NO _x Emissions (NO _{x,in}) to SCR	0.168 lb/MMBtu	Number of empty catalyst layers (R_{empty})	1
Outlet NO _x Emissions (NO _{x,out}) from SCR	0.017 lb/MMBtu	Ammonia Slip (Slip) provided by vendor	2 ppm
Stoichiometric Ratio Factor (SRF)	1.050	Volume of the catalyst layers (Vol _{catalyst}) (Enter "UNK" if value is not known)	UNK Cubic feet
*The SRF value of 1.05 is a default value. User should enter actual value, if known.		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	Gas temperature at the SCR inlet (T)	650 °F
Estimated SCR equipment life	25 Years*	Base case fuel gas volumetric flow rate factor (Q _{fuel})	431 ft ³ /min-MMBtu/hour
* For industrial boilers, the typical equipment life is between 20 and 25 years.			

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

Select the reagent used
Ammonia ▼

Densities of typical SCR reagents:
50% urea solution 71 lbs/ft³
29.4% aqueous NH₃ 56 lbs/ft³

Enter the cost data for the proposed SCR:

Desired dollar-year	2019	CEPCI = Chemical Engineering Plant Cost Index
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 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.

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		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 .	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/ft ³ * 0.134 ft ³ /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) =	$(Q_B \times 1.0E6 \times 8760)/HHV =$	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}) =	$(Mactual/Mfuel) \times (tscr/tplant) =$	1.000	fraction	
Total operating time for the SCR (t_{op}) =	$CF_{total} \times 8760 =$	8760	hours	Based on 8760 hours (PTE)
NO _x Removal Efficiency (EF) =	$(NO_{x,in} - NO_{x,out})/NO_{x,in} =$	90.0	percent	
NO _x removed per hour =	$NO_{x,in} \times EF \times Q_B =$	44.88	lb/hour	
Total NO _x removed per year =	$(NO_{x,in} \times EF \times Q_B \times t_{op})/2000 =$	196.56	tons/year	Based on 218.4 tpy PSEL
NO _x removal factor (NRF) =	EF/80 =	1.13		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	$Q_{fuel} \times Q_B \times (460 + T)/(460 + 700)n_{scr} =$	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 =	$(\%S/100) \times (64/32) \times 1 \times 10^6 / HHV =$			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) =	$2116 \times [(59 - (0.00356 \times h) + 459.7)/518.6]^{5.256} \times (1/144)^* =$	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://spaceflightssystems.grc.nasa.gov/education/rocket/atmos.html>.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	$(\text{interest rate}) / (1 / ((1 + \text{interest rate})^Y - 1))$, where $Y = H_{catalysts} / (t_{SCR} \times 24 \text{ hours})$ rounded to the nearest integer	0.3180	Fraction
Catalyst volume ($Vol_{catalyst}$) =	$2.81 \times Q_B \times EF_{adj} \times Slip_{adj} \times NO_{x,adj} \times S_{adj} \times (T_{adj}/N_{scr})$	1,209.41	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas} / (16 \text{ ft/sec} \times 60 \text{ sec/min})$	127	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}) =	$1.15 \times A_{catalyst}$	147	ft ²
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	12.1	feet
Reactor height =	$(R_{layer} + R_{empty}) \times (7ft + h_{layer}) + 9ft$	54	feet

Reagent Data:

Type of reagent used

Ammonia

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

Density = 56 lb/ft³

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NO_{x,in} \times Q_{fb} \times EF \times SRF \times MW_R) / MW_{NOx} =$	17	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent} / C_{sol} =$	60	lb/hour
	$(m_{sol} \times 7.4805) / \text{Reagent Density}$	8	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24) / \text{Reagent Density} =$	2,700	gallons (storage needed to store a 14 day reagent supply rounded 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	0.0692

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

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

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)

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

Annual Maintenance Cost =	$0.005 \times \text{TCI} =$	\$47,795 in 2019 dollars
Annual Reagent Cost =	$m_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$248,422 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$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
	$n_{\text{scr}} \times \text{Vol}_{\text{cat}} \times (\text{CC}_{\text{replace}}/\text{R}_{\text{layer}}) \times \text{FWF}$	
Direct Annual Cost =		\$1,510,631 in 2019 dollars

Indirect Annual Cost (IDAC)

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

Administrative Charges (AC) =	$0.03 \times (\text{Operator Cost} + 0.4 \times \text{Annual Maintenance Cost}) =$	\$3,202 in 2019 dollars
Capital Recovery Costs (CR)=	$\text{CRF} \times \text{TCI} =$	\$661,485 in 2019 dollars
Indirect Annual Cost (IDAC) =	$\text{AC} + \text{CR} =$	\$664,686 in 2019 dollars

Cost Effectiveness

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

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 burning 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 SCR reactor chambers (n_{SCR})	1
Number of days the boiler operates (t_{plant})	358 days	Number of catalyst layers (R_{layer})	3
Inlet NO _x Emissions (NO _{x,in}) to SCR	0.280 lb/MMBtu	Number of empty catalyst layers (R_{empty})	1
Outlet NO _x Emissions (NO _{x,out}) from SCR	0.028 lb/MMBtu	Ammonia Slip (Slip) provided by vendor	2 ppm
Stoichiometric Ratio Factor (SRF)	1.050	Volume of the catalyst layers (Vol _{catalyst}) (Enter "UNK" if value is not known)	UNK Cubic feet
*The SRF value of 1.05 is a default value. User should enter actual value, if known.		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	Gas temperature at the SCR inlet (T)	650 °F
Estimated SCR equipment life	25 Years*	Base case fuel gas volumetric flow rate factor (Q _{fuel})	431 ft ³ /min-MMBtu/hour
* For industrial boilers, the typical equipment life is between 20 and 25 years.			

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

Select the reagent used

Ammonia

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

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

Maintenance and Administrative Charges Cost Factors:

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

0.005
0.03

Data Sources for Default Values Used in Calculations:

Data Element		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 .	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/ft ³ * 0.134 ft ³ /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) =	$(Q_B \times 1.0E6 \times 8760)/HHV =$	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}) =	$(Mactual/Mfuel) \times (tscr/tplant) =$	0.579	fraction	
Total operating time for the SCR (t_{op}) =	$CF_{total} \times 8760 =$	8572	hours	Based on 2017 Operating Hours
NO _x Removal Efficiency (EF) =	$(NO_{x,in} - NO_{x,out})/NO_{x,in} =$	90.0	percent	
NO _x removed per hour =	$NO_{x,in} \times EF \times Q_B =$	74.73	lb/hour	
Total NO _x removed per year =	$(NO_{x,in} \times EF \times Q_B \times t_{op})/2000 =$	189.54	tons/year	Based on 2017 Actual Emissions
NO _x removal factor (NRF) =	$EF/80 =$	1.13		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	$Q_{fuel} \times Q_B \times (460 + T)/(460 + 700)n_{scr} =$	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 =	$(\%S/100) \times (64/32) \times 1 \times 10^6 / HHV =$			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEV) =	$14.7\ psia/P =$			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at sea level (P) =	$2116 \times [(59 - (0.00356 \times h) + 459.7)/518.6]^{5.256} \times (1/144)^* =$	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://spaceflight systems.grc.nasa.gov/education/rocket/atmos.html>.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	$(\text{interest rate}) / (1 / ((1 + \text{interest rate})^Y - 1))$, where $Y = H_{catalysts} / (t_{SCR} \times 24 \text{ hours})$ rounded to the nearest integer	0.3180	Fraction
Catalyst volume ($Vol_{catalyst}$) =	$2.81 \times Q_B \times EF_{adj} \times Slip_{adj} \times NO_{x,adj} \times S_{adj} \times (T_{adj}/N_{scr})$	1,257.29	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas} / (16\text{ft/sec} \times 60\text{ sec/min})$	127	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}) =	$1.15 \times A_{catalyst}$	147	ft ²
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	12.1	feet
Reactor height =	$(R_{layer} + R_{empty}) \times (7ft + h_{layer}) + 9ft$	54	feet

Reagent Data:

Type of reagent used

Ammonia

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

Density = 56 lb/ft³

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOX_{in} \times Q_B \times EF \times SRF \times MW_R) / MW_{NOx} =$	29	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent} / C_{sol} =$	100	lb/hour
	$(m_{sol} \times 7.4805) / \text{Reagent Density}$	13	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24) / \text{Reagent Density} =$	4,500	gallons (storage needed to store a 14 day reagent supply rounded to the nearest 100)

Capital Recovery Factor:

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

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

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

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)

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

Annual Maintenance Cost =	$0.005 \times \text{TCI} =$	\$47,795 in 2019 dollars
Annual Reagent Cost =	$m_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$404,802 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$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
	$n_{\text{scr}} \times \text{Vol}_{\text{cat}} \times (\text{CC}_{\text{replace}}/\text{R}_{\text{layer}}) \times \text{FWF}$	
Direct Annual Cost =		\$1,642,671 in 2019 dollars

Indirect Annual Cost (IDAC)

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

Administrative Charges (AC) =	$0.03 \times (\text{Operator Cost} + 0.4 \times \text{Annual Maintenance Cost}) =$	\$3,151 in 2019 dollars
Capital Recovery Costs (CR)=	$\text{CRF} \times \text{TCI} =$	\$661,485 in 2019 dollars
Indirect Annual Cost (IDAC) =	$\text{AC} + \text{CR} =$	\$664,636 in 2019 dollars

Cost Effectiveness

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

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 burning 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-21 - 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})	365 days
Number of days the boiler operates (t_{plant})	365 days
Inlet NO _x Emissions (NO _{x,in}) to SCR	0.272 lb/MMBtu
Outlet NO _x Emissions (NO _{x,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.

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

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

*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.

Select the reagent used Ammonia ▼

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

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

Densities of typical SCR reagents:

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

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		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 .	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/ft ³ * 0.134 ft ³ /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) =	$(Q_B \times 1.0E6 \times 8760)/HHV =$	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}) =	$(Mactual/Mfuel) \times (tscr/tplant) =$	1.000	fraction	
Total operating time for the SCR (t_{op}) =	$CF_{total} \times 8760 =$	8760	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in} =$	90.0	percent	
NOx removed per hour =	$NOx_{in} \times EF \times Q_B =$	45.96	lb/hour	
Total NO _x removed per year =	$(NOx_{in} \times EF \times Q_B \times t_{op})/2000 =$	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 ($q_{flue\ gas}$) =	$Q_{fuel} \times Q_B \times (460 + T)/(460 + 700)n_{scr} =$	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 =	$(\%S/100) \times (64/32) \times 1 \times 10^6 / HHV =$			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) =	$2116 \times [(59 - (0.00356 \times h)) + 459.7] / 518.6^{5.256} \times (1/144)^* =$	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) =	$(\text{interest rate})(1/((1 + \text{interest rate})^Y - 1))$, where $Y = H_{\text{catalysts}}/(t_{\text{SCR}} \times 24 \text{ hours})$ rounded to the nearest integer	0.3180	Fraction
Catalyst volume ($\text{Vol}_{\text{catalyst}}$) =	$2.81 \times Q_B \times EF_{\text{adj}} \times \text{Slip}_{\text{adj}} \times \text{NOx}_{\text{adj}} \times S_{\text{adj}} \times (T_{\text{adj}}/N_{\text{scr}})$	792.76	Cubic feet
Cross sectional area of the catalyst (A_{catalyst}) =	$q_{\text{flue gas}}/(16\text{ft/sec} \times 60 \text{ sec/min})$	81	ft^2
Height of each catalyst layer (H_{layer}) =	$(\text{Vol}_{\text{catalyst}}/(R_{\text{layer}} \times A_{\text{catalyst}})) + 1$ (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	$1.15 \times A_{\text{catalyst}}$	93	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{\text{SCR}})^{0.5}$	9.6	feet
Reactor height =	$(R_{\text{layer}} + R_{\text{empty}}) \times (7\text{ft} + h_{\text{layer}}) + 9\text{ft}$	54	feet

Reagent Data:

Type of reagent used

Ammonia

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

Density = 56 lb/ft³

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NOx}_{\text{in}} \times Q_{\text{g}} \times \text{EF} \times \text{SRF} \times \text{MW}_{\text{R}}) / \text{MW}_{\text{NOx}} =$	18	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}} / \text{CSol} =$	62	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density}$	8	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24) / \text{Reagent Density} =$	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) =	$A \times 1,000 \times 0.0056 \times (\text{CoalF} \times \text{HRF})^{0.43} =$ 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)

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

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)

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

Annual Maintenance Cost =	$0.005 \times \text{TCI} =$	\$35,475 in 2019 dollars
Annual Reagent Cost =	$m_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$254,439 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$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
	$n_{\text{scr}} \times \text{Vol}_{\text{cat}} \times (\text{CC}_{\text{replace}}/R_{\text{layer}}) \times \text{FWF}$	
Direct Annual Cost =		\$1,242,082 in 2019 dollars

Indirect Annual Cost (IDAC)

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

Administrative Charges (AC) =	$0.03 \times (\text{Operator Cost} + 0.4 \times \text{Annual Maintenance Cost}) =$	\$3,054 in 2019 dollars
Capital Recovery Costs (CR)=	$\text{CRF} \times \text{TCI} =$	\$490,975 in 2019 dollars
Indirect Annual Cost (IDAC) =	$\text{AC} + \text{CR} =$	\$494,029 in 2019 dollars

Cost Effectiveness

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

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 burning 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 SCR reactor chambers (n_{SCR})	1
Number of days the boiler operates (t_{plant})	356 days	Number of catalyst layers (R_{layer})	3
Inlet NO _x Emissions (NO _{x,in}) to SCR	0.280 lb/MMBtu	Number of empty catalyst layers (R_{empty})	1
Outlet NO _x Emissions (NO _{x,out}) from SCR	0.028 lb/MMBtu	Ammonia Slip (Slip) provided by vendor	2 ppm
Stoichiometric Ratio Factor (SRF)	1.050	Volume of the catalyst layers (Vol _{catalyst}) (Enter "UNK" if value is not known)	UNK Cubic feet
*The SRF value of 1.05 is a default value. User should enter actual value, if known.		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	Gas temperature at the SCR inlet (T)	650 °F
Estimated SCR equipment life	25 Years*	Base case fuel gas volumetric flow rate factor (Q _{fuel})	431 ft ³ /min-MMBtu/hour
* For industrial boilers, the typical equipment life is between 20 and 25 years.			

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

Select the reagent used

Ammonia

<u>Densities of typical SCR reagents:</u>	
50% urea solution	71 lbs/ft ³
29.4% aqueous NH ₃	56 lbs/ft ³

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 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-21a - SCR for GP Toledo No. 1 Power Boiler

Maintenance and Administrative Charges Cost Factors:

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

0.005
0.03

Data Sources for Default Values Used in Calculations:

Data Element		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 .	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) =	$(Q_B \times 1.0E6 \times 8760)/HHV =$	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}) =	$(Mactual/Mfuel) \times (tscr/tplant) =$	0.653	fraction	
Total operating time for the SCR (t_{op}) =	$CF_{total} \times 8760 =$	8540	hours	Based on 2017 Operating Hours
NOx Removal Efficiency (EF) =	$(NO_{x_{in}} - NO_{x_{out}})/NO_{x_{in}} =$	90.0	percent	
NOx removed per hour =	$NO_{x_{in}} \times EF \times Q_B =$	47.24	lb/hour	
Total NO _x removed per year =	$(NO_{x_{in}} \times EF \times Q_B \times t_{op})/2000 =$	135.09	tons/year	Based on 2017 Actual Emissions
NO _x removal factor (NRF) =	EF/80 =	1.13		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	$Q_{fuel} \times Q_B \times (460 + T)/(460 + 700)n_{scr} =$	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 =	$(\%S/100) \times (64/32) \times 1 \times 10^6 / HHV =$			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) =	$2116 \times [(59 - (0.00356 \times h)) + 459.7] / 518.6^{5.256} \times (1/144)^* =$	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://spaceflight systems.grc.nasa.gov/education/rocket/atmos.html>.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	$(\text{interest rate})(1/((1 + \text{interest rate})^Y - 1))$, where $Y = H_{\text{catalysts}}/(t_{\text{SCR}} \times 24 \text{ hours})$ rounded to the nearest integer	0.3180	Fraction
Catalyst volume ($\text{Vol}_{\text{catalyst}}$) =	$2.81 \times Q_B \times EF_{\text{adj}} \times \text{Slip}_{\text{adj}} \times \text{NOx}_{\text{adj}} \times S_{\text{adj}} \times (T_{\text{adj}}/N_{\text{scr}})$	794.82	Cubic feet
Cross sectional area of the catalyst (A_{catalyst}) =	$q_{\text{flue gas}}/(16\text{ft/sec} \times 60 \text{ sec/min})$	81	ft^2
Height of each catalyst layer (H_{layer}) =	$(\text{Vol}_{\text{catalyst}}/(R_{\text{layer}} \times A_{\text{catalyst}})) + 1$ (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	$1.15 \times A_{\text{catalyst}}$	93	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{\text{SCR}})^{0.5}$	9.6	feet
Reactor height =	$(R_{\text{layer}} + R_{\text{empty}}) \times (7\text{ft} + h_{\text{layer}}) + 9\text{ft}$	54	feet

Reagent Data:

Type of reagent used

Ammonia

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

Density = 56 lb/ft³

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NOx}_{\text{in}} \times Q_{\text{g}} \times \text{EF} \times \text{SRF} \times \text{MW}_{\text{R}}) / \text{MW}_{\text{NOx}} =$	18	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}} / \text{CSol} =$	63	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density}$	8	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24) / \text{Reagent Density} =$	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) =	$A \times 1,000 \times 0.0056 \times (\text{CoalF} \times \text{HRF})^{0.43} =$ 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)

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

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)

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

Annual Maintenance Cost =	$0.005 \times \text{TCI} =$	\$35,475 in 2019 dollars
Annual Reagent Cost =	$m_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$254,948 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$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
	$n_{\text{scr}} \times \text{Vol}_{\text{cat}} \times (\text{CC}_{\text{replace}}/R_{\text{layer}}) \times \text{FWF}$	
Direct Annual Cost =		\$1,219,164 in 2019 dollars

Indirect Annual Cost (IDAC)

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

Administrative Charges (AC) =	$0.03 \times (\text{Operator Cost} + 0.4 \times \text{Annual Maintenance Cost}) =$	\$2,989 in 2019 dollars
Capital Recovery Costs (CR)=	$\text{CRF} \times \text{TCI} =$	\$490,975 in 2019 dollars
Indirect Annual Cost (IDAC) =	$\text{AC} + \text{CR} =$	\$493,964 in 2019 dollars

Cost Effectiveness

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

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 burning 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-22 - 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})	365 days
Number of days the boiler operates (t_{plant})	365 days
Inlet NO _x Emissions (NO _{x,in}) to SCR	0.160 lb/MMBtu
Outlet NO _x Emissions (NO _{x,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.

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

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

*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.

Select the reagent used Ammonia ▼

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

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

Densities of typical SCR reagents:

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

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		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 .	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) =	$(Q_B \times 1.0E6 \times 8760)/HHV =$	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}) =	$(Mactual/Mfuel) \times (tscr/tpant) =$	0.984	fraction	
Total operating time for the SCR (t_{op}) =	$CF_{total} \times 8760 =$	8760	hours	Based on 8760 (PTE)
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in} =$	90.0	percent	
NOx removed per hour =	$NOx_{in} \times EF \times Q_B =$	22.47	lb/hour	
Total NO _x removed per year =	$(NOx_{in} \times EF \times Q_B \times t_{op})/2000 =$	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 ($q_{flue\ gas}$) =	$Q_{fuel} \times Q_B \times (460 + T)/(460 + 700)n_{scr} =$	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 =	$(\%S/100) \times (64/32) \times 1 \times 10^6 / HHV =$			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) =	$2116 \times [(59 - (0.00356 \times h) + 459.7)/518.6]^{5.256} \times (1/144) \times =$	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://spaceflight systems.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 $Y = H_{catalysts}/(t_{SCR} \times 24\ hours)$ rounded to the nearest integer	0.3180	Fraction
Catalyst volume ($Vol_{catalyst}$) =	$2.81 \times Q_B \times EF_{adj} \times Slip_{adj} \times NOx_{adj} \times S_{adj} \times (T_{adj}/N_{scr})$	635.44	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas} / (16ft/sec \times 60\ sec/min)$	67	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}) =	$1.15 \times A_{catalyst}$	77	ft ²
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	8.8	feet
Reactor height =	$(R_{layer} + R_{empty}) \times (7ft + h_{layer}) + 9ft$	54	feet

Reagent Data:

Type of reagent used

Ammonia

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

Density = 56 lb/ft³

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NO_{x,in} \times Q_B \times EF \times SRF \times MW_R) / MW_{NO_x} =$	9	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent} / C_{sol} =$	30	lb/hour
	$(m_{sol} \times 7.4805) / \text{Reagent Density}$	4	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24) / \text{Reagent Density} =$	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) =	$A \times 1,000 \times 0.0056 \times (\text{CoalF} \times \text{HRF})^{0.43} =$ 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)

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

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)

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

Annual Maintenance Cost =	$0.005 \times TCI =$	\$31,517 in 2019 dollars
Annual Reagent Cost =	$m_{sol} \times \text{Cost}_{reag} \times t_{op} =$	\$124,382 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{elect} \times t_{op} =$	\$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
	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	
Direct Annual Cost =		\$875,781 in 2019 dollars

Indirect Annual Cost (IDAC)

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

Administrative Charges (AC) =	$0.03 \times (\text{Operator Cost} + 0.4 \times \text{Annual Maintenance Cost}) =$	\$3,006 in 2019 dollars
Capital Recovery Costs (CR)=	$CRF \times TCI =$	\$436,196 in 2019 dollars
Indirect Annual Cost (IDAC) =	$AC + CR =$	\$439,202 in 2019 dollars

Cost Effectiveness

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

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 burning 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 SCR reactor chambers (n_{SCR})	1
Number of days the boiler operates (t_{plant})	356 days	Number of catalyst layers (R_{layer})	3
Inlet NO _x Emissions (NO _{x,in}) to SCR	0.164 lb/MMBtu	Number of empty catalyst layers (R_{empty})	1
Outlet NO _x Emissions (NO _{x,out}) from SCR	0.016 lb/MMBtu	Ammonia Slip (Slip) provided by vendor	2 ppm
Stoichiometric Ratio Factor (SRF)	1.050	Volume of the catalyst layers (Vol _{catalyst}) (Enter "UNK" if value is not known)	UNK Cubic feet
*The SRF value of 1.05 is a default value. User should enter actual value, if known.		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	Gas temperature at the SCR inlet (T)	650 °F
Estimated SCR equipment life	25 Years*	Base case fuel gas volumetric flow rate factor (Q _{fuel})	431 ft ³ /min-MMBtu/hour
* For industrial boilers, the typical equipment life is between 20 and 25 years.			

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

Select the reagent used

Ammonia

<u>Densities of typical SCR reagents:</u>	
50% urea solution	71 lbs/ft ³
29.4% aqueous NH ₃	56 lbs/ft ³

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 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-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		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 .	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) =	$(Q_B \times 1.0E6 \times 8760)/HHV =$	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}) =	$(Mactual/Mfuel) \times (tscr/tpant) =$	0.673	fraction
Total operating time for the SCR (t_{op}) =	$CF_{total} \times 8760 =$	8531	hours
NO _x Removal Efficiency (EF) =	$(NO_{x,in} - NO_{x,out})/NO_{x,in} =$	90.0	percent
NO _x removed per hour =	$NO_{x,in} \times EF \times Q_B =$	15.95	lb/hour
Total NO _x removed per year =	$(NO_{x,in} \times EF \times Q_B \times t_{op})/2000 =$	68.04	tons/year
NO _x removal factor (NRF) =	EF/80 =	1.13	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	$Q_{fuel} \times Q_B \times (460 + T)/(460 + 700)n_{scr} =$	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 =	$(\%S/100) \times (64/32) \times 1 \times 10^6 / HHV =$		
Elevation Factor (ELEVF) =	14.7 psia/P =		
Atmospheric pressure at sea level (P) =	$2116 \times [(59 - (0.00356 \times h) + 459.7)/518.6]^{5.256} \times (1/144)^* =$	14.6	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.50	

Based on 2017 Operating Hours

Based on 2017 Actual Emissions

Not applicable; factor applies only to coal-fired boilers

Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.

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

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	$(\text{interest rate}) \{1 / [(1 + \text{interest rate})^Y - 1]\}$, where $Y = H_{catalysts} / (t_{SCR} \times 24 \text{ hours})$ rounded to the nearest integer	0.3180	Fraction
Catalyst volume ($Vol_{catalyst}$) =	$2.81 \times Q_B \times EF_{adj} \times Slip_{adj} \times NO_{x,adj} \times S_{adj} \times (T_{adj}/N_{scr})$	636.45	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas} / (16 \text{ ft/sec} \times 60 \text{ sec/min})$	67	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}) =	$1.15 \times A_{catalyst}$	77	ft ²
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	8.8	feet
Reactor height =	$(R_{layer} + R_{empty}) \times (7ft + h_{layer}) + 9ft$	54	feet

Reagent Data:

Type of reagent used

Ammonia

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

Density = 56 lb/ft³

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NO_{x,in} \times Q_B \times EF \times SRF \times MW_R) / MW_{NO_x} =$	9	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent} / C_{sol} =$	31	lb/hour
	$(m_{sol} \times 7.4805) / \text{Reagent Density}$	4	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24) / \text{Reagent Density} =$	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) =	$A \times 1,000 \times 0.0056 \times (\text{CoalF} \times \text{HRF})^{0.43} =$ 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)

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

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)

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

Annual Maintenance Cost =	$0.005 \times TCI =$	\$31,517 in 2019 dollars
Annual Reagent Cost =	$m_{sol} \times \text{Cost}_{reag} \times t_{op} =$	\$124,521 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{elect} \times t_{op} =$	\$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
	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	
Direct Annual Cost =		\$857,509 in 2019 dollars

Indirect Annual Cost (IDAC)

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

Administrative Charges (AC) =	$0.03 \times (\text{Operator Cost} + 0.4 \times \text{Annual Maintenance Cost}) =$	\$2,941 in 2019 dollars
Capital Recovery Costs (CR)=	$CRF \times TCI =$	\$436,196 in 2019 dollars
Indirect Annual Cost (IDAC) =	$AC + CR =$	\$439,138 in 2019 dollars

Cost Effectiveness

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

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 ▼

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?

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 burning 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-23 - 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})	365 days
Number of days the boiler operates (t_{plant})	365 days
Inlet NO _x Emissions (NO _{x,in}) to SCR	0.058 lb/MMBtu
Outlet NO _x Emissions (NO _{x,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.

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.

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.

Select the reagent used Ammonia ▼

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

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

Densities of typical SCR reagents:

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

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) =
 Administrative Charges Factor (ACF) =

0.005
0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost (\$/gallon)	\$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) =	$(Q_B \times 1.0E6 \times 8760)/HHV =$	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}) =	$(Mactual/Mfuel) \times (tscr/tplant) =$	1.000	fraction	
Total operating time for the SCR (t_{op}) =	$CF_{total} \times 8760 =$	8760	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in} =$	90.0	percent	
NOx removed per hour =	$NOx_{in} \times EF \times Q_B =$	18.38	lb/hour	
Total NO _x removed per year =	$(NOx_{in} \times EF \times Q_B \times t_{op})/2000 =$	80.55	tons/year	Based on 89.5 tpy PSEL
NO _x removal factor (NRF) =	EF/80 =	1.13		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	$Q_{fuel} \times Q_B \times (460 + T)/(460 + 700)n_{scr} =$	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 =	$(\%S/100) \times (64/32) \times 1 \times 10^6 / HHV =$			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) =	$2116 \times [(59 - (0.00356 \times h)) + 459.7] / 518.6^{5.256} \times (1/144)^* =$	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://spaceflight systems.grc.nasa.gov/education/rocket/atmos.html>.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	$(\text{interest rate})(1/((1 + \text{interest rate})^Y - 1))$, where $Y = H_{\text{catalysts}}/(t_{\text{SCR}} \times 24 \text{ hours})$ rounded to the nearest integer	0.3180	Fraction
Catalyst volume ($\text{Vol}_{\text{catalyst}}$) =	$2.81 \times Q_B \times EF_{\text{adj}} \times \text{Slip}_{\text{adj}} \times \text{NOx}_{\text{adj}} \times S_{\text{adj}} \times (T_{\text{adj}}/N_{\text{scr}})$	1,380.15	Cubic feet
Cross sectional area of the catalyst (A_{catalyst}) =	$q_{\text{flue gas}} / (16\text{ft/sec} \times 60 \text{ sec/min})$	151	ft^2
Height of each catalyst layer (H_{layer}) =	$(\text{Vol}_{\text{catalyst}} / (R_{\text{layer}} \times A_{\text{catalyst}})) + 1$ (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	$1.15 \times A_{\text{catalyst}}$	174	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{\text{SCR}})^{0.5}$	13.2	feet
Reactor height =	$(R_{\text{layer}} + R_{\text{empty}}) \times (7\text{ft} + h_{\text{layer}}) + 9\text{ft}$	53	feet

Reagent Data:

Type of reagent used

Ammonia

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

Density = 56 lb/ft³

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NOx}_{\text{in}} \times Q_{\text{g}} \times \text{EF} \times \text{SRF} \times \text{MW}_{\text{R}}) / \text{MW}_{\text{NOx}} =$	7	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}} / \text{C}_{\text{sol}} =$	25	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density}$	3	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24) / \text{Reagent Density} =$	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) =	$A \times 1,000 \times 0.0056 \times (\text{CoalF} \times \text{HRF})^{0.43} =$ 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)

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

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)

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

Annual Maintenance Cost =	$0.005 \times \text{TCl} =$	\$53,442 in 2019 dollars
Annual Reagent Cost =	$m_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$101,774 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$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
	$n_{\text{scr}} \times \text{Vol}_{\text{cat}} \times (\text{CC}_{\text{replace}}/\text{R}_{\text{layer}}) \times \text{FWF}$	
Direct Annual Cost =		\$1,390,668 in 2019 dollars

Indirect Annual Cost (IDAC)

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

Administrative Charges (AC) =	$0.03 \times (\text{Operator Cost} + 0.4 \times \text{Annual Maintenance Cost}) =$	\$3,269 in 2019 dollars
Capital Recovery Costs (CR)=	$\text{CRF} \times \text{TCl} =$	\$739,642 in 2019 dollars
Indirect Annual Cost (IDAC) =	$\text{AC} + \text{CR} =$	\$742,911 in 2019 dollars

Cost Effectiveness

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

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

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 burning 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

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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 (NO _{x,in}) to SCR	0.045 lb/MMBtu
Outlet NO _x Emissions (NO _{x,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.

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.

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.

Select the reagent used Ammonia ▼

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

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

Densities of typical SCR reagents:

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

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-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/ft ³ * 0.134 ft ³ /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) =	$(Q_B \times 1.0E6 \times 8760)/HHV =$	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}) =	$(Mactual/Mfuel) \times (tscr/tplant) =$	0.554	fraction	
Total operating time for the SCR (t_{op}) =	$CF_{total} \times 8760 =$	8586	hours	Based on 2017 Operating Hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in} =$	90.0	percent	
NOx removed per hour =	$NOx_{in} \times EF \times Q_B =$	14.26	lb/hour	
Total NO _x removed per year =	$(NOx_{in} \times EF \times Q_B \times t_{op})/2000 =$	34.29	tons/year	Based on 2017 Annual Emissions
NO _x removal factor (NRF) =	EF/80 =	1.13		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	$Q_{fuel} \times Q_B \times (460 + T)/(460 + 700)n_{scr} =$	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 =	$(\%S/100) \times (64/32) \times 1 \times 10^6 / HHV =$			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) =	$2116 \times [(59 - (0.00356 \times h)) + 459.7] / 518.6^{5.256} \times (1/144)^* =$	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) =	$(\text{interest rate})(1/((1 + \text{interest rate})^Y - 1))$, where $Y = H_{\text{catalysts}}/(t_{\text{SCR}} \times 24 \text{ hours})$ rounded to the nearest integer	0.3180	Fraction
Catalyst volume ($\text{Vol}_{\text{catalyst}}$) =	$2.81 \times Q_B \times EF_{\text{adj}} \times \text{Slip}_{\text{adj}} \times \text{NOx}_{\text{adj}} \times S_{\text{adj}} \times (T_{\text{adj}}/N_{\text{scr}})$	1,373.55	Cubic feet
Cross sectional area of the catalyst (A_{catalyst}) =	$q_{\text{flue gas}} / (16\text{ft/sec} \times 60 \text{ sec/min})$	151	ft^2
Height of each catalyst layer (H_{layer}) =	$(\text{Vol}_{\text{catalyst}} / (R_{\text{layer}} \times A_{\text{catalyst}})) + 1$ (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	$1.15 \times A_{\text{catalyst}}$	174	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{\text{SCR}})^{0.5}$	13.2	feet
Reactor height =	$(R_{\text{layer}} + R_{\text{empty}}) \times (7\text{ft} + h_{\text{layer}}) + 9\text{ft}$	53	feet

Reagent Data:

Type of reagent used

Ammonia

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

Density = 56 lb/ft³

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NOx}_{\text{in}} \times Q_{\text{g}} \times \text{EF} \times \text{SRF} \times \text{MW}_{\text{R}}) / \text{MW}_{\text{NOx}} =$	6	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}} / \text{CSol} =$	19	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density}$	3	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24) / \text{Reagent Density} =$	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) =	$A \times 1,000 \times 0.0056 \times (\text{CoalF} \times \text{HRF})^{0.43} =$ 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)

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

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)

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

Annual Maintenance Cost =	$0.005 \times TCI =$	\$53,442 in 2019 dollars
Annual Reagent Cost =	$m_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$77,389 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$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
	$n_{\text{scr}} \times \text{Vol}_{\text{cat}} \times (CC_{\text{replace}}/R_{\text{layer}}) \times \text{FWF}$	
Direct Annual Cost =		\$1,342,176 in 2019 dollars

Indirect Annual Cost (IDAC)

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

Administrative Charges (AC) =	$0.03 \times (\text{Operator Cost} + 0.4 \times \text{Annual Maintenance Cost}) =$	\$3,219 in 2019 dollars
Capital Recovery Costs (CR)=	$\text{CRF} \times TCI =$	\$739,642 in 2019 dollars
Indirect Annual Cost (IDAC) =	$AC + CR =$	\$742,861 in 2019 dollars

Cost Effectiveness

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

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 burning 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 (NO _{x,in}) to SCR	0.341 lb/MMBtu
Outlet NO _x Emissions (NO _{x,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.

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.

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.

Select the reagent used Ammonia ▼

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

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

Densities of typical SCR reagents:

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

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 .	
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) =	$(Q_B \times 1.0E6 \times 8760)/HHV =$	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}) =	$(Mactual/Mfuel) \times (tscr/tplant) =$	0.708	fraction	
Total operating time for the SCR (t_{op}) =	$CF_{total} \times 8760 =$	8760	hours	Based on 8760 (PTE)
NOx Removal Efficiency (EF) =	$(NO_{x_{in}} - NO_{x_{out}})/NO_{x_{in}} =$	90.0	percent	
NOx removed per hour =	$NO_{x_{in}} \times EF \times Q_B =$	171.66	lb/hour	
Total NO _x removed per year =	$(NO_{x_{in}} \times EF \times Q_B \times t_{op})/2000 =$	532.08	tons/year	Based on PSEL of 591.2
NO _x removal factor (NRF) =	EF/80 =	1.13		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	$Q_{fuel} \times Q_B \times (460 + T)/(460 + 700)n_{scr} =$	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 =	$(\%S/100) \times (64/32) \times 1 \times 10^6 / HHV =$			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) =	$2116 \times [(59 - (0.00356 \times h)) + 459.7] / 518.6^{5.256} \times (1/144)^* =$	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) =	$(\text{interest rate})(1/((1 + \text{interest rate})^Y - 1))$, where $Y = H_{\text{catalysts}}/(t_{\text{SCR}} \times 24 \text{ hours})$ rounded to the nearest integer	0.3180	Fraction
Catalyst volume ($\text{Vol}_{\text{catalyst}}$) =	$2.81 \times Q_B \times EF_{\text{adj}} \times \text{Slip}_{\text{adj}} \times \text{NOx}_{\text{adj}} \times S_{\text{adj}} \times (T_{\text{adj}}/N_{\text{scr}})$	2,422.86	Cubic feet
Cross sectional area of the catalyst (A_{catalyst}) =	$q_{\text{flue gas}} / (16\text{ft/sec} \times 60 \text{ sec/min})$	241	ft^2
Height of each catalyst layer (H_{layer}) =	$(\text{Vol}_{\text{catalyst}} / (R_{\text{layer}} \times A_{\text{catalyst}})) + 1$ (rounded to next highest integer)	4	feet

SCR Reactor Data:

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

Reagent Data:

Type of reagent used

Ammonia

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

Density = 56 lb/ft³

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NOx}_{\text{in}} \times Q_{\text{g}} \times \text{EF} \times \text{SRF} \times \text{MW}_{\text{R}}) / \text{MW}_{\text{NOx}} =$	67	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}} / \text{CSol} =$	230	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density}$	31	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24) / \text{Reagent Density} =$	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) =	$A \times 1,000 \times 0.0056 \times (\text{CoalF} \times \text{HRF})^{0.43} =$ 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)

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

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)

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

Annual Maintenance Cost =	$0.005 \times TCI =$	\$72,243 in 2019 dollars
Annual Reagent Cost =	$m_{sol} \times \text{Cost}_{reag} \times t_{op} =$	\$950,277 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{elect} \times t_{op} =$	\$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
	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	
Direct Annual Cost =		\$3,441,336 in 2019 dollars

Indirect Annual Cost (IDAC)

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

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

Cost Effectiveness

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

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

Table A-24a - SCR 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 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 burning 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 SCR reactor chambers (n_{SCR})	1
Number of days the boiler operates (t_{plant})	183 days	Number of catalyst layers (R_{layer})	3
Inlet NO _x Emissions (NO _{x,in}) to SCR	0.465 lb/MMBtu	Number of empty catalyst layers (R_{empty})	1
Outlet NO _x Emissions (NO _{x,out}) from SCR	0.046 lb/MMBtu	Ammonia Slip (Slip) provided by vendor	2 ppm
Stoichiometric Ratio Factor (SRF)	1.050	Volume of the catalyst layers (Vol _{catalyst}) (Enter "UNK" if value is not known)	UNK Cubic feet
*The SRF value of 1.05 is a default value. User should enter actual value, if known.		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	Gas temperature at the SCR inlet (T)	650 °F
Estimated SCR equipment life	25 Years*	Base case fuel gas volumetric flow rate factor (Q _{fuel})	431 ft ³ /min-MMBtu/hour
* For industrial boilers, the typical equipment life is between 20 and 25 years.			

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

Select the reagent used

Ammonia

<u>Densities of typical SCR reagents:</u>	
50% urea solution	71 lbs/ft ³
29.4% aqueous NH ₃	56 lbs/ft ³

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 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-24a - SCR for GP Wauna Power Boiler

Maintenance and Administrative Charges Cost Factors:

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

0.005
0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost (\$/gallon)	\$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) =	$(Q_B \times 1.0E6 \times 8760)/HHV =$	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}) =	$(Mactual/Mfuel) \times (tscr/tplant) =$	0.233	fraction	
Total operating time for the SCR (t_{op}) =	$CF_{total} \times 8760 =$	4392	hours	Based on 2017 Operating Hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in} =$	90.0	percent	
NOx removed per hour =	$NOx_{in} \times EF \times Q_B =$	234.24	lb/hour	
Total NO _x removed per year =	$(NOx_{in} \times EF \times Q_B \times t_{op})/2000 =$	238.91	tons/year	Based on 2017 Annual Emissions
NO _x removal factor (NRF) =	EF/80 =	1.13		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	$Q_{fuel} \times Q_B \times (460 + T)/(460 + 700)n_{scr} =$	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 =	$(\%S/100) \times (64/32) \times 1 \times 10^6 / HHV =$			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) =	$2116 \times [(59 - (0.00356 \times h)) + 459.7] / 518.6^{5.256} \times (1/144)^* =$	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) =	$(\text{interest rate})(1/((1 + \text{interest rate})^Y - 1))$, where $Y = H_{\text{catalysts}}/(t_{\text{SCR}} \times 24 \text{ hours})$ rounded to the nearest integer	0.1819	Fraction
Catalyst volume ($\text{Vol}_{\text{catalyst}}$) =	$2.81 \times Q_B \times EF_{\text{adj}} \times \text{Slip}_{\text{adj}} \times \text{NOx}_{\text{adj}} \times S_{\text{adj}} \times (T_{\text{adj}}/N_{\text{scr}})$	2,523.22	Cubic feet
Cross sectional area of the catalyst (A_{catalyst}) =	$q_{\text{flue gas}}/(16\text{ft/sec} \times 60 \text{ sec/min})$	241	ft^2
Height of each catalyst layer (H_{layer}) =	$(\text{Vol}_{\text{catalyst}}/(R_{\text{layer}} \times A_{\text{catalyst}})) + 1$ (rounded to next highest integer)	4	feet

SCR Reactor Data:

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

Reagent Data:

Type of reagent used

Ammonia

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

Density = 56 lb/ft³

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NOx}_{\text{in}} \times Q_{\text{g}} \times \text{EF} \times \text{SRF} \times \text{MW}_{\text{R}}) / \text{MW}_{\text{NOx}} =$	91	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}} / \text{C}_{\text{sol}} =$	314	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density}$	42	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24) / \text{Reagent Density} =$	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) =	$A \times 1,000 \times 0.0056 \times (\text{CoalF} \times \text{HRF})^{0.43} =$ 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)

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

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)

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

Annual Maintenance Cost =	$0.005 \times TCI =$	\$72,243 in 2019 dollars
Annual Reagent Cost =	$m_{sol} \times \text{Cost}_{reag} \times t_{op} =$	\$650,133 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{elect} \times t_{op} =$	\$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
	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	
Direct Annual Cost =		\$1,940,597 in 2019 dollars

Indirect Annual Cost (IDAC)

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

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

Cost Effectiveness

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

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 SCR reactor chambers (n_{scr})	1
Number of days the boiler operates (t_{plant})	365 days	Number of catalyst layers (R_{layer})	3
Inlet NO _x Emissions (NO _x _{in}) to SCR	0.256 lb/MMBtu	Number of empty catalyst layers (R_{empty})	1
Outlet NO _x Emissions (NO _x _{out}) from SCR	0.026 lb/MMBtu	Ammonia Slip (Slip) provided by vendor	2 ppm
Stoichiometric Ratio Factor (SRF)	1.050	Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
*The SRF value of 1.05 is a default value. User should enter actual value, if known.		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	Gas temperature at the SCR inlet (T)	650 °F
Estimated SCR equipment life	25 Years*	Base case fuel gas volumetric flow rate factor (Q_{fuel})	484 ft ³ /min-MMBtu/hour
* For industrial boilers, the typical equipment life is between 20 and 25 years.			

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

Select the reagent used

Ammonia ▼

Densities of typical SCR reagents:

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

Table A-25 - 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
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.

Maintenance and Administrative Charges Cost Factors:

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

Table A-25 - 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. $0.47/\text{lb} * 56 \text{ lb}/\text{ft}^3 * 0.134 \text{ ft}^3/\text{gal} = \$3.53/\text{gal}$
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) =	$(Q_B \times 1.0E6 \times 8760)/HHV =$	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}) =	$(Mactual/Mfuel) \times (tscr/tplant) =$	0.833	fraction	
Total operating time for the SCR (t_{op}) =	$CF_{total} \times 8760 =$	8760	hours	Based on 8760 (PTE)
NOx Removal Efficiency (EF) =	$(NO_{x_{in}} - NO_{x_{out}})/NO_{x_{in}} =$	90.0	percent	
NOx removed per hour =	$NO_{x_{in}} \times EF \times Q_B =$	55.33	lb/hour	
Total NO _x removed per year =	$(NO_{x_{in}} \times EF \times Q_B \times t_{op})/2000 =$	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 ($q_{flue\ gas}$) =	$Q_{fuel} \times Q_B \times (460 + T)/(460 + 700)n_{scr} =$	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 =	$(\%S/100) \times (64/32) \times 1 \times 10^6 / HHV =$	< 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) =	$2116 \times [(59 - (0.00356 \times h)) + 459.7] / 518.6^{5.256} \times (1/144)^* =$	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) =	$(\text{interest rate})(1/((1 + \text{interest rate})^Y - 1))$, where $Y = H_{\text{catalysts}}/(t_{\text{SCR}} \times 24 \text{ hours})$ rounded to the nearest integer	0.3180	Fraction
Catalyst volume ($\text{Vol}_{\text{catalyst}}$) =	$2.81 \times Q_B \times EF_{\text{adj}} \times \text{Slip}_{\text{adj}} \times \text{NOx}_{\text{adj}} \times S_{\text{adj}} \times (T_{\text{adj}}/N_{\text{scr}})$	1,012.46	Cubic feet
Cross sectional area of the catalyst (A_{catalyst}) =	$q_{\text{flue gas}} / (16\text{ft/sec} \times 60 \text{ sec/min})$	116	ft^2
Height of each catalyst layer (H_{layer}) =	$(\text{Vol}_{\text{catalyst}} / (R_{\text{layer}} \times A_{\text{catalyst}})) + 1$ (rounded to next highest integer)	4	feet

SCR Reactor Data:

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

Reagent Data:

Type of reagent used

Ammonia

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

Density = 56 lb/ft³

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NOx}_{\text{in}} \times Q_{\text{B}} \times \text{EF} \times \text{SRF} \times \text{MW}_{\text{R}}) / \text{MW}_{\text{NOx}} =$	22	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}} / \text{CSol} =$	74	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density}$	10	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24) / \text{Reagent Density} =$	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) =	$A \times 1,000 \times 0.0056 \times (\text{CoalF} \times \text{HRF})^{0.43} =$ 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:

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

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

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

Reagent Preparation Costs (RPC) =

\$2,587,623 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:

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

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

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

Balance of Plant Costs (BOP_{cost}) =

\$3,380,828 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

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

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)

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

Annual Maintenance Cost =	$0.005 \times TCI =$	\$103,387 in 2019 dollars
Annual Reagent Cost =	$m_{sol} \times \text{Cost}_{reag} \times t_{op} =$	\$306,300 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{elect} \times t_{op} =$	\$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 calculate the catalyst replacement cost.		
Method 1 (for all fuel types):	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	* Calculation Method 1 selected.
Method 2 (for coal-fired industrial boilers):	$(Q_g/NPHR) \times 0.4 \times (CoalF)^{2.9} \times (NRF)^{0.71} \times (CC_{replace}) \times 35.3$	
Direct Annual Cost =		\$1,608,638 in 2019 dollars

Indirect Annual Cost (IDAC)

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

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

Cost Effectiveness

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

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

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

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?

Industrial ▼

What type of fuel does the unit burn?

Coal ▼

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

Retrofit ▼

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

1.5

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

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?

240 MMBtu/hour

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

4,500 Btu/lb

What is the estimated actual annual fuel consumption?

162,094,000 lbs/year

Enter the net plant heat input rate (NPHR)

10 MMBtu/MW

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

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

Plant Elevation

20 Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned:

Bituminous ▼

Enter the sulfur content (%S) =

0.07 percent by weight

For units burning coal blends:

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

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

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

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

- ☒ Method 1
☐ Method 2
☐ Not applicable

Enter the following design parameters for the proposed SCR:

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

Number of days the SCR operates (t_{SCR})	341 days	Number of SCR reactor chambers (n_{scr})	1
Number of days the boiler operates (t_{plant})	341 days	Number of catalyst layers (R_{layer})	3
Inlet NO _x Emissions (NO _x _{in}) to SCR	0.467 lb/MMBtu	Number of empty catalyst layers (R_{empty})	1
Outlet NO _x Emissions (NO _x _{out}) from SCR	0.047 lb/MMBtu	Ammonia Slip (Slip) provided by vendor	2 ppm
Stoichiometric Ratio Factor (SRF)	1.050	Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
<div>*The SRF value of 1.05 is a default value. User should enter actual value, if known.</div>		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	Gas temperature at the SCR inlet (T)	650 °F
Estimated SCR equipment life	25 Years*	Base case fuel gas volumetric flow rate factor (Q_{fuel})	484 ft ³ /min-MMBtu/hour
<div>* For industrial boilers, the typical equipment life is between 20 and 25 years.</div>			

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

Select the reagent used

Ammonia

▼

Densities of typical SCR reagents:

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

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 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.

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. $0.47/\text{lb} * 56 \text{ lb}/\text{ft}^3 * 0.134 \text{ ft}^3/\text{gal} = \$3.53/\text{gal}$
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) =	$(Q_B \times 1.0E6 \times 8760)/HHV =$	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}) =	$(Mactual/Mfuel) \times (tscr/tplant) =$	0.347	fraction	
Total operating time for the SCR (t_{op}) =	$CF_{total} \times 8760 =$	8175	hours	Based on 2017 Operating Hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in} =$	90.0	percent	
NOx removed per hour =	$NOx_{in} \times EF \times Q_B =$	100.98	lb/hour	
Total NO _x removed per year =	$(NOx_{in} \times EF \times Q_B \times t_{op})/2000 =$	153.45	tons/year	Based on 2017 Annual Emissions
NO _x removal factor (NRF) =	EF/80 =	1.13		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	$Q_{fuel} \times Q_B \times (460 + T)/(460 + 700)n_{scr} =$	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 =	$(\%S/100) \times (64/32) \times 1 \times 10^6 / HHV =$	< 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) =	$2116 \times [(59 - (0.00356 \times h)) + 459.7] / 518.6^{5.256} \times (1/144)^* =$	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) =	$(\text{interest rate})(1/((1 + \text{interest rate})^Y - 1))$, where $Y = H_{\text{catalysts}}/(t_{\text{SCR}} \times 24 \text{ hours})$ rounded to the nearest integer	0.3180	Fraction
Catalyst volume ($\text{Vol}_{\text{catalyst}}$) =	$2.81 \times Q_B \times EF_{\text{adj}} \times \text{Slip}_{\text{adj}} \times \text{NOx}_{\text{adj}} \times S_{\text{adj}} \times (T_{\text{adj}}/N_{\text{scr}})$	1,085.90	Cubic feet
Cross sectional area of the catalyst (A_{catalyst}) =	$q_{\text{flue gas}} / (16\text{ft/sec} \times 60 \text{ sec/min})$	116	ft^2
Height of each catalyst layer (H_{layer}) =	$(\text{Vol}_{\text{catalyst}} / (R_{\text{layer}} \times A_{\text{catalyst}})) + 1$ (rounded to next highest integer)	4	feet

SCR Reactor Data:

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

Reagent Data:

Type of reagent used

Ammonia

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

Density = 56 lb/ft³

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NOx}_{\text{in}} \times Q_{\text{g}} \times \text{EF} \times \text{SRF} \times \text{MW}_{\text{R}}) / \text{MW}_{\text{NOx}} =$	39	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}} / \text{Csol} =$	135	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density}$	18	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24) / \text{Reagent Density} =$	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) =	$A \times 1,000 \times 0.0056 \times (\text{CoalF} \times \text{HRF})^{0.43} =$ 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:

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

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

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

Reagent Preparation Costs (RPC) =

\$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:

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

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

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

Balance of Plant Costs (BOP_{cost}) =

\$3,380,828 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

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

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)

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

Annual Maintenance Cost =	$0.005 \times \text{TCl} =$	\$106,117 in 2019 dollars
Annual Reagent Cost =	$m_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$521,660 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$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 calculate the catalyst replacement cost.		
Method 1 (for all fuel types):	$n_{\text{scr}} \times \text{Vol}_{\text{cat}} \times (\text{CC}_{\text{replace}}/\text{R}_{\text{layer}}) \times \text{FWF}$	* Calculation Method 1 selected.
Method 2 (for coal-fired industrial boilers):	$(Q_{\text{g}}/\text{NPHR}) \times 0.4 \times (\text{CoalF})^{2.9} \times (\text{NRF})^{0.71} \times (\text{CC}_{\text{replace}}) \times 35.3$	
Direct Annual Cost =		\$1,750,054 in 2019 dollars

Indirect Annual Cost (IDAC)

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

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

Cost Effectiveness

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

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 burning 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-26 - SCR for IP Springfield 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 (NO_{x,in}) to SCR

0.46 lb/MMBtu

Outlet NO_x Emissions (NO_{x,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 °F

Base case fuel gas volumetric flow rate factor (Q_{fuel})431 ft³/min-MMBtu/hourConcentration of reagent as stored (C_{stored})

50

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.

Select the reagent used

Ammonia

Densities of typical SCR reagents:

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

Table A-26 - 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 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.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =

0.005

Administrative Charges Factor (ACF) =

0.03

Table A-26 - SCR for IP Springfield Power Boiler

Data Sources for Default Values Used in Calculations:

Data Element		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 .	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/ft ³ * 0.134 ft ³ /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) =	$(Q_B \times 1.0E6 \times 8760)/HHV =$	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}) =	$(Mactual/Mfuel) \times (tscr/tplant) =$	0.797	fraction	
Total operating time for the SCR (t_{op}) =	$CF_{total} \times 8760 =$	8760	hours	Based on 8760 (PTE)
NOx Removal Efficiency (EF) =	$(NO_{x_{in}} - NO_{x_{out}})/NO_{x_{in}} =$	90.0	percent	
NOx removed per hour =	$NO_{x_{in}} \times EF \times Q_B =$	225.22	lb/hour	
Total NO _x removed per year =	$(NO_{x_{in}} \times EF \times Q_B \times t_{op})/2000 =$	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 ($q_{flue\ gas}$) =	$Q_{fuel} \times Q_B \times (460 + T)/(460 + 700)n_{scr} =$	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 =	$(\%S/100) \times (64/32) \times 1 \times 10^6 / HHV =$			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) =	$2116 \times [(59 - (0.00356 \times h)) + 459.7] / 518.6^{5.256} \times (1/144)^* =$	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) =	$(\text{interest rate})(1/((1 + \text{interest rate})^Y - 1))$, where $Y = H_{\text{catalysts}}/(t_{\text{SCR}} \times 24 \text{ hours})$ rounded to the nearest integer	0.3180	Fraction
Catalyst volume ($\text{Vol}_{\text{catalyst}}$) =	$2.81 \times Q_B \times EF_{\text{adj}} \times \text{Slip}_{\text{adj}} \times \text{NOx}_{\text{adj}} \times S_{\text{adj}} \times (T_{\text{adj}}/N_{\text{scr}})$	2,447.38	Cubic feet
Cross sectional area of the catalyst (A_{catalyst}) =	$q_{\text{flue gas}} / (16\text{ft/sec} \times 60 \text{ sec/min})$	234	ft^2
Height of each catalyst layer (H_{layer}) =	$(\text{Vol}_{\text{catalyst}} / (R_{\text{layer}} \times A_{\text{catalyst}})) + 1$ (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	$1.15 \times A_{\text{catalyst}}$	269	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{\text{SCR}})^{0.5}$	16.4	feet
Reactor height =	$(R_{\text{layer}} + R_{\text{empty}}) \times (7\text{ft} + h_{\text{layer}}) + 9\text{ft}$	55	feet

Reagent Data:

Type of reagent used

Ammonia

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

Density = 56 lb/ft³

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NOx}_{\text{in}} \times Q_{\text{g}} \times \text{EF} \times \text{SRF} \times \text{MW}_{\text{R}}) / \text{MW}_{\text{NOx}} =$	88	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}} / \text{Csol} =$	302	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density}$	40	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24) / \text{Reagent Density} =$	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) =	$A \times 1,000 \times 0.0056 \times (\text{CoalF} \times \text{HRF})^{0.43} =$ 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)

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

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)

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

Annual Maintenance Cost =	$0.005 \times \text{TCI} =$	\$70,894 in 2019 dollars
Annual Reagent Cost =	$m_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$1,246,736 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$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
	$n_{\text{scr}} \times \text{Vol}_{\text{cat}} \times (\text{CC}_{\text{replace}}/R_{\text{layer}}) \times \text{FWF}$	
Direct Annual Cost =		\$2,637,164 in 2019 dollars

Indirect Annual Cost (IDAC)

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

Administrative Charges (AC) =	$0.03 \times (\text{Operator Cost} + 0.4 \times \text{Annual Maintenance Cost}) =$	\$3,479 in 2019 dollars
Capital Recovery Costs (CR)=	$\text{CRF} \times \text{TCI} =$	\$981,178 in 2019 dollars
Indirect Annual Cost (IDAC) =	$\text{AC} + \text{CR} =$	\$984,657 in 2019 dollars

Cost Effectiveness

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

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

*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

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 burning 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:

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

351 days

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

351 days

Inlet NO_x Emissions (NO_{x,in}) to SCR

0.22 lb/MMBtu

Outlet NO_x Emissions (NO_{x,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 ft³/min-MMBtu/hourConcentration of reagent as stored (C_{stored})

50

Density of reagent as stored (ρ_{stored})

29 percent*

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.

Select the reagent used

Ammonia

Densities of typical SCR reagents:

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

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
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})	\$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst)	227.00	* \$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		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 .	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/ft ³ * 0.134 ft ³ /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) =	$(Q_B \times 1.0E6 \times 8760)/HHV =$	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}) =	$(Mactual/Mfuel) \times (tscr/tplant) =$	0.268	fraction	
Total operating time for the SCR (t_{op}) =	$CF_{total} \times 8760 =$	8424	hours	Based on 2017 Operating Hours
NOx Removal Efficiency (EF) =	$(NO_{x_{in}} - NO_{x_{out}})/NO_{x_{in}} =$	90.0	percent	
NOx removed per hour =	$NO_{x_{in}} \times EF \times Q_B =$	107.71	lb/hour	
Total NO _x removed per year =	$(NO_{x_{in}} \times EF \times Q_B \times t_{op})/2000 =$	126.31	tons/year	Based on 2017 Actual Emissions
NO _x removal factor (NRF) =	EF/80 =	1.13		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	$Q_{fuel} \times Q_B \times (460 + T)/(460 + 700)n_{scr} =$	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 =	$(\%S/100) \times (64/32) \times 1 \times 10^6 / HHV =$			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) =	$2116 \times [(59 - (0.00356 \times h)) + 459.7] / 518.6^{5.256} \times (1/144)^* =$	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) =	$(\text{interest rate})(1/((1 + \text{interest rate})^Y - 1))$, where $Y = H_{\text{catalysts}}/(t_{\text{SCR}} \times 24 \text{ hours})$ rounded to the nearest integer	0.3180	Fraction
Catalyst volume ($\text{Vol}_{\text{catalyst}}$) =	$2.81 \times Q_B \times EF_{\text{adj}} \times \text{Slip}_{\text{adj}} \times \text{NOx}_{\text{adj}} \times S_{\text{adj}} \times (T_{\text{adj}}/N_{\text{scr}})$	2,258.95	Cubic feet
Cross sectional area of the catalyst (A_{catalyst}) =	$q_{\text{flue gas}} / (16\text{ft/sec} \times 60 \text{ sec/min})$	234	ft^2
Height of each catalyst layer (H_{layer}) =	$(\text{Vol}_{\text{catalyst}} / (R_{\text{layer}} \times A_{\text{catalyst}})) + 1$ (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	$1.15 \times A_{\text{catalyst}}$	269	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{\text{SCR}})^{0.5}$	16.4	feet
Reactor height =	$(R_{\text{layer}} + R_{\text{empty}}) \times (7\text{ft} + h_{\text{layer}}) + 9\text{ft}$	54	feet

Reagent Data:

Type of reagent used

Ammonia

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

Density = 56 lb/ft³

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NOx}_{\text{in}} \times Q_{\text{g}} \times \text{EF} \times \text{SRF} \times \text{MW}_{\text{R}}) / \text{MW}_{\text{NOx}} =$	42	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}} / \text{Csol} =$	144	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density}$	19	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24) / \text{Reagent Density} =$	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) =	$A \times 1,000 \times 0.0056 \times (\text{CoalF} \times \text{HRF})^{0.43} =$ 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)

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

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)

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

Annual Maintenance Cost =	$0.005 \times TCI =$	\$70,894 in 2019 dollars
Annual Reagent Cost =	$m_{sol} \times \text{Cost}_{reag} \times t_{op} =$	\$573,394 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{elect} \times t_{op} =$	\$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
	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	
Direct Annual Cost =		\$1,910,935 in 2019 dollars

Indirect Annual Cost (IDAC)

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

Administrative Charges (AC) =	$0.03 \times (\text{Operator Cost} + 0.4 \times \text{Annual Maintenance Cost}) =$	\$3,378 in 2019 dollars
Capital Recovery Costs (CR)=	$CRF \times TCI =$	\$981,178 in 2019 dollars
Indirect Annual Cost (IDAC) =	$AC + CR =$	\$984,556 in 2019 dollars

Cost Effectiveness

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

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 burning 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 SCR reactor chambers (n_{scr})	1
Number of days the boiler operates (t_{plant})	365 days	Number of catalyst layers (R_{layer})	3
Inlet NO _x Emissions (NO _{x,in}) to SCR	0.2 lb/MMBtu	Number of empty catalyst layers (R_{empty})	1
Outlet NO _x Emissions (NO _{x,out}) from SCR	0.02 lb/MMBtu	Ammonia Slip (Slip) provided by vendor	2 ppm
Stoichiometric Ratio Factor (SRF)	1.050	Volume of the catalyst layers (Vol _{catalyst}) (Enter "UNK" if value is not known)	UNK Cubic feet
*The SRF value of 1.05 is a default value. User should enter actual value, if known.		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	Gas temperature at the SCR inlet (T)	650 °F
Estimated SCR equipment life	25 Years*	Base case fuel gas volumetric flow rate factor (Q _{fuel})	431 ft ³ /min-MMBtu/hour
* For industrial boilers, the typical equipment life is between 20 and 25 years.			

Concentration of reagent as stored (C _{stored})	29 percent*	*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.
Density of reagent as stored (ρ _{stored})	56 lb/cubic feet*	
Number of days reagent is stored (t _{storage})	14 days	

Select the reagent used
Ammonia

Densities of typical SCR reagents:
50% urea solution 71 lbs/ft³
29.4% aqueous NH₃ 56 lbs/ft³

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.

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		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 .	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) =	$(Q_B \times 1.0E6 \times 8760)/HHV =$	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}) =	$(Mactual/Mfuel) \times (tscr/tplant) =$	1.000	fraction	
Total operating time for the SCR (t_{op}) =	$CF_{total} \times 8760 =$	8760	hours	Based on 8760 (PTE)
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in} =$	90.0	percent	
NOx removed per hour =	$NOx_{in} \times EF \times Q_B =$	61.20	lb/hour	
Total NO _x removed per year =	$(NOx_{in} \times EF \times Q_B \times t_{op})/2000 =$	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 ($q_{flue\ gas}$) =	$Q_{fuel} \times Q_B \times (460 + T)/(460 + 700)n_{scr} =$	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 =	$(\%S/100) \times (64/32) \times 1 \times 10^6 / HHV =$			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) =	$2116 \times [(59 - (0.00356 \times h)) + 459.7] / 518.6^{5.256} \times (1/144)^* =$	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) =	$(\text{interest rate})(1/((1 + \text{interest rate})^Y - 1))$, where $Y = H_{\text{catalysts}}/(t_{\text{SCR}} \times 24 \text{ hours})$ rounded to the nearest integer	0.3180	Fraction
Catalyst volume ($\text{Vol}_{\text{catalyst}}$) =	$2.81 \times Q_B \times EF_{\text{adj}} \times \text{Slip}_{\text{adj}} \times \text{NOx}_{\text{adj}} \times S_{\text{adj}} \times (T_{\text{adj}}/N_{\text{scr}})$	1,402.03	Cubic feet
Cross sectional area of the catalyst (A_{catalyst}) =	$q_{\text{flue gas}} / (16\text{ft/sec} \times 60 \text{ sec/min})$	146	ft^2
Height of each catalyst layer (H_{layer}) =	$(\text{Vol}_{\text{catalyst}} / (R_{\text{layer}} \times A_{\text{catalyst}})) + 1$ (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	$1.15 \times A_{\text{catalyst}}$	168	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{\text{SCR}})^{0.5}$	13.0	feet
Reactor height =	$(R_{\text{layer}} + R_{\text{empty}}) \times (7\text{ft} + h_{\text{layer}}) + 9\text{ft}$	54	feet

Reagent Data:

Type of reagent used

Ammonia

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

Density = 56 lb/ft³

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NOx}_{\text{in}} \times Q_{\text{B}} \times \text{EF} \times \text{SRF} \times \text{MW}_{\text{R}}) / \text{MW}_{\text{NOx}} =$	24	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}} / \text{C}_{\text{sol}} =$	82	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density}$	11	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24) / \text{Reagent Density} =$	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) =	$A \times 1,000 \times 0.0056 \times (\text{CoalF} \times \text{HRF})^{0.43} =$ 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)

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

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)

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

Annual Maintenance Cost =	$0.005 \times TCI =$	\$52,232 in 2019 dollars
Annual Reagent Cost =	$m_{sol} \times \text{Cost}_{reag} \times t_{op} =$	\$338,787 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{elect} \times t_{op} =$	\$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
	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	
Direct Annual Cost =		\$1,404,282 in 2019 dollars

Indirect Annual Cost (IDAC)

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

Administrative Charges (AC) =	$0.03 \times (\text{Operator Cost} + 0.4 \times \text{Annual Maintenance Cost}) =$	\$3,255 in 2019 dollars
Capital Recovery Costs (CR)=	$CRF \times TCI =$	\$722,886 in 2019 dollars
Indirect Annual Cost (IDAC) =	$AC + CR =$	\$726,141 in 2019 dollars

Cost Effectiveness

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

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 ▼

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?

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 burning 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 SCR reactor chambers (n_{scr})	1
Number of days the boiler operates (t_{plant})	17 days	Number of catalyst layers (R_{layer})	3
Inlet NO_x Emissions ($NO_{x,in}$) to SCR	0.07 lb/MMBtu	Number of empty catalyst layers (R_{empty})	1
Outlet NO_x Emissions ($NO_{x,out}$) from SCR	0.007 lb/MMBtu	Ammonia Slip (Slip) provided by vendor	2 ppm
Stoichiometric Ratio Factor (SRF)	1.050	Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
*The SRF value of 1.05 is a default value. User should enter actual value, if known.		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	Gas temperature at the SCR inlet (T)	650 °F
Estimated SCR equipment life	25 Years*	Base case fuel gas volumetric flow rate factor (Q_{fuel})	431 ft ³ /min-MMBtu/hour
* For industrial boilers, the typical equipment life is between 20 and 25 years.			

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

Select the reagent used

Ammonia

Densities of typical SCR reagents:
 50% urea solution 71 lbs/ft³
 29.4% aqueous NH₃ 56 lbs/ft³

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-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			If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost (\$/gallon)	/gallon 50% urea so \$0.293/gallon 29% ammonia solution	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 .	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) =	$(Q_B \times 1.0E6 \times 8760)/HHV =$	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}) =	$(Mactual/Mfuel) \times (tscr/tplant) =$	0.013	fraction	
Total operating time for the SCR (t_{op}) =	$CF_{total} \times 8760 =$	394	hours	Based on 2017 Operating Hours
NOx Removal Efficiency (EF) =	$(NO_{x_{in}} - NO_{x_{out}})/NO_{x_{in}} =$	90.0	percent	
NOx removed per hour =	$NO_{x_{in}} \times EF \times Q_B =$	21.42	lb/hour	
Total NO _x removed per year =	$(NO_{x_{in}} \times EF \times Q_B \times t_{op})/2000 =$	1.26	tons/year	Based on 2017 Annual Emissions
NO _x removal factor (NRF) =	EF/80 =	1.13		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	$Q_{fuel} \times Q_B \times (460 + T)/(460 + 700)n_{scr} =$	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 =	$(\%S/100) \times (64/32) \times 1 \times 10^6 / HHV =$			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) =	$2116 \times [(59 - (0.00356 \times h)) + 459.7] / 518.6^{5.256} \times (1/144)^* =$	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) =	$(\text{interest rate})(1/((1 + \text{interest rate})^Y - 1))$, where $Y = H_{\text{catalysts}}/(t_{\text{SCR}} \times 24 \text{ hours})$ rounded to the nearest integer	0.0033	Fraction
Catalyst volume ($\text{Vol}_{\text{catalyst}}$) =	$2.81 \times Q_B \times EF_{\text{adj}} \times \text{Slip}_{\text{adj}} \times \text{NOx}_{\text{adj}} \times S_{\text{adj}} \times (T_{\text{adj}}/N_{\text{scr}})$	1,338.24	Cubic feet
Cross sectional area of the catalyst (A_{catalyst}) =	$q_{\text{flue gas}} / (16\text{ft/sec} \times 60 \text{ sec/min})$	146	ft^2
Height of each catalyst layer (H_{layer}) =	$(\text{Vol}_{\text{catalyst}} / (R_{\text{layer}} \times A_{\text{catalyst}})) + 1$ (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	$1.15 \times A_{\text{catalyst}}$	168	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{\text{SCR}})^{0.5}$	13.0	feet
Reactor height =	$(R_{\text{layer}} + R_{\text{empty}}) \times (7\text{ft} + h_{\text{layer}}) + 9\text{ft}$	53	feet

Reagent Data:

Type of reagent used

Ammonia

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

Density = 56 lb/ft³

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NOx}_{\text{in}} \times Q_{\text{g}} \times \text{EF} \times \text{SRF} \times \text{MW}_{\text{R}}) / \text{MW}_{\text{NOx}} =$	8	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}} / \text{CSol} =$	29	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density}$	4	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24) / \text{Reagent Density} =$	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) =	$A \times 1,000 \times 0.0056 \times (\text{CoalF} \times \text{HRF})^{0.43} =$ 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)

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

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)

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

Annual Maintenance Cost =	$0.005 \times \text{TCI} =$	\$52,232 in 2019 dollars
Annual Reagent Cost =	$m_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$5,335 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$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
	$n_{\text{scr}} \times \text{Vol}_{\text{cat}} \times (\text{CC}_{\text{replace}}/R_{\text{layer}}) \times \text{FWF}$	
Direct Annual Cost =		\$101,968 in 2019 dollars

Indirect Annual Cost (IDAC)

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

Administrative Charges (AC) =	$0.03 \times (\text{Operator Cost} + 0.4 \times \text{Annual Maintenance Cost}) =$	\$749 in 2019 dollars
Capital Recovery Costs (CR)=	$\text{CRF} \times \text{TCI} =$	\$722,886 in 2019 dollars
Indirect Annual Cost (IDAC) =	$\text{AC} + \text{CR} =$	\$723,635 in 2019 dollars

Cost Effectiveness

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

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)			ANNUALIZED COSTS			
COST ITEM	COST FACTOR	COST (\$)	COST ITEM	COST FACTOR	RATE	COST (\$)
Direct Costs			Direct Annual Costs			
<u>Purchased Equipment Costs</u>			<u>Operating Labor^(c)</u>			
(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	<u>Maintenance^(e)</u>			
B Total Purchased Equipment Cost		\$5,448,095	(b) Maintenance labor	hours/shift	\$34.00 per hour ^(d)	\$0
<u>Direct Installation Costs</u>			(b) Maintenance materials	of purchased equipment costs		\$0
(b) Foundations and Supports ^(c)	0.04 B	\$0	<u>Utilities^(e)</u>			
(b) Handling and Erection	0.50 B	\$2,724,047	Additional Electricity	299 kW	\$0.060 per kWh ^(b)	\$156,937
(b) Electrical	0.08 B	\$435,848	Total Direct Annual Costs			
(b) Piping	0.01 B	\$54,481				\$156,937
(b) Insulation	0.02 B	\$108,962	Indirect Annual Costs			
(b) Painting	0.02 B	\$108,962	(c) Overhead	60% Labor and Material Costs		\$0
Direct Installation Cost		\$3,432,300	(c) General and administrative	2% of TCI		\$0
Total Direct Costs		\$8,880,395	(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	Total Indirect Annual Costs			
(b) Start-up	0.01 B	\$54,481				\$1,181,207
(b) Performance test	0.01 B	\$54,481	Total Annual Costs			
(b) Model Study	0.02 B	\$108,962				\$1,338,144
(b) Contingencies	0.03 B	\$163,443	Cost Effectiveness (\$/ton)			
Total Indirect Costs		\$3,105,414	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) :	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 PM₁₀ 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			
<u>Purchased Equipment Costs</u>			<u>Operating Labor^(c)</u>			
(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	<u>Maintenance^(e)</u>			
B Total Purchased Equipment Cost		\$5,448,095	(b) Maintenance labor	hours/shift	\$34.00 per hour ^(d)	\$0
<u>Direct Installation Costs</u>			(b) Maintenance materials	of purchased equipment costs		\$0
(b) Foundations and Supports ^(c)	0.04 B	\$0	<u>Utilities^(e)</u>			
(b) Handling and Erection	0.50 B	\$2,724,047	Additional Electricity	299 kW	\$0.060 per kWh ^(b)	\$151,938
(b) Electrical	0.08 B	\$435,848	Total Direct Annual Costs			
(b) Piping	0.01 B	\$54,481				\$151,938
(b) Insulation	0.02 B	\$108,962	Indirect Annual Costs			
(b) Painting	0.02 B	\$108,962	(c) Overhead	60% Labor and Material Costs		\$0
Direct Installation Cost		\$3,432,300	(c) General and administrative	2% of TCI		\$0
Total Direct Costs		\$8,880,395	(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	Total Indirect Annual Costs			
(b) Start-up	0.01 B	\$54,481				\$1,181,207
(b) Performance test	0.01 B	\$54,481	Total Annual Costs			
(b) Model Study	0.02 B	\$108,962				\$1,333,145
(b) Contingencies	0.03 B	\$163,443	Cost Effectiveness (\$/ton)			
Total Indirect Costs		\$3,105,414	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 PM₁₀ 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)			ANNUALIZED COSTS			
COST ITEM	COST FACTOR	COST (\$)	COST ITEM	COST FACTOR	RATE	COST (\$)
Direct Costs			Direct Annual Costs			
<u>Purchased Equipment Costs</u>			<u>Operating Labor^(c)</u>			
(a) A ESP		\$3,148,314	(b) Operator	hours/shift	\$31.00 per hour ^(d)	\$0
(b) Instrumentation	0.10 A	\$314,831	(b) Supervisor	of operator labor		\$0
(b) Sales Tax	0.03 A	\$94,449	(b) Coordinator	of operator labor		\$0
(b) Freight	0.05 A	\$157,416	<u>Maintenance^(e)</u>			
B Total Purchased Equipment Cost		\$3,715,011	(b) Maintenance labor	hours/shift	\$34.00 per hour ^(d)	\$0
<u>Direct Installation Costs</u>			(b) Maintenance materials	of purchased equipment costs		\$0
(b) Foundations and Supports ^(c)	0.04 B	\$0	<u>Utilities^(e)</u>			
(b) Handling and Erection	0.50 B	\$1,857,506	Electricity	158 kW	\$0.060 per kWh ^(b)	\$82,906
(b) Electrical	0.08 B	\$297,201	Total Direct Annual Costs			
(b) Piping	0.01 B	\$37,150				\$82,906
(b) Insulation	0.02 B	\$74,300	Indirect Annual Costs			
(b) Painting	0.02 B	\$74,300	(c) Overhead	60% Labor and Material Costs		\$0
Direct Installation Cost		\$2,340,457	(c) General and administrative	2% of TCI		\$0
Total Direct Costs		\$6,055,468	(b) Property taxes	1% of TCI		\$81,730
Indirect Costs			(b) Insurance	1% of TCI		\$81,730
(b) Engineering	0.20 B	\$743,002	(b) Capital recovery	0.079 x TCI		\$641,995
(b) Construction Management	0.20 B	\$743,002	Life of the control:	20 years at	4.75% interest	
(b) Contractor fees	0.10 B	\$371,501	Total Indirect Annual Costs			
(b) Start-up	0.01 B	\$37,150				\$805,455
(b) Performance test	0.01 B	\$37,150	Total Annual Costs			
(b) Model Study	0.02 B	\$74,300				\$888,361
(b) Contingencies	0.03 B	\$111,450	Cost Effectiveness (\$/ton)			
Total Indirect Costs		\$2,117,556	PM ₁₀ Control Efficiency ^(f) :	99.5%		
Total Capital Investment (TCI)^(a)		\$8,173,024	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 PM₁₀ 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)			ANNUALIZED COSTS			
COST ITEM	COST FACTOR	COST (\$)	COST ITEM	COST FACTOR	RATE	COST (\$)
Direct Costs			Direct Annual Costs			
<u>Purchased Equipment Costs</u>			<u>Operating Labor^(c)</u>			
(a) A ESP		\$3,148,314	(b) Operator	hours/shift	\$31.00 per hour ^(d)	\$0
(b) Instrumentation	0.10 A	\$314,831	(b) Supervisor	of operator labor		\$0
(b) Sales Tax	0.03 A	\$94,449	(b) Coordinator	of operator labor		\$0
(b) Freight	0.05 A	\$157,416	<u>Maintenance^(e)</u>			
B Total Purchased Equipment Cost		\$3,715,011	(b) Maintenance labor	hours/shift	\$34.00 per hour ^(d)	\$0
<u>Direct Installation Costs</u>			(b) Maintenance materials	of purchased equipment costs		\$0
(b) Foundations and Supports ^(c)	0.04 B	\$0	<u>Utilities^(e)</u>			
(b) Handling and Erection	0.50 B	\$1,857,506	Electricity	158 kW	\$0.060 per kWh ^(b)	\$76,934
(b) Electrical	0.08 B	\$297,201	Total Direct Annual Costs			
(b) Piping	0.01 B	\$37,150				\$76,934
(b) Insulation	0.02 B	\$74,300	Indirect Annual Costs			
(b) Painting	0.02 B	\$74,300	(c) Overhead	60% Labor and Material Costs		\$0
Direct Installation Cost		\$2,340,457	(c) General and administrative	2% of TCI		\$0
Total Direct Costs		\$6,055,468	(b) Property taxes	1% of TCI		\$81,730
Indirect Costs			(b) Insurance	1% of TCI		\$81,730
(b) Engineering	0.20 B	\$743,002	(b) Capital recovery	0.079 x TCI		\$641,995
(b) Construction Management	0.20 B	\$743,002	Life of the control: 20 years at 4.75% interest			
(b) Contractor fees	0.10 B	\$371,501	Total Indirect Annual Costs			
(b) Start-up	0.01 B	\$37,150				\$805,455
(b) Performance test	0.01 B	\$37,150	Total Annual Costs			
(b) Model Study	0.02 B	\$74,300				\$882,389
(b) Contingencies	0.03 B	\$111,450	Cost Effectiveness (\$/ton)			
Total Indirect Costs		\$2,117,556	PM ₁₀ Control Efficiency ^(f) :	99.5%		
Total Capital Investment (TCI)^(a)		\$8,173,024	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 PM₁₀ 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)			ANNUALIZED COSTS			
COST ITEM	COST FACTOR	COST (\$)	COST ITEM	COST FACTOR	RATE	COST (\$)
Direct Costs			Direct Annual Costs			
<u>Purchased Equipment Costs</u>			<u>Operating Labor^(c)</u>			
(a) A ESP		\$3,148,314	(b) Operator	hours/shift	\$31.00 per hour ^(d)	\$0
(b) Instrumentation	0.10 A	\$314,831	(b) Supervisor	of operator labor		\$0
(b) Sales Tax	0.03 A	\$94,449	(b) Coordinator	of operator labor		\$0
(b) Freight	0.05 A	\$157,416	<u>Maintenance^(e)</u>			
B Total Purchased Equipment Cost		\$3,715,011	(b) Maintenance labor	hours/shift	\$34.00 per hour ^(d)	\$0
<u>Direct Installation Costs</u>			(b) Maintenance materials	of purchased equipment costs		\$0
(b) Foundations and Supports ^(c)	0.04 B	\$0	<u>Utilities^(e)</u>			
(b) Handling and Erection	0.50 B	\$1,857,506	Electricity	158 kW	\$0.060 per kWh ^(b)	\$82,906
(b) Electrical	0.08 B	\$297,201	Total Direct Annual Costs			
(b) Piping	0.01 B	\$37,150				\$82,906
(b) Insulation	0.02 B	\$74,300	Indirect Annual Costs			
(b) Painting	0.02 B	\$74,300	(c) Overhead	60% Labor and Material Costs		\$0
Direct Installation Cost		\$2,340,457	(c) General and administrative	2% of TCI		\$0
Total Direct Costs		\$6,055,468	(b) Property taxes	1% of TCI		\$81,730
Indirect Costs			(b) Insurance	1% of TCI		\$81,730
(b) Engineering	0.20 B	\$743,002	(b) Capital recovery	0.079 x TCI		\$641,995
(b) Construction Management	0.20 B	\$743,002	Life of the control:	20 years at	4.75% interest	
(b) Contractor fees	0.10 B	\$371,501	Total Indirect Annual Costs			
(b) Start-up	0.01 B	\$37,150				\$805,455
(b) Performance test	0.01 B	\$37,150	Total Annual Costs			
(b) Model Study	0.02 B	\$74,300				\$888,361
(b) Contingencies	0.03 B	\$111,450	Cost Effectiveness (\$/ton)			
Total Indirect Costs		\$2,117,556	PM ₁₀ Control Efficiency ^(f) :	99.5%		
Total Capital Investment (TCI)^(a)		\$8,173,024	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 PM₁₀ 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)			ANNUALIZED COSTS			
COST ITEM	COST FACTOR	COST (\$)	COST ITEM	COST FACTOR	RATE	COST (\$)
Direct Costs			Direct Annual Costs			
<u>Purchased Equipment Costs</u>			<u>Operating Labor^(c)</u>			
(a) A ESP		\$3,148,314	(b) Operator	hours/shift	\$31.00 per hour ^(d)	\$0
(b) Instrumentation	0.10 A	\$314,831	(b) Supervisor	of operator labor		\$0
(b) Sales Tax	0.03 A	\$94,449	(b) Coordinator	of operator labor		\$0
(b) Freight	0.05 A	\$157,416	<u>Maintenance^(e)</u>			
B Total Purchased Equipment Cost		\$3,715,011	(b) Maintenance labor	hours/shift	\$34.00 per hour ^(d)	\$0
<u>Direct Installation Costs</u>			(b) Maintenance materials	of purchased equipment costs		\$0
(b) Foundations and Supports ^(c)	0.04 B	\$0	<u>Utilities^(e)</u>			
(b) Handling and Erection	0.50 B	\$1,857,506	Electricity	158 kW	\$0.060 per kWh ^(b)	\$76,934
(b) Electrical	0.08 B	\$297,201	Total Direct Annual Costs			
(b) Piping	0.01 B	\$37,150				\$76,934
(b) Insulation	0.02 B	\$74,300	Indirect Annual Costs			
(b) Painting	0.02 B	\$74,300	(c) Overhead	60% Labor and Material Costs		\$0
Direct Installation Cost		\$2,340,457	(c) General and administrative	2% of TCI		\$0
Total Direct Costs		\$6,055,468	(b) Property taxes	1% of TCI		\$81,730
Indirect Costs			(b) Insurance	1% of TCI		\$81,730
(b) Engineering	0.20 B	\$743,002	(b) Capital recovery	0.079 x TCI		\$641,995
(b) Construction Management	0.20 B	\$743,002	Life of the control: 20 years at 4.75% interest			
(b) Contractor fees	0.10 B	\$371,501	Total Indirect Annual Costs			
(b) Start-up	0.01 B	\$37,150				\$805,455
(b) Performance test	0.01 B	\$37,150	Total Annual Costs			
(b) Model Study	0.02 B	\$74,300				\$882,389
(b) Contingencies	0.03 B	\$111,450	Cost Effectiveness (\$/ton)			
Total Indirect Costs		\$2,117,556	PM ₁₀ Control Efficiency ^(f) :	99.5%		
Total Capital Investment (TCI)^(a)		\$8,173,024	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 PM₁₀ 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)			ANNUALIZED COSTS			
COST ITEM	COST FACTOR	COST (\$)	COST ITEM	COST FACTOR	RATE	COST (\$)
Direct Costs			Direct Annual Costs			
<u>Purchased Equipment Costs</u>			<u>Operating Labor^(c)</u>			
(a) A ESP		\$5,501,569	(b) Operator	hours/shift	\$31.00 per hour ^(d)	\$0
(b) Instrumentation	0.10 A	\$550,157	(b) Supervisor	of operator labor		\$0
(b) Sales Tax	0.03 A	\$165,047	(b) Coordinator	of operator labor		\$0
(b) Freight	0.05 A	\$275,078	<u>Maintenance^(e)</u>			
B Total Purchased Equipment Cost		\$6,491,852	(b) Maintenance labor	hours/shift	\$34.00 per hour ^(d)	\$0
<u>Direct Installation Costs</u>			(b) Maintenance materials	of purchased equipment costs		\$0
(b) Foundations and Supports ^(c)	0.04 B	\$0	<u>Utilities^(e)</u>			
(b) Handling and Erection	0.50 B	\$3,245,926	Electricity	400 kW	\$0.060 per kWh ^(b)	\$210,183
(b) Electrical	0.08 B	\$519,348	Total Direct Annual Costs			
(b) Piping	0.01 B	\$64,919				\$210,183
(b) Insulation	0.02 B	\$129,837	Indirect Annual Costs			
(b) Painting	0.02 B	\$129,837	(c) Overhead	60% Labor and Material Costs		\$0
Direct Installation Cost		\$4,089,867	(c) General and administrative	2% of TCI		\$0
Total Direct Costs		\$10,581,719	(b) Property taxes	1% of TCI		\$142,821
Indirect Costs			(b) Insurance	1% of TCI		\$142,821
(b) Engineering	0.20 B	\$1,298,370	(b) Capital recovery	0.079 x TCI		\$1,121,864
(b) Construction Management	0.20 B	\$1,298,370	Life of the control:	20 years at	4.75% interest	
(b) Contractor fees	0.10 B	\$649,185	Total Indirect Annual Costs			
(b) Start-up	0.01 B	\$64,919				\$1,407,505
(b) Performance test	0.01 B	\$64,919	Total Annual Costs			
(b) Model Study	0.02 B	\$129,837				\$1,617,688
(b) Contingencies	0.03 B	\$194,756	Cost Effectiveness (\$/ton)			
Total Indirect Costs		\$3,700,356	PM ₁₀ Control Efficiency ^(f) :	99.5%		
Total Capital Investment (TCI)^(a)		\$14,282,074	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 PM₁₀ emissions are estimated by calculating uncontrolled PSEL emissions assuming a 99% control efficiency, controlling emissions by 99.5%, and taking the difference between the PSEL emissions vs. the emissions post upgrade.

Table A-31a
Georgia-Pacific Consumer Products LP - Wauna
Capital and Annual Costs Associated with ESP Upgrade for Recovery Furnace

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

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

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

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

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

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

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

^(g) PM₁₀ 2017 Actual Emissions

^(h) Controlled PM₁₀ 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)			ANNUALIZED COSTS			
COST ITEM	COST FACTOR	COST (\$)	COST ITEM	COST FACTOR	RATE	COST (\$)
Direct Costs			Direct Annual Costs			
<u>Purchased Equipment Costs</u>			<u>Operating Labor^(c)</u>			
(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	<u>Maintenance^(e)</u>			
B Total Purchased Equipment Cost		\$6,366,543	(b) Maintenance labor	hours/shift	\$34.00 per hour ^(d)	\$0
<u>Direct Installation Costs</u>			(b) Maintenance materials	of purchased equipment costs		\$0
(b) Foundations and Supports ^(c)	0.04 B	\$0	<u>Utilities^(e)</u>			
(b) Handling and Erection	0.50 B	\$3,183,271	Electricity	387 kW	\$0.060 per kWh ^(b)	\$203,465
(b) Electrical	0.08 B	\$509,323	Total Direct Annual Costs			
(b) Piping	0.01 B	\$63,665				\$203,465
(b) Insulation	0.02 B	\$127,331	Indirect Annual Costs			
(b) Painting	0.02 B	\$127,331	(c) Overhead	60% Labor and Material Costs		\$0
Direct Installation Cost		\$4,010,922	(c) General and administrative	2% of TCI		\$0
Total Direct Costs		\$10,377,464	(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	Total Indirect Annual Costs			
(b) Start-up	0.01 B	\$63,665				\$1,380,337
(b) Performance test	0.01 B	\$63,665	Total Annual Costs			
(b) Model Study	0.02 B	\$127,331				\$1,583,802
(b) Contingencies	0.03 B	\$190,996	Cost Effectiveness (\$/ton)			
Total Indirect Costs		\$3,628,929	PM ₁₀ Control Efficiency ^(f) :	99.5%		
Total Capital Investment (TCI)^(a)		\$14,006,394	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 PM₁₀ 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			
<u>Purchased Equipment Costs</u>			<u>Operating Labor^(c)</u>			
(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	<u>Maintenance^(e)</u>			
B Total Purchased Equipment Cost		\$6,366,543	(b) Maintenance labor	hours/shift	\$34.00 per hour ^(d)	\$0
<u>Direct Installation Costs</u>			(b) Maintenance materials	of purchased equipment costs		\$0
(b) Foundations and Supports ^(c)	0.04 B	\$0	<u>Utilities^(e)</u>			
(b) Handling and Erection	0.50 B	\$3,183,271	Electricity	387 kW	\$0.060 per kWh ^(b)	\$201,653
(b) Electrical	0.08 B	\$509,323	Total Direct Annual Costs			
(b) Piping	0.01 B	\$63,665				\$201,653
(b) Insulation	0.02 B	\$127,331	Indirect Annual Costs			
(b) Painting	0.02 B	\$127,331	(c) Overhead	60% Labor and Material Costs		\$0
Direct Installation Cost		\$4,010,922	(c) General and administrative	2% of TCI		\$0
Total Direct Costs		\$10,377,464	(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	Total Indirect Annual Costs			
(b) Start-up	0.01 B	\$63,665				\$1,380,337
(b) Performance test	0.01 B	\$63,665	Total Annual Costs			
(b) Model Study	0.02 B	\$127,331				\$1,581,990
(b) Contingencies	0.03 B	\$190,996	Cost Effectiveness (\$/ton)			
Total Indirect Costs		\$3,628,929	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 PM₁₀ 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			ANNUALIZED COSTS			
COST ITEM	COST FACTOR	COST (\$)	COST ITEM	COST FACTOR	RATE	COST (\$)
Direct Costs			Direct Annual Costs			
<u>Purchased Equipment Costs</u>			<u>Operating Labor</u>			
(a) A WESP		\$3,669,186	(b) Operator ^(c)	1 hours/shift	\$31.00 per hour ^(d)	\$33,945
(b) Instrumentation and controls	0.10 A	\$366,919	(b) Supervisor	15% of operator labor		\$5,091.75
(b) Sales Tax	0.03 A	\$110,076	(b) Coordinator	33% of operator labor		\$11,201.85
(b) Freight	0.05 A	\$183,459	<u>Maintenance</u>			
B Total Purchased Equipment Cost		\$4,329,639	(b) Maintenance labor ^(c)	0.5 hours/shift	\$34.00 per hour ^(d)	\$18,615
<u>Direct Installation Costs</u>			(b) Maintenance materials	1% of purchased equipment costs		\$43,296
(b) Foundations and Supports	0.04 B	\$173,186	<u>Utilities</u> ^{(c)(e)}			
(b) Handling and Erection	0.50 B	\$2,164,820	Electricity	215 kW	\$0.060 per kWh ^(d)	\$112,785
(b) Electrical	0.08 B	\$346,371	Water	10,000 gal/day	\$0.01 per gal	\$36,500
(b) Piping	0.01 B	\$43,296	Total Direct Annual Costs			
(b) Insulation for Ductwork	0.02 B	\$86,593				\$261,435
(b) Painting	0.02 B	\$86,593	Indirect Annual Costs			
Direct Installation Cost		\$2,900,858	(b) Overhead	60% Labor and Material Costs		\$67,289.99
Total Direct Costs		\$7,230,497	(b) General and administrative	2% of TCI		\$193,968
Indirect Costs			(b) Property taxes	1% of TCI		\$96,984
(b) Engineering	0.20 B	\$865,928	(b) Insurance	1% of TCI		\$96,984
(b) Construction and Field Expenses	0.20 B	\$865,928	(b) Capital recovery	0.079 x TCI		\$761,813
(b) Contractor fees	0.10 B	\$432,964	Life of the control: 20 years at 4.75% interest			
(b) Start-up	0.01 B	\$43,296	Total Indirect Annual Costs			
(b) Performance test	0.01 B	\$43,296				\$1,217,039
(b) Model Study	0.02 B	\$86,593	Total Annual Costs			
(b) Contingencies	0.03 B	\$129,889				\$1,478,474
Total Indirect Costs		\$2,467,894	Cost Effectiveness (\$/ton)			
Total Capital Investment (TCI)		\$9,698,392	Addl PM ₁₀ Control ^(f) :	80%	Total Annual Costs/Controlled PM ₁₀ Emissions:	
			PM ₁₀ Emissions ^(g) :	107.4 tpy		
			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 PM₁₀ emissions.

^(g) PSEL

Table A-33a
Cascade Pacific Pulp - Halsey
Capital and Annual Costs Associated with WESP for Recovery Furnace

CAPITAL COSTS			ANNUALIZED COSTS			
COST ITEM	COST FACTOR	COST (\$)	COST ITEM	COST FACTOR	RATE	COST (\$)
Direct Costs			Direct Annual Costs			
<u>Purchased Equipment Costs</u>			<u>Operating Labor</u>			
(a) A WESP		\$3,669,186	(b) Operator ^(c)	1 hours/shift	\$31.00 per hour ^(d)	\$32,864
(b) Instrumentation and controls	0.10 A	\$366,919	(b) Supervisor	15% of operator labor		\$4,929.58
(b) Sales Tax	0.03 A	\$110,076	(b) Coordinator	33% of operator labor		\$10,845.08
(b) Freight	0.05 A	\$183,459	<u>Maintenance</u>			
B Total Purchased Equipment Cost		\$4,329,639	(b) Maintenance labor ^(c)	0.5 hours/shift	\$34.00 per hour ^(d)	\$18,022
<u>Direct Installation Costs</u>			(b) Maintenance materials	1% of purchased equipment costs		\$43,296
(b) Foundations and Supports	0.04 B	\$173,186	<u>Utilities ^{(c)(e)}</u>			
(b) Handling and Erection	0.50 B	\$2,164,820	Electricity	215 kW	\$0.060 per kWh ^(d)	\$109,193
(b) Electrical	0.08 B	\$346,371	Water	10,000 gal/day	\$0.01 per gal	\$36,500
(b) Piping	0.01 B	\$43,296	Total Direct Annual Costs			
(b) Insulation for Ductwork	0.02 B	\$86,593				\$255,650
(b) Painting	0.02 B	\$86,593	Indirect Annual Costs			
Direct Installation Cost		\$2,900,858	(b) Overhead	60% Labor and Material Costs		\$65,974.23
Total Direct Costs		\$7,230,497	(b) General and administrative	2% of TCI		\$193,968
Indirect Costs			(b) Property taxes	1% of TCI		\$96,984
(b) Engineering	0.20 B	\$865,928	(b) Insurance	1% of TCI		\$96,984
(b) Construction and Field Expenses	0.20 B	\$865,928	(b) Capital recovery	0.079 x TCI		\$761,813
(b) Contractor fees	0.10 B	\$432,964	Life of the control: 20 years at 4.75% interest			
(b) Start-up	0.01 B	\$43,296	Total Indirect Annual Costs			
(b) Performance test	0.01 B	\$43,296				\$1,215,723
(b) Model Study	0.02 B	\$86,593	Total Annual Costs			
(b) Contingencies	0.03 B	\$129,889				\$1,471,373
Total Indirect Costs		\$2,467,894	Cost Effectiveness (\$/ton)			
Total Capital Investment (TCI)		\$9,698,392	Addl PM ₁₀ Control ^(f) :	80%	Total Annual Costs/Controlled PM ₁₀ Emissions:	
			PM ₁₀ Emissions ^(g) :	171.6 tpy		
			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 PM₁₀ 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			ANNUALIZED COSTS			
COST ITEM	COST FACTOR	COST (\$)	COST ITEM	COST FACTOR	RATE	COST (\$)
Direct Costs			Direct Annual Costs			
<u>Purchased Equipment Costs</u>			<u>Operating Labor</u>			
(a) A WESP		\$1,938,335	(b) Operator ^(c)	1 hours/shift	\$29.06 per hour ^(d)	\$31,821
(b) Instrumentation and controls	0.10 A	\$193,833	(b) Supervisor	15% of operator labor		\$4,773.11
(b) Sales Tax	0.03 A	\$58,150	(b) Coordinator	33% of operator labor		\$10,500.83
(b) Freight	0.05 A	\$96,917	<u>Maintenance</u>			
B Total Purchased Equipment Cost		\$2,287,235	(b) Maintenance labor ^(c)	0.5 hours/shift	\$24.82 per hour ^(d)	\$13,589
<u>Direct Installation Costs</u>			(b) Maintenance materials	1% of purchased equipment costs		\$22,872
(b) Foundations and Supports	0.04 B	\$91,489	<u>Utilities ^{(c)(e)}</u>			
(b) Handling and Erection	0.50 B	\$1,143,617	Electricity	215 kW	\$0.060 per kWh	\$112,785
(b) Electrical	0.08 B	\$182,979	Water	10,000 gal/day	\$0.01 per gal	\$876,000
(b) Piping	0.01 B	\$22,872	Total Direct Annual Costs			
(b) Insulation for Ductwork	0.02 B	\$45,745				\$1,072,341
(b) Painting	0.02 B	\$45,745	Indirect Annual Costs			
Direct Installation Cost		\$1,532,447	(b) Overhead	60% Labor and Material Costs		\$50,133.56
Total Direct Costs		\$3,819,682	(b) General and administrative	2% of TCI		\$102,468
Indirect Costs			(b) Property taxes	1% of TCI		\$51,234
(b) Engineering	0.20 B	\$457,447	(b) Insurance	1% of TCI		\$51,234
(b) Construction and Field Expenses	0.20 B	\$457,447	(b) Capital recovery	0.079 x TCI		\$402,446
(b) Contractor fees	0.10 B	\$228,723	Life of the control: 20 years at 4.75% interest			
(b) Start-up	0.01 B	\$22,872	Total Indirect Annual Costs			
(b) Performance test	0.01 B	\$22,872				\$657,516
(b) Model Study	0.02 B	\$45,745	Total Annual Costs			
(b) Contingencies	0.03 B	\$68,617				\$1,729,857
Total Indirect Costs		\$1,303,724	Cost Effectiveness (\$/ton)			
Total Capital Investment (TCI)		\$5,123,406	PM ₁₀ Control Efficiency ^(f) :	80%	Total Annual Costs/Controlled PM ₁₀ Emissions:	
			2017 PM ₁₀ Emissions ^(g) :	29 tpy		
			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 PM₁₀ emissions.

^(g) PSEL

Table A-34a
Georgia-Pacific - Toledo
Capital and Annual Costs Associated with WESP for No. 1 Recovery Furnace

CAPITAL COSTS			ANNUALIZED COSTS			
COST ITEM	COST FACTOR	COST (\$)	COST ITEM	COST FACTOR	RATE	COST (\$)
Direct Costs			Direct Annual Costs			
<u>Purchased Equipment Costs</u>			<u>Operating Labor</u>			
(a) A WESP		\$1,938,335	(b) Operator ^(c)	1 hours/shift	\$29.06 per hour ^(d)	\$29,529
(b) Instrumentation and controls	0.10 A	\$193,833	(b) Supervisor	15% of operator labor		\$4,429.29
(b) Sales Tax	0.03 A	\$58,150	(b) Coordinator	33% of operator labor		\$9,744.44
(b) Freight	0.05 A	\$96,917	<u>Maintenance</u>			
B Total Purchased Equipment Cost		\$2,287,235	(b) Maintenance labor ^(c)	0.5 hours/shift	\$24.82 per hour ^(d)	\$12,610
<u>Direct Installation Costs</u>			(b) Maintenance materials	1% of purchased equipment costs		\$22,872
(b) Foundations and Supports	0.04 B	\$91,489	<u>Utilities ^{(c)(e)}</u>			
(b) Handling and Erection	0.50 B	\$1,143,617	Electricity	215 kW	\$0.060 per kWh	\$104,661
(b) Electrical	0.08 B	\$182,979	Water	10,000 gal/day	\$0.01 per gal	\$812,900
(b) Piping	0.01 B	\$22,872	Total Direct Annual Costs			
(b) Insulation for Ductwork	0.02 B	\$45,745				\$996,746
(b) Painting	0.02 B	\$45,745	Indirect Annual Costs			
Direct Installation Cost		\$1,532,447	(b) Overhead	60% Labor and Material Costs		\$47,510.87
Total Direct Costs		\$3,819,682	(b) General and administrative	2% of TCI		\$102,468
Indirect Costs			(b) Property taxes	1% of TCI		\$51,234
(b) Engineering	0.20 B	\$457,447	(b) Insurance	1% of TCI		\$51,234
(b) Construction and Field Expenses	0.20 B	\$457,447	(b) Capital recovery	0.079 x TCI		\$402,446
(b) Contractor fees	0.10 B	\$228,723	Total Indirect Annual Costs			
(b) Start-up	0.01 B	\$22,872				\$654,893
(b) Performance test	0.01 B	\$22,872	Total Annual Costs			
(b) Model Study	0.02 B	\$45,745				\$1,651,639
(b) Contingencies	0.03 B	\$68,617	Cost Effectiveness (\$/ton)			
Total Indirect Costs		\$1,303,724	PM ₁₀ Control Efficiency ^(f) :	80%	Total Annual Costs/Controlled PM ₁₀ Emissions:	
Total Capital Investment (TCI)		\$5,123,406	2017 PM ₁₀ Emissions ^(g) :	26.4 tpy		
			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 PM₁₀ 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			ANNUALIZED COSTS			
COST ITEM	COST FACTOR	COST (\$)	COST ITEM	COST FACTOR	RATE	COST (\$)
Direct Costs			Direct Annual Costs			
<u>Purchased Equipment Costs</u>			<u>Operating Labor</u>			
(a) A WESP		\$1,938,335	(b) Operator ^(c)	1 hours/shift	\$29.06 per hour ^(d)	\$31,821
(b) Instrumentation and controls	0.10 A	\$193,833	(b) Supervisor	15% of operator labor		\$4,773.11
(b) Sales Tax	0.03 A	\$58,150	(b) Coordinator	33% of operator labor		\$10,500.83
(b) Freight	0.05 A	\$96,917	<u>Maintenance</u>			
B Total Purchased Equipment Cost		\$2,287,235	(b) Maintenance labor ^(c)	0.5 hours/shift	\$24.82 per hour ^(d)	\$13,589
<u>Direct Installation Costs</u>			(b) Maintenance materials	1% of purchased equipment costs		\$22,872
(b) Foundations and Supports	0.04 B	\$91,489	<u>Utilities ^{(c)(e)}</u>			
(b) Handling and Erection	0.50 B	\$1,143,617	Electricity	215 kW	\$0.060 per kWh	\$112,785
(b) Electrical	0.08 B	\$182,979	Water	10,000 gal/day	\$0.01 per gal	\$876,000
(b) Piping	0.01 B	\$22,872	Total Direct Annual Costs			
(b) Insulation for Ductwork	0.02 B	\$45,745				\$1,072,341
(b) Painting	0.02 B	\$45,745	Indirect Annual Costs			
Direct Installation Cost		\$1,532,447	(b) Overhead	60% Labor and Material Costs		\$50,133.56
Total Direct Costs		\$3,819,682	(b) General and administrative	2% of TCI		\$102,468
Indirect Costs			(b) Property taxes	1% of TCI		\$51,234
(b) Engineering	0.20 B	\$457,447	(b) Insurance	1% of TCI		\$51,234
(b) Construction and Field Expenses	0.20 B	\$457,447	(b) Capital recovery	0.079 x TCI		\$402,446
(b) Contractor fees	0.10 B	\$228,723	Life of the control: 20 years at 4.75% interest			
(b) Start-up	0.01 B	\$22,872	Total Indirect Annual Costs			
(b) Performance test	0.01 B	\$22,872				\$657,516
(b) Model Study	0.02 B	\$45,745	Total Annual Costs			
(b) Contingencies	0.03 B	\$68,617				\$1,729,857
Total Indirect Costs		\$1,303,724	Cost Effectiveness (\$/ton)			
Total Capital Investment (TCI)		\$5,123,406	PM ₁₀ Control Efficiency ^(f) :	80%	Total Annual Costs/Controlled PM ₁₀ Emissions:	
			2017 PM ₁₀ Emissions ^(g) :	29 tpy		
			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 PM₁₀ emissions.

^(g) PSEL

Table A-35a
Georgia-Pacific - Toledo
Capital and Annual Costs Associated with WESP for No. 2 Recovery Furnace

CAPITAL COSTS			ANNUALIZED COSTS			
COST ITEM	COST FACTOR	COST (\$)	COST ITEM	COST FACTOR	RATE	COST (\$)
Direct Costs			Direct Annual Costs			
<u>Purchased Equipment Costs</u>			<u>Operating Labor</u>			
(a) A WESP		\$1,938,335	(b) Operator ^(c)	1 hours/shift	\$29.06 per hour ^(d)	\$29,529
(b) Instrumentation and controls	0.10 A	\$193,833	(b) Supervisor	15% of operator labor		\$4,429.29
(b) Sales Tax	0.03 A	\$58,150	(b) Coordinator	33% of operator labor		\$9,744.44
(b) Freight	0.05 A	\$96,917	<u>Maintenance</u>			
B Total Purchased Equipment Cost		\$2,287,235	(b) Maintenance labor ^(c)	0.5 hours/shift	\$24.82 per hour ^(d)	\$12,610
<u>Direct Installation Costs</u>			(b) Maintenance materials	1% of purchased equipment costs		\$22,872
(b) Foundations and Supports	0.04 B	\$91,489	<u>Utilities</u> ^{(c)(e)}			
(b) Handling and Erection	0.50 B	\$1,143,617	Electricity	215 kW	\$0.060 per kWh	\$104,661
(b) Electrical	0.08 B	\$182,979	Water	10,000 gal/day	\$0.01 per gal	\$812,900
(b) Piping	0.01 B	\$22,872	Total Direct Annual Costs			
(b) Insulation for Ductwork	0.02 B	\$45,745				\$996,746
(b) Painting	0.02 B	\$45,745	Indirect Annual Costs			
Direct Installation Cost		\$1,532,447	(b) Overhead	60% Labor and Material Costs		\$47,510.87
Total Direct Costs		\$3,819,682	(b) General and administrative	2% of TCI		\$102,468
Indirect Costs			(b) Property taxes	1% of TCI		\$51,234
(b) Engineering	0.20 B	\$457,447	(b) Insurance	1% of TCI		\$51,234
(b) Construction and Field Expenses	0.20 B	\$457,447	(b) Capital recovery	0.079 x TCI		\$402,446
(b) Contractor fees	0.10 B	\$228,723	Life of the control: 20 years at 4.75% interest			
(b) Start-up	0.01 B	\$22,872	Total Indirect Annual Costs			
(b) Performance test	0.01 B	\$22,872				\$654,893
(b) Model Study	0.02 B	\$45,745	Total Annual Costs			
(b) Contingencies	0.03 B	\$68,617				\$1,651,639
Total Indirect Costs		\$1,303,724	Cost Effectiveness (\$/ton)			
Total Capital Investment (TCI)		\$5,123,406	PM ₁₀ Control Efficiency ^(f) :	80%	Total Annual Costs/Controlled PM ₁₀ Emissions:	
			2017 PM ₁₀ Emissions ^(g) :	26.8 tpy		
			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 PM₁₀ emissions.

^(g) 2017 Actual Emissions

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

CAPITAL COSTS			ANNUALIZED COSTS			
COST ITEM	COST FACTOR	COST (\$)	COST ITEM	COST FACTOR	RATE	COST (\$)
Direct Costs			Direct Annual Costs			
<u>Purchased Equipment Costs</u>			<u>Operating Labor</u>			
(a) A WESP		\$4,914,088	(b) Operator ^(c)	1 hours/shift	\$29.06 per hour ^(d)	\$31,821
(b) Instrumentation and controls	0.10 A	\$491,409	(b) Supervisor	15% of operator labor		\$4,773.11
(b) Sales Tax	0.03 A	\$147,423	(b) Coordinator	33% of operator labor		\$10,500.83
(b) Freight	0.05 A	\$245,704	<u>Maintenance</u>			
B Total Purchased Equipment Cost		\$5,798,624	(b) Maintenance labor ^(c)	0.5 hours/shift	\$24.82 per hour ^(d)	\$13,589
<u>Direct Installation Costs</u>			(b) Maintenance materials	1% of purchased equipment costs		\$57,986
(b) Foundations and Supports	0.04 B	\$231,945	<u>Utilities</u> ^{(c)(e)}			
(b) Handling and Erection	0.50 B	\$2,899,312	Electricity	215 kW	\$0.060 per kWh	\$112,785
(b) Electrical	0.08 B	\$463,890	Water	10,000 gal/day	\$0.01 per gal	\$36,500
(b) Piping	0.01 B	\$57,986	Total Direct Annual Costs			
(b) Insulation for Ductwork	0.02 B	\$115,972				\$267,955
(b) Painting	0.02 B	\$115,972	Indirect Annual Costs			
Direct Installation Cost		\$3,885,078	(b) Overhead	60% Labor and Material Costs		\$71,201.89
Total Direct Costs		\$9,683,702	(b) General and administrative	2% of TCI		\$259,778
Indirect Costs			(b) Property taxes	1% of TCI		\$129,889
(b) Engineering	0.20 B	\$1,159,725	(b) Insurance	1% of TCI		\$129,889
(b) Construction and Field Expenses	0.20 B	\$1,159,725	(b) Capital recovery	0.079 x TCI		\$1,020,286
(b) Contractor fees	0.10 B	\$579,862	Life of the control:	20 years at	4.75% interest	
(b) Start-up	0.01 B	\$57,986	Total Indirect Annual Costs			
(b) Performance test	0.01 B	\$57,986				\$1,611,044
(b) Model Study	0.02 B	\$115,972	Total Annual Costs			
(b) Contingencies	0.03 B	\$173,959				\$1,878,999
Total Indirect Costs		\$3,305,216	Cost Effectiveness (\$/ton)			
Total Capital Investment (TCI)		\$12,988,917	PM ₁₀ Control Efficiency ^(f) :	80%	Total Annual Costs/Controlled PM ₁₀ Emissions:	
			2017 PM ₁₀ Emissions ^(g) :	290 tpy		
			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 PM₁₀ emissions.

^(g) PSEL

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

CAPITAL COSTS			ANNUALIZED COSTS			
COST ITEM	COST FACTOR	COST (\$)	COST ITEM	COST FACTOR	RATE	COST (\$)
Direct Costs			Direct Annual Costs			
<u>Purchased Equipment Costs</u>			<u>Operating Labor</u>			
(a) A WESP		\$4,914,088	(b) Operator ^(c)	1 hours/shift	\$29.06 per hour ^(d)	\$29,154
(b) Instrumentation and controls	0.10 A	\$491,409	(b) Supervisor	15% of operator labor		\$4,373.17
(b) Sales Tax	0.03 A	\$147,423	(b) Coordinator	33% of operator labor		\$9,620.97
(b) Freight	0.05 A	\$245,704	<u>Maintenance</u>			
B Total Purchased Equipment Cost		\$5,798,624	(b) Maintenance labor ^(c)	0.5 hours/shift	\$24.82 per hour ^(d)	\$12,450
<u>Direct Installation Costs</u>			(b) Maintenance materials	1% of purchased equipment costs		\$57,986
(b) Foundations and Supports	0.04 B	\$231,945	<u>Utilities</u> ^{(c)(e)}			
(b) Handling and Erection	0.50 B	\$2,899,312	Electricity	215 kW	\$0.060 per kWh	\$103,335
(b) Electrical	0.08 B	\$463,890	Water	10,000 gal/day	\$0.01 per gal	\$36,500
(b) Piping	0.01 B	\$57,986	Total Direct Annual Costs			
(b) Insulation for Ductwork	0.02 B	\$115,972				\$253,420
(b) Painting	0.02 B	\$115,972	Indirect Annual Costs			
Direct Installation Cost		\$3,885,078	(b) Overhead	60% Labor and Material Costs		\$68,151.09
Total Direct Costs		\$9,683,702	(b) General and administrative	2% of TCI		\$259,778
Indirect Costs			(b) Property taxes	1% of TCI		\$129,889
(b) Engineering	0.20 B	\$1,159,725	(b) Insurance	1% of TCI		\$129,889
(b) Construction and Field Expenses	0.20 B	\$1,159,725	(b) Capital recovery	0.079 x TCI		\$1,020,286
(b) Contractor fees	0.10 B	\$579,862	Life of the control: 20 years at 4.75% interest			
(b) Start-up	0.01 B	\$57,986	Total Indirect Annual Costs			
(b) Performance test	0.01 B	\$57,986				\$1,607,993
(b) Model Study	0.02 B	\$115,972	Total Annual Costs			
(b) Contingencies	0.03 B	\$173,959				\$1,861,413
Total Indirect Costs		\$3,305,216	Cost Effectiveness (\$/ton)			
Total Capital Investment (TCI)		\$12,988,917	PM ₁₀ Control Efficiency ^(f) :	80%	Total Annual Costs/Controlled PM ₁₀ Emissions:	
			2017 PM ₁₀ Emissions ^(g) :	226.4 tpy		
			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 PM₁₀ 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			ANNUALIZED COSTS			
COST ITEM	COST FACTOR	COST (\$)	COST ITEM	COST FACTOR	RATE	COST (\$)
Direct Costs			Direct Annual Costs			
<u>Purchased Equipment Costs</u>			<u>Operating Labor</u>			
(a) A WESP		\$4,757,017	(b) Operator ^(c)	1 hours/shift	\$31.00 per hour ^(d)	\$33,945
(b) Instrumentation and controls	0.10 A	\$475,702	(b) Supervisor	15% of operator labor		\$5,091.75
(b) Sales Tax	0.03 A	\$142,711	(b) Coordinator	33% of operator labor		\$11,201.85
(b) Freight	0.05 A	\$237,851	<u>Maintenance</u>			
B Total Purchased Equipment Cost		\$5,613,280	(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
<u>Direct Installation Costs</u>			<u>Utilities ^{(c)(e)}</u>			
(b) Foundations and Supports	0.04 B	\$224,531	Electricity	215 kW	\$0.060 per kWh	\$112,785
(b) Handling and Erection	0.50 B	\$2,806,640	Water	10,000 gal/day	\$0.01 per gal	\$876,000
(b) Electrical	0.08 B	\$449,062	Total Direct Annual Costs			
(b) Piping	0.01 B	\$56,133				\$1,113,771
(b) Insulation for Ductwork	0.02 B	\$112,266	Indirect Annual Costs			
(b) Painting	0.02 B	\$112,266	(b) Overhead	60% Labor and Material Costs		\$74,991.84
Direct Installation Cost		\$3,760,897	(b) General and administrative	2% of TCI		\$251,475
Total Direct Costs		\$9,374,177	(b) Property taxes	1% of TCI		\$125,737
Indirect Costs			(b) Insurance	1% of TCI		\$125,737
(b) Engineering	0.20 B	\$1,122,656	(b) Capital recovery	0.079 x TCI		\$987,674
(b) Construction and Field Expenses	0.20 B	\$1,122,656	Life of the control:	20 years at	4.75% interest	
(b) Contractor fees	0.10 B	\$561,328	Total Indirect Annual Costs			
(b) Start-up	0.01 B	\$56,133				\$1,565,615
(b) Performance test	0.01 B	\$56,133	Total Annual Costs			
(b) Model Study	0.02 B	\$112,266				\$2,679,387
(b) Contingencies	0.03 B	\$168,398	Cost Effectiveness (\$/ton)			
Total Indirect Costs		\$3,199,569	PM ₁₀ Control Efficiency ^(f) :	80%	Total Annual Costs/Controlled PM ₁₀ Emissions:	
Total Capital Investment (TCI)		\$12,573,747	PM ₁₀ Emissions ^(g) :	145.8 tpy		
			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 PM₁₀ emissions.

^(g) PSEL

Table A-37a
International Paper - Springfield
Capital and Annual Costs Associated with WESP for No. 4 Recovery Furnace

CAPITAL COSTS			ANNUALIZED COSTS			
COST ITEM	COST FACTOR	COST (\$)	COST ITEM	COST FACTOR	RATE	COST (\$)
Direct Costs			Direct Annual Costs			
<u>Purchased Equipment Costs</u>			<u>Operating Labor</u>			
(a) A WESP		\$4,757,017	(b) Operator ^(c)	1 hours/shift	\$31.00 per hour ^(d)	\$33,643
(b) Instrumentation and controls	0.10 A	\$475,702	(b) Supervisor	15% of operator labor		\$5,046.41
(b) Sales Tax	0.03 A	\$142,711	(b) Coordinator	33% of operator labor		\$11,102.11
(b) Freight	0.05 A	\$237,851	<u>Maintenance</u>			
B Total Purchased Equipment Cost		\$5,613,280	(b) Maintenance labor ^(c)	0.5 hours/shift	\$34.00 per hour ^(d)	\$18,449
<u>Direct Installation Costs</u>			(b) Maintenance materials	1% of purchased equipment costs		\$56,133
(b) Foundations and Supports	0.04 B	\$224,531	<u>Utilities ^{(c)(e)}</u>			
(b) Handling and Erection	0.50 B	\$2,806,640	Electricity	215 kW	\$0.060 per kWh	\$111,781
(b) Electrical	0.08 B	\$449,062	Water	10,000 gal/day	\$0.01 per gal	\$868,200
(b) Piping	0.01 B	\$56,133	Total Direct Annual Costs			
(b) Insulation for Ductwork	0.02 B	\$112,266				\$1,104,354
(b) Painting	0.02 B	\$112,266	<u>Indirect Annual Costs</u>			
Direct Installation Cost		\$3,760,897	(b) Overhead	60% Labor and Material Costs		\$74,623.99
Total Direct Costs		\$9,374,177	(b) General and administrative	2% of TCI		\$251,475
Indirect Costs			(b) Property taxes	1% of TCI		\$125,737
(b) Engineering	0.20 B	\$1,122,656	(b) Insurance	1% of TCI		\$125,737
(b) Construction and Field Expenses	0.20 B	\$1,122,656	(b) Capital recovery	0.079 x TCI		\$987,674
(b) Contractor fees	0.10 B	\$561,328	Life of the control: 20 years at 4.75% interest			
(b) Start-up	0.01 B	\$56,133	Total Indirect Annual Costs			
(b) Performance test	0.01 B	\$56,133				\$1,565,248
(b) Model Study	0.02 B	\$112,266	Total Annual Costs			
(b) Contingencies	0.03 B	\$168,398				\$2,669,602
Total Indirect Costs		\$3,199,569	<u>Cost Effectiveness (\$/ton)</u>			
Total Capital Investment (TCI)		\$12,573,747	PM ₁₀ Control Efficiency ^(f) :	80%	Total Annual Costs/Controlled PM ₁₀ Emissions:	
			PM ₁₀ Emissions ^(g) :	120.2 tpy		
			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 PM₁₀ 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)			ANNUALIZED COSTS			
COST ITEM	COST FACTOR	COST (\$)	COST ITEM	COST FACTOR	RATE	COST (\$)
Direct Costs			Direct Annual Costs			
<u>Purchased Equipment Costs</u>			<u>Operating Labor</u>			
(a) A Equipment Costs		\$7,276,846	(b) Operator ^(c)	0.5 hours/shift	\$31.00 per hour ^(d)	\$16,973
(b) Instrumentation	0.10 A	\$727,685	(b) Supervisor	15% of operator labor		\$2,546
(b) Sales Tax	0.03 A	\$218,305	<u>Maintenance</u>			
(b) Freight	0.05 A	\$363,842	(b) Maintenance labor ^(c)	0.5 hours/shift	\$34.00 per hour ^(d)	\$18,615
B Total Purchased Equipment Cost		\$8,586,678	(b) Maintenance materials	100% of maintenance labor		\$18,615
<u>Direct Installation Costs</u>			<u>Utilities^(e)</u>			
(b) Foundations and Supports	0.12 B	\$1,030,401	Electricity	1,185 kW	\$0.060 per kWh ^(b)	\$622,783
(b) Handling and erection	0.40 B	\$3,434,671	Chemicals	829 lb/hr NaOH	\$0.25 per lb NaOH ^(d)	\$1,815,197
(b) Electrical	0.01 B	\$85,867	Fresh water usage	108 gpm	\$0.20 per 1000 gallon ^(b)	\$11,303
(b) Piping	0.30 B	\$2,576,003	Wastewater disposal	10.90 gpm	\$3.80 per 1000 gallon ^(b)	\$21,765
(b) Insulation for ductwork	0.01 B	\$85,867	Total Direct Annual Costs			
(b) Painting	0.01 B	\$85,867				\$2,527,796
Direct Installation Cost		\$7,298,676	Indirect Annual Costs			
Total Direct Costs		\$15,885,354	Overhead	60% Labor and Material Costs		\$34,049
Indirect Costs			General and administrative	2% of TCI		\$377,814
(b) Engineering	0.10 B	\$858,668	Property taxes	1% of TCI		\$188,907
(b) Construction Management	0.10 B	\$858,668	Insurance	1% of TCI		\$188,907
(b) Contractor fees	0.10 B	\$858,668	Capital recovery	0.095 x TCI		\$1,789,348
(b) Start-up	0.01 B	\$85,867	Life of the control:	15 years at 4.75% interest		
(b) Performance test	0.01 B	\$85,867	Total Indirect Annual Costs			
(b) Contingencies	0.03 B	\$257,600				\$2,579,024
Total Indirect Costs		\$3,005,337	Total Annual Costs			
Total Capital Investment (TCI)		\$18,890,691	\$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 SO₂ 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)			ANNUALIZED COSTS							
COST ITEM		COST FACTOR	COST (\$)	COST ITEM		COST FACTOR	RATE		COST (\$)	
Direct Costs				Direct Annual Costs						
<u>Purchased Equipment Costs</u>				<u>Operating Labor</u>						
(a)	A	Equipment Costs		\$7,276,846	(b)	Operator ^(c)	0.5 hours/shift	\$31.00 per hour ^(d)	\$16,432	
(b)		Instrumentation	0.10	A	\$727,685	(b)	Supervisor	15% of operator labor	\$2,465	
(b)		Sales Tax	0.03	A	\$218,305	<u>Maintenance</u>				
(b)		Freight	0.05	A	\$363,842	(b)	Maintenance labor ^(c)	0.5 hours/shift	\$34.00 per hour ^(d)	\$18,022
B		Total Purchased Equipment Cost		\$8,586,678	(b)	Maintenance materials	100% of maintenance labor		\$18,022	
<u>Direct Installation Costs</u>				<u>Utilities^(e)</u>						
(b)		Foundations and Supports	0.12	B	\$1,030,401	Electricity	1,185 kW	\$0.060 per kWh ^(b)	\$602,948	
(b)		Handling and erection	0.40	B	\$3,434,671	Chemicals	829 lb/hr NaOH	\$0.25 per lb NaOH ^(d)	\$1,757,384	
(b)		Electrical	0.01	B	\$85,867	Fresh water usage	108 gpm	\$0.20 per 1000 gallon ^(b)	\$10,943	
(b)		Piping	0.30	B	\$2,576,003	Wastewater disposal	10.90 gpm	\$3.80 per 1000 gallon ^(b)	\$21,072	
(b)		Insulation for ductwork	0.01	B	\$85,867	Total Direct Annual Costs				\$2,447,288
(b)		Painting	0.01	B	\$85,867	Indirect Annual Costs				
		Direct Installation Cost		\$7,298,676	Overhead	60% Labor and Material Costs			\$32,965	
		Total Direct Costs		\$15,885,354	General and administrative	2% of TCI			\$377,814	
Indirect Costs					Property taxes	1% of TCI			\$188,907	
(b)		Engineering	0.10	B	\$858,668	Insurance	1% of TCI		\$188,907	
(b)		Construction Management	0.10	B	\$858,668	Capital recovery	0.095 x TCI		\$1,789,348	
(b)		Contractor fees	0.10	B	\$858,668	Life of the control:	15 years at	4.75% interest		
(b)		Start-up	0.01	B	\$85,867	Total Indirect Annual Costs				\$2,577,940
(b)		Performance test	0.01	B	\$85,867	Total Annual Costs				\$5,025,227
(b)		Contingencies	0.03	B	\$257,600	Cost Effectiveness (\$/ton)				
		Total Indirect Costs		\$3,005,337	SO ₂ Control Efficiency ^(f) :	98%				
		Total Capital Investment (TCI)		\$18,890,691	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 SO₂ 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)			ANNUALIZED COSTS						
COST ITEM		COST FACTOR	COST (\$)	COST ITEM		COST FACTOR	RATE		COST (\$)
Direct Costs				Direct Annual Costs					
<u>Purchased Equipment Costs</u>				<u>Operating Labor</u>					
(a)	A	Equipment Costs	\$4,962,021	(b)	Operator ^(c)	0.5 hours/shift	\$31.00 per hour ^(d)		\$16,973
(b)		Instrumentation	0.10 A	\$496,202	(b)	Supervisor	15% of operator labor		\$2,546
(b)		Sales Tax	0.03 A	\$148,861	<u>Maintenance</u>				
(b)		Freight	0.05 A	\$248,101	(b)	Maintenance labor ^(c)	0.5 hours/shift	\$34.00 per hour ^(d)	\$18,615
B		Total Purchased Equipment Cost	\$5,855,185	(b)	Maintenance materials	100% of maintenance labor			\$18,615
<u>Direct Installation Costs</u>				<u>Utilities^(e)</u>					
(b)		Foundations and Supports	0.12 B	\$702,622		Electricity	626 kW	\$0.060 per kWh ^(b)	\$329,000
(b)		Handling and erection	0.40 B	\$2,342,074		Chemicals	438 lb/hr NaOH	\$0.25 per lb NaOH ^(d)	\$958,921
(b)		Electrical	0.01 B	\$58,552		Fresh water usage	57 gpm	\$0.20 per 1000 gallon ^(b)	\$5,971
(b)		Piping	0.30 B	\$1,756,555		Wastewater disposal	5.76 gpm	\$3.80 per 1000 gallon ^(b)	\$11,498
(b)		Insulation for ductwork	0.01 B	\$58,552	Total Direct Annual Costs				
(b)		Painting	0.01 B	\$58,552	\$1,362,138				
		Direct Installation Cost	\$4,976,907	Indirect Annual Costs					
		Total Direct Costs	\$10,832,092		Overhead	60% Labor and Material Costs			\$34,049
Indirect Costs					General and administrative	2% of TCI			\$257,628
(b)		Engineering	0.10 B	\$585,518		Property taxes	1% of TCI		\$128,814
(b)		Construction Management	0.10 B	\$585,518		Insurance	1% of TCI		\$128,814
(b)		Contractor fees	0.10 B	\$585,518		Capital recovery	0.095 x TCI		\$1,220,141
(b)		Start-up	0.01 B	\$58,552		Life of the control:	15 years at	4.75% interest	
(b)		Performance test	0.01 B	\$58,552	Total Indirect Annual Costs				
(b)		Contingencies	0.03 B	\$175,656	\$1,769,447				
		Total Indirect Costs	\$2,049,315	Total Annual Costs					
		Total Capital Investment (TCI)	\$12,881,407	\$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		

Table A-39a
Georgia-Pacific - Toledo
Capital and Annual Costs Associated with Wet Scrubbing for Recovery Furnace No. 1

CAPITAL COSTS ^(a)			ANNUALIZED COSTS			
COST ITEM	COST FACTOR	COST (\$)	COST ITEM	COST FACTOR	RATE	COST (\$)
Direct Costs			Direct Annual Costs			
<u>Purchased Equipment Costs</u>			<u>Operating Labor</u>			
(a) A Equipment Costs		\$4,962,021	(b) Operator ^(c)	0.5 hours/shift	\$31.00 per hour ^(d)	\$15,750
(b) Instrumentation	0.10 A	\$496,202	(b) Supervisor	15% of operator labor		\$2,362
(b) Sales Tax	0.03 A	\$148,861	<u>Maintenance</u>			
(b) Freight	0.05 A	\$248,101	(b) Maintenance labor ^(c)	0.5 hours/shift	\$34.00 per hour ^(d)	\$17,274
B Total Purchased Equipment Cost		\$5,855,185	(b) Maintenance materials	100% of maintenance labor		\$17,274
<u>Direct Installation Costs</u>			<u>Utilities^(e)</u>			
(b) Foundations and Supports	0.12 B	\$702,622	Electricity	626 kW	\$0.060 per kWh ^(b)	\$305,302
(b) Handling and erection	0.40 B	\$2,342,074	Chemicals	438 lb/hr NaOH	\$0.25 per lb NaOH ^(d)	\$889,848
(b) Electrical	0.01 B	\$58,552	Fresh water usage	57 gpm	\$0.20 per 1000 gallon ^(b)	\$5,541
(b) Piping	0.30 B	\$1,756,555	Wastewater disposal	5.76 gpm	\$3.80 per 1000 gallon ^(b)	\$10,670
(b) Insulation for ductwork	0.01 B	\$58,552	Total Direct Annual Costs			
(b) Painting	0.01 B	\$58,552				\$1,264,021
Direct Installation Cost		\$4,976,907	Indirect Annual Costs			
Total Direct Costs		\$10,832,092	Overhead	60% Labor and Material Costs		\$31,596
Indirect Costs			General and administrative	2% of TCI		\$257,628
(b) Engineering	0.10 B	\$585,518	Property taxes	1% of TCI		\$128,814
(b) Construction Management	0.10 B	\$585,518	Insurance	1% of TCI		\$128,814
(b) Contractor fees	0.10 B	\$585,518	Capital recovery	0.095 x TCI		\$1,220,141
(b) Start-up	0.01 B	\$58,552	Life of the control:	15 years at 4.75% interest		
(b) Performance test	0.01 B	\$58,552	Total Indirect Annual Costs			
(b) Contingencies	0.03 B	\$175,656				\$1,766,994
Total Indirect Costs		\$2,049,315	Total Annual Costs			
Total Capital Investment (TCI)		\$12,881,407	\$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 SO₂ 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)			ANNUALIZED COSTS						
COST ITEM		COST FACTOR	COST (\$)	COST ITEM		COST FACTOR	RATE		COST (\$)
Direct Costs				Direct Annual Costs					
<u>Purchased Equipment Costs</u>				<u>Operating Labor</u>					
(a)	A	Equipment Costs		(b)	Operator ^(c)	0.5 hours/shift		\$31.00 per hour ^(d)	\$16,973
(b)		Instrumentation	0.10 A	(b)	Supervisor	15% of operator labor			\$2,546
(b)		Sales Tax	0.03 A	<u>Maintenance</u>					
(b)		Freight	0.05 A	(b)	Maintenance labor ^(c)	0.5 hours/shift		\$34.00 per hour ^(d)	\$18,615
B		Total Purchased Equipment Cost		(b)	Maintenance materials	100% of maintenance labor			\$18,615
				<u>Utilities^(e)</u>					
<u>Direct Installation Costs</u>					Electricity	626 kW		\$0.060 per kWh ^(b)	\$329,000
(b)		Foundations and Supports	0.12 B		Chemicals	438 lb/hr NaOH		\$0.25 per lb NaOH ^(d)	\$958,921
(b)		Handling and erection	0.40 B		Fresh water usage	57 gpm		\$0.20 per 1000 gallon ^(b)	\$5,971
(b)		Electrical	0.01 B		Wastewater disposal	5.76 gpm		\$3.80 per 1000 gallon ^(b)	\$11,498
(b)		Piping	0.30 B	Total Direct Annual Costs					
(b)		Insulation for ductwork	0.01 B						\$1,362,138
(b)		Painting	0.01 B	Indirect Annual Costs					
		Direct Installation Cost			Overhead	60% Labor and Material Costs			\$34,049
		Total Direct Costs			General and administrative	2% of TCI			\$257,628
					Property taxes	1% of TCI			\$128,814
Indirect Costs					Insurance	1% of TCI			\$128,814
(b)		Engineering	0.10 B		Capital recovery	0.095 x TCI			\$1,220,141
(b)		Construction Management	0.10 B			Life of the control: 15 years at 4.75% interest			
(b)		Contractor fees	0.10 B	Total Indirect Annual Costs					
(b)		Start-up	0.01 B						\$1,769,447
(b)		Performance test	0.01 B	Total Annual Costs					
(b)		Contingencies	0.03 B						\$3,131,585
Total Indirect Costs				Cost Effectiveness (\$/ton)					
					SO ₂ Control Efficiency ^(f) :	98%			
Total Capital Investment (TCI)					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 SO₂ 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)			ANNUALIZED COSTS						
COST ITEM		COST FACTOR	COST (\$)	COST ITEM		COST FACTOR	RATE		COST (\$)
Direct Costs				Direct Annual Costs					
<u>Purchased Equipment Costs</u>				<u>Operating Labor</u>					
(a)	A	Equipment Costs		(b)	Operator ^(c)	0.5 hours/shift	\$31.00 per hour ^(d)		\$15,750
(b)		Instrumentation	0.10 A	(b)	Supervisor	15% of operator labor			\$2,362
(b)		Sales Tax	0.03 A	<u>Maintenance</u>					
(b)		Freight	0.05 A	(b)	Maintenance labor ^(c)	0.5 hours/shift	\$34.00 per hour ^(d)		\$17,274
B		Total Purchased Equipment Cost	\$5,855,185	(b)	Maintenance materials	100% of maintenance labor			\$17,274
<u>Direct Installation Costs</u>				<u>Utilities^(e)</u>					
(b)		Foundations and Supports	0.12 B		Electricity	626 kW	\$0.060 per kWh ^(b)		\$305,302
(b)		Handling and erection	0.40 B		Chemicals	438 lb/hr NaOH	\$0.25 per lb NaOH ^(d)		\$889,848
(b)		Electrical	0.01 B		Fresh water usage	57 gpm	\$0.20 per 1000 gallon ^(b)		\$5,541
(b)		Piping	0.30 B		Wastewater disposal	5.76 gpm	\$3.80 per 1000 gallon ^(b)		\$10,670
(b)		Insulation for ductwork	0.01 B	Total Direct Annual Costs					
(b)		Painting	0.01 B	\$1,264,021					
		Direct Installation Cost	\$4,976,907	Indirect Annual Costs					
		Total Direct Costs	\$10,832,092		Overhead	60% Labor and Material Costs			\$31,596
Indirect Costs					General and administrative	2% of TCI			\$257,628
(b)		Engineering	0.10 B		Property taxes	1% of TCI			\$128,814
(b)		Construction Management	0.10 B		Insurance	1% of TCI			\$128,814
(b)		Contractor fees	0.10 B		Capital recovery	0.095 x TCI			\$1,220,141
(b)		Start-up	0.01 B			Life of the control:	15 years at	4.75% interest	
(b)		Performance test	0.01 B	Total Indirect Annual Costs					
(b)		Contingencies	0.03 B	\$1,766,994					
		Total Indirect Costs	\$2,049,315	Total Annual Costs					
		Total Capital Investment (TCI)	\$12,881,407	\$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 SO₂ 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)			ANNUALIZED COSTS			
COST ITEM	COST FACTOR	COST (\$)	COST ITEM	COST FACTOR	RATE	COST (\$)
Direct Costs			Direct Annual Costs			
<u>Purchased Equipment Costs</u>			<u>Operating Labor</u>			
(a) A Equipment Costs		\$8,670,958	(b) Operator ^(c)	0.5 hours/shift	\$31.00 per hour ^(d)	\$16,973
(b) Instrumentation	0.10 A	\$867,096	(b) Supervisor	15% of operator labor		\$2,546
(b) Sales Tax	0.03 A	\$260,129	<u>Maintenance</u>			
(b) Freight	0.05 A	\$433,548	(b) Maintenance labor ^(c)	0.5 hours/shift	\$34.00 per hour ^(d)	\$18,615
B Total Purchased Equipment Cost		\$10,231,731	(b) Maintenance materials	100% of maintenance labor		\$18,615
<u>Direct Installation Costs</u>			<u>Utilities^(e)</u>			
(b) Foundations and Supports	0.12 B	\$1,227,808	Electricity	1,587 kW	\$0.060 per kWh ^(b)	\$834,085
(b) Handling and erection	0.40 B	\$4,092,692	Chemicals	1,110 lb/hr NaOH	\$0.25 per lb NaOH ^(d)	\$2,431,068
(b) Electrical	0.01 B	\$102,317	Fresh water usage	144 gpm	\$0.20 per 1000 gallon ^(b)	\$15,137
(b) Piping	0.30 B	\$3,069,519	Wastewater disposal	14.59 gpm	\$3.80 per 1000 gallon ^(b)	\$29,149
(b) Insulation for ductwork	0.01 B	\$102,317	Total Direct Annual Costs			
(b) Painting	0.01 B	\$102,317				\$3,366,187
Direct Installation Cost		\$8,696,971	Indirect Annual Costs			
Total Direct Costs		\$18,928,702	Overhead	60% Labor and Material Costs		\$34,049
Indirect Costs			General and administrative	2% of TCI		\$450,196
(b) Engineering	0.10 B	\$1,023,173	Property taxes	1% of TCI		\$225,098
(b) Construction Management	0.10 B	\$1,023,173	Insurance	1% of TCI		\$225,098
(b) Contractor fees	0.10 B	\$1,023,173	Capital recovery	0.095 x TCI		\$2,132,155
(b) Start-up	0.01 B	\$102,317		Life of the control: 15 years at 4.75% interest		
(b) Performance test	0.01 B	\$102,317	Total Indirect Annual Costs			
(b) Contingencies	0.03 B	\$306,952				\$3,066,596
Total Indirect Costs		\$3,581,106	Total Annual Costs			
Total Capital Investment (TCI)		\$22,509,808	\$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 SO₂ 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)				ANNUALIZED COSTS					
COST ITEM		COST FACTOR	COST (\$)	COST ITEM		COST FACTOR		RATE	COST (\$)
Direct Costs				Direct Annual Costs					
<u>Purchased Equipment Costs</u>				<u>Operating Labor</u>					
(a)	A	Equipment Costs	\$8,670,958	(b)	Operator ^(c)	0.5 hours/shift		\$31.00 per hour ^(d)	\$15,550
(b)		Instrumentation	0.10 A \$867,096	(b)	Supervisor	15% of operator labor			\$2,333
(b)		Sales Tax	0.03 A \$260,129	<u>Maintenance</u>					
(b)		Freight	0.05 A \$433,548	(b)	Maintenance labor ^(c)	0.5 hours/shift		\$34.00 per hour ^(d)	\$17,055
B		Total Purchased Equipment Cost	\$10,231,731	(b)	Maintenance materials	100% of maintenance labor			\$17,055
<u>Direct Installation Costs</u>				<u>Utilities^(e)</u>					
(b)		Foundations and Supports	0.12 B \$1,227,808		Electricity	1,587 kW		\$0.060 per kWh ^(b)	\$764,197
(b)		Handling and erection	0.40 B \$4,092,692		Chemicals	1,110 lb/hr NaOH		\$0.25 per lb NaOH ^(d)	\$2,227,369
(b)		Electrical	0.01 B \$102,317		Fresh water usage	144 gpm		\$0.20 per 1000 gallon ^(b)	\$13,869
(b)		Piping	0.30 B \$3,069,519		Wastewater disposal	14.59 gpm		\$3.80 per 1000 gallon ^(b)	\$26,707
(b)		Insulation for ductwork	0.01 B \$102,317	Total Direct Annual Costs					
(b)		Painting	0.01 B \$102,317	\$3,084,135					
		Direct Installation Cost	\$8,696,971	Indirect Annual Costs					
		Total Direct Costs	\$18,928,702		Overhead	60% Labor and Material Costs			\$31,196
Indirect Costs					General and administrative	2% of TCI			\$450,196
(b)		Engineering	0.10 B \$1,023,173		Property taxes	1% of TCI			\$225,098
(b)		Construction Management	0.10 B \$1,023,173		Insurance	1% of TCI			\$225,098
(b)		Contractor fees	0.10 B \$1,023,173		Capital recovery	0.095 x TCI			\$2,132,155
(b)		Start-up	0.01 B \$102,317	Total Indirect Annual Costs					
(b)		Performance test	0.01 B \$102,317	\$3,063,743					
(b)		Contingencies	0.03 B \$306,952	Total Annual Costs					
		Total Indirect Costs	\$3,581,106	\$6,147,878					
		Total Capital Investment (TCI)	\$22,509,808	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 SO₂ 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)			ANNUALIZED COSTS			
COST ITEM	COST FACTOR	COST (\$)	COST ITEM	COST FACTOR	RATE	COST (\$)
Direct Costs			Direct Annual Costs			
<u>Purchased Equipment Costs</u>			<u>Operating Labor</u>			
(a) A Equipment Costs		\$8,503,587	(b) Operator ^(c)	0.5 hours/shift	\$31.00 per hour ^(d)	\$16,973
(b) Instrumentation	0.10 A	\$850,359	(b) Supervisor	15% of operator labor		\$2,546
(b) Sales Tax	0.03 A	\$255,108	<u>Maintenance</u>			
(b) Freight	0.05 A	\$425,179	(b) Maintenance labor ^(c)	0.5 hours/shift	\$34.00 per hour ^(d)	\$18,615
B Total Purchased Equipment Cost		\$10,034,232	(b) Maintenance materials	100% of maintenance labor		\$18,615
<u>Direct Installation Costs</u>			<u>Utilities^(e)</u>			
(b) Foundations and Supports	0.12 B	\$1,204,108	Electricity	1,536 kW	\$0.060 per kWh ^(b)	\$807,424
(b) Handling and erection	0.40 B	\$4,013,693	Chemicals	1,075 lb/hr NaOH	\$0.25 per lb NaOH ^(d)	\$2,353,362
(b) Electrical	0.01 B	\$100,342	Fresh water usage	139 gpm	\$0.20 per 1000 gallon ^(b)	\$14,653
(b) Piping	0.30 B	\$3,010,270	Wastewater disposal	14.13 gpm	\$3.80 per 1000 gallon ^(b)	\$28,218
(b) Insulation for ductwork	0.01 B	\$100,342	Total Direct Annual Costs			
(b) Painting	0.01 B	\$100,342				\$3,260,406
Direct Installation Cost		\$8,529,098	Indirect Annual Costs			
Total Direct Costs		\$18,563,330	(b) Overhead	60% Labor and Material Costs		\$34,049
Indirect Costs			(b) General and administrative	2% of TCI		\$441,506
(b) Engineering	0.10 B	\$1,003,423	(b) Property taxes	1% of TCI		\$220,753
(b) Construction Management	0.10 B	\$1,003,423	(b) Insurance	1% of TCI		\$220,753
(b) Contractor fees	0.10 B	\$1,003,423	(b) Capital recovery	0.095 x TCI		\$2,090,999
(b) Start-up	0.01 B	\$100,342	Total Indirect Annual Costs			
(b) Performance test	0.01 B	\$100,342				\$3,008,060
(b) Contingencies	0.03 B	\$301,027	Total Annual Costs			
Total Indirect Costs		\$3,511,981				\$6,268,466
Total Capital Investment (TCI)		\$22,075,311	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 SO₂ 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)			ANNUALIZED COSTS			
COST ITEM	COST FACTOR	COST (\$)	COST ITEM	COST FACTOR	RATE	COST (\$)
Direct Costs			Direct Annual Costs			
<u>Purchased Equipment Costs</u>			<u>Operating Labor</u>			
(a) A Equipment Costs		\$8,503,587	(b) Operator ^(c)	0.5 hours/shift	\$31.00 per hour ^(d)	\$16,821
(b) Instrumentation	0.10 A	\$850,359	(b) Supervisor	15% of operator labor		\$2,523
(b) Sales Tax	0.03 A	\$255,108	<u>Maintenance</u>			
(b) Freight	0.05 A	\$425,179	(b) Maintenance labor ^(c)	0.5 hours/shift	\$34.00 per hour ^(d)	\$18,449
B Total Purchased Equipment Cost		\$10,034,232	(b) Maintenance materials	100% of maintenance labor		\$18,449
<u>Direct Installation Costs</u>			<u>Utilities^(e)</u>			
(b) Foundations and Supports	0.12 B	\$1,204,108	Electricity	1,536 kW	\$0.060 per kWh ^(b)	\$800,235
(b) Handling and erection	0.40 B	\$4,013,693	Chemicals	1,075 lb/hr NaOH	\$0.25 per lb NaOH ^(d)	\$2,332,408
(b) Electrical	0.01 B	\$100,342	Fresh water usage	139 gpm	\$0.20 per 1000 gallon ^(b)	\$14,523
(b) Piping	0.30 B	\$3,010,270	Wastewater disposal	14.13 gpm	\$3.80 per 1000 gallon ^(b)	\$27,967
(b) Insulation for ductwork	0.01 B	\$100,342	Total Direct Annual Costs			
(b) Painting	0.01 B	\$100,342				\$3,231,375
Direct Installation Cost		\$8,529,098	Indirect Annual Costs			
Total Direct Costs		\$18,563,330	(b) Overhead	60% Labor and Material Costs		\$33,746
Indirect Costs			(b) General and administrative	2% of TCI		\$441,506
(b) Engineering	0.10 B	\$1,003,423	(b) Property taxes	1% of TCI		\$220,753
(b) Construction Management	0.10 B	\$1,003,423	(b) Insurance	1% of TCI		\$220,753
(b) Contractor fees	0.10 B	\$1,003,423	(b) Capital recovery	0.095 x TCI		\$2,090,999
(b) Start-up	0.01 B	\$100,342	Total Indirect Annual Costs			
(b) Performance test	0.01 B	\$100,342				\$3,007,757
(b) Contingencies	0.03 B	\$301,027	Total Annual Costs			
Total Indirect Costs		\$3,511,981				\$6,239,132
Total Capital Investment (TCI)		\$22,075,311	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 SO₂ 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)			ANNUALIZED COSTS			
COST ITEM	COST FACTOR	COST (\$)	COST ITEM	COST FACTOR	RATE	COST (\$)
Direct Costs			Direct Annual Costs			
<u>Purchased Equipment Costs</u>			<u>Operating Labor</u>			
(a) A ESP		\$2,704,709	(b) Operator	1 hours/shift	\$31.00 per hour ^(d)	\$33,945
(b) Instrumentation	0.10 A	\$270,471	(b) Supervisor	15% of operator labor		\$5,092
(b) Sales Tax	0.03 A	\$81,141	(b) Coordinator	33% of operator labor		\$11,202
(b) Freight	0.05 A	\$135,235	<u>Maintenance</u>			
B Total Purchased Equipment Cost		\$3,191,557	(b) Maintenance labor	0.25 hours/shift	\$34.00 per hour ^(d)	\$9,308
<u>Direct Installation Costs</u>			(b) Maintenance materials	1% of purchased equipment costs		\$31,916
(b) Foundations and Supports	0.04 B	\$127,662	<u>Utilities</u>			
(b) Handling and Erection	0.50 B	\$1,595,778	Additional Electricity	208 kW	\$0.060 per kWh ^(b)	\$109,491
(b) Electrical	0.08 B	\$255,325	Total Direct Annual Costs			
(b) Piping	0.01 B	\$31,916				\$200,953
(b) Insulation	0.02 B	\$63,831	Indirect Annual Costs			
(b) Painting	0.02 B	\$63,831	(b) Overhead	60% Labor and Material Costs		\$54,877
Direct Installation Cost		\$2,138,343	(b) General and administrative	2% of TCI		\$142,982
Total Direct Costs		\$5,329,900	(b) Property taxes	1% of TCI		\$71,491
Indirect Costs			(b) Insurance	1% of TCI		\$71,491
(b) Engineering	0.20 B	\$638,311	(b) Capital recovery	0.079 x TCI		\$561,564
(b) Construction Management	0.20 B	\$638,311	Life of the control:	20 years at	4.75% interest	
(b) Contractor fees	0.10 B	\$319,156	Total Indirect Annual Costs			
(b) Start-up	0.01 B	\$31,916				\$902,405
(b) Performance test	0.01 B	\$31,916	Total Annual Costs			
(b) Model Study	0.02 B	\$63,831				\$1,103,358
(b) Contingencies	0.03 B	\$95,747	Cost Effectiveness (\$/ton)			
Total Indirect Costs		\$1,819,187	PM ₁₀ Control Improvement ^(f) :	90%		
Total Capital Investment (TCI)^(a)		\$7,149,088	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)			ANNUALIZED COSTS			
COST ITEM	COST FACTOR	COST (\$)	COST ITEM	COST FACTOR	RATE	COST (\$)
Direct Costs			Direct Annual Costs ^(c)			
<u>Purchased Equipment Costs</u>			<u>Operating Labor</u>			
(a) A ESP		\$2,704,709	(b) Operator	1 hours/shift	\$31.00 per hour ^(d)	\$33,945
(b) Instrumentation	0.10 A	\$270,471	(b) Supervisor	15% of operator labor		\$5,092
(b) Sales Tax	0.03 A	\$81,141	(b) Coordinator	33% of operator labor		\$11,202
(b) Freight	0.05 A	\$135,235	<u>Maintenance</u>			
B Total Purchased Equipment Cost		\$3,191,557	(b) Maintenance labor	0.25 hours/shift	\$34.00 per hour ^(d)	\$9,308
<u>Direct Installation Costs</u>			(b) Maintenance materials	1% of purchased equipment costs		\$31,916
(b) Foundations and Supports	0.04 B	\$127,662	<u>Utilities</u>			
(b) Handling and Erection	0.50 B	\$1,595,778	Additional Electricity	208 kW ^(e)	\$0.060 per kWh ^(b)	\$105,317
(b) Electrical	0.08 B	\$255,325	Total Direct Annual Costs			
(b) Piping	0.01 B	\$31,916				\$196,778
(b) Insulation	0.02 B	\$63,831	Indirect Annual Costs			
(b) Painting	0.02 B	\$63,831	(b) Overhead	60% Labor and Material Costs		\$54,877
Direct Installation Cost		\$2,138,343	(b) General and administrative	2% of TCI		\$142,982
Total Direct Costs		\$5,329,900	(b) Property taxes	1% of TCI		\$71,491
Indirect Costs			(b) Insurance	1% of TCI		\$71,491
(b) Engineering	0.20 B	\$638,311	(b) Capital recovery	0.079 x TCI		\$561,564
(b) Construction Management	0.20 B	\$638,311	Life of the control: 20 years at 4.75% interest			
(b) Contractor fees	0.10 B	\$319,156	Total Indirect Annual Costs			
(b) Start-up	0.01 B	\$31,916				\$902,405
(b) Performance test	0.01 B	\$31,916	Total Annual Costs			
(b) Model Study	0.02 B	\$63,831				\$1,099,183
(b) Contingencies	0.03 B	\$95,747	Cost Effectiveness (\$/ton)			
Total Indirect Costs		\$1,819,187	PM ₁₀ Control Improvement ^(f) :	90%		
Total Capital Investment (TCI)^(a)		\$7,149,088	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			
<u>Purchased Equipment Costs</u>			<u>Operating Labor</u>			
(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	<u>Maintenance</u>			
B Total Purchased Equipment Cost		\$4,477,773	(b) Maintenance labor	0.25 hours/shift	\$34.00 per hour ^(d)	\$9,308
<u>Direct Installation Costs</u>			(b) Maintenance materials	1% of purchased equipment costs		\$44,778
(b) Foundations and Supports	0.04 B	\$179,111	<u>Utilities</u>			
(b) Handling and Erection	0.50 B	\$2,238,886	Electricity	366 kW	\$0.060 per kWh ^(b)	\$192,521
(b) Electrical	0.08 B	\$358,222	Total Direct Annual Costs			
(b) Piping	0.01 B	\$44,778				\$296,845
(b) Insulation	0.02 B	\$89,555	Indirect Annual Costs			
(b) Painting	0.02 B	\$89,555	(b) Overhead	60% Labor and Material Costs		\$62,594
Direct Installation Cost		\$3,000,108	(b) General and administrative	2% of TCI		\$200,604
Total Direct Costs		\$7,477,881	(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	Total Indirect Annual Costs			
(b) Start-up	0.01 B	\$44,778				\$1,251,681
(b) Performance test	0.01 B	\$44,778	Total Annual Costs			
(b) Model Study	0.02 B	\$89,555				\$1,548,526
(b) Contingencies	0.03 B	\$134,333	Cost Effectiveness (\$/ton)			
Total Indirect Costs		\$2,552,331	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			
<u>Purchased Equipment Costs</u>			<u>Operating Labor</u>			
(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	<u>Maintenance</u>			
B Total Purchased Equipment Cost		\$4,477,773	(b) Maintenance labor	0.25 hours/shift	\$34.00 per hour ^(d)	\$9,308
<u>Direct Installation Costs</u>			(b) Maintenance materials	1% of purchased equipment costs		\$44,778
(b) Foundations and Supports	0.04 B	\$179,111	<u>Utilities</u>			
(b) Handling and Erection	0.50 B	\$2,238,886	Electricity	366 kW	\$0.060 per kWh ^(b)	\$180,214
(b) Electrical	0.08 B	\$358,222	Total Direct Annual Costs			
(b) Piping	0.01 B	\$44,778				\$284,538
(b) Insulation	0.02 B	\$89,555	Indirect Annual Costs			
(b) Painting	0.02 B	\$89,555	(b) Overhead	60% Labor and Material Costs		\$62,594
Direct Installation Cost		\$3,000,108	(b) General and administrative	2% of TCI		\$200,604
Total Direct Costs		\$7,477,881	(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	Total Indirect Annual Costs			
(b) Start-up	0.01 B	\$44,778				\$1,251,681
(b) Performance test	0.01 B	\$44,778	Total Annual Costs			
(b) Model Study	0.02 B	\$89,555				\$1,536,218
(b) Contingencies	0.03 B	\$134,333	Cost Effectiveness (\$/ton)			
Total Indirect Costs		\$2,552,331	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)			ANNUALIZED COSTS			
COST ITEM	COST FACTOR	COST (\$)	COST ITEM	COST FACTOR	RATE	COST (\$)
Direct Costs			Direct Annual Costs			
<u>Purchased Equipment Costs</u>			<u>Operating Labor</u>			
(a) A ESP		\$3,227,069	(b) Operator	1 hours/shift	\$31.00 per hour ^(d)	\$33,945
(b) Instrumentation	0.10 A	\$322,707	(b) Supervisor	15% of operator labor		\$5,092
(b) Sales Tax	0.03 A	\$96,812	(b) Coordinator	33% of operator labor		\$11,202
(b) Freight	0.05 A	\$161,353	<u>Maintenance</u>			
B Total Purchased Equipment Cost		\$3,807,941	(b) Maintenance labor	0.25 hours/shift	\$34.00 per hour ^(d)	\$9,308
<u>Direct Installation Costs</u>			(b) Maintenance materials	1% of purchased equipment costs		\$38,079
(b) Foundations and Supports	0.04 B	\$152,318	<u>Utilities</u>			
(b) Handling and Erection	0.50 B	\$1,903,970	Electricity	280 kW	\$0.060 per kWh ^(b)	\$146,958
(b) Electrical	0.08 B	\$304,635	Total Direct Annual Costs			
(b) Piping	0.01 B	\$38,079				\$244,583
(b) Insulation	0.02 B	\$76,159	Indirect Annual Costs			
(b) Painting	0.02 B	\$76,159	(b) Overhead	60% Labor and Material Costs		\$58,575
Direct Installation Cost		\$2,551,320	(b) General and administrative	2% of TCI		\$170,596
Total Direct Costs		\$6,359,261	(b) Property taxes	1% of TCI		\$85,298
Indirect Costs			(b) Insurance	1% of TCI		\$85,298
(b) Engineering	0.20 B	\$761,588	(b) Capital recovery	0.079 x TCI		\$670,019
(b) Construction Management	0.20 B	\$761,588	Total Indirect Annual Costs			
(b) Contractor fees	0.10 B	\$380,794				\$1,069,786
(b) Start-up	0.01 B	\$38,079	Total Annual Costs			
(b) Performance test	0.01 B	\$38,079				\$1,314,369
(b) Model Study	0.02 B	\$76,159	Cost Effectiveness (\$/ton)			
(b) Contingencies	0.03 B	\$114,238	PM ₁₀ Control Improvement ^(f) :	90.0%		
Total Indirect Costs		\$2,170,526	PM ₁₀ Emissions ^(g) :	32.1 tpy	Total Annual Costs/Controlled PM ₁₀ Emissions:	
Total Capital Investment (TCI)^(a)		\$8,529,788	Reduction in PM ₁₀ Emissions ^(h) :	28.9 tpy		\$45,496

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

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

^(c) Reserved

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

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

^(f) Estimated additional reduction in emissions already controlled by wet scrubber.

^(g) PM₁₀ PSEL

^(h) The reduction in PM₁₀ emissions is estimated assuming the ESP will provide an additional 90% PM₁₀ control.

Table A-45a
GP Wauna
Capital and Annual Costs Associated with New ESP for Lime Kiln

CAPITAL COSTS ^(a)			ANNUALIZED COSTS			
COST ITEM	COST FACTOR	COST (\$)	COST ITEM	COST FACTOR	RATE	COST (\$)
Direct Costs			Direct Annual Costs			
<u>Purchased Equipment Costs</u>			<u>Operating Labor</u>			
(a) A ESP		\$3,227,069	(b) Operator	1 hours/shift	\$31.00 per hour ^(d)	\$33,945
(b) Instrumentation	0.10 A	\$322,707	(b) Supervisor	15% of operator labor		\$5,092
(b) Sales Tax	0.03 A	\$96,812	(b) Coordinator	33% of operator labor		\$11,202
(b) Freight	0.05 A	\$161,353	<u>Maintenance</u>			
B Total Purchased Equipment Cost		\$3,807,941	(b) Maintenance labor	0.25 hours/shift	\$34.00 per hour ^(d)	\$9,308
<u>Direct Installation Costs</u>			(b) Maintenance materials	1% of purchased equipment costs		\$38,079
(b) Foundations and Supports	0.04 B	\$152,318	<u>Utilities</u>			
(b) Handling and Erection	0.50 B	\$1,903,970	Electricity	280 kW	\$0.060 per kWh ^(b)	\$132,044
(b) Electrical	0.08 B	\$304,635	Total Direct Annual Costs			
(b) Piping	0.01 B	\$38,079				\$229,669
(b) Insulation	0.02 B	\$76,159	Indirect Annual Costs			
(b) Painting	0.02 B	\$76,159	(b) Overhead	60% Labor and Material Costs		\$58,575
Direct Installation Cost		\$2,551,320	(b) General and administrative	2% of TCI		\$170,596
Total Direct Costs		\$6,359,261	(b) Property taxes	1% of TCI		\$85,298
Indirect Costs			(b) Insurance	1% of TCI		\$85,298
(b) Engineering	0.20 B	\$761,588	(b) Capital recovery	0.079 x TCI		\$670,019
(b) Construction Management	0.20 B	\$761,588	Total Indirect Annual Costs			
(b) Contractor fees	0.10 B	\$380,794				\$1,069,786
(b) Start-up	0.01 B	\$38,079	Total Annual Costs			
(b) Performance test	0.01 B	\$38,079				\$1,299,455
(b) Model Study	0.02 B	\$76,159	Cost Effectiveness (\$/ton)			
(b) Contingencies	0.03 B	\$114,238	PM ₁₀ Control Improvement ^(f) :	90.0%		
Total Indirect Costs		\$2,170,526	PM ₁₀ Emissions ^(g) :	87.3 tpy	Total Annual Costs/Controlled PM ₁₀ Emissions:	
Total Capital Investment (TCI)^(a)		\$8,529,788	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			
<u>Purchased Equipment Costs</u>			<u>Operating Labor^(c)</u>			
(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	<u>Maintenance^(c)</u>			
B Total Purchased Equipment Cost		\$1,643,374	(b) Maintenance labor	hours/shift	\$34.00 per hour ^(d)	\$0
<u>Direct Installation Costs</u>			(b) Maintenance materials	of purchased equipment costs		\$0
(b) Foundations and Supports ^(c)	0.04 B	\$0	<u>Utilities^(e)</u>			
(b) Handling and Erection	0.50 B	\$821,687	Electricity	108 kW	\$0.060 per kWh ^(b)	\$57,000
(b) Electrical	0.08 B	\$131,470	Total Direct Annual Costs			
(b) Piping	0.01 B	\$16,434				\$57,000
(b) Insulation	0.02 B	\$32,867	Indirect Annual Costs			
(b) Painting	0.02 B	\$32,867	(c) Overhead	60% Labor and Material Costs		\$0
Direct Installation Cost		\$1,035,326	(c) General and administrative	2% of TCI		\$0
Total Direct Costs		\$2,678,699	(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	Total Indirect Annual Costs			
(b) Start-up	0.01 B	\$16,434				\$356,302
(b) Performance test	0.01 B	\$16,434	Total Annual Costs			
(b) Model Study	0.02 B	\$32,867				\$413,302
(b) Contingencies	0.03 B	\$49,301	Cost Effectiveness (\$/ton)			
Total Indirect Costs		\$936,723	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 PM₁₀ 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)			ANNUALIZED COSTS			
COST ITEM	COST FACTOR	COST (\$)	COST ITEM	COST FACTOR	RATE	COST (\$)
Direct Costs			Direct Annual Costs			
<u>Purchased Equipment Costs</u>			<u>Operating Labor^(c)</u>			
(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	<u>Maintenance^(c)</u>			
B Total Purchased Equipment Cost		\$1,643,374	(b) Maintenance labor	hours/shift	\$34.00 per hour ^(d)	\$0
<u>Direct Installation Costs</u>			(b) Maintenance materials	of purchased equipment costs		\$0
(b) Foundations and Supports ^(c)	0.04 B	\$0	<u>Utilities^(e)</u>			
(b) Handling and Erection	0.50 B	\$821,687	Electricity	108 kW	\$0.060 per kWh ^(b)	\$56,675
(b) Electrical	0.08 B	\$131,470	Total Direct Annual Costs			
(b) Piping	0.01 B	\$16,434				\$56,675
(b) Insulation	0.02 B	\$32,867	Indirect Annual Costs			
(b) Painting	0.02 B	\$32,867	(c) Overhead	60% Labor and Material Costs		\$0
Direct Installation Cost		\$1,035,326	(c) General and administrative	2% of TCI		\$0
Total Direct Costs		\$2,678,699	(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	Total Indirect Annual Costs			
(b) Start-up	0.01 B	\$16,434				\$356,302
(b) Performance test	0.01 B	\$16,434	Total Annual Costs			
(b) Model Study	0.02 B	\$32,867				\$412,976
(b) Contingencies	0.03 B	\$49,301	Cost Effectiveness (\$/ton)			
Total Indirect Costs		\$936,723	PM ₁₀ Control Efficiency ^(f) :	99.5%		
Total Capital Investment (TCI)^(a)		\$3,615,422	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 PM₁₀ 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)			ANNUALIZED COSTS					
COST ITEM		COST FACTOR	COST (\$)	COST ITEM		COST FACTOR	RATE	COST (\$)
Direct Costs				Direct Annual Costs				
<u>Purchased Equipment Costs</u>				<u>Operating Labor</u>				
(a)	A	Equipment Costs	\$4,153,832	(b)	Operator ^(c)	0.5 hours/shift	\$31.00 per hour ^(d)	\$16,973
(b)		Instrumentation	0.10 A \$415,383	(b)	Supervisor	15% of operator labor		\$2,546
(b)		Sales Tax	0.03 A \$124,615	<u>Maintenance</u>				
(b)		Freight	0.05 A \$207,692	(b)	Maintenance labor ^(c)	0.5 hours/shift	\$34.00 per hour ^(d)	\$18,615
B		Total Purchased Equipment Cost	\$4,901,522	(b)	Maintenance materials	100% of maintenance labor		\$18,615
<u>Direct Installation Costs</u>				<u>Utilities</u> ^(e)				
(b)		Foundations and Supports	0.12 B \$588,183		Electricity	465 kW	\$0.060 per kWh ^(b)	\$244,632
(b)		Handling and erection	0.40 B \$1,960,609		Chemicals	326 lb/hr NaOH	\$0.25 per lb NaOH ^(d)	\$713,017
(b)		Electrical	0.01 B \$49,015		Fresh water usage	42 gpm	\$0.20 per 1000 gallon ^(b)	\$4,440
(b)		Piping	0.30 B \$1,470,456		Wastewater disposal	4.28 gpm	\$3.80 per 1000 gallon ^(b)	\$8,549
(b)		Insulation for ductwork	0.01 B \$49,015	Total Direct Annual Costs				
(b)		Painting	0.01 B \$49,015	\$1,027,387				
		Direct Installation Cost	\$4,166,293	Indirect Annual Costs				
		Total Direct Costs	\$9,067,815	(b)	Overhead	60% Labor and Material Costs		\$34,049
Indirect Costs				(b)	General and administrative	2% of TCI		\$215,667
(b)		Engineering	0.10 B \$490,152	(b)	Property taxes	1% of TCI		\$107,833
(b)		Construction Management	0.10 B \$490,152	(b)	Insurance	1% of TCI		\$107,833
(b)		Contractor fees	0.10 B \$490,152	(b)	Capital recovery	0.095 x TCI		\$1,021,411
(b)		Start-up	0.01 B \$49,015	Life of the control: 15 years at 4.8% interest				
(b)		Performance test	0.01 B \$49,015	Total Indirect Annual Costs				
(b)		Contingencies	0.03 B \$147,046	\$1,486,794				
		Total Indirect Costs	\$1,715,533	Total Annual Costs				
		Total Capital Investment (TCI)	\$10,783,348	\$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 SO₂ 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)			ANNUALIZED COSTS			
COST ITEM	COST FACTOR	COST (\$)	COST ITEM	COST FACTOR	RATE	COST (\$)
Direct Costs			Direct Annual Costs			
<u>Purchased Equipment Costs</u>			<u>Operating Labor</u>			
(a) A Equipment Costs		\$4,153,832	(b) Operator ^(c)	0.5 hours/shift	\$31.00 per hour ^(d)	\$16,876
(b) Instrumentation	0.10 A	\$415,383	(b) Supervisor	15% of operator labor		\$2,531
(b) Sales Tax	0.03 A	\$124,615	<u>Maintenance</u>			
(b) Freight	0.05 A	\$207,692	(b) Maintenance labor ^(c)	0.5 hours/shift	\$34.00 per hour ^(d)	\$18,509
B Total Purchased Equipment Cost		\$4,901,522	(b) Maintenance materials	100% of maintenance labor		\$18,509
<u>Direct Installation Costs</u>			<u>Utilities^(e)</u>			
(b) Foundations and Supports	0.12 B	\$588,183	Electricity	465 kW	\$0.060 per kWh ^(b)	\$243,236
(b) Handling and erection	0.40 B	\$1,960,609	Chemicals	326 lb/hr NaOH	\$0.25 per lb NaOH ^(d)	\$708,948
(b) Electrical	0.01 B	\$49,015	Fresh water usage	42 gpm	\$0.20 per 1000 gallon ^(b)	\$4,414
(b) Piping	0.30 B	\$1,470,456	Wastewater disposal	4.28 gpm	\$3.80 per 1000 gallon ^(b)	\$8,501
(b) Insulation for ductwork	0.01 B	\$49,015	Total Direct Annual Costs			
(b) Painting	0.01 B	\$49,015				\$1,021,523
Direct Installation Cost		\$4,166,293	Indirect Annual Costs			
Total Direct Costs		\$9,067,815	(b) Overhead	60% Labor and Material Costs		\$33,855
Indirect Costs			(b) General and administrative	2% of TCI		\$215,667
(b) Engineering	0.10 B	\$490,152	(b) Property taxes	1% of TCI		\$107,833
(b) Construction Management	0.10 B	\$490,152	(b) Insurance	1% of TCI		\$107,833
(b) Contractor fees	0.10 B	\$490,152	(b) Capital recovery	0.095 x TCI		\$1,021,411
(b) Start-up	0.01 B	\$49,015	Total Indirect Annual Costs			
(b) Performance test	0.01 B	\$49,015				\$1,486,599
(b) Contingencies	0.03 B	\$147,046	Total Annual Costs			
Total Indirect Costs		\$1,715,533				\$2,508,122
Total Capital Investment (TCI)		\$10,783,348	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 SO₂ 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)			ANNUALIZED COSTS						
COST ITEM		COST FACTOR	COST (\$)	COST ITEM		COST FACTOR	RATE		COST (\$)
Direct Costs				Direct Annual Costs					
<u>Purchased Equipment Costs</u>				<u>Operating Labor</u>					
(a)	A	Equipment Costs	\$829,793	(b)	Operator ^(c)	hours/shift	\$31.00 per hour ^(d)		\$0
(b)		Instrumentation	0.10 A \$82,979	(b)	Supervisor	15% of operator labor			\$0
(b)		Sales Tax	0.03 A \$24,894	<u>Maintenance</u>					
(b)		Freight	0.05 A \$41,490	(b)	Maintenance labor ^(c)	hours/shift	\$34.00 per hour ^(d)		\$0
B		Total Purchased Equipment Cost	\$979,156	(b)	Maintenance materials	100% of maintenance labor			\$0
<u>Direct Installation Costs</u>				<u>Utilities^(e)</u>					
(b)		Foundations and Supports	0.12 B \$117,499	Electricity		229 kW	\$0.060 per kWh ^(b)		\$120,280
(b)		Handling and erection	0.40 B \$391,662	Total Direct Annual Costs					
(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	Indirect Annual Costs					
		Total Direct Costs	\$1,811,439	Overhead		60% Labor and Material Costs			\$0
Indirect Costs				General and administrative		2% of TCI			\$43,083
(b)		Engineering	0.10 B \$97,916	Property taxes		1% of TCI			\$21,541
(b)		Construction Management	0.10 B \$97,916	Insurance		1% of TCI			\$21,541
(b)		Contractor fees	0.10 B \$97,916	Capital recovery		0.095 x TCI			\$204,043
(b)		Start-up	0.01 B \$9,792	Life of the control:		15 years at 4.75% interest			
(b)		Performance test	0.01 B \$9,792	Total Indirect Annual Costs					
(b)		Contingencies	0.03 B \$29,375						
		Total Indirect Costs	\$342,705	Total Annual Costs					
		Total Capital Investment (TCI)	\$2,154,144	\$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)				ANNUALIZED COSTS					
COST ITEM		COST FACTOR	COST (\$)	COST ITEM		COST FACTOR	RATE		COST (\$)
Direct Costs				Direct Annual Costs					
<u>Purchased Equipment Costs</u>				<u>Operating Labor</u>					
(a)	A	Equipment Costs	\$829,793	(b)	Operator ^(c)	hours/shift	\$31.00 per hour ^(d)		\$0
(b)		Instrumentation	0.10 A \$82,979	(b)	Supervisor	15% of operator labor			\$0
(b)		Sales Tax	0.03 A \$24,894	<u>Maintenance</u>					
(b)		Freight	0.05 A \$41,490	(b)	Maintenance labor ^(c)	hours/shift	\$34.00 per hour ^(d)		\$0
B Total Purchased Equipment Cost			\$979,156	(b)	Maintenance materials	100% of maintenance labor			\$0
<u>Direct Installation Costs</u>				<u>Utilities^(e)</u>					
(b)		Foundations and Supports	0.12 B \$117,499	Electricity		229 kW	\$0.060 per kWh ^(b)		\$116,765
(b)		Handling and erection	0.40 B \$391,662	Total Direct Annual Costs					
(b)		Electrical	0.01 B \$9,792	\$116,765					
(b)		Piping	0.30 B \$293,747	Indirect Annual Costs					
(b)		Insulation for ductwork	0.01 B \$9,792	Overhead		60% Labor and Material Costs			\$0
(b)		Painting	0.01 B \$9,792	General and administrative		2% of TCI			\$43,083
Direct Installation Cost			\$832,283	Property taxes		1% of TCI			\$21,541
Total Direct Costs			\$1,811,439	Insurance		1% of TCI			\$21,541
Indirect Costs				Capital recovery		0.095 x TCI			\$204,043
(b)		Engineering	0.10 B \$97,916	Life of the control:		15 years at 4.75% interest			
(b)		Construction Management	0.10 B \$97,916	Total Indirect Annual Costs					
(b)		Contractor fees	0.10 B \$97,916	\$290,209					
(b)		Start-up	0.01 B \$9,792	Total Annual Costs					
(b)		Performance test	0.01 B \$9,792	\$406,974					
(b)		Contingencies	0.03 B \$29,375	Cost Effectiveness (\$/ton)					
Total Indirect Costs			\$342,705	Additional PM10 Control Efficiency ^(f) :		50%			
Total Capital Investment (TCI)			\$2,154,144	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				
<u>Purchased Equipment Costs</u>				<u>Operating Labor</u>				
(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	<u>Maintenance</u>				
(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
<u>Direct Installation Costs</u>				<u>Utilities^(e)</u>				
(b)		Foundations and Supports	0.12 B \$80,121	Electricity		121 kW	\$0.060 per kWh ^(b)	\$63,541
(b)		Handling and erection	0.40 B \$267,071	Total Direct Annual Costs				
(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	Indirect Annual Costs				
Direct Installation Cost		\$567,527						
Total Direct Costs		\$1,235,205						
Indirect Costs								
(b)		Engineering	0.10 B \$66,768	Overhead		60% Labor and Material Costs		\$0
(b)		Construction Management	0.10 B \$66,768	General and administrative		2% of TCI		\$29,378
(b)		Contractor fees	0.10 B \$66,768	Property taxes		1% of TCI		\$14,689
(b)		Start-up	0.01 B \$6,677	Insurance		1% of TCI		\$14,689
(b)		Performance test	0.01 B \$6,677	Capital recovery		0.095 x TCI		\$139,135
(b)		Contingencies	0.03 B \$20,030	Life of the control:		15 years at 4.75% interest		
Total Indirect Costs		\$233,687	Total Indirect Annual Costs					
Total Capital Investment (TCI)		\$1,468,893	Total Annual Costs					
			Cost Effectiveness (\$/ton)					
			Additional PM10 Control Efficiency ^(f) :		50%			
			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				
<u>Purchased Equipment Costs</u>				<u>Operating Labor</u>				
(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	<u>Maintenance</u>			
(b)		Freight	0.05 A	\$28,291	(b)	Maintenance labor ^(c)	hours/shift	\$34.00 per hour ^(d)
B Total Purchased Equipment Cost			\$667,679	(b)	Maintenance materials	100% of maintenance labor		\$0
<u>Direct Installation Costs</u>				<u>Utilities^(e)</u>				
(b)		Foundations and Supports	0.12 B	\$80,121	Electricity		121 kW	\$0.060 per kWh ^(b)
(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			
(b)		Insulation for ductwork	0.01 B	\$6,677				
(b)		Painting	0.01 B	\$6,677				
Direct Installation Cost			\$567,527	Indirect Annual Costs				
Total Direct Costs			\$1,235,205	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		
Indirect Costs				Total Indirect Annual 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 Annual Costs				
Total Capital Investment (TCI)			\$1,468,893	\$256,855				
				Cost Effectiveness (\$/ton)				
				Additional PM10 Control Efficiency ^(f) :		50%		
				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	

Table A-50
Georgia-Pacific - Toledo
Capital and Annual Costs Associated with Replacing the No. 2 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				
<u>Purchased Equipment Costs</u>				<u>Operating Labor</u>				
(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	<u>Maintenance</u>				
(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
<u>Direct Installation Costs</u>				<u>Utilities^(e)</u>				
(b)		Foundations and Supports	0.12 B \$80,121	Electricity		121 kW	\$0.060 per kWh ^(b)	\$63,541
(b)		Handling and erection	0.40 B \$267,071	Total Direct Annual Costs				
(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	Indirect Annual Costs				
Direct Installation Cost		\$567,527						
Total Direct Costs		\$1,235,205						
Indirect Costs								
(b)		Engineering	0.10 B \$66,768	Overhead		60% Labor and Material Costs		\$0
(b)		Construction Management	0.10 B \$66,768	General and administrative		2% of TCI		\$29,378
(b)		Contractor fees	0.10 B \$66,768	Property taxes		1% of TCI		\$14,689
(b)		Start-up	0.01 B \$6,677	Insurance		1% of TCI		\$14,689
(b)		Performance test	0.01 B \$6,677	Capital recovery		0.095 x TCI		\$139,135
(b)		Contingencies	0.03 B \$20,030	Life of the control:		15 years at 4.75% interest		
Total Indirect Costs		\$233,687		Total Indirect Annual Costs				
Total Capital Investment (TCI)		\$1,468,893		Total Annual Costs				
				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)				ANNUALIZED COSTS					
COST ITEM		COST FACTOR	COST (\$)	COST ITEM		COST FACTOR		RATE	COST (\$)
Direct Costs				Direct Annual Costs					
<u>Purchased Equipment Costs</u>				<u>Operating Labor</u>					
(a)	A	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	<u>Maintenance</u>				
(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
<u>Direct Installation Costs</u>				<u>Utilities^(e)</u>					
(b)		Foundations and Supports	0.12 B	\$80,121	Electricity		121 kW	\$0.060 per kWh ^(b)	\$59,479
(b)		Handling and erection	0.40 B	\$267,071	Total Direct Annual Costs				
(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	Indirect Annual Costs				
Direct Installation Cost			\$567,527						
Total Direct Costs			\$1,235,205						
Indirect Costs									
(b)		Engineering	0.10 B	\$66,768	Overhead	60% Labor and Material Costs			\$0
(b)		Construction Management	0.10 B	\$66,768	General and administrative	2% of TCI			\$29,378
(b)		Contractor fees	0.10 B	\$66,768	Property taxes	1% of TCI			\$14,689
(b)		Start-up	0.01 B	\$6,677	Insurance	1% of TCI			\$14,689
(b)		Performance test	0.01 B	\$6,677	Capital recovery	0.095 x TCI			\$139,135
(b)		Contingencies	0.03 B	\$20,030	Life of the control:	15 years at	4.75% interest		
Total Indirect Costs			\$233,687	Total Indirect Annual Costs					
Total Capital Investment (TCI)			\$1,468,893	Total Annual Costs					
				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			

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				
<u>Purchased Equipment Costs</u>				<u>Operating Labor</u>				
(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	<u>Maintenance</u>				
(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
<u>Direct Installation Costs</u>				<u>Utilities^(e)</u>				
(b)		Foundations and Supports	0.12 B \$140,009	Electricity		306 kW	\$0.060 per kWh ^(b)	\$161,089
(b)		Handling and erection	0.40 B \$466,698	Total Direct Annual Costs				
(b)		Electrical	0.01 B \$11,667	\$161,089				
(b)		Piping	0.30 B \$350,023	Indirect Annual Costs				
(b)		Insulation for ductwork	0.01 B \$11,667	Overhead		60% Labor and Material Costs		\$0
(b)		Painting	0.01 B \$11,667	General and administrative		2% of TCI		\$51,337
Direct Installation Cost			\$991,733	Property taxes		1% of TCI		\$25,668
Total Direct Costs			\$2,158,478	Insurance		1% of TCI		\$25,668
Indirect Costs				Capital recovery		0.095 x TCI		\$243,134
(b)		Engineering	0.10 B \$116,674	Life of the control:		15 years at 4.75% interest		
(b)		Construction Management	0.10 B \$116,674	Total Indirect Annual Costs				
(b)		Contractor fees	0.10 B \$116,674	\$345,807				
(b)		Start-up	0.01 B \$11,667	Total Annual Costs				
(b)		Performance test	0.01 B \$11,667	\$506,897				
(b)		Contingencies	0.03 B \$35,002	Cost Effectiveness (\$/ton)				
Total Indirect Costs			\$408,361	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)			ANNUALIZED COSTS										
COST ITEM		COST FACTOR	COST (\$)	COST ITEM		COST FACTOR	RATE	COST (\$)					
Direct Costs				Direct Annual Costs									
<u>Purchased Equipment Costs</u>				<u>Operating Labor</u>									
(a)	A	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	<u>Maintenance</u>									
(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					
<u>Direct Installation Costs</u>				<u>Utilities^(e)</u>									
(b)		Foundations and Supports	0.12 B \$140,009			Electricity	306 kW	\$0.060 per kWh ^(b) \$147,592					
(b)		Handling and erection	0.40 B \$466,698	Total Direct Annual Costs									
(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	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
Indirect Costs											Property taxes	1% of TCI	\$25,668
(b)		Engineering	0.10 B \$116,674			Insurance	1% of TCI	\$25,668					
(b)		Construction Management	0.10 B \$116,674			Capital recovery	0.095 x TCI	\$243,134					
(b)		Contractor fees	0.10 B \$116,674			Life of the control:	15 years at 4.75% interest						
(b)		Start-up	0.01 B \$11,667	Total Indirect Annual Costs									
(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	Total Annual Costs									
				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					

Table A-52
IP Springfield
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				
<u>Purchased Equipment Costs</u>				<u>Operating Labor</u>				
(a)	A	Equipment Costs	\$969,681	(b)	Operator ^(c)	hours/shift	\$31.00 per hour ^(d)	\$0
(b)		Instrumentation	0.10 A \$96,968	(b)	Supervisor	15% of operator labor		\$0
(b)		Sales Tax	0.03 A \$29,090	<u>Maintenance</u>				
(b)		Freight	0.05 A \$48,484	(b)	Maintenance labor ^(c)	hours/shift	\$34.00 per hour ^(d)	\$0
B Total Purchased Equipment Cost			\$1,144,224	(b)	Maintenance materials	100% of maintenance labor		\$0
<u>Direct Installation Costs</u>				<u>Utilities^(e)</u>				
(b)		Foundations and Supports	0.12 B \$137,307	Electricity		297 kW	\$0.060 per kWh ^(b)	\$155,940
(b)		Handling and erection	0.40 B \$457,690	Total Direct Annual Costs				
(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	Indirect Annual Costs				
Total Direct Costs			\$2,116,814	Overhead		60% Labor and Material Costs		\$0
Indirect Costs				General and administrative		2% of TCI		\$0
(b)		Engineering	0.10 B \$114,422	(b)	Property taxes	1% of TCI		\$25,173
(b)		Construction Management	0.10 B \$114,422	(b)	Insurance	1% of TCI		\$25,173
(b)		Contractor fees	0.10 B \$114,422	(b)	Capital recovery	0.095 x TCI		\$238,441
(b)		Start-up	0.01 B \$11,442	Life of the control:		15 years at 4.75% interest		
(b)		Performance test	0.01 B \$11,442	Total Indirect Annual Costs				
(b)		Contingencies	0.03 B \$34,327					
Total Indirect Costs			\$400,478	Total Annual Costs				
Total Capital Investment (TCI)			\$2,517,292	\$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)				ANNUALIZED COSTS				
COST ITEM		COST FACTOR	COST (\$)	COST ITEM		COST FACTOR	RATE	COST (\$)
Direct Costs				Direct Annual Costs				
<u>Purchased Equipment Costs</u>				<u>Operating Labor</u>				
(a)	A	Equipment Costs	\$969,681	(b)	Operator ^(c)	hours/shift	\$31.00 per hour ^(d)	\$0
(b)		Instrumentation	0.10 A \$96,968	(b)	Supervisor	15% of operator labor		\$0
(b)		Sales Tax	0.03 A \$29,090	<u>Maintenance</u>				
(b)		Freight	0.05 A \$48,484	(b)	Maintenance labor ^(c)	hours/shift	\$34.00 per hour ^(d)	\$0
B Total Purchased Equipment Cost			\$1,144,224	(b)	Maintenance materials	100% of maintenance labor		\$0
<u>Direct Installation Costs</u>				<u>Utilities^(e)</u>				
(b)		Foundations and Supports	0.12 B \$137,307	Electricity		297 kW	\$0.060 per kWh ^(b)	\$152,327
(b)		Handling and erection	0.40 B \$457,690	Total Direct Annual Costs				
(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	Indirect Annual Costs				
Direct Installation Cost			\$972,590					
Total Direct Costs			\$2,116,814					
Indirect Costs								
(b)		Engineering	0.10 B \$114,422	Overhead		60% Labor and Material Costs		\$0
(b)		Construction Management	0.10 B \$114,422	General and administrative		2% of TCI		\$0
(b)		Contractor fees	0.10 B \$114,422	(b)	Property taxes	1% of TCI		\$25,173
(b)		Start-up	0.01 B \$11,442	(b)	Insurance	1% of TCI		\$25,173
(b)		Performance test	0.01 B \$11,442	(b)	Capital recovery	0.095 x TCI		\$238,441
(b)		Contingencies	0.03 B \$34,327	Life of the control:		15 years at 4.75% interest		
Total Indirect Costs			\$400,478	Total Indirect Annual Costs				
Total Capital Investment (TCI)			\$2,517,292	Total Annual Costs				
				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 SO₂/HCl Control Cost Development Methodology

Final

April 2017

Project 13527-001

Eastern Research Group, Inc.

Prepared by



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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 SO₂/HCl reduction on coal-fired boilers. Demonstrations and utility testing have shown SO₂/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 SO₂, when this sorbent is used, significant SO₂ 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 SO₂ removal is much reduced. In either case, actual testing must be carried out before the permanent DSI system for SO₂ 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:

$$\frac{\frac{(\text{moles of Na injected})}{(\text{moles of SO}_2 \text{ in flue gas})}}{(\text{theoretical moles of Na required})}$$

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 SO₂ mitigation system are primarily dependent on sorbent feed rate. This rate is a function of NSR and the required SO₂ removal (the latter is set by the utility and is not a function of unit size). Therefore, the required SO₂ removal is determined by the user-specified SO₂ emission limit, and the cost estimation is based on sorbent feed rate and not unit size. Because HCl concentrations are low compared with SO₂ concentrations, any unused reagent for SO₂ removal is assumed to be used for HCl removal, resulting in a very small change in the NSR used for SO₂ 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 SO₂ 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 SO₂ 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 SO₂ without an increase in particulate emissions, whereas hydrated lime may remove an even lower percentage of SO₂. A baghouse used with sodium-based sorbents generally achieves a higher SO₂ 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 SO₂/MMBtu.

Units with a baghouse and limited NO_x control that target a high SO₂ removal efficiency with sodium sorbents may experience a brown plume resulting from the conversion of NO to NO₂. The formation of NO₂ 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 NO₂.

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, SO₂ 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 SO₂ 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 SO₂ removal should be limited to 20% to achieve maximum HCl removal.

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

Outputs

Total Project Costs (TPC)

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

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

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

DSI Cost Methodology

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

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

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

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

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

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

Fixed O&M (FOM)

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

The following factors and assumptions underlie calculations of the FOM:

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

DSI Cost Methodology

Variable O&M (VOM)

Variable O&M is a function of the following:

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

The following factors and assumptions underlie calculations of the VOM:

- All of the VOM costs are tabulated on a per megawatt-hour (MWh) basis.
- The additional power required includes increased fan power to account for the added DSI system and, as applicable, air blowers and transport-air drying equipment for the SO₂ 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 SO₂ 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 SO₂, 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 CaSO₄ and Na₂SO₄ and unreacted dry sorbent such as Ca(OH)₂ and Na₂CO₃, 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 = 85% Milled Trona with an ESP = 80% Unmilled Trona with a BGH = 80% Milled Trona with a BGH = 90% Hydrated Lime with an ESP = 30% Hydrated Lime with a BGH = 55%
Heat Input	J	(Btu/hr)	4.76E+09	A*C*1000
NSR	K		1.43	Unmilled Trona with an ESP = if (H<40,0.0350*H,0.352e*(0.0346*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<40,0.0180*H,0.208e*(0.0281*H)) Hydrated Lime with an ESP = 0.504*H*0.3905 Hydrated Lime with a BGH = 0.0067*H*0.8505
Sorbent Feed Rate	M	(ton/hr)	16.33	Trona = (1.2011 x 10^-08)*K*A*C*D Hydrated Lime = (6.0055 x 10^-07)*K*A*C*D
Estimated HCl Removal	V	(%)	83	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? <input checked="" type="checkbox"/>	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? <input checked="" type="checkbox"/>	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 difficult 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))	\$ 18,348,000	Base module for unmilled sorbent includes all equipment from unloading to injection, including dehumidification 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
SO ₂ 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 = 85% Milled Trona with an ESP = 80% Unmilled Trona with a BGH = 80% Milled Trona with a BGH = 90% Hydrated Lime with an ESP = 30% Hydrated Lime with a BGH = 55%
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<40,0.0180*H,0.208e*(0.0281*H)) Hydrated Lime with an ESP = 0.504*H+0.3905 Hydrated Lime with a BGH = 0.0067*H+0.6505
Sorbent Feed Rate	M	(ton/hr)	9.67	Trona = (1.2011 x 10^-08)*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 = 80.88*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+0.12 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? <input checked="" type="checkbox"/>	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? <input checked="" type="checkbox"/>	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 difficult to dispose = \$100)
Aux Power Cost	T	(\$/kWh)	0.06	<--- User Input
Operating Labor Rate	U	(\$/hr)	60	<--- User Input (Labor cost including all benefits)

Costs are all based on 2016 dollars

Capital Cost Calculation	Example	Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty		
BM (\$) = Unmilled Trona or Hydrated Lime if (M>25 then (745,000*B*M) else 7,500,000*B*(M^0.284)) Milled Trona if (M>25 then (820,000*B*M) else 8,300,000*B*(M^0.284))	\$ 15,812,000	Base module for unmilled sorbent includes all equipment from unloading to injection, including dehumidification system
BM (\$/kW) =	32	Base module cost per kW
Total Project Cost		
A1 = 10% of BM	\$ 1,581,000	Engineering and Construction Management costs
A2 = 5% of BM	\$ 791,000	Labor adjustment for 8 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
SO ₂ 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% Unmilled Trona with an ESP = 80% Unmilled Trona with an BGH = 80% Unmilled 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 ⁻⁶) * K * A * C * D Hydrated Lime = (6.0055 x 10 ⁻⁶) * 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? <input checked="" type="checkbox"/>	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 = 0.2
Aux Power Include in VOM? <input checked="" type="checkbox"/>	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 difficult 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
SO ₂ 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*(0.0287*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 = (8.0055 x 10^-07)*K*A*C*D
Estimated HCl Removal	V	(%)	97	Milled or Unmilled Trona with an ESP = 80.88*H+0.1081, or 0.002 lb/MBtu Milled or Unmilled Trona with a BGH = 84.568*H+0.0348 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? <input checked="" type="checkbox"/>	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 = 9400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal
Aux Power Include in VOM? <input checked="" type="checkbox"/>	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 difficult 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

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)

BM (\$/kW) =

Total Project Cost

A1 = 10% of BM

A2 = 5% of BM

A3 = 5% of BM

CECC (\$) - Excludes Owner's Costs = BM+A1+A2+A3

CECC (\$/kW) - Excludes Owner's Costs =

B1 = 5% of CECC

TPC' (\$) - Includes Owner's Costs = CECC + B1

TPC' (\$/kW) - Includes Owner's Costs =

B2 = 0% of (CECC + B1)

TPC (\$) = CECC + B1 + B2

TPC (\$/kW) =

Fixed O&M Cost

FOMO (\$/kW yr) = (2 additional operator)*2080*U/(A*1000)

FOMM (\$/kW yr) = BM*0.01/(B*A*1000)

FOMA (\$/kW yr) = 0.03*(FOMO+0.4*FOMM)

FOM (\$/kW yr) = FOMO + FOMM + FOMA

Variable O&M Cost

VOMR (\$/MWh) = M*R/A

VOMW (\$/MWh) = (N+P)*S/A

VOMP (\$/MWh) = Q*T*10

VOM (\$/MWh) = VOMR + VOMW + VOMP

Example

Comments

\$	15,468,000	Base module for unmilled sorbent includes all equipment from unloading to injection, including dehumidification system
31		Base module cost per kW
\$	1,547,000	Engineering and Construction Management costs
\$	773,000	Labor adjustment for 8 x 10 hour shift premium, per diem, etc...
\$	773,000	Contractor profit and fees
\$	18,561,000	Capital, engineering and construction cost subtotal
37		Capital, engineering and construction cost subtotal per kW
\$	928,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
\$	19,489,000	Total project cost without AFUDC
39		Total project cost per kW without AFUDC
\$	-	AFUDC (Zero for less than 1 year engineering and construction cycle)
\$	19,489,000	Total project cost
39		Total project cost per kW
\$	0.50	Fixed O&M additional operating labor costs
\$	0.31	Fixed O&M additional maintenance material and labor costs
\$	0.02	Fixed O&M additional administrative labor costs
\$	0.83	Total Fixed O&M costs
\$	5.78	Variable O&M costs for sorbent
\$	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
\$	0.28	Variable O&M costs for additional auxiliary power required (Refer to Aux Power % above)
\$	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
SO ₂ 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 = 85% Milled Trona with an ESP = 80% Unmilled Trona with a BGH = 80% Milled Trona with a BGH = 90% Hydrated Lime with an ESP = 90% 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 = 0.0067*H+0.6505
Sorbent Feed Rate	M	(ton/hr)	10.85	Trona = (1.2011 x 10^-06)*K*A*C*D Hydrated Lime = (8.0055 x 10^-07)*K*A*C*D
Estimated HCl Removal	V	(%)	95	Milled or Unmilled Trona with an ESP = 80.86*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? <input checked="" type="checkbox"/>	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? <input checked="" type="checkbox"/>	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 difficult 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

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)

BM (\$/kW) =

Total Project Cost

A1 = 10% of BM

A2 = 5% of BM

A3 = 5% of BM

CECC (\$) - Excludes Owner's Costs = BM+A1+A2+A3

CECC (\$/kW) - Excludes Owner's Costs =

B1 = 5% of CECC

TPC' (\$) - Includes Owner's Costs = CECC + B1

TPC' (\$/kW) - Includes Owner's Costs =

B2 = 0% of (CECC + B1)

TPC (\$) = CECC + B1 + B2

TPC (\$/kW) =

Fixed O&M Cost

FOMO (\$/kW yr) = (2 additional operator)*2080*U/(A*1000)

FOMM (\$/kW yr) = BM*0.01/(B*A*1000)

FOMA (\$/kW yr) = 0.03*(FOMO+0.4*FOMM)

FOM (\$/kW yr) = FOMO + FOMM + FOMA

Variable O&M Cost

VOMR (\$/MWh) = M^2/R/A

VOMW (\$/MWh) = (N+P)*S/A

VOMP (\$/MWh) = Q*T^10

VOM (\$/MWh) = VOMR + VOMW + VOMP

Example

Comments

\$	14,762,000	Base module for unmilled sorbent includes all equipment from unloading to injection, including dehumidification system
	30	Base module cost per kW
\$	1,476,000	Engineering and Construction Management costs
\$	738,000	Labor adjustment for 8 x 10 hour shift premium, per diem, etc...
\$	738,000	Contractor profit and fees
\$	17,714,000	Capital, engineering and construction cost subtotal
	35	Capital, engineering and construction cost subtotal per kW
\$	886,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
\$	18,600,000	Total project cost without AFUDC
	37	Total project cost per kW without AFUDC
\$	-	AFUDC (Zero for less than 1 year engineering and construction cycle)
\$	18,600,000	Total project cost
	37	Total project cost per kW
\$	0.50	Fixed O&M additional operating labor costs
\$	0.30	Fixed O&M additional maintenance material and labor costs
\$	0.02	Fixed O&M additional administrative labor costs
\$	0.81	Total Fixed O&M costs
\$	3.28	Variable O&M costs for sorbent
\$	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
\$	0.23	Variable O&M costs for additional auxiliary power required (Refer to Aux Power % above)
\$	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)	9600	<--- User Input
SO ₂ 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+08	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*(0.0287*H)) Milled Trona with a BGH = if (H<40,0.0180*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)	8.19	Trona = (1.2011 x 10 ⁻⁴)*D*(A*C*D) Hydrated Lime = (8.0055 x 10 ⁻⁴)*K*A*C*D
Estimated HCl Removal	V	(%)	99	Milled or Unmilled Trona with an ESP = 80.88*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 = 54.62*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? <input checked="" type="checkbox"/>	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? <input checked="" type="checkbox"/>	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 difficult to dispose = \$100)
Aux Power Cost	T	(\$/kWh)	0.06	<--- User Input
Operating Labor Rate	U	(\$/hr)	60	<--- User Input (Labor cost including all benefits)

Costs are all based on 2016 dollars

Capital Cost Calculation	Example	Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty		
BM (\$) = Unmilled Trona or Hydrated Lime if (M>25 then (745,000*B*M) else 7,500,000*B*(M^0.284) Milled Trona if (M>25 then (820,000*B*M) else 8,300,000*B*(M^0.284)	\$ 12,588,000	Base module for unmilled sorbent includes all equipment from unloading to injection, including dehumidification 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 8 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		
FOMC (\$/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*(FOMC+0.4*FOMM)	\$ 0.02	Fixed O&M additional administrative labor costs
FOM (\$/kW yr) = FOMC + 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



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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 $[\text{Cost of Project A} \times (\text{AF\&PA rate} / \text{Project A})^{0.6}]$ 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 based 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 quaternary air system yielding a NO_x level in the stack gases of 80 ppm @ 8% oxygen. Equipment sized for a NDCE recovery furnace burning 3.7×10^6 (Mm) lb BLS per day.

4.1.2. Major Equipment

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

4.1.3. Basis for Estimate

Southeast Kraft mill recovery furnace firing 2.6×10^6 -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
- ✓ Power 75 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 placed 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 10⁶ (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 ft³ 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 10⁶ (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 ft³ 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 ft³ 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 ft³ 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 ft³ per yr. @ \$350 per ft³
- ✓ 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 ft³ per yr. @ \$350 per ft³
- ✓ 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 ft³ per yr. @ \$350 per ft³
- ✓ 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 ft³ per yr. @ \$350 per ft³
- ✓ 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. SO₂ Reduction – Good Technology Limits

6.1. NDCE Recovery Boiler

6.1.1. Description

Installation of a chemical scrubber to achieve sulfur dioxide (SO₂) 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 2.5×10^6 -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 (SO₂) 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 2.5×10^6 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 SO₂ 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 SO₂ 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. SO₂ Reduction – Best Technology Limits

7.1. NDCE Recovery Boiler

7.1.1. Description

Installation of a caustic scrubber to achieve sulfur dioxide (SO₂) 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 2.5×10^6 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 (SO₂) 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 2.5×10^6 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 SO₂ 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 SO₂ 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/10¹² Btu to 8 lb/10¹² 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/10¹² Btu to 0.286 lb/10¹² 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



**AF&PA Emission Control Study –
Cost Estimate & Industry-Wide Model
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- ✓ 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 2.15×10^6 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 3.7×10^6 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 2.70×10^6 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 3.7×10^6 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 2.15×10^6 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 1.7×10^6 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 3.7×10^6 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 2.15×10^6 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 3.7×10^6 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 2.70×10^6 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 3.7×10^6 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 2.15×10^6 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 1.7×10^6 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 3.7×10^6 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: 202 gpm
- ✓ 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



**AF&PA Emission Control Study –
Cost Estimate & Industry-Wide Model
Phase I Pulp & Paper Industry
September 20, 2001**

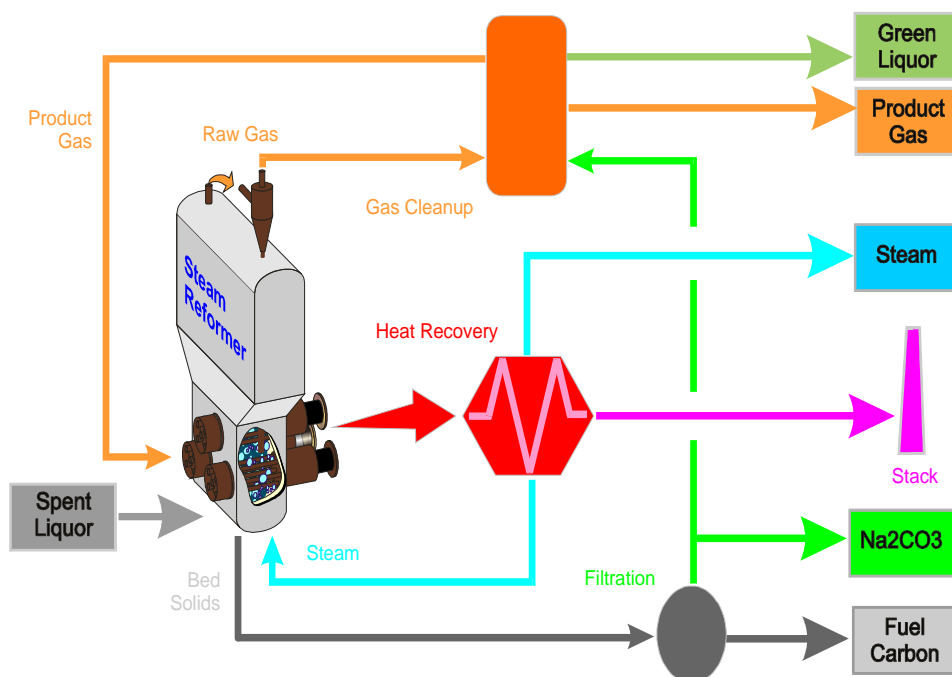


- ✓ Testing: \$5,000 per year
- ✓ Water: 10gpm
- ✓ Wastewater: 10 gpm

16. Gasification

16.1. Description of Technology

For this study, chemical recovery via gasification is based on the PulseEnhancedTM Steam Reformation technology developed by MTCI/ThermoChem, which is designed to process spent liquor and recover its chemical and energy value. A simplified diagram of the technology is shown below.



The recovery of chemicals and energy from spent liquor is effected by an indirectly heated steam-reforming process which results in the generation of a hydrogen-rich, medium-Btu product gas and bed solids, a dry alkali, which flow from the bottom of the reformer. Neither direct combustion nor alkali salt smelt formation occurs in this steam-reforming process.

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

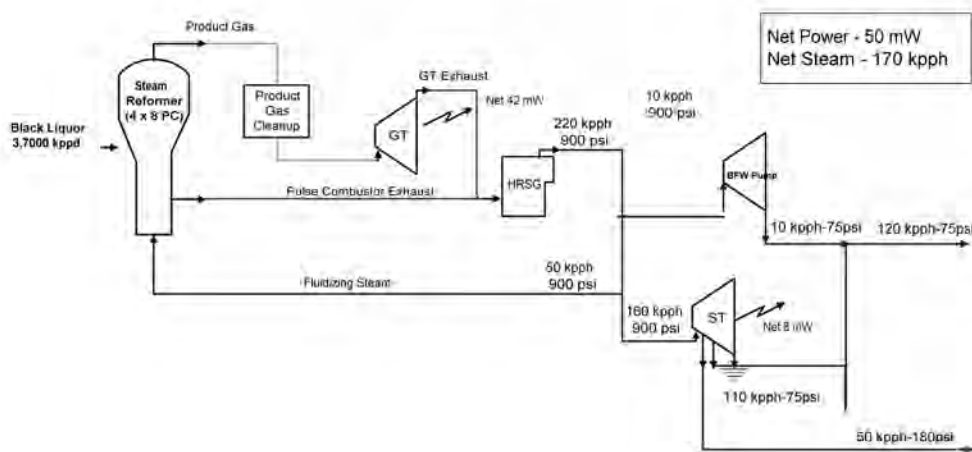
The product gas is cleaned, compressed, and then sent to the pulse heaters to provide the indirect heat in the reformer and to a combustion turbine to produce electricity. The combustion turbine exhaust is combined with the pulse heater exhaust and then sent to a

heat recovery steam generator. The resulting high-pressure steam is then sent to an extraction/condensing steam turbine where addition electricity is produced and lower pressure steam is made available to the mill. A process flow diagram showing the complete system is shown on the following page.

AF&PA/BE&K

**Black Liquor Gasification Combined Cycle System
Block Flow diagram**

Project 12104
23 June, 2001



The scope developed assumes that the mill can supply concentrated black liquor (80% solids). Since the costs for doing this can vary widely between mills and modern recovery boilers would require a similar concentration, these costs have been omitted from this study.

We recognize that the steam produced by this system is probably not sufficient for a typical Kraft mill. The additional steam requirements will either need to be provided by a biomass gasifier or boiler or a power boiler. These additional systems offer the opportunity for further power generation as well as steam production. This too is site specific and not included in this study.

16.2. Major Equipment

The major subsystems include liquor injection, steam reformer, gas cleanup, combustion turbine, heat recovery and steam generation, steam turbine, bed solids dissolution, sodium carbonate solution filter, and bed solids storage.

16.2.1. Black Liquor Supply and Steam Reformer

High solids black liquor is supplied to the reformer via a recirculation line feeding multiple steam jacketed injectors. Four reformers each containing 8-pulse heaters are required for this size plant. Each steam reformer is a carbon steel; fabricated vessel lined with refractory. The upper region of the vessel is expanded to reduce gas velocity, permitting entrained particles to disengage and fall back to the fluid bed. Internal stainless cyclones, mounted from the roof of the reformer, provide primary dust collection and a second set of external cyclones further captures fines. The reformer is fluidized with superheated steam using stainless fluidizer headers that are located just above the refractory floor. Bed drains penetrate the refractory floor for removal of bed solids via lock hoppers during normal operation.

Pulsed jet heater modules (fired heat exchangers) are used to indirectly heat the reformer. Pulsed heater modules are cantilever-mounted in the reformer utilizing a flange located on the front of the vessel. Each module extends through the reformer with its 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
	<u>(lb/hr)</u>	<u>(lb/hr)</u>	<u>(lb/hr)</u>
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 ₂ S)	0.0	0.0	0.0

Recovery Boiler & Smelt Dissolver Emission Estimates

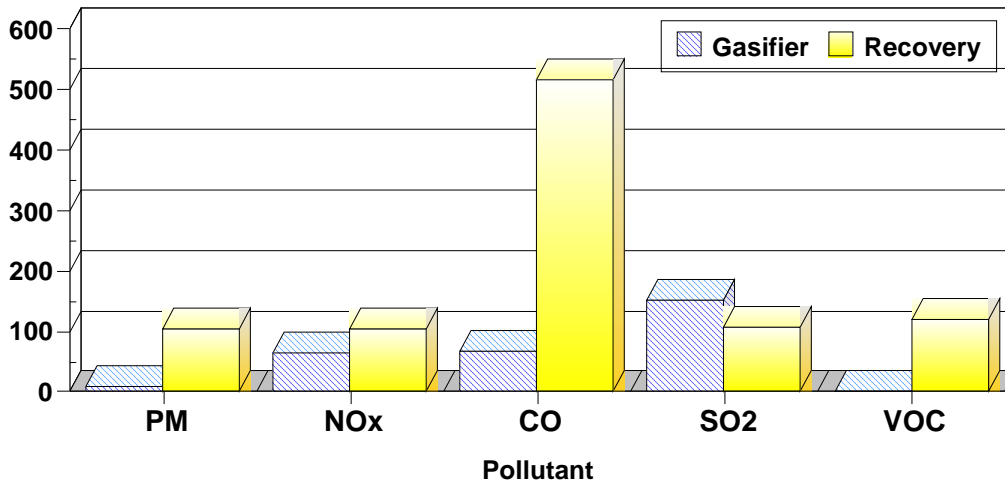
	Recovery Boiler Exhaust	Smelt Dissolving Exhaust	Total
	<u>lb/hr</u>	<u>lb/hr</u>	<u>lb/hr</u>
Particulate matter	93.9	9.4	103.3
Nitrous oxides (NO _x)	89.2	16.1	105.3
Carbon monoxide (CO)	516.5	0.3	516.8
Sulfur dioxide (SO ₂)	98.7	9.4	108.1
Volatile organic (as carbon)	37.6	7.5	45.1
as Methanol	100.2	20.0	120.2
TRS (as H ₂ S)	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 rates, lb/hour



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; $\text{gpm/feed rate} \times \text{feed rate} \times 1440 \text{ min/day} \times 365 \text{ dy/yr}$. The water usage used the same formula but with only 350 dy/yr.

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- ✓ 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. CO₂ Emission Assumptions

- ✓ The CO₂ emissions were calculated by multiplying the 1995 NCASI fossil fuel usage from the power boilers, recovery furnaces, and lime kilns times the CO₂ 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 CO₂ 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.

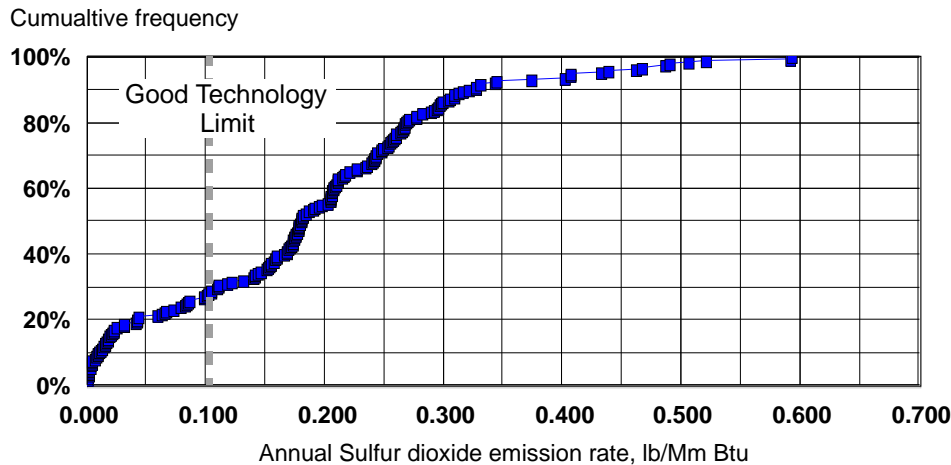
NDCE at 80 ppm	0.1415 lb / Mm Btu
NDCE at 40 ppm	0.0726 lb / Mm Btu
DCE at 30 ppm	0.0544 lb / Mm Btu
- ✓ The annual NO_x emission rates from the NCASI database were converted to lb/Mm Btu and compared with 80% of the above limits. The NO_x limits are based upon 30-day averages and it was assumed that 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. SO₂ 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 SO₂ emission rates from the NCASI database were converted to lb/Mm Btu basis and compared with 80% of the above limits. The SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 were 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 $[(1-0.3) \times (1-0.6)]$.

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,



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- ✓ 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 SO₂, and NO_x yearly emission rates were converted to pounds and divided by Btus to determine a lb/MmBtu emission rate.
- ✓ The SO₂ 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 SO₂ control technology, no control costs were assumed for any boiler designated as a wood or gas boiler, regardless of the emission level.
- ✓ NCASI has listed 1225 boilers or turbines, and had fuel consumption information on 1074 of them. Control technology estimates for boilers were only made if fuel consumption information was provided.



17.6. Coal Boiler Assumptions

17.6.1. General

- ✓ If more than 80% of the gross Btu's originated from coal, then the boiler was assumed a coal boiler.

17.6.2. NO_x Limits

- ✓ Any coal boilers after 1990 are assumed to have low NO_x burners and are assumed to meet the 0.3 lb/10⁶ 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 / 10⁶ Btu for boilers less than and greater than 100 million Btu/hr, respectively.

17.6.3. SO₂ 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/10¹² 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 SO₂ 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 SO₂ control is installed there will be no need to install HCl controls as well; the chemical addition rate for SO₂ 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/10⁶ 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. SO₂ 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/10¹² Btu for coal and by 0.572 lb/10¹² 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/10⁶ 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/10⁶ 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. SO₂ 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/10⁶ 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/10¹² 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 controls 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

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	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

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	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	SO ₂	NDCE Kraft Recovery Furnace	3
Best	SO ₂	NDCE Kraft Recovery Furnace	3
Good	NO _x	NDCE Kraft Recovery Furnace	3
Best	NO _x	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	SO ₂	DCE Kraft Recovery Furnace	3
Best	SO ₂	DCE Kraft Recovery Furnace	3
Best	NO _x	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	NO _x	Lime Kilns	3
Best	NO _x	Lime Kilns	5
Good	PM	Coal Boiler	3
Best	PM	Coal Boiler	3

**AF&PA Emission Control Study –
Cost Estimate & Industry-Wide Model
Phase I Pulp & Paper Industry
September 20, 2001**



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	SO ₂	Coal or Coal/Wood boiler (50/50)	3
Best	SO ₂	Coal or Coal/Wood boiler (50/50)	3
Good	NO _x	Coal or Coal/Wood boiler (50/50)	3
Best	NO _x	Coal or Coal/Wood boiler (50/50)	5
Best	NO _x	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	NO _x	Gas boiler	3
Best	NO _x	Gas boiler	5
Good	NO _x	Gas turbine	5
Good	NO _x	Gas turbine	5
Best	NO _x	Gas turbine	5
Good	PM	Oil boiler	3
Best	PM	Oil boiler	3
Good	SO ₂	Oil boiler	3
Best	SO ₂	Oil boiler	3
Good	NO _x	Oil boiler	3
Best	NO _x	Oil boiler	5
Good	PM	Wood boiler	5
Best	PM	Wood boiler	3
Best	PM	Wood boiler	5
Good	NO _x	Wood boiler	3
Best	NO _x	Wood boiler	3

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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



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	15%	Subtotal	20%	5%	5%	Total	Annual Operating and Maintenance Costs and Assumptions						Chemical (2) for design rate	
															Engineering		Contingency of direct costs + engineering	Owner's Cost % of direct costs	Construction Management % of direct costs		Size of base unit	Feed rate	Materials Consumables (fabric filters, SCR media, etc.) at design	Chemical for design rate	Units	Type of chemical		
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	\$ 426,600	\$ 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	\$ 389,826	\$ 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																								

No.	Good / Best	Pollutant	Equipment	Units	Type of chemical	Maintenance labor & materials, % of TIC	Energy, kw/feet 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/Mmb 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/Mmb 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/Mmb 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/Mmb 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/Mmb 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/Mmb 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/Mmb 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/Mmb 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/Mmb 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/Mmb 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/Mmb 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/Mmb 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/Mmb BLS	70%	3.00	\$ 5,000	-	-	294.12	lb/hr/Mmb BLS/day	-	NA	\$ -	NA	-	NA	-	NA	-	NA	4
14	Best	VOC	DCE Kraft Recovery Furnace	NA	NA	3.00%	264.96165	kw/Mmb BLS	70%	3.00	\$ 5,000	-	-	(15.873)	lb/hr/Mmb BLS/day	-	NA	\$ -	NA	-	NA	-	NA	-	NA	20
15	Good	PM	Smelt Dissolving tank	NA	NA	2.00%	77.47584	kw/Mmb 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/Mmb BLS	80%	1.50	\$ 5,000	-	-	-	NA	-	NA	\$ -	NA	-	NA	-	NA	-	NA	3
17	Good	PM	Lime Kilns	NA	NA	3.00%	0.77981	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	-	79.380	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	-	-	-	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/Mmb BLS	70%	-	\$ 5,000	-	650.00	#####	lb/hr/Mmb 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/Mmb 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/Mmb 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.																			



Oregon

Kate Brown, Governor

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Portland, OR 97232
(503) 229-5696
FAX (503) 229-6124
TTY 711

August 14, 2020

Lisa Scott
Cascade Pacific Pulp – Halsey Mill
lisa.scott@igic.com
PO Box 400
Halsey, OR 97348-0400

Sent via EMAIL

Re: Round 2 Regional Haze Program, Four Factor Analysis
Cascade Pacific Pulp – Halsey Mill, Title V facility 22-3501

Dear Lisa Scott,

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

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

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

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

- Step 1: Divide emissions units for each facility into three bins:
 - Bin 1. Likely cost-effective candidates. Control devices with cost less than \$10,000/ton, or those that appear to be technically feasible but for which no cost analysis was provided.

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

After initial review, DEQ ruled out control devices that:

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

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

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

Emission Unit(s)	Control Device	Status Note
Power boiler #1 (PB1EU)	LNB	The initial four factor analysis submittal used LNB costs from a 2001 BE&K Engineering study. Please provide a recent vendor quote or other more recent information.
Recovery Furnace (RFEU)	SCR	The previous 4FA submittal indicated that SCR was not technically feasible for recovery boilers, but NCASI technical bulletin #1051, sections 3.1.6 and 3.1.7, suggest that it may be technically feasible. Please provide additional explanation as to why SCR is not feasible, or contact a vendor and provide a statement (if the vendor feels it is infeasible) or a cost estimate (if the vendor feels it is feasible).
Power boiler #1 (PB1EU)	SNCR	
Recovery Furnace (RFEU)	Wet Scrubber	The initial 4FA analysis cost estimate was based on ~20 year old data. Even though the NaOH reagent cost is a significant factor in the total annual cost, the cost estimate was a nominal estimate, not a vendor quote. Please provide a vendor quote for capital and reagent costs, and also evaluate limestone as an alternative to NaOH.

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

- (1) Agree that the control device is cost effective. In this case, DEQ does not need more detailed cost analysis, and work can shift to planning for installation.

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

- (2) If your facility's Q/d based on actual emissions is less than the screening value of 5.00, you have the option to reduce PSELs to a level below 5.00 Q/d. Facilities with Q/d below 5.00 are not required to do further regional haze analysis or control device installation during Round 2.
- (3) Provide a site-specific cost estimate for each emissions unit and associated control device listed in the table above. DEQ prefers unit-specific vendor quotes but will consider other recent, similarly supported cost estimates. DEQ will continue to use criteria used in the first FFA screening step to evaluate the more detailed cost information facilities submit.

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

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

Sincerely,



Ali Mirzakhali
Air Quality Division Administrator
Department of Environmental Quality

Cc: Karen Williams
D Pei Wu, PhD
Joe Westersund
Michael Orman
Claudia Davis
Yuki Puram

Revised Cost Estimate - Actual Emissions
Cascade Pacific Pulp - Halsey
Low NO_x 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 2019 quote cost for 31 MMBtu/hr boiler adjusted for 236 MMBtu/hr boiler.		\$3,436,654
(b)	Instrumentation	0.10 × A	\$343,665
(b)	Sales Tax	0.03 × A	\$103,100
(b)	Freight	0.05 × A	\$171,833
	Total Purchased Equipment Cost, B =	B	\$4,055,252
Total Direct Cost:			TDC \$4,055,252
Indirect Capital Costs			
(c)	Engineering	0.10 × B	\$405,525
(c)	Contingencies	0.20 × B	\$811,050
(c)	General Facilities	0.05 × B	\$202,763
(b)	Testing	0.01 × B	\$40,553
Total Indirect Cost:			TIC \$1,459,891
Total Capital Investment:			TCI \$5,515,143

ANNUALIZED COSTS				
	COST ITEM	COST FACTOR	UNIT COST	COST (\$)
Annual Operating Costs - Direct Annual Costs				
(d)	Maintenance Costs	2.75% of TCI		\$151,666
Utilities				
(a)	Electricity	277 kW	\$0.060 per kWh	\$145,542
Total Direct Annual Costs:				DAC \$297,209
Annual Operating Costs - Indirect Annual Costs				
(b)	Overhead	60% of sum of operating & maintenance costs		\$91,000
(b)	Administrative Charges	2% of TCI		\$110,303
(b)	Property Taxes	1% of TCI		\$55,151
(b)	Insurance	1% of TCI		\$55,151
Total Indirect Annual Costs:				IDAC \$311,606
Total Annual Costs:				TAC \$608,814
Cost Effectiveness				
(b)	Expected lifetime of equipment, years	30 DEQ default		
(b)	Interest rate, %/yr	3.25% DEQ default		
(b)	Capital recovery factor	0.053		
(b)	Total Capital Investment Cost	\$5,515,143		
Annualized Capital Investment Cost:				\$290,547
Total Annualized Cost:				\$899,361
(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:				\$249,823

- (a) Equipment cost information obtained from a recent Zeeco quote for a gas-fired auxiliary boiler. The \$128,700 equipment cost of installing LNB, FGR, new fan on a gas-fired boiler was scaled based on CPP boiler capacity. Labor (3.6x equipment cost), materials (1.3x equipment cost), and subcontracting (2.0x equipment cost) were added to the equipment cost to calculate the installed cost, as it was not included in the original quote. 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

Revised Cost Estimate - PSEL Basis
Cascade Pacific Pulp - Halsey
Low NO_x 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 2019 quote cost for 31 MMBtu/hr boiler adjusted for 236 MMBtu/hr boiler.		\$3,436,654
(b)	Instrumentation	0.10 × A	\$343,665
(b)	Sales Tax	0.03 × A	\$103,100
(b)	Freight	0.05 × A	\$171,833
	Total Purchased Equipment Cost, B =	B	\$4,055,252
Total Direct Cost:			TDC \$4,055,252
Indirect Capital Costs			
(c)	Engineering	0.10 × B	\$405,525
(c)	Contingencies	0.20 × B	\$811,050
(c)	General Facilities	0.05 × B	\$202,763
(b)	Testing	0.01 × B	\$40,553
Total Indirect Cost:			TIC \$1,459,891
Total Capital Investment:			TCI \$5,515,143

ANNUALIZED COSTS				
	COST ITEM	COST FACTOR	UNIT COST	COST (\$)
Annual Operating Costs - Direct Annual Costs				
(d)	Maintenance Costs	2.75% of TCI		\$151,666
Utilities				
(a)	Electricity	277 kW	\$0.060 per kWh	\$145,542
Total Direct Annual Costs:				DAC \$297,209
Annual Operating Costs - Indirect Annual Costs				
(b)	Overhead	60% of sum of operating & maintenance costs		\$91,000
(b)	Administrative Charges	2% of TCI		\$110,303
(b)	Property Taxes	1% of TCI		\$55,151
(b)	Insurance	1% of TCI		\$55,151
Total Indirect Annual Costs:				IDAC \$311,606
Total Annual Costs:				TAC \$608,814
Cost Effectiveness				
(b)	Expected lifetime of equipment, years	30 DEQ default		
(b)	Interest rate, %/yr	3.25% DEQ default		
(b)	Capital recovery factor	0.053		
(b)	Total Capital Investment Cost	\$5,515,143		
Annualized Capital Investment Cost:				\$290,547
Total Annualized Cost:				\$899,361
(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:				\$10,559

- (a) Equipment cost information obtained from a recent Zeeco quote for a gas-fired auxiliary boiler. The \$128,700 equipment cost of installing LNB, FGR, new fan on a gas-fired boiler was scaled based on CPP boiler capacity. Labor (3.6x equipment cost), materials (1.3x equipment cost), and subcontracting (2.0x equipment cost) were added to the equipment cost to calculate the installed cost, as it was not included in the original quote. 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/cate/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

Revised cost estimate to retrofit the CPP Halsey Mill's Recovery Furnace with a Wet Scrubber - PSEL Basis

Variable	Designation	Units	Value	Calculation
EPC Project?			<input type="checkbox"/> FALSE	
Wastewater Treatment		Phys Chem-Biological		
Unit Size	A	(MW)	68	<--- User Input - Based on 704 MMBtu/hr on BLS and 33% efficiency
Retrofit Factor	B		1.00	<--- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	10000	<--- User Input Estimate
SO2 Rate	D	(lb/MMBtu)	0.15	<--- User Input Based on PSEL
Type of Coal	E		Bituminous	<--- User Input
Coal Factor	F		1	Bit = 1.0, PRB = 1.05, Lig = 1.07
Heat Rate Factor	G		1	C/10000
Heat Input	H	(Btu/hr)	7.04E+08	Est. heat input is 704 MMBtu/hr based on est. heat content of BLS
Capacity Factor	I	(%)	100	<--- User Input PSEL
Operating SO2 Removal	J	(%)	98	<--- User Input (Used to adjust actual operating costs)
Design Limestone Rate	K	(ton/hr)	0.09	17.52*A*D*G/2000 (Based on 98% removal)
Design Waste Rate	L	(ton/hr)	0	1.811*K (Based on 98% removal)
Aux Power Include in VOM?	<input checked="" type="checkbox"/>	M	(%)	1.15 (1.12e*(0.155*D))*F*G
Makeup Water Rate	N	(1000 gph)	5	(1.674*D+74.68)*A*F*G/1000
Limestone Cost	P	(\$/ton)	30	<--- User Input Based on values online
Waste Disposal Cost	Q	(\$/ton)	30	<--- User Input Default value
Aux Power Cost	R	(\$/kWh)	0.06	<--- User Input
Makeup Water Cost	S	(\$/kgal)	1	<--- User Input
Operating Labor Rate	T	(\$/hr)	32.5	<--- User Input (Labor cost including all benefits)

CEPCI

2016 541.7
2019 607.5

Base Costs are in 2016 dollars

Capital Cost Calculation

Includes - Equipment, intallation, buildings, foundations, electrical, and retrofit difficulty.

BMR (\$) = 584000*(B)*((F*G)^0.6)*((D/2)^0.02)*(A^0.716)

BMF (\$) = 202000*(B)*((D*G)^0.3)*(A^0.716)

BMW (\$) = 106000*(B)*((D*G)^0.45)*(A^0.716)

BMB (\$) = 1070000*(B)*((F*G)^0.4)*(A^0.716)

BMWW (\$, If type is Bio-Chem, then 106000000*(B)*A/500^0.6), else 0

BM (\$) = BMR + BMF + BMW + BMB + BMWW

BM (\$/kW) =

Example

\$ 11,380,000

\$ 2,346,000

\$ 926,000

\$ 21,958,000

\$ 3,202,908

\$ 39,812,908

585

Comments

Base absorber island cost

Base reagent preparation cost

Base waste handling cost

Base balance of plant costs including: ID or booster fans, new wet chimney, piping, ductwork modifications and strengthening, minor WWT, etc...

Base wastewater treatment facility, beyond minor physical/chemical treatment

Total base module cost including retrofit factor

Base cost per kW

Total Project Cost

A1 = 10% of BM

\$ 3,981,000

Engineering and Construction Management costs

A2= 10% of BM

\$ 3,981,000

Labor adjustment for 6 x 10 hour shift premium, per diem, etc...

A3 = 10% of BM

\$ 3,981,000

Contractor profit and fees

CECC (\$) = BM + A1 + A2 + A3

\$ 51,755,908

Capital, engineering and construction cost subtotal

CECC (\$/kW) =

761

Capital, engineering and construction cost subtotal per kW

B1 = 5% of CECC

\$ 2,588,000

Owners costs including all "home office" costs (owners engineering, management, and procurement activities)

TPC' (\$) - Includes Owner's Costs = CECC + B1

\$ 54,343,908

Total project cost without AFUDC

TPC' (\$/kW) - Includes Owner's Costs

799

Total project cost per kW without AFUDC

B2 = 10% of (CECC + B1)

\$ 5,434,000

AFUDC (Based on a 3 year engineering and construction cycle)

C1 = 15% of CECC+B1

\$ -

EPC fees of 15%

TPC (\$) = Includes Owner's Costs and AFUDC = CECC + B1 + B2 + C1

\$ 67,039,097

Total project cost, adjusted from 2016 to 2019 dollars using CEPCI

Fixed O&M Cost

FOMO (\$/kW yr) = (if MW>500 then 16 additional operators, else 12 operators)*2080*T/(A*1000)

\$ 11.92

Fixed O&M additional operating labor costs

FOMM (\$/kW yr) =(BM*0.015)/(B*A*1000)

\$ 8.78

Fixed O&M additional maintenance material and labor costs

FOMA (\$/kW yr) = 0.03*(FOMO + 0.4*FOMM)

\$ 0.46

Fixed O&M additional administrative labor costs

FOMWW (\$/kW yr) =

0

Fixed O&M costs for wastewater treatment facility

FOM (\$/kW yr) = FOMO +FOMM+FOMA+ FOMWW

\$ 21.17

Total Fixed O&M costs

Variable O&M Cost

VOMR (\$/MWh) = $K \cdot P / (A \cdot J) / 98$	\$	0.04	Variable O&M costs for limestone reagent
VOMW (\$/MWh) = $L \cdot Q / (A \cdot J) / 98$	\$	0.07	Variable O&M costs for waste disposal
VOMP (\$/MWh) = $M \cdot R \cdot 10$	\$	0.69	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM (\$/MWh) = $N \cdot S / A$	\$	0.08	Variable O&M costs for makeup water
VOMWW (\$/MWh) =	\$	0.17	Variable O&M costs for wastewater treatment facility
VOM (\$/MWh) = VOMR + VOMW + VOMP + VOMM + VOMWW	\$	1.04	Total Variable O&M costs

Annual Capacity Factor =	100%	(PSEL)
Annual MWhts =	595,943	
Annual Heat Input MMBtu =	6,167,040	Based on 704 MMBtu/hr
Annual Tons SO2 Created =	453	PSEL
Annual Tons SO2 Removed =	444	at removal efficiency = 98%
Annual Tons SO2 Emission =	9	
Annual Avg SO2 Emission Rate, lb/MMBtu =	0.003	Value is BELOW a 0.06 floor rate

Annual Capital Recovery Factor =	0.053	Wet FGD	3.25% interest and 30 years
Annual Capital Cost (Including AFUDC), \$ =	3,532,000		
Annual FOM Cost, \$ =	1,440,000		
Annual VOM Cost, \$ =	621,000		
Total Annual Scrubber Cost, \$ =	5,593,000		

Capital Cost, \$/ton =	7,951
FOM Cost, \$/ton =	3,242
VOM Cost, \$/ton =	1,398
Total Scrubber Cost, \$/ton =	12,590

Source - algorithms developed by Sargent and Lundy and used in the 2016 version of U.S. EPA's CoST model.

See <https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-analysis-modelstoos-air-pollution#control%20strategy%20tool>

Revised cost estimate to retrofit the CPP Halsey Mill's Recovery Furnace with a Wet Scrubber - Actual Emissions Basis

Variable	Designation	Units	Value	Calculation
EPC Project?			<input type="checkbox"/> FALSE	
Wastewater Treatment		Phys Chem-Biological		
Unit Size	A	(MW)	68	<--- User Input - Based on 704 MMBtu/hr on BLS and 33% efficiency
Retrofit Factor	B		1.00	<--- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	10000	<--- User Input Estimate
SO2 Rate	D	(lb/MMBtu)	0.02	<--- User Input Based on actual emissions
Type of Coal	E		Bituminous	<--- User Input
Coal Factor	F		1	Bit = 1.0, PRB = 1.05, Lig = 1.07
Heat Rate Factor	G		1	C/10000
Heat Input	H	(Btu/hr)	7.04E+08	Est. heat input is 704 MMBtu/hr based on est. heat content of BLS
Capacity Factor	I	(%)	96.82	<--- User Input actual operating hours
Operating SO2 Removal	J	(%)	98	<--- User Input (Used to adjust actual operating costs)
Design Limestone Rate	K	(ton/hr)	0.01	17.52*A*D*G/2000 (Based on 98% removal)
Design Waste Rate	L	(ton/hr)	0	1.811*K (Based on 98% removal)
Aux Power Include in VOM?	<input checked="" type="checkbox"/>	M	(%)	1.12 (1.12e*(0.155*D))*F*G
Makeup Water Rate	N	(1000 gph)	5	(1.674*D+74.68)*A*F*G/1000
Limestone Cost	P	(\$/ton)	30	<--- User Input Based on values online
Waste Disposal Cost	Q	(\$/ton)	30	<--- User Input Default value
Aux Power Cost	R	(\$/kWh)	0.06	<--- User Input
Makeup Water Cost	S	(\$/kgal)	1	<--- User Input
Operating Labor Rate	T	(\$/hr)	32.5	<--- User Input (Labor cost including all benefits)

CEPCI

2016 541.7
2019 607.5

Base Costs are in 2016 dollars

Capital Cost Calculation

Includes - Equipment, intallation, buildings, foundations, electrical, and retrofit difficulty.

BMR (\$) = 584000*(B)*((F*G)^0.6)*((D/2)^0.02)*(A^0.716)

BMF (\$) = 202000*(B)*((D*G)^0.3)*(A^0.716)

BMW (\$) = 106000*(B)*((D*G)^0.45)*(A^0.716)

BMB (\$) = 1070000*(B)*((F*G)^0.4)*(A^0.716)

BMWW (\$, if type is Bio-Chem, then 106000000*(B)*A/500^0.6), else 0

BM (\$) = BMR + BMF + BMW + BMB + BMWW

BM (\$/kW) =

Example

\$ 10,930,000

\$ 1,282,000

\$ 374,000

\$ 21,958,000

\$ 3,202,908

\$ 37,746,908

555

Comments

Base absorber island cost

Base reagent preparation cost

Base waste handling cost

Base balance of plant costs including: ID or booster fans, new wet chimney, piping, ductwork modifications and strengthening, minor WWT, etc...

Base wastewater treatment facility, beyond minor physical/chemical treatment

Total base module cost including retrofit factor

Base cost per kW

Total Project Cost

A1 = 10% of BM

\$ 3,775,000

Engineering and Construction Management costs

A2= 10% of BM

\$ 3,775,000

Labor adjustment for 6 x 10 hour shift premium, per diem, etc...

A3 = 10% of BM

\$ 3,775,000

Contractor profit and fees

CECC (\$) = BM + A1 + A2 + A3

\$ 49,071,908

Capital, engineering and construction cost subtotal

CECC (\$/kW) =

721

Capital, engineering and construction cost subtotal per kW

B1 = 5% of CECC

\$ 2,454,000

Owners costs including all "home office" costs (owners engineering, management, and procurement activities)

TPC' (\$) - Includes Owner's Costs = CECC + B1

\$ 51,525,908

Total project cost without AFUDC

TPC' (\$/kW) - Includes Owner's Costs

757

Total project cost per kW without AFUDC

B2 = 10% of (CECC + B1)

\$ 5,153,000

AFUDC (Based on a 3 year engineering and construction cycle)

C1 = 15% of CECC+B1

\$ -

EPC fees of 15%

TPC (\$) = Includes Owner's Costs and AFUDC = CECC + B1 + B2 + C1

\$ 63,563,664

Total project cost, adjusted from 2016 to 2019 dollars using CEPCI

Fixed O&M Cost

FOMO (\$/kW yr) = (if MW>500 then 16 additional operators, else 12 operators)*2080*T/(A*1000)

\$ 11.92

Fixed O&M additional operating labor costs

FOMM (\$/kW yr) =(BM*0.015)/(B*A*1000)

\$ 8.32

Fixed O&M additional maintenance material and labor costs

FOMA (\$/kW yr) = 0.03*(FOMO + 0.4*FOMM)

\$ 0.46

Fixed O&M additional administrative labor costs

FOMWW (\$/kW yr) =

0

Fixed O&M costs for wastewater treatment facility

FOM (\$/kW yr) = FOMO +FOMM+FOMA+ FOMWW

\$ 20.70

Total Fixed O&M costs

Variable O&M Cost

VOMR (\$/MWh) = $K \cdot P / (A \cdot J)^{.98}$	\$	0.01	Variable O&M costs for limestone reagent
VOMW (\$/MWh) = $L \cdot Q / (A \cdot J)^{.98}$	\$	0.01	Variable O&M costs for waste disposal
VOMP (\$/MWh) = $M \cdot R \cdot 10$	\$	0.67	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM (\$/MWh) = $N \cdot S / A$	\$	0.08	Variable O&M costs for makeup water
VOMWW (\$/MWh) =	\$	0.17	Variable O&M costs for wastewater treatment facility
VOM (\$/MWh) = VOMR + VOMW + VOMP + VOMM + VOMWW	\$	0.93	Total Variable O&M costs

Annual Capacity Factor =	97%	actual operating hours
Annual MWhts =	576,963	
Annual Heat Input MMBtu =	6,167,040	Based on 704 MMBtu/hr
Annual Tons SO ₂ Created =	45.2	2017 actual
Annual Tons SO ₂ Removed =	44.3	at removal efficiency = 98%
Annual Tons SO ₂ Emission =	1	
Annual Avg SO ₂ Emission Rate, lb/MMBtu =	0.0003	Value is BELOW a 0.06 floor rate

Annual Capital Recovery Factor =	0.053	Wet FGD	3.25% interest and 30 years
Annual Capital Cost (including AFUDC), \$ =	3,349,000		
Annual FOM Cost, \$ =	1,409,000		
Annual VOM Cost, \$ =	539,000		
Total Annual Scrubber Cost, \$ =	5,297,000		

Capital Cost, \$/ton =	75,605
FOM Cost, \$/ton =	31,809
VOM Cost, \$/ton =	12,168
Total Scrubber Cost, \$/ton =	119,582

Source - wet scrubber cost algorithms developed by Sargent and Lundy and used in the 2016 version of U.S. EPA's CoST model.

See <https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-analysis-modelstoos-air-pollution#control%20strategy%20tool>

September 10, 2020

To: Brian Brazil, International Paper
Lisa Scott, Cascade Pacific Pulp
Jeff Sorensen, Georgia-Pacific

From: Vipin Varma, NCASI

Re: Additional perspective on feasibility of Selective Catalytic Reduction (SCR) on kraft recovery furnaces

This Memorandum is in response to Member Company requests that NCASI provide additional information that expands on the discussion, in sections 3.1.6 and 3.1.7 of NCASI Technical Bulletin (TB) No. 1051, regarding the applicability of SCR on kraft recovery furnaces.

Section 3.1 of the above technical bulletin summarizes fundamental research, made available in literature in the past decade, on NO_x formation and emissions control in kraft recovery furnaces. Specifically, sections 3.1.6 and 3.1.7 discuss the abstracts and summaries of two papers presented during the 2017 International Recovery Conference held at Halifax, Nova Scotia, Canada.

The first paper was a **theoretical study** for the retrofit of a recovery furnace where an SCR could be utilized to lower NO_x from 200 to 100 mg/m³ (6% O₂, dry gas). The paper went on to identify the key challenges in deploying SCR technology as being a) maintaining flue gas temperature at the appropriate level at the SCR reactor inlet, b) potential for higher SO₂ in the flue gas, and c) potential for high particulate concentration after the electrostatic precipitator. The above theoretical study therefore contemplated a retrofit that included a dedicated flue gas bypass, with an ESP, for scenarios where either the flue gas temperature was too low or the dust loading and/or SO₂ was too high for the SCR.

The second paper (section 3.1.7) presented results **from pilot tests** and first experiences with full-scale installation in a kraft recovery furnace. This paper contemplated a tail-end application, as opposed to a high or low-dust loading application, citing the above-identified issues with dust loading and the resulting catalyst poisoning. We are not aware of follow-up studies or long-term performance data from full-scale installations.

The use of SCR on a kraft recovery furnace has not been demonstrated on a full-scale due to the above challenges. The impact of high particulate matter concentrations in the economizer region and fine dust particles on catalyst effectiveness is a major concern. Catalyst poisoning by soluble alkali metals in the gas stream is also a concern. In the case of SCRs installed after the ESP to get around the particulate concern, the additional energy penalty associated with reheating the flue gas is another aspect that makes this infeasible.

Please do not hesitate to contact me at vvarma@ncasi.org or (352) 244 0965 if you have additional questions.

September 16, 2020

Department of Environmental Quality
D Pei Wu
Joe Westersund
700 NE Multnomah Street, Suite 600
Portland, OR 97232

Re: Round 2 Regional Haze Program, Four Factor Analysis
Cascade Pacific Pulp-Halsey Mill, Title V Facility 22-3501

Dear Dr. Wu and Mr. Westersund,

As requested in the Round 2-Regional Haze Program letter dated August 14, 2020, Cascade Pacific Pulp's responses are outlined below.

DEQ Action Item 1

- (1) Agree that the control device is cost effective. In this case, DEQ does not need more detailed cost analysis, and work can shift to planning for installation.*

Cascade Pacific Pulp does not agree that any of the control devices are cost effective as described in the DEQ correspondence letter dated August 14, 2020 or in the original report, Regional Haze Rule Four-Factor Analysis for Four Oregon Pulp and Paper Mills, June 2020.

DEQ Action Item 2

- (2) If your facility's Q/d based on actual emissions is less than the screening value of 5.00, you have the option to reduce PSELs to a level below 5.00 Q/d. Facilities with Q/d below 5.00 are not required to do further regional haze analysis or control device installation during Round 2.*

Cascade Pacific Pulp's screening level based on actual emissions was not below the screening level of 5.00. Reducing PSELs below the screening value of 5.00 is not a viable operating option for Cascade Pacific Pulp.

DEQ Action Item 3

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

Cascade Pacific Pulp contracted with All4 to provide updated cost information for a LNB for No. 1 Power Boiler and a wet scrubber using limestone for the Recovery Furnace. NCASI provided additional information that indicates and supports that SCR is not technically feasible in a Recovery Furnace. NCASI memo included with this submittal. Tables 1 and 2 provide cost estimates for PSELs and for the actual emissions from 2017.

For the SNCR system for the No. 1 Power Boiler, DEQ did not provide adequate time to determine the feasibility of the technology. The No. 1 Power Boiler is a swing boiler for the mill and has been running

at a minimum rate. There is not any historical data that shows the temperature profile of the boiler at varying loads. The temperature profile data is required to determine if SNCR would be effective for NO_x control. Even if SNCR were feasible, multiple levels of injectors would be required to make an SNCR operate effectively and it is not likely there is room in the boiler to accommodate the system, even if the temperature profile is adequate. Regardless, the original cost estimate for SNCR, following the latest EPA guidance, showed that SNCR was not cost effective. See original report, Regional Haze Rule Four-Factor Analysis for Four Oregon Pulp and Paper Mills, June 2020, Page 2-18 and 2-19.

Table 1-Round 2 Cost Analysis based on PSEL

Emission Unit(s)	Control Device	Capital Cost (\$/yr.)	Annual Cost (\$/yr.)	Cost Effectiveness (\$/ton)
Power boiler #1 (PB1EU)	LNB NO _x	\$5.5 million	\$899,361	\$10,559
Recovery Furnace (RFEU)	SCR NO _x	Not Technically Feasible. See NCASI Memo clarifying the technical feasibility of SCR in a Recovery Furnace. Memo included in the submittal.		
Power boiler #1 (PB1EU)	SNCR NO _x	See Original Report. Regional Haze Rule Four-Factor Analysis for Four Oregon Pulp and Paper Mills, June 2020, Page 2-18.		
Recovery Furnace (RFEU)	Wet Scrubber Using Limestone SO ₂	\$67 Million	\$5.6 Million	\$12,590

Table 2-Round 2 Cost Analysis based on actual emissions from 2017

Emission Unit(s)	Control Device	Capital Cost (\$/yr.)	Annual Cost (\$/yr.)	Cost Effectiveness (\$/ton)
Power boiler #1 (PB1EU)	LNB NO _x	\$5.5 million	\$899,361	\$249,823
Recovery Furnace (RFEU)	SCR NO _x	Not Technically Feasible see NCASI Memo clarifying the technical feasibility of SCR in a Recovery Furnace. Memo included in the submittal.		
Power boiler #1 (PB1EU)	SNCR NO _x	See Original Report. Regional Haze Rule Four-Factor Analysis for Four Oregon Pulp and Paper Mills, June 2020, Page 2-18.		
Recovery Furnace (RFEU)	Wet Scrubber Using Limestone SO ₂	\$63.6 million	\$5.3 million	\$119,582

September 16, 2020

Page 3

In summary, Cascade Pacific Pulp has fulfilled DEQ's request for further information in good faith. The control technologies listed by DEQ are not reasonable to install under the Regional Haze Rule. The original four factor analysis submitted in June 2020 also demonstrated that there were no control technologies that were reasonable to install.

If you have any further questions, please contact me at 541-369-1752 or Toby Smith at 541-369-1196.

Sincerely,

A handwritten signature in black ink, appearing to read "Lisa Scott", with a stylized flourish at the end.

Lisa Scott

c. Toby Smith-Cascade Pacific Pulp
Yuki Puram

Table A-2
Cascade Pacific Pulp - Halsey
Low NO_x 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 2019 quote cost for 31 MMBtu/hr boiler adjusted for 236 MMBtu/hr boiler		\$3,436,654
(b)	Instrumentation	0.10 × A	\$343,665
(b)	Sales Tax	0.00 × A	\$0
(b)	Freight	0.05 × A	\$171,833
	Total Purchased Equipment Cost, B =	B	\$3,952,152
Total Direct Cost:			TDC \$3,952,152
Indirect Capital Costs			
(c)	Engineering	0.10 × B	\$395,215
(c)	Contingencies	0.10 × B	
(c)	General Facilities	0.05 × B	\$0
(b)	Testing	0.01 × B	\$39,522
Total Indirect Cost:			TIC \$434,737
Contingencies			0.1 \$438,688.88
Total Capital Investment:			TCI \$4,825,578

Is instrumentation already included in the quote? Copy was not included.
No sales tax in OR

Default value (EPA's Cost manual Section 3

ANNUALIZED COSTS				
	COST ITEM	COST FACTOR	UNIT COST	COST (\$)
Annual Operating Costs - Direct Annual Costs				
(d)	Maintenance Costs	2.75% of TCI		\$132,703
Utilities				
(a)	Electricity	277 kW	\$0.060 per kWh	\$145,542
Total Direct Annual Costs:				DAC \$278,246
Annual Operating Costs - Indirect Annual Costs				
(b)	Overhead	60% of sum of operating & maintenance costs		\$79,622
(b)	Administrative Charges	2% of TCI		\$96,512
(b)	Property Taxes	1% of TCI		\$48,255.78
(b)	Insurance	1% of TCI		\$48,255.78
Total Indirect Annual Costs:				IDAC \$272,645
Total Annual Costs:				TAC \$550,891
Cost Effectiveness				
(b)	Expected lifetime of equipment, years	30		
(b)	Interest rate, %/yr	3.25%		
(b)	Capital recovery factor	0.053		
(b)	Total Capital Investment Cost	\$4,825,578		
Annualized Capital Investment Cost:				\$254,220
Total Annualized Cost:				\$805,110
(e)	NO _x Reduction	64%		
(f)	Pre-retrofit NO _x	132.8 tons NO _x /yr	PSEL2020	
	Post-retrofit NO _x using LNB	47.43 tons NO _x /yr		
	NO _x Removed	85.37 tons NO _x /yr		
Annual Cost/Ton Removed:				\$9,431

- (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-2
Cascade Pacific Pulp - Halsey
Low NO_x 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		\$2,325,645
(b) Instrumentation	0.10 × A	\$0
(b) Sales Tax	0.00 × A	\$0
(b) Freight	0.05 × A	\$116,282
Total Purchased Equipment Cost, B =	B	\$2,441,927
Total Direct Cost:		TDC \$2,441,927
Indirect Capital Costs		
(c) Engineering	0.10 × B	\$244,193
(c) Contingencies	0.10 × B	
(c) General Facilities	0.05 × B	\$0
(b) Testing	0.01 × B	\$24,419
Total Indirect Cost:		TIC \$268,612
Contingencies		0.1 \$271,054
Total Capital Investment:		TCI \$2,981,593

*Removed Labor and Subcontracts from the scaling factor (Assumed the same regardless of the size of the boiler and material cost already included. No sales tax in OR

Default value (EPA's Cost manual Section 3)

ANNUALIZED COSTS			
COST ITEM	COST FACTOR	UNIT COST	COST (\$)
Annual Operating Costs - Direct Annual Costs			
(d) Maintenance Costs	2.75% of TCI		\$81,994
Utilities			
(a) Electricity	277 kW	\$0.060 per kWh	\$145,542
Total Direct Annual Costs:			DAC \$227,536
Annual Operating Costs - Indirect Annual Costs			
(b) Overhead	60% of sum of operating & maintenance costs		\$136,522
(b) Administrative Charges	2% of TCI		\$59,632
(b) Property Taxes	1% of TCI		\$0
(b) Insurance	1% of TCI		\$0
Total Indirect Annual Costs:			IDAC \$196,153
Total Annual Costs:			TAC \$423,689
Cost Effectiveness			
(b) Expected lifetime of equipment, years	30		
(b) Interest rate, %/yr	3.25%		
(b) Capital recovery factor	0.053		
(b) Total Capital Investment Cost	\$2,981,593		
Annualized Capital Investment Cost:			\$157,075
Total Annualized Cost:			\$580,765
(e) NO _x Reduction	64%		
(f) Pre-retrofit NO _x	132.8 tons NO _x /yr	PSEL2020	
Post-retrofit NO _x using LNB	47.43 tons NO _x /yr		
NO _x Removed	85.37 tons NO _x /yr		
Annual Cost/Ton Removed:			\$6,803

- 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.
- 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.
- 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.
- 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).
- Control efficiency based on a comparison of AP-42 natural gas pre-NSPS uncontrolled and LNB/FGR emission factors.
- PSEL

Table A-3
Cascade Pacific Pulp - Halsey
Low NO_x 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		\$2,325,645
(b) Instrumentation	0.10 × A	\$0
(b) Sales Tax	0.03 × A	\$0
(b) Freight	0.05 × A	\$116,282
Total Purchased Equipment Cost, B =	B	\$2,441,927
Total Direct Cost:		TDC \$2,441,927
Indirect Capital Costs		
(c) Engineering	0.10 × B	\$244,193
(c) Contingencies	0.20 × B	\$0
(c) General Facilities	0.05 × B	\$0
(b) Testing	0.01 × B	\$24,419
Total Indirect Cost:		TIC \$268,612
Contingencies		0.1 \$271,054
Total Capital Investment:		TCI \$2,981,593

*Removed Labor and Subcontracts from the scaling factor (Assumed the same regardless of the size of the Labor and material cost already included No sales tax in OR

ANNUALIZED COSTS				
COST ITEM		COST FACTOR	UNIT COST	COST (\$)
Annual Operating Costs - Direct Annual Costs				
(d)	Maintenance Costs	2.75% of TCI		\$81,994
Utilities				
(a)	Electricity	277 kW	\$0.060 per kWh	\$145,542
Total Direct Annual Costs:			DAC	\$227,536
Annual Operating Costs - Indirect Annual Costs				
(b)	Overhead	60% of sum of operating & maintenance costs		\$136,522
(b)	Administrative Charges	2% of TCI		\$59,631.86
(b)	Property Taxes	1% of TCI		\$0
(b)	Insurance	1% of TCI		\$0
Total Indirect Annual Costs:			IDAC	\$196,153
Total Annual Costs:			TAC	\$423,689
Cost Effectiveness				
(b)	Expected lifetime of equipment, years	30		
(b)	Interest rate, %/yr	3.25%		
(b)	Capital recovery factor	0.053		
(b)	Total Capital Investment Cost	\$2,981,593		
Annualized Capital Investment Cost:				\$157,075
Total Annualized Cost:				\$580,765
(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:				\$12,029

- (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

Air Pollution Control Cost Estimation Spreadsheet For Selective Non-Catalytic Reduction (SNCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(June 2019)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Non-Catalytic Reduction (SNCR) control device. SNCR is a post-combustion control technology for reducing NO_x emissions by injecting an ammonia-base reagent (urea or ammonia) into the furnace at a location where the temperature is in the appropriate range for ammonia radicals to react with NO_x to form nitrogen and water.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SNCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SNCR control technology and the cost methodologies, see Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: <http://www3.epa.gov/ttn/catc/products.html#cccinfo>.

The spreadsheet can be used to estimate capital and annualized costs for applying SNCR, and particularly to the following types of combustion units:

- (1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
- (4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM version 6). The size and costs of the SNCR are based primarily on four parameters: the boiler size or heat input, the type of fuel burned, the required level of NO_x reduction, and the reagent consumption. This approach provides study-level estimates ($\pm 30\%$) of SNCR capital and annual costs. Default data in the spreadsheet is taken from the SNCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions, such as the boiler configuration and fuel type. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. For additional information regarding the IPM, see the EPA Clean Air Markets webpage at <http://www.epa.gov/airmarkets/power-sector-modeling>. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the **Data Inputs** tab and click on the **Reset Form** button. This will reset the NSR, plant elevation, estimated equipment life, desired dollar year, cost index (to match desired dollar year), annual interest rate, unit costs for fuel, electricity, reagent, water and ash disposal, and the cost factors for maintenance cost and administrative charges. All other data entry fields will be blank.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SNCR is for new construction or retrofit of an existing boiler. If the SNCR will be installed on an existing boiler, enter a retrofit factor equal to or greater than 0.84. Use 1 for retrofits with an average level of difficulty. For more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you selected coal, select the type of coal burned from the drop down menu. The NO_x emissions rate, weight percent coal ash and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided.

Step 4: Complete all of the cells highlighted in yellow. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.015 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the **SNCR Design Parameters** tab to see the calculated design parameters and the **Cost Estimate** tab to view the calculated cost data for the installation and operation of the SNCR.

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

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

Che.3.23

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
orSelect the appropriate SO₂ emission rate:

Not Applicable

Ash content (%Ash):

percent by weight

Not applicable to units burning 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:

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

Number of days the SNCR operates (t_{SNCR})	365 days	Plant Elevation	278 Feet above sea level
Inlet NO_x Emissions ($\text{NO}_{x,\text{in}}$) to SNCR	0.276 lb/MMBtu		
Outlet NO_x Emissions ($\text{NO}_{x,\text{out}}$) from SNCR	0.152 lb/MMBtu		
Estimated Normalized Stoichiometric Ratio (NSR)	2.04		

*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	30 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)	3.25	Percent		
Fuel ($\text{Cost}_{\text{fuel}}$)	5.00	\$/MMBtu		
Reagent ($\text{Cost}_{\text{reag}}$)	1.66	\$/gallon for a 50 percent solution of urea*		
Water ($\text{Cost}_{\text{water}}$)	0.0042	\$/gallon*		
Electricity ($\text{Cost}_{\text{elect}}$)	0.0676	\$/kWh*		
Ash Disposal (for coal-fired boilers only) (Cost_{ash})		\$/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 . . .
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Table A-9 - SNCR for CPP Halsey Power Boiler No. 1

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 (%)	3.25	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 (m_{fuel}) =	$(Q_B \times 1.0E6 \text{ Btu/MMBtu} \times 8760)/HHV =$	2,026,823,529	scf/Year	
Actual Annual fuel consumption (M_{actual}) =		856,000,000	scf/Year	
Heat Rate Factor (HRF) =	$NPHR/10 =$	0.82		
Total System Capacity Factor (CF_{total}) =	$(M_{actual}/M_{fuel}) \times (t_{SNCR}/365) =$	0.00	fraction	
Total operating time for the SNCR (t_{op}) =	$CF_{total} \times 8760 =$	8760	hours	Based on 8760 (PTE)
NOx Removal Efficiency (EF) =	$(NO_{x_{in}} - NO_{x_{out}})/NO_{x_{in}} =$	45	percent	
NOx removed per hour =	$NO_{x_{in}} \times EF \times Q_B =$	29.36	lb/hour	
Total NO _x removed per year =	$(NO_{x_{in}} \times EF \times Q_B \times t_{op})/2000 =$	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 =	$(\%S/100) \times (64/32) \times (1 \times 10^6)/HHV =$			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEV _F) =	$14.7 \text{ psia}/P =$			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at 278 feet above sea level (P) =	$2116 \times [(59 - (0.00356 \times h)) + 459.7]/518.6^{5.256} \times (1/144)^* =$	14.6	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00		

* 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 ($m_{reagent}$) =	$(NO_{x_{in}} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR) =$ (whre SR = 1 for NH ₃ ; 2 for Urea)	87	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol} =$	174	lb/hour
	$(m_{sol} \times 7.4805)/\text{Reagent Density} =$	18.3	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24 \text{ hours/day})/\text{Reagent Density} =$	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	0.0527

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times \text{NOx}_{\text{in}} \times \text{NSR} \times Q_{\text{g}}) / \text{NPHR} =$	7.6	kW/hour
Water Usage: Water consumption (q_w) =	$(m_{\text{sol}} / \text{Density of water}) \times ((C_{\text{stored}} / C_{\text{inj}}) - 1) =$	83	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$H_v \times m_{\text{reagent}} \times ((1/C_{\text{inj}}) - 1) =$	0.70	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta\text{fuel} \times \% \text{Ash} \times 1 \times 10^6) / \text{HHV} =$	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 ($SNCR_{cost}$) =	\$621,910 in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	\$0 in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	\$1,085,931 in 2019 dollars
Total Capital Investment (TCI) =	\$2,220,194 in 2019 dollars

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

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

SNCR Capital Costs ($SNCR_{cost}$) =	\$621,910 in 2019 dollars	Ch
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Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

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

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

Balance of Plant Costs (BOP_{cost}) =	\$1,085,931 in 2019 dollars
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Annual Costs

Total Annual Cost (TAC)

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

Direct Annual Costs (DAC) =	\$337,790 in 2019 dollars
Indirect Annual Costs (IDAC) =	\$118,003 in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	\$455,793 in 2019 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	$0.015 \times \text{TCI} =$	\$33,303 in 2019 dollars
Annual Reagent Cost =	$q_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$266,117 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$4,516 in 2019 dollars
Annual Water Cost =	$q_{\text{water}} \times \text{Cost}_{\text{water}} \times t_{\text{op}} =$	\$3,041 in 2019 dollars
Additional Fuel Cost =	$\Delta \text{Fuel} \times \text{Cost}_{\text{fuel}} \times t_{\text{op}} =$	\$30,812 in 2019 dollars
Additional Ash Cost =	$\Delta \text{Ash} \times \text{Cost}_{\text{ash}} \times t_{\text{op}} \times (1/2000) =$	\$0 in 2019 dollars
Direct Annual Cost =		\$337,790 in 2019 dollars

Indirect Annual Cost (IDAC)

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

Administrative Charges (AC) =	$0.03 \times \text{Annual Maintenance Cost} =$	\$999 in 2019 dollars
Capital Recovery Costs (CR)=	$\text{CRF} \times \text{TCI} =$	\$117,004 in 2019 dollars
Indirect Annual Cost (IDAC) =	$\text{AC} + \text{CR} =$	\$118,003 in 2019 dollars

Cost Effectiveness

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

Total Annual Cost (TAC) =	\$455,793 per year in 2019 dollars
NOx Removed =	60 tons/year
Cost Effectiveness =	\$7,644 per ton of NOx removed in 2019 dollars



January 21, 2021

Lisa Scott

lisa.scott@igic.com

Cascade Pacific Pulp, LLC - Halsey Pulp Mill

PO Box 400

Halsey, OR 97348-0400

Sent via EMAIL

Re: Round 2 Regional Haze Program, Preliminary Determination of Cost Effective Controls;
Cascade Pacific Pulp, LLC - Halsey Pulp Mill, 22-3501

Dear Lisa Scott:

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

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

Emissions Unit	Control Device	Target Pollutant
Power boiler #1 (PB1EU)	LNB/FGR	NOx
Facility-wide	Eliminate use of #6 oil, use ULSD as backup instead	SO2

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

If you disagree with, or would like to discuss DEQ's preliminary determination as outlined in this letter, we encourage you to reach out to the DEQ now. After DEQ adopts rules, it intends to

impose Round 2 regional haze requirements promptly thereafter and without additional discussion to meet federal timelines for submission of the State Implementation Plan.

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

Sincerely,

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

Ali Mirzakhali
Air Quality Division Administrator
Oregon Department of Environmental Quality

Cc: Karen Williams
Joe Westersund
Michael Orman
Yuki Puram
Mike Eisele
Claudia Davis



January 27, 2021

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

Sent via EMAIL

Re: Round 2 Regional Haze Program, Preliminary Determination of Cost-effective Controls, Cascade Pacific Pulp-Halsey Mill, Title V Facility 22-3501

Dear Michael Orman,

Cascade Pacific Pulp has received the letter dated January 21, 2021 from DEQ estimating that additional controls and fuel changes will be required at the facility.

The letter submitted to DEQ on September 16, 2020 provided additional information for installing Low NO_x Burner and Flue Gas Recirculation (LNB/FGR) at the #1 Power Boiler. Below is the Cost Analysis Tables from the September 16, 2020 letter. The Cost Effectiveness (\$/ton) for installing controls is greater than \$10,000/ton. DEQ's August 14, 2020 letter suggested cost-effectiveness for installing pollution control was less than \$10,000/ton.

Table 1-Round 2 Cost Analysis based on PSEL.

Emission Unit(s)	Control Device	Capital Cost (\$/yr.)	Annual Cost (\$/yr.)	Cost Effectiveness (\$/ton)
Power boiler #1 (PB1EU)	LNB NO _x	\$5.5 million	\$899,361	\$10,559

Table 2-Round 2 Cost Analysis based on actual emissions from 2017.

Emission Unit(s)	Control Device	Capital Cost (\$/yr.)	Annual Cost (\$/yr.)	Cost Effectiveness (\$/ton)
Power boiler #1 (PB1EU)	LNB NO _x	\$5.5 million	\$899,361	\$26,446*

*Number corrected from the September 14, 2020 submittal.



Cascade Pacific Pulp requests DEQ explain and provide its analysis and assumptions for the cost-effectiveness determination for installing LNB/FGR at the #1 Power Boiler.

If you have any questions, please contact me at 541-369-1752 or lisa.scott@igic.com

Sincerely,

A handwritten signature in blue ink that reads "Lisa Scott".

Lisa Scott
Technical Manager
Cascade Pacific Pulp

CC: Pat Rank
Toby Smith
Brien Flanagan
Karen Williams
Joe Westersund
D Wu
Yuki Puram
Mike Eisele
Claudia Davis

Regional Haze 4FA \$/Ton Calculator

For adjusting cost estimates for consistency

Recommended values (unless site-specific data justifies a different number):

3.25%	interest rate
30	lifetime of control device (years)

Enter the quantities in green columns.

Values in orange columns should match the defaults unless data justifies a different number.

Facility	Emission Unit(s)	Control Device		initial capital expense	interest rate	Lifetime of control device (years)	capital recovery factor	annualized capital recovery expense	Direct Annual Costs	Indirect Annual Costs (NOT including capital recovery)	Annual Operating Expenses all annual costs except capital recovery	total annual costs	Target Pollutant(s)	PSEL for target pollutant(s) (tons/year)	control efficiency	tons of pollutant reduced	\$/ton	
CPP Halsey	Power Boiler #1	LNB/FGR	as submitted	\$3,916,942	4.75%	10	12.794%	\$501,122	\$253,258	\$221,307	\$474,565	\$975,687	NOx	132.8	64%	85.37143	\$11,429	original 4FA
CPP Halsey			adjusted	\$2,981,593	3.25%	30	5.268%	\$157,075	\$227,536	\$196,153	\$423,689	\$580,764	NOx	132.8	64%	85.37143	\$6,803	see 'YP_CPP_LNB.xlsx'
CPP Halsey			as submitted2	\$5,515,142	3.25%	30	5.268%	\$290,547	\$297,209	\$311,606	\$608,814	\$899,361	NOx	132.8	64%	85.37143	\$10,535	submitted with letter dated 9/16/2020, see 'LNB as submitted 2'
CPP Halsey			adjusted2	\$800,936	3.25%	30	5.268%	\$42,195	\$167,568	\$45,253	\$212,821	\$255,015	NOx	132.8	64%	85.37143	\$2,987	see 'LNB DEQ estimate'

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 2019 quote cost for 31 MMBtu/hr boiler adjusted for 236 MMBtu/hr boiler		\$3,436,654
(b)	Instrumentation	0.10 × A	\$343,665
(b)	Sales Tax	0.03 × A	\$103,100
(b)	Freight	0.05 × A	\$171,833
	Total Purchased Equipment Cost, B =	B	\$4,055,252
Total Direct Cost:			TDC \$4,055,252
Indirect Capital Costs			
(c)	Engineering	0.10 × B	\$405,525
(c)	Contingencies	0.20 × B	\$811,050
(c)	General Facilities	0.05 × B	\$202,763
(b)	Testing	0.01 × B	\$40,553
Total Indirect Cost:			TIC \$1,459,891
Total Capital Investment:			TCI \$5,515,142

ANNUALIZED COSTS				
	COST ITEM	COST FACTOR	UNIT COST	COST (\$)
Annual Operating Costs - Direct Annual Costs				
(d)	Maintenance Costs	2.75% of TCI		\$151,666
Utilities				
(a)	Electricity	277 kW	\$0.060 per kWh	\$145,542
Total Direct Annual Costs:			DAC	\$297,209
Annual Operating Costs - Indirect Annual Costs				
(b)	Overhead	60% of sum of operating & maintenance costs		\$91,000
(b)	Administrative Charges	2% of TCI		\$110,303
(b)	Property Taxes	1% of TCI		\$55,151.42
(b)	Insurance	1% of TCI		\$55,151.42
Total Indirect Annual Costs:			IDAC	\$311,606
Total Annual Costs:			TAC	\$608,814
Cost Effectiveness				
(b)	Expected lifetime of equipment, years	30		
(b)	Interest rate, %/yr	3.25%		
(b)	Capital recovery factor	0.053		
(b)	Total Capital Investment Cost	\$5,515,142		
Annualized Capital Investment Cost:				\$290,547
Total Annualized Cost:				\$899,361
(e)	NO _x Reduction	64%		
(f)	Pre-retrofit NO _x	132.8 tons NO _x /yr		
	Post-retrofit NO _x using LNB	47.43 tons NO _x /yr		
	NO _x Removed	85.37 tons NO _x /yr		
Annual Cost/Ton Removed:				\$10,535

- (a) Equipment cost information obtained from a recent Zeeco quote for a gas-fired auxiliary boiler. The \$128,700 equipment cost of installing LNB, FGR, new fan on a gas-fired boiler was scaled based on CPP boiler capacity. Labor (3.6x equipment cost), materials (1.3x equipment cost), and subcontracting (2.0x equipment cost) were added to the equipment cost to calculate the installed cost, as it was not included in the original quote. 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 - NOX 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-2
 Cascade Pacific Pulp - Halsey
 Low NO_x Burner and FGR Retrofit - No. 1 Power Boiler

CAPITAL COSTS			
	COST ITEM	FACTOR	COST (\$)
Costs to Purchase Equipment			
(a)	LNB and FGR Retrofit 2019 quote cost for 31 MMBtu/hr boiler adjusted for 236 MMBtu/hr boiler		\$435,020
(b)	Instrumentation	0.10 × A	\$43,502
(b)	Sales Tax	0.03 × A	
(b)	Freight	0.05 × A	\$21,751
	Total Purchased Equipment Cost, B =	B	\$500,272
Total Purchased Equipment Cost:			TDC \$500,272
Total Capital Investment:			1.60 × B TCI \$800,936

As far as I know, a copy of the quote for the 31 MMBtu/hr LNB FGR has not been provided to DEQ. CPP's labor, materials and subcontracting multipliers appear to be high compared to similar equipment listed in EPA's Control Cost Estimation spreadsheets.

For this calculation I've separated labor, materials and subcontracting from the PEC calculation and instead included them in a factor calculated in the "TCI calculation" worksheet.

It's not clear whether sales tax applies to this purchase.

ANNUALIZED COSTS				
	COST ITEM	COST FACTOR	UNIT COST	COST (\$)
Annual Operating Costs - Direct Annual Costs				
(d)	Maintenance Costs	2.75% of TCI		\$22,026
Utilities				
(a)	Electricity	277 kW	\$0.060 per kWh	\$145,542
Total Direct Annual Costs:			DAC	\$167,568
Annual Operating Costs - Indirect Annual Costs				
(b)	Overhead	60% of sum of operating and maintenance costs, not counting electricity		\$13,215
(b)	Administrative Charges	2% of TCI		\$16,018.72
(b)	Property Taxes	1% of TCI		\$8,009.36
(b)	Insurance	1% of TCI		\$8,009.36
Total Indirect Annual Costs:			IDAC	\$45,253
Total Annual Costs:			TAC	\$212,821
Cost Effectiveness				
(b)	Expected lifetime of equipment, years	30		
(b)	Interest rate, %/yr	3.25%		
(b)	Capital recovery factor	0.053		
(b)	Total Capital Investment Cost	\$800,936		
Annualized Capital Investment Cost:				\$42,195
Total Annualized Cost:				\$255,015
(e)	NO _x Reduction	64%		
(f)	Pre-retrofit NO _x	132.8 tons NO _x /yr		
	Post-retrofit NO _x using LNB	47.43 tons NO _x /yr		
	NO _x Removed	85.37 tons NO _x /yr		
Annual Cost/Ton Removed:				\$2,987

- (a) Equipment cost information obtained from a recent Zeeco quote for a gas-fired auxiliary boiler. The \$128,700 equipment cost of installing LNB, FGR, new fan on a gas-fired boiler was scaled based on CPP boiler capacity. Labor (3.6x equipment cost), materials (1.3x equipment cost), and subcontracting (2.0x equipment cost) were added to the equipment cost to calculate the installed cost, as it was not included in the original quote. 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

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Methods for Evaluating the Costs of Utility NO_x Control Technologies

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INTRODUCTION

Titles I and IV of the 1990 Clean Air Act Amendments (CAA) are the driving forces behind the control of nitrogen oxides as precursor air pollutants. Title I addresses the control of nitrogen oxides (NO_x) as a means of achieving the National Ambient Air Quality Standard (NAAQS) for ozone attainment. Title IV targets nitrogen oxides for the prevention of acid rain formation. In addition to these regulations, certain areas have adopted stricter regulations for the control of NO_x . For example, the Northeast States Coordinated Air Use Management (NESAUM) agency and the South Coast Air Basin (SCAB) in California have developed stricter NO_x emission limits in order to meet local air quality standards.¹

A variety of technologies have been developed to reduce NO_x emissions from fossil-fuel-fired utility boilers. Combustion controls for NO_x include operating modifications, burners out of service (BOOS), flue gas recirculation (FGR), low- NO_x burners (LNB), overfire air (OFA) and reburning. Combustion control technologies are generally adopted by utilities in which low to moderate reductions are needed.² Of these combustion controls, LNB and LNB combined with OFA (LNB+OFA) are most commonly applied to coal-fired power plants with tangential and wall-fired boilers.^{3,4,5}

PULVERIZED-COAL-FIRING CONFIGURATIONS

The design of combustion-based NO_x control technologies depends on the design of a furnace. Most of the installed coal-fired power plant capacity in the U.S. is comprised of pulverized coal-fired systems. The burners required to combust the pulverized coal can be arranged in two general configurations: horizontally on the furnace walls or in the corners of the furnace. The first configuration, referred to as "wall-fired," includes burner arrangements on one or more walls of the furnace. In the wall-fired configuration, the burners are independent of each other and provide separate flame envelopes. The second configuration is referred to as tangential-fired. The tangential-fired configuration is such that one flame envelope is produced at the center of the furnace. The implications of these two furnace designs for NO_x formation and control are discussed.

NO_x Formation Mechanisms

Nitrogen oxides (NO_x) production in combustion systems is primarily due to two mechanisms: fuel and thermal NO_x . Fuel NO_x is produced when chemically bound nitrogen compounds in the fuel are oxidized. Formation of fuel NO_x is dependent on O_2 availability and the concentration of nitrogen in the fuel. Fuel nitrogen conversion rates increase with increasing flame air-to-fuel ratio or fuel nitrogen content. Thermal NO_x , on the other hand, is formed due to reactions of nitrogen and oxygen in the combustion air at high temperatures. At high temperatures N_2 and O_2 are dissociated into radicals that react to form NO . Fuel and thermal NO_x formation in coal-fired combustion systems can be reduced or controlled by adjusting the air-to-fuel stoichiometry, the rate of air and fuel mixing and the temperatures at which combustion takes place. The technique most applied in coal-fired utilities for the control of NO_x is operation of the bulk of the flame zone under fuel rich conditions to reduce the availability of O_2 at high temperatures, followed by a fuel lean zone to complete the burn-out of the fuel.¹ This technique is commonly referred to as staged combustion. Combustion-based NO_x control technologies, such as LNB and LNB+OFA, apply this technique for the control of NO_x emissions in utility boilers.

Wall-Fired Boilers

Wall-fired boilers have several configurations. The burners can be arranged as single-wall or opposed-wall. Single-wall fired boilers have burners on one wall of the furnace. Opposed-wall boilers have burners on two opposing walls. Each wall with burners has several circular burners. Each burner has its own flame zone. Coal and primary air are fed via nozzles at the center of each burner. The inlet vanes in the furnace windbox assembly, from which secondary combustion air is drawn, can be adjusted to achieve better fuel and air mixing. Air swirl and high velocities combined with the contour of the burner throat results in a recirculation pattern across the furnace.⁵ The recirculation of flue gas back to the burner provides more thermal energy to the burner for more efficient combustion. Temperature and air circulation control in wall-fired boilers is achieved by adjusting the amount of excess air and the heat input.

The air swirling and circulation patterns can often lead to turbulence. The high level of turbulence results in poor mixing between the fuel and the secondary air creating two conditions in which NO_x formation is

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



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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 $[\text{Cost of Project A} \times (\text{AF\&PA rate} / \text{Project A})^{0.6}]$ 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 based 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 quaternary air system yielding a NO_x level in the stack gases of 80 ppm @ 8% oxygen. Equipment sized for a NDCE recovery furnace burning 3.7×10^6 (Mm) lb BLS per day.

4.1.2. Major Equipment

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

4.1.3. Basis for Estimate

Southeast Kraft mill recovery furnace firing 2.6×10^6 -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
- ✓ Power 75 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 placed 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 10⁶ (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 ft³ 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 10⁶ (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 ft³ 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 ft³ 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 ft³ 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 ft³ per yr. @ \$350 per ft³
- ✓ 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 ft³ per yr. @ \$350 per ft³
- ✓ 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 ft³ per yr. @ \$350 per ft³
- ✓ 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 ft³ per yr. @ \$350 per ft³
- ✓ 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. SO₂ Reduction – Good Technology Limits

6.1. NDCE Recovery Boiler

6.1.1. Description

Installation of a chemical scrubber to achieve sulfur dioxide (SO₂) 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 2.5×10^6 -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 (SO₂) 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 2.5×10^6 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 SO₂ 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 SO₂ 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. SO₂ Reduction – Best Technology Limits

7.1. NDCE Recovery Boiler

7.1.1. Description

Installation of a caustic scrubber to achieve sulfur dioxide (SO₂) 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 2.5×10^6 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 (SO₂) 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 2.5×10^6 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 SO₂ 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 SO₂ 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/10¹² Btu to 8 lb/10¹² 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/10¹² Btu to 0.286 lb/10¹² 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



**AF&PA Emission Control Study –
Cost Estimate & Industry-Wide Model
Phase I Pulp & Paper Industry
September 20, 2001**



- ✓ 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 2.15×10^6 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 3.7×10^6 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 2.70×10^6 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 3.7×10^6 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 2.15×10^6 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 1.7×10^6 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 3.7×10^6 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 2.15×10^6 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 3.7×10^6 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 2.70×10^6 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 3.7×10^6 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 2.15×10^6 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 1.7×10^6 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 3.7×10^6 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



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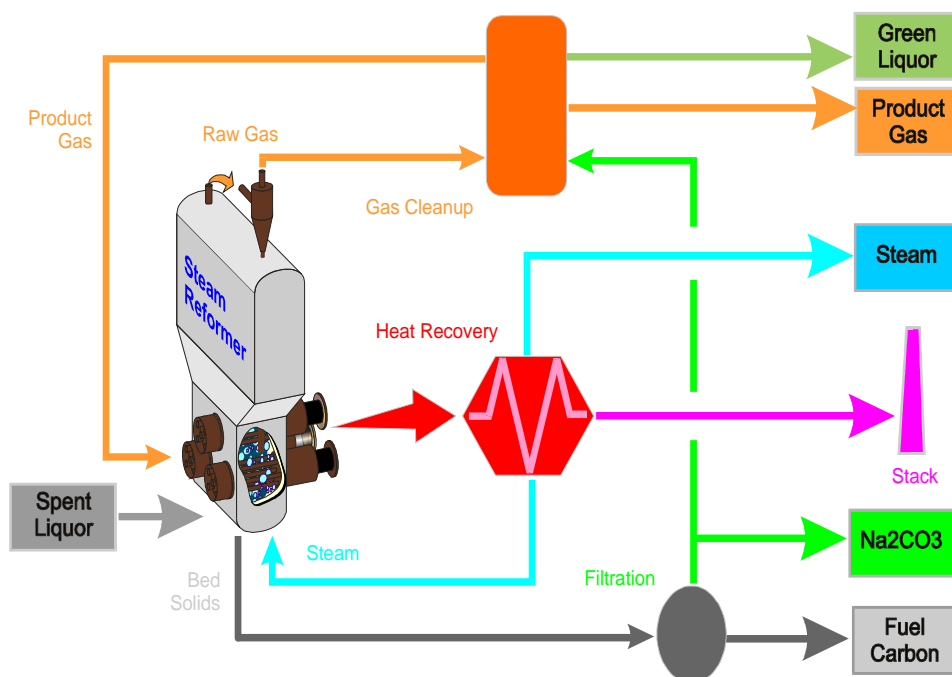


- ✓ Testing: \$5,000 per year
- ✓ Water: 10gpm
- ✓ Wastewater: 10 gpm

16. Gasification

16.1. Description of Technology

For this study, chemical recovery via gasification is based on the PulseEnhancedTM Steam Reforming technology developed by MTCI/ThermoChem, which is designed to process spent liquor and recover its chemical and energy value. A simplified diagram of the technology is shown below.



The recovery of chemicals and energy from spent liquor is effected by an indirectly heated steam-reforming process which results in the generation of a hydrogen-rich, medium-Btu product gas and bed solids, a dry alkali, which flow from the bottom of the reformer. Neither direct combustion nor alkali salt smelt formation occurs in this steam-reforming process.

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

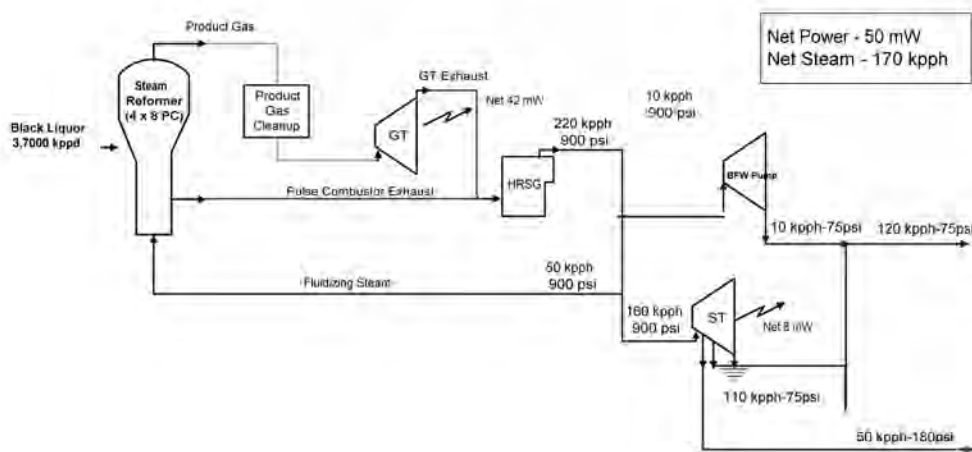
The product gas is cleaned, compressed, and then sent to the pulse heaters to provide the indirect heat in the reformer and to a combustion turbine to produce electricity. The combustion turbine exhaust is combined with the pulse heater exhaust and then sent to a

heat recovery steam generator. The resulting high-pressure steam is then sent to an extraction/condensing steam turbine where addition electricity is produced and lower pressure steam is made available to the mill. A process flow diagram showing the complete system is shown on the following page.

AF&PA/BE&K

**Black Liquor Gasification Combined Cycle System
Block Flow diagram**

Project 12104
23 June, 2001



The scope developed assumes that the mill can supply concentrated black liquor (80% solids). Since the costs for doing this can vary widely between mills and modern recovery boilers would require a similar concentration, these costs have been omitted from this study.

We recognize that the steam produced by this system is probably not sufficient for a typical Kraft mill. The additional steam requirements will either need to be provided by a biomass gasifier or boiler or a power boiler. These additional systems offer the opportunity for further power generation as well as steam production. This too is site specific and not included in this study.



16.2. Major Equipment

The major subsystems include liquor injection, steam reformer, gas cleanup, combustion turbine, heat recovery and steam generation, steam turbine, bed solids dissolution, sodium carbonate solution filter, and bed solids storage.

16.2.1. Black Liquor Supply and Steam Reformer

High solids black liquor is supplied to the reformer via a recirculation line feeding multiple steam jacketed injectors. Four reformers each containing 8-pulse heaters are required for this size plant. Each steam reformer is a carbon steel; fabricated vessel lined with refractory. The upper region of the vessel is expanded to reduce gas velocity, permitting entrained particles to disengage and fall back to the fluid bed. Internal stainless cyclones, mounted from the roof of the reformer, provide primary dust collection and a second set of external cyclones further captures fines. The reformer is fluidized with superheated steam using stainless fluidizer headers that are located just above the refractory floor. Bed drains penetrate the refractory floor for removal of bed solids via lock hoppers during normal operation.

Pulsed jet heater modules (fired heat exchangers) are used to indirectly heat the reformer. Pulsed heater modules are cantilever-mounted in the reformer utilizing a flange located on the front of the vessel. Each module extends through the reformer with its 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
	<u>(lb/hr)</u>	<u>(lb/hr)</u>	<u>(lb/hr)</u>
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 ₂ S)	0.0	0.0	0.0

Recovery Boiler & Smelt Dissolver Emission Estimates

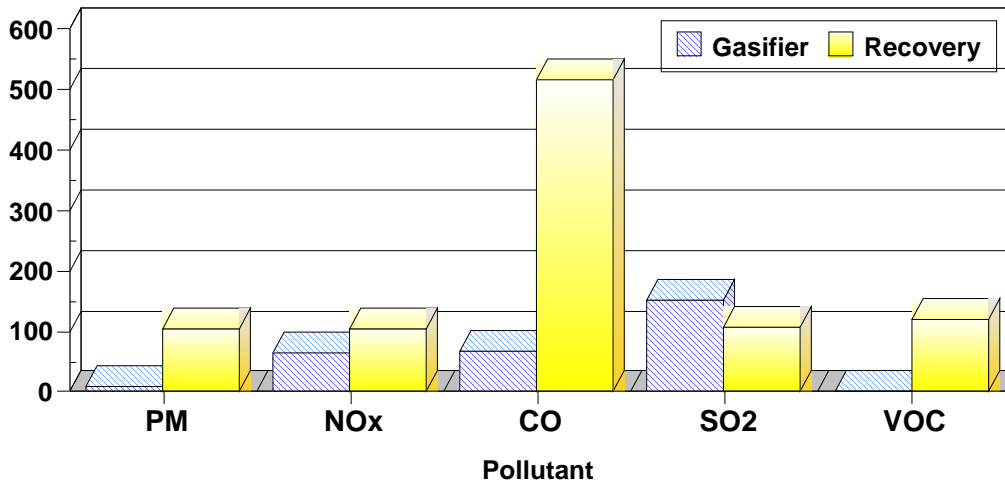
	Recovery Boiler Exhaust	Smelt Dissolving Exhaust	Total
	<u>lb/hr</u>	<u>lb/hr</u>	<u>lb/hr</u>
Particulate matter	93.9	9.4	103.3
Nitrous oxides (NO _x)	89.2	16.1	105.3
Carbon monoxide (CO)	516.5	0.3	516.8
Sulfur dioxide (SO ₂)	98.7	9.4	108.1
Volatile organic (as carbon)	37.6	7.5	45.1
as Methanol	100.2	20.0	120.2
TRS (as H ₂ S)	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 rates, lb/hour



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; $\text{gpm/feed rate} \times \text{feed rate} \times 1440 \text{ min/day} \times 365 \text{ dy/yr}$. The water usage used the same formula but with only 350 dy/yr.

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- ✓ 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. CO₂ Emission Assumptions

- ✓ The CO₂ emissions were calculated by multiplying the 1995 NCASI fossil fuel usage from the power boilers, recovery furnaces, and lime kilns times the CO₂ 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 CO₂ 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.

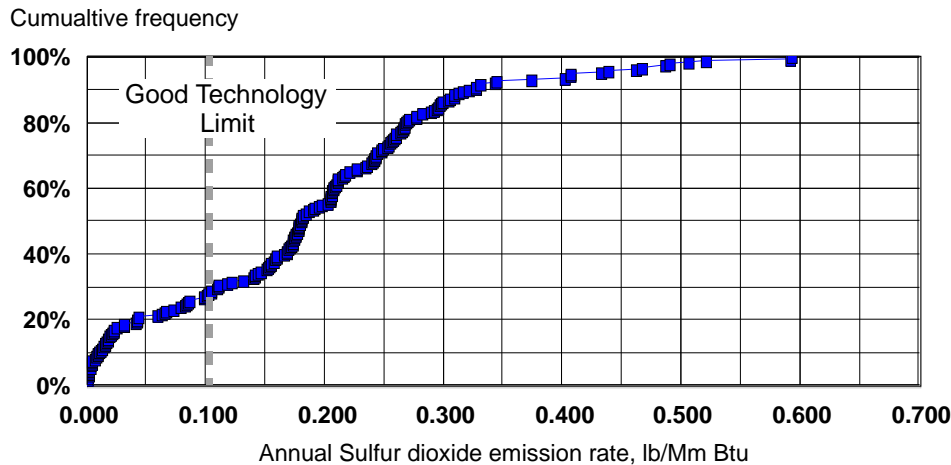
NDCE at 80 ppm	0.1415 lb / Mm Btu
NDCE at 40 ppm	0.0726 lb / Mm Btu
DCE at 30 ppm	0.0544 lb / Mm Btu
- ✓ The annual NO_x emission rates from the NCASI database were converted to lb/Mm Btu and compared with 80% of the above limits. The NO_x limits are based upon 30-day averages and it was assumed that 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. SO₂ 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 SO₂ emission rates from the NCASI database were converted to lb/Mm Btu basis and compared with 80% of the above limits. The SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 were 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 $[(1-0.3) \times (1-0.6)]$.

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,



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- ✓ 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 SO₂, and NO_x yearly emission rates were converted to pounds and divided by Btus to determine a lb/MmBtu emission rate.
- ✓ The SO₂ 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 SO₂ control technology, no control costs were assumed for any boiler designated as a wood or gas boiler, regardless of the emission level.
- ✓ NCASI has listed 1225 boilers or turbines, and had fuel consumption information on 1074 of them. Control technology estimates for boilers were only made if fuel consumption information was provided.





17.6. Coal Boiler Assumptions

17.6.1. General

- ✓ If more than 80% of the gross Btu's originated from coal, then the boiler was assumed a coal boiler.

17.6.2. NO_x Limits

- ✓ Any coal boilers after 1990 are assumed to have low NO_x burners and are assumed to meet the 0.3 lb/10⁶ 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 / 10⁶ Btu for boilers less than and greater than 100 million Btu/hr, respectively.

17.6.3. SO₂ 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/10¹² 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 SO₂ 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 SO₂ control is installed there will be no need to install HCl controls as well; the chemical addition rate for SO₂ 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/10⁶ 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. SO₂ 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/10¹² Btu for coal and by 0.572 lb/10¹² 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/10⁶ 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/10⁶ 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. SO₂ 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/10⁶ 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/10¹² 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 controls 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

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	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

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	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	SO ₂	NDCE Kraft Recovery Furnace	3
Best	SO ₂	NDCE Kraft Recovery Furnace	3
Good	NO _x	NDCE Kraft Recovery Furnace	3
Best	NO _x	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	SO ₂	DCE Kraft Recovery Furnace	3
Best	SO ₂	DCE Kraft Recovery Furnace	3
Best	NO _x	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	NO _x	Lime Kilns	3
Best	NO _x	Lime Kilns	5
Good	PM	Coal Boiler	3
Best	PM	Coal Boiler	3

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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	SO ₂	Coal or Coal/Wood boiler (50/50)	3
Best	SO ₂	Coal or Coal/Wood boiler (50/50)	3
Good	NO _x	Coal or Coal/Wood boiler (50/50)	3
Best	NO _x	Coal or Coal/Wood boiler (50/50)	5
Best	NO _x	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	NO _x	Gas boiler	3
Best	NO _x	Gas boiler	5
Good	NO _x	Gas turbine	5
Good	NO _x	Gas turbine	5
Best	NO _x	Gas turbine	5
Good	PM	Oil boiler	3
Best	PM	Oil boiler	3
Good	SO ₂	Oil boiler	3
Best	SO ₂	Oil boiler	3
Good	NO _x	Oil boiler	3
Best	NO _x	Oil boiler	5
Good	PM	Wood boiler	5
Best	PM	Wood boiler	3
Best	PM	Wood boiler	5
Good	NO _x	Wood boiler	3
Best	NO _x	Wood boiler	3

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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

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	15%		20%		5%		5%		Annual Operating and Maintenance Costs and Assumptions										Chemical (2) for design rate
															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							
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	\$ 426,600	\$ 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																												

No.	Good / Best	Pollutant	Equipment	Units	Type of chemical	Maintenance labor & materials, % of TIC	Energy, kw/feet 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/Mmb 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/Mmb 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/Mmb 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/Mmb 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/Mmb 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/Mmb 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/Mmb 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/Mmb 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/Mmb 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/Mmb 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/Mmb 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/Mmb 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/Mmb BLS	70%	3.00	\$ 5,000	-	-	294.12	lb/hr/Mmb BLS/day	-	NA	\$ -	NA	-	NA	-	NA	-	NA	4
14	Best	VOC	DCE Kraft Recovery Furnace	NA	NA	3.00%	264.96165	kw/Mmb BLS	70%	3.00	\$ 5,000	-	-	(15.873)	lb/hr/Mmb BLS/day	-	NA	\$ -	NA	-	NA	-	NA	-	NA	20
15	Good	PM	Smelt Dissolving tank	NA	NA	2.00%	77.47584	kw/Mmb 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/Mmb BLS	80%	1.50	\$ 5,000	-	-	-	NA	-	NA	\$ -	NA	-	NA	-	NA	-	NA	3
17	Good	PM	Lime Kilns	NA	NA	3.00%	0.77981	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	-	79.380	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	-	-	-	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/Mmb BLS	70%	-	\$ 5,000	-	650.00	#####	lb/hr/Mmb 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/Mmb 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/Mmb 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.																			

avored. First, under these conditions, the combustion gas temperatures are high. With high temperatures, thermal NO_x is formed. Second, the turbulence reduces the residence time of the combustion process. With less residence time, the reducing reactions that would convert nitrogen species to diatomic nitrogen are not allowed to proceed to completion.

As an example to indicate both the range and average of emissions from wall-fired boilers, emissions testing of 18 dry-bottom, wall-fired boilers, has shown the range of NO_x emissions to be 0.42-1.77 lb/10⁶ BTU.³ The average of this range was 0.95 lb/10⁶ BTU.

Tangential-Fired Boilers

In tangential-fired boilers, fuel and air are combined and combusted while being projected towards the center of the furnace. The flames produced evolve into a rotating “fireball” due to high turbulence and mixing. Four air zones are handled by the windbox: primary, fuel, overfire, and auxiliary. Primary air injected through the coal nozzle assembly dries and transports the coal. Fuel air or secondary air is supplied via secondary air nozzles. The overfire air portion is injected via ports either on top of or separate from the windbox. The auxiliary air is the portion of air needed for complete combustion besides the primary, secondary, and OFA portions. The auxiliary air is also introduced via the windbox.

The windbox assembly, which includes the fuel and air nozzles, is tilted uniformly during the combustion process. A tilting mechanism allows the fireball to travel up and down the furnace, enabling control of the flue gas and steam temperatures during changes in the boiler load. The position of the fireball along the furnace is adjusted based upon the accumulation of ash on the furnace walls. It begins at the bottom of the furnace and travels upward. With ash build-up, less heat is absorbed by the furnace walls, and less heat is transferred at the convective pass of the boiler. When this occurs, the fireball is moved upward by tilting the windbox assembly to compensate for the heat loss. The fireball will cycle back down once the ash deposits are removed, for example, after soot-blowing incidents.

In the burner assembly, the secondary air nozzles are located between the two coal nozzles. This arrangement allows the fuel and air to mix well and for efficient combustion to occur. Because of the more uniform fuel-to-air ratio created by the fireball-firing configuration, the uncontrolled NO_x emissions from tangential-fired boilers tend to be lower than for wall-fired boilers. Emission testing of 19 units has shown the range of baseline uncontrolled NO_x emissions to be 0.45-0.80 lb/10⁶ Btu for tangential-fired boilers.³ The average of this range was 0.65 lb/10⁶ BTU, 32 percent lower compared to the average baseline emission rate of wall-fired boilers.

NO_x COMBUSTION CONTROL TECHNOLOGIES

OFA, LNB and LNB+OFA are the most commonly employed technologies for combustion based NO_x control. These technologies are briefly reviewed here.

OFA Technology

In a conventional boiler, all of the air required for combustion is introduced into the furnace through the burners. Over-fire air (OFA) is an application of two-staged combustion in which a portion of the combustion air is diverted to injection ports above the top row of burners or between the burner rows in the furnace. The existing windbox or duct systems are installed to supply secondary air to the OFA ports. When OFA is employed, the primary air flow to the burners is reduced to promote fuel rich combustion in the flame zone. The secondary air promotes the burnout of products of incomplete combustion from the primary flame zone. This control technique reduces NO_x emissions by two mechanisms. First, the combustion process is delayed due to the staging, resulting in a lower flame temperature which suppresses thermal NO_x formation. The second mechanism involves the inhibition of fuel NO_x formation due to low O_2 levels in the combustion zone.⁶

For wall-fired systems, OFA has been applied as a “stand-alone” NO_x combustion control technology and in combination with other control technologies such as LNB. OFA systems for wall-fired boilers can be described as either conventional OFA or advanced OFA (AOFA). In the traditional systems, there is one OFA port above each burner column, and 20 percent of the total air flow is diverted equally to these OFA ports. In the AOFA systems, the OFA ports are installed on walls other than the burner walls of the

furnace, and the diverted flow is typically 45 percent of the total air flow. Existing traditional OFA systems can be modified by adding additional OFA ports and adjusting the air flow. The process of adjusting air flows through multiple OFA ports is referred to as biasing. Some AOFA systems include not only OFA ports on the walls of the furnace but also ports in the corners of the furnace and between the burner levels. These wing and auxiliary OFA ports allow air to be introduced in areas normally starved of air in conventional OFA systems.⁷

For tangential-fired boilers, the OFA systems can include either close-coupled OFA (CCOFA) or separated OFA (SOFA). CCOFA is analogous to the conventional system of wall-fired boilers while SOFA is similar to the AOFA. In the SOFA system, a separate windbox and duct system supply the OFA.⁵ These OFA systems were used in tangential-fired boilers for the control of NO_x in pre- and NSPS boilers.

LNB Technology for Wall-fired Boilers

LNB utilizes staging for the reduction of NO_x formation. Through the application of LNBs, thermal NO_x is reduced by the reduction of flame temperature and reduced residence time at peak temperature; while fuel NO_x is reduced by sub-stoichiometric oxygen levels in the primary flame zone.⁹ Because the design and performance of the LNB technology differ for wall-fired and tangential-fired boilers, the technology for the tangential-fired boilers will be discussed separately.

Two general categories of LNBs are delayed combustion and internal staged. In delayed combustion burners, the fuel is combusted slowly with long, low-intensity flames. This burner design is different from conventional burner designs. Combustion in conventional burners is achieved rapidly in turbulent, high-intensity flames. Internal-staged LNBs inhibit NO_x formation by creating fuel-rich and fuel-lean conditions near the burner zone. In the fuel-rich regions, fuel nitrogen is converted to N_2 instead of NO due to oxygen-deficient conditions. In the fuel-lean regions, thermal NO_x formation is inhibited by lower-temperature conditions.

Tests of retrofitted LNBs have shown NO_x reduction efficiencies ranging from 40 to 60 percent.¹ Data in the open literature indicate that the NO_x reduction efficiencies for wall-fired boilers range from 30 to 60 percent.^{3,4,5} The extent to which NO_x is reduced depends upon the LNB system and the specific unit performance characteristics such as fuel properties and combustion temperatures.³

LNB Technology for Tangential-fired Boilers

The LNB technology configurations for tangential-fired boilers differ from those of wall-fired boilers, even though the theory behind the LNB controls is similar. Some wall-fired LNB technologies are currently being tested and applied to tangential-fired boilers, but the most accepted technologies are those designed specifically for tangential-fired boilers. An example is the Low NO_x Concentric Firing System (LNCFS). This system is common in U.S. coal-fired boilers. LNCFS retrofit requires replacement of all fuel and air nozzles and some changes in the boiler structure, windbox, and waterwall.

The basic NO_x control strategy behind the development of the LNCFS is directing the fuel and a fraction of the secondary combustion air towards the center of the furnace while directing the rest of the secondary air horizontally and parallel to the furnace walls. Redistributing the secondary air in the combustion zone creates separation between fuel and air. This separation creates fuel-rich conditions at the center of the furnace. With low O_2 availability, NO_x formation is inhibited. This firing configuration also creates a blanket of air along the walls of the furnace. This layer of air reduces the slagging and corrosion potential under fuel-rich or reducing conditions of the low NO_x firing configuration.

Four different types of air are handled by the windbox: primary, secondary, auxiliary, and fuel. The LNCFS is designed to inhibit NO_x emissions by controlling the mixing of the fuel and the combustion air. Instead of directing the auxiliary air directly towards the fireball as done in conventional tangential-fired boilers, the air is directed towards a bigger imaginary circle surrounding the fireball. As a result, the fireball area of the furnace becomes fuel-rich.

LNCFS systems come in three configurations, Levels I, II, and III. In all three designs, combustion staging is achieved along with some protection against waterwall corrosion by diverting the combustion air towards the walls of the furnace.³ Level I (LNCFS I) is the level at which the LNB is operated with close-

coupled over-fire air (CCOFA). The CCOFA is integrated directly into the windbox by exchanging the highest coal nozzle with the air nozzle immediately below it. This level is considered as the representative LNB technology applied to tangential-fired boilers.

The NO_x reduction efficiencies for this technology range from 25 to 35 percent.³ Even though this range is lower than the range for LNB technologies in wall-fired boilers, the efficiency can be sufficient to meet the applicable NO_x standards. This is because uncontrolled tangential-fired boilers typically emit less NO_x on a lb/10⁶ BTU basis than uncontrolled wall-fired boilers.

LNB+OFA Technology

For further control of NO_x emissions, the LNB technology may be combined with OFA technology. For wall-fired boilers, the “stand-alone” OFA and LNB technologies are operated simultaneously to achieve NO_x reductions ranging from 40 to 60 percent. LNB+OFA systems in tangential-fired boilers include the LNCFS, Levels II and III (LNCFS II and LNCFS III). LNCFS II operates using the LNCFS with SOFA while LNCFS III incorporates both CCOFA and SOFA. These systems can achieve NO_x reduction efficiencies ranging from 30 to 50%.³ These technologies allow more efficient use of staging and as a result, further control of thermal and fuel NO_x formation.

SYSTEM IMPACTS

The LNB and LNB+OFA technologies are successful at controlling NO_x emissions from coal-fired, tangential- and wall-fired boilers, but their impact on the base plant performance can be significant. These adverse impacts include increased unburned carbon levels and carbon monoxide (CO) emissions. The increase in total unburned carbon can result in a decrease in the boiler efficiency. In addition, high levels of unburned carbon in the flyash can lead to costs associated with the potential inability to sell the flyash as a byproduct.

In general, there is an upper limit to the amount of combustion air which can be diverted from the primary air supplied with the coal. If the primary air flow is too low, then incomplete combustion will occur in the flame zone. Therefore, the extent of staging for OFA systems is limited by operational problems caused by incomplete combustion conditions due to low primary air flow⁶ or due to poor mixing of the secondary air with the combustion products.⁷

Operation of LNBs in tangential-fired and wall-fired boilers have shown negligible to significant increases in unburned carbon (UBC). Unburned carbon includes uncombusted carbon residue contained in both the bottom ash and fly ash. Loss on ignition (LOI) refers specifically to UBC in the flyash only. Both UBC and LOI are indicators of reduced combustion efficiency. For example, significant increases in UBC were observed at Edgewater Unit 4⁸, Hammond Unit 4, Stuart Unit 4³, and Gaston Unit 2, whereas little to no increase in UBC was observed at Pleasants Unit 2⁹ and Four Corners Unit 4.¹⁰

Another impact, aside from reduced plant efficiency, that results from increases in the LOI is the impact on the flyash saleability. Several utilities indicated that the LOI increases may prevent sale of the flyash as a byproduct. The byproduct specifications are such that only a certain level of unburned carbon are allowed in the flyash. Once this level is exceeded, the flyash is no longer suitable for byproduct sales. The inability to sell the flyash can result in substantial costs associated with the disposal of the unsaleable flyash.

COSTS OF NO_x COMBUSTION CONTROL TECHNOLOGIES

This section contains a brief review of published cost data for retrofit LNB and LNB+OFA technologies.

LNB Technology

Retrofit of LNBs in wall-fired boilers normally involves small modifications to the waterwall, but major modifications to the windbox for improved air distribution may also be required in some cases. The economic analysis study of low-NO_x combustion systems by Lissauskas et al estimated the total capital cost, including indirect costs, of the LNB technology to be \$1.4/kW to \$2.8 /kW for a modification of existing burners and \$4.6/kW to \$8.7 /kW for a total burner replacement in 1987 dollars.⁷ Vatsky reports

the retrofit material cost, not including indirect costs, for the LNB technology to range from \$4.0/kW to \$9.3 /kW in 1990 dollars.³ For boilers surveyed by the Acid Rain Division of the U.S. Environmental Protection Agency, the reported total capital costs ranged from \$9.32/kW to 36.05 \$/kW.⁴ The design basis underlying these cost data are often not completely reported.

The LNCFS I retrofits require replacement of all air and fuel nozzles. Installed capital costs typically include the costs associated with the new burner system and modifications to the existing equipment. Few cost data are publicly available for LNCFS I retrofits. The capital cost reported for Gallatin Unit 4's LNCFS I retrofit was \$21/kW in 1992 dollars.³

LNB+OFA Technology

The capital cost of retrofitting LNB+OFA technologies differs for wall-fired and tangential-fired units due to differences in the modifications required. Cost estimates for wall-fired units in the open literature range from \$6/kW to \$40/kW.^{3,12} Lower cost estimates have been reported for wall-fired applications such as those for Schiller Stations 4, 5, and 6. The installed costs for the LNB+OFA technologies at the Schiller Stations 4, 5, and 6 were \$6.81/kW, \$6.25/kW, and \$7.62/kW, respectively. These costs included direct and indirect expenses, exempt and non-exempt labor, materials, and outside purchases.¹² Several studies have shown LNB+OFA costs to be higher in wall-fired boilers than tangential-fired boilers.^{3,4} Retrofit costs of LNB+OFA in tangential-fired boilers have been reported to range from \$20/kW to \$33\$/kW.³ These cost ranges are expressed in early 1990s dollars. Escalation to 1994 dollars shows that the cost estimates would be approximately six percent higher.¹¹ It is difficult to compare the costs of LNB+OFA to the costs of LNB or OFA only if the comparisons are for different power plants. This is because of variability in the modifications required and often unreported differences in the design basis.

EXISTING NO_x CONTROL COST MODELS

Several performance and cost studies have been conducted to address the performance and cost implications of NO_x combustion technologies as applied to coal-fired power plants.^{3,4,5} In addition to these studies, several cost and performance models are available. These include, for example, the NO_xPERT™ CODE¹³, IAPCS¹⁴, IECM¹⁵, and the CAT Workstation.¹³ The NO_xPERT™ CODE and the CAT Workstation models are proprietary packages with substantial licensing fees. Therefore, they are not readily accessible to the public. The IAPCS was developed under contract to the U.S. EPA and focuses on both combustion and post-combustion NO_x control technologies. The IECM was developed at Carnegie Mellon University for the U.S. Department of Energy and incorporates post-combustion technologies for the control of NO_x emissions. In addition to these models, several cost algorithms have been derived from actual retrofit and estimated cost data.^{3,4,5} A study of the NESCAUM region produced cost algorithms for NO_x combustion control technologies for several different types of fossil-fuel fired boilers.³ Recently, a similar study was conducted for fossil-fuel fired boilers in the U.S. by the Emission Standards Division (ESD) of the U.S. EPA.⁵ The U.S. EPA Acid Rain Division (ARD) is currently publishing a report on a cost-effectiveness study of LNB technology for the wall- and tangential-fired boilers already retrofitted as required by Title IV of the CAA.⁴

The latter three cost studies focused on the capital costs and the cost effectiveness associated with the combustion control technologies, but the manner in which the operating and maintenance costs were estimated differed. In the NESCAUM³ and ESD⁵ studies, the plant performance impacts imposed by these technologies were reflected in a decrease in the boiler efficiency. In order to maintain the plant electrical output, the reduction in boiler efficiency was compensated for by an increase in the fuel consumption, and the costs associated with the increase in fuel usage were reflected in the operating and maintenance cost. However, for some technologies, operating and maintenance cost components were not included in the cost estimates due to either lack of data or insignificant impacts on the boiler performance.⁵ The impact on the boiler efficiency for each technology is treated as an input to the cost algorithm. These inputs were estimates obtained from either data available in the open literature,^{3,5} data obtained from actual retrofits,^{4,5} or estimates given by vendors.^{3,5}

Many capital cost estimates for NO_x combustion control technologies in the open literature include cost components such as coal pulverizer mill upgrades, electrostatic precipitator upgrades, or other unit upgrades which may not be directly related to the NO_x technology to be installed. In some cases, upgrades

are necessitated by the effect of retrofit NO_x technologies on power plant performance, but in other cases the upgrades may have been done for other reasons. Including the costs of upgrades may result in overestimating the costs associated with the NO_x control technology. Because most capital cost data reported in the open literature are not clearly defined, it is difficult to assess how precise the data are pertaining to the control technologies being studied.

OBJECTIVES FOR DEVELOPMENT OF A NEW NO_x CONTROL PERFORMANCE AND COST MODEL

Combustion-based NO_x controls affect the base plant performance and impose capital and operating costs. Performance and cost models of the different technologies are needed to aid decision-making regarding which technologies will achieve performance and emissions goals with acceptable costs. The capability of predicting the performance and cost impacts associated with each control technology or system allows a utility or plant manager to determine the best control technology for their plant. A performance and cost model for combustion control technologies can also be useful for air quality planning. Such models can be used to explore alternative emission reduction strategies for multiple sources and to more accurately evaluate the costs of compliance.

Performance and cost of both the base plant and the control technologies are analyzed. In this report, efforts to develop a new series of performance and cost models of combustion-based NO_x control technologies are described. The necessary foundation for such a model is accurate performance and cost data from actual retrofits or installations of these combustion control technologies. Such data have been compiled directly from several utilities. These new data are used as a basis for the development of model input assumptions. The model is comprised of two main modules: (1) performance and cost of the base plant and the LNB; and (2) LNB+OFA technologies for a coal-fired boiler.

METHODOLOGY

The application of different NO_x combustion technologies can have significant impacts on the performance and cost of wall-fired and tangential-fired boilers. In an attempt to assess and predict these impacts, a cost and performance model has been developed for LNB and LNB+OFA technologies for wall-fired and tangential-fired boilers. The following is a discussion of the modeling approach and the basis for each performance and cost parameter being considered for each technology and the base plant.

Data Collection

Cost and performance data for LNB and LNB+OFA technologies were obtained from several utilities. Data were available for 29 boilers, of which 21 were tangential-fired and eight were wall-fired boilers. For proprietary reasons, the units and plants are identified using letter notation. These data have not been provided or included in previous reports referenced in this paper. The data are organized as follows:

- Table 1. Includes performance data for seven tangential-fired units retrofitted with LNB technology.
- Table 2. Retrofit LNB+OFA performance data were available for eight wall-fired units and two tangential-fired units.
- Table 3. Includes statistical analyses results for data presented in Tables 1 and 2.
- Table 4. This table includes the input assumptions for the performance module.
- Table 5. Capital cost data were available for retrofit LNB technology for four tangential-fired units.
- Table 6. Capital cost assumptions were available for retrofit LNB+OFA for eight wall-fired units and two tangential-fired units.

Performance Data. The baseline emissions for Sites A through Z provided in Tables 1 and 2 were data obtained from emissions testing. The controlled emission rates for Sites K to Z, as reported in Table 1, were obtained after retrofit of the control device. The controlled emission rates given for Sites A to J, as reported in Table 2, are estimates of controlled emission rates guaranteed by control technology vendors.

Cost Data. All cost data were provided as either total capital cost of the technology (Sites K, L, R, X) or as direct installed costs (Sites A through J). For the data provided as installed direct costs, the indirect costs were assumed to be 35 percent of the total cost of the equipment, based on 10 percent project contingency, 10 percent process contingency, 10 percent engineering and office fees, and five percent general facilities.¹⁶ The total capital cost data are provided in Tables 5 and 6. The estimated cost data for Sites A to J depend on the following modification requirements: (1) replacement or modification of existing burners; (2) installation of control and management systems for the LNB+OFA technology; (3) fan and primary flow elements modifications; and (4) replacement of ignitors and scanners.

Performance Models

In this section, performance models for both the base plant and NO_x control technologies are described.

Base Plant Performance Module. The base plant performance model was adopted from the (IECM) which is implemented in a modeling environment called Demos.¹⁴ However, the new models developed here were implemented in FORTRAN, to allow for integration with air quality modeling decision support systems. Process parameters adopted from the IECM model include those associated with the flue gas and solid streams. These parameters account for the quantity of different gases and solids which originate at the combustion zone and are transported through the pollution control system to the stack exit. Detailed equations and explanations to this model can be found in the IECM report developed by Rubin et al.¹⁵

The changes in the composition and flow rate of the flue gas and solids streams due to these control technologies produce changes in the base plant operating parameters. The extent of carbon, sulfur and nitrogen combustion determines the products of combustion. Carbon in the fuel can oxidize to CO or CO₂ or it can remain unoxidized as unburned carbon. Sulfur in the coal can oxidize to SO₂ or SO₃ or it can be retained in the ash. The nitrogen in the coal can oxidize to either NO₂ or NO or be emitted as N₂. The amount of NO_x formed by both fuel and thermal mechanisms is represented by the NO₂ emission factor. The fraction of NO_x as NO is an input parameter. For coal, the NO_x emission factor is based upon the coal type and boiler type. From these input parameters, the combustion products are determined by a mass balance.

The boiler efficiency is the ratio of energy absorbed by the steam cycle to the energy in the fuel. Energy not absorbed by the steam cycle is considered lost energy. The loss of energy is defined in five categories: (1) sensible heat loss of the dry flue gas; (2) sensible and latent heat loss from water vapor in the flue gas; (3) unburned carbon and carbon monoxide, which are indicative of incomplete combustion; (4) radiative heat transfer from the boiler to the surroundings; and (5) unaccounted losses.

Combustion-based NO_x control technologies may decrease the boiler efficiency due to unburned carbon increases. Energy loss due to carbon losses is associated with the formation of CO and unburned carbon. The energy loss associated with each pound of unburned carbon is 14,100 BTU. The energy loss associated with each pound of CO formed instead of CO₂ is 9,755 BTU.

NO_x Control Technologies' Effect on Base Plant Performance. Application of the NO_x control technologies can fall under two categories: retrofit at an existing facility or installation at a new plant. This distinction is important when considering performance and cost implications of the control technology to the base plant. The plant performance parameters effected by the application of these technologies are briefly discussed.

NO_x Emissions. The control efficiency of each technology is an input into the performance model. Using the control efficiency, the uncontrolled NO_x emission rate is modified to determine a new emission factor.

Unburned Carbon. Changes in the total unburned carbon in the base plant can include changes in the unburned carbon content of the flyash and bottom ash, both expressed as mass percent. Increases in any of these parameters as a result of NO_x combustion controls are given as inputs to the performance model. The total amount of unburned carbon (lb C/lb fuel) in the ash is the sum of the unburned carbon content in the flyash and the bottom ash.

CO Emissions. Operation of NO_x combustion control technologies can result in higher concentrations of CO emissions. The percentage increase in CO emissions is an input to the model. The model calculates the CO₂ content in the flue gas based on a mass balance that includes carbon in the fuel, unburned carbon in the bottom ash and flyash, and carbon emitted as CO. As a result, the flue gas composition will change with any increases in the CO emissions.

Boiler Efficiency. Increases in the ash carbon content and the CO concentration will result in an increase in carbon losses and a decrease in boiler efficiency. The boiler efficiency algorithm contained in the performance model calculates the effect of user-specified levels of unburned carbon, using the same method as in the IECM.¹⁴

Fuel Consumption. With a decrease in boiler efficiency, the plant manager can choose to accept the decrease in electricity output or increase the fuel consumption to compensate for the decrease in boiler performance. With a decrease in boiler efficiency, the plant heat rate increases. The increase in heat rate may be met by increasing the fuel flow rate into the furnace to maintain a constant plant output, or by accepting a derate on plant output for a given fuel flow rate.

Flyash Saleability. The impacts associated with the inability to sale flyash as a byproduct due to the unburned carbon increases in the flyash are reflected in an increase in the disposal cost.

NO_x Combustion Control Technologies Performance Models. The following is a discussion of how the decrease in boiler efficiency is addressed for each control technology. This discussion applies to both wall- and tangential-fired boilers. Also specified are the differences associated with retrofit at an existing plant versus installation of the control device at a new plant.

Low NO_x Burners. LNB retrofits can cause a decrease in the electricity output of the unit. This decrease results from more carbon loss due to increases in the flyash and bottom ash unburned carbon levels and CO emissions. The decrease in boiler efficiency is reflected in an increase in the net heat rate. With a higher net heat rate and a constant fuel flow rate, the electricity output is decreased. Alternatively, if the plant has sufficient excess capacity to increase the amount of gross megawatts of electricity generated, it may be possible to increase fuel flow and maintain the net electrical output at the same value as before the retrofit. However, in some cases additional capital costs may be required for pulverizer mill or other upgrades to accommodate the latter approach.

For the performance of the LNB technology at a new unit, the loss in electricity output due to the carbon losses will be addressed by increasing the gross capacity of the boiler. As a result, the fuel consumption will also be increased to meet the expected electricity output.

Low-NO_x Burners + Overfire Air. The LNB+OFA application's adverse effects to the base plant performance are similar those discussed for the individual LNB and OFA technologies. The performance algorithm described for the LNB technology can also be applied to the performance of this technology.

Cost Models

In this section, cost models for both the base plant and NO_x control technologies are presented.

Base Plant Cost Module. The algorithm for the base plant economics was adopted from the IECM. In the IECM, the power plant and the pollution control equipment are considered separate entities. Any power consumed by the control equipment is bought from the base plant. For the base plant, electricity or steam is required to run pulverizers, steam cycle pumps, flue gas fans, cooling system and miscellaneous other equipment. The internal utility consumption or auxiliary power requirement reduces the amount of electricity that the power plant can sell and increases the net plant heat rate.

For the base plant, operating and maintenance costs are associated with fuel use or non-fuel expenses. The fuel cost depends on the fuel consumption. The non-fuel cost typically depends on the size of the plant and the amount of nonfuel consumables required. Non-fuel costs are costs associated with labor, maintenance, overhead, and taxes. The total revenue requirement is obtained by annualizing the total capital cost and levelizing the total operating and maintenance costs.

NO_x Control Technology Cost Module. The following is a discussion of the cost algorithm for the cost estimation of the NO_x combustion control technologies. The cost algorithm addresses costs associated with adverse effects on the base plant performance as a result of operating the NO_x combustion control technologies. The total installed capital cost for each technology is an input to the cost model. Therefore, the cost model calculates: (1) total capital cost on a \$/kW basis; (2) the operating and maintenance costs associated with each technology; and (3) annualized total revenue requirements.

For the O&M costs, the model assumes that no significant costs are associated with material and labor, because such data are not publicly available or have been cited as insignificant.^{3,4,5} Specifically, it is anticipated that there is no significant increase in the operating and maintenance requirement for LNB or LNB+OFA than there would be for a conventional burner. Therefore, the O&M costs associated with each control technology are due primarily to the fuel or utility cost, and to the impact on flyash saleability. These O&M cost components will depend on the type of control technology being applied and whether the technology is applied at an existing facility or at a new plant. The methodology in determining the O&M costs for each technology can be applied to both wall- and tangential-fired boilers. This methodology is applied here to both LNB and LNB+OFA technologies.

In the retrofit case, in which the decrease in boiler efficiency is reflected in a decrease in the electricity output, the control device is charged a utility expense. The reduction in net electricity output is treated as a lost source of revenue that is charged to the control device. Therefore, the cost of the not meeting the original plant net output is absorbed by the control technology as a utility expense (M\$/yr).

In the new plant case, in which the plant size is adjusted to accommodate the boiler efficiency effects of the NO_x control technologies, the costs for the increase in plant size are reflected in the NO_x control capital costs. The O&M costs associated with the increase in fuel consumption are absorbed by the control technology.

MODEL APPLICATIONS

The new performance and cost models of combustion-based NO_x controls were applied in a series of case studies to illustrate key factors that should be addressed in evaluating the system impacts of such controls. The case studies developed here utilize recent data on performance and cost obtained from selected electric utilities.

Model Inputs

The following is a discussion on the model inputs.

Baseline Emissions. Analyses of the performance data given in Table 2 show that the baseline emissions for the wall-fired plants range from 0.55 to 1.43 lb/10⁶ BTU, with an average emission rate of 0.99 lb/10⁶ BTU (Table 3). The range and average are comparable to the NESCAUM data previously discussed.

The baseline emissions for the tangential-fired units given in Tables 1 and 2 range from 0.53 to 0.73 lb/10⁶ BTU, with a corresponding average of 0.62 lb/10⁶ BTU (Table 3). The range and average are comparable to the NESCAUM data previously discussed. Thus, the baseline emissions for tangential-fired boilers in both the utility and publicly reported data sets have lower average and narrower ranges than the wall-fired boilers. The wall-fired units' average emission rate is approximately 37 percent higher than the tangential-fired units in the utility survey. This is consistent with findings in previous studies.^{3,4,5}

Retrofit LNB Technology Controlled Emissions. For the LNB technology, retrofit performance data were available for the tangential-fired units. No performance data were available for LNB retrofit in wall-fired boilers. The performance data for tangential-fired units included data for the LNCFS I technology. Of the 17 tangential-fired units, retrofit LNCFS I data were available for seven. The controlled emission rates ranged from 0.40 to 0.45 lb/10⁶ BTU, with an average of 0.43 lb/10⁶ BTU corresponding to a reduction efficiency of 31 percent. The controlled emission rate average is consistent

with long-term test results of several tangential-fired units' emission rates of 0.41 lb/10⁶ BTU after retrofit of the LNCFS I technology as reported in previous studies.⁴

Retrofit LNB+OFA Technology Controlled Emissions. Performance data given in Table 2 for the LNB+OFA technology were available for eight wall-fired units and two tangential-fired units. The controlled emission rates for the wall-fired units ranged from 0.32 to 0.51 lb/10⁶ BTU, with an average controlled emission rate of 0.39 lb/10⁶ BTU. Compared to the average baseline emission rate, the reduction efficiency is approximately 61 percent. This value is consistent with the efficiency ranges reported in the Alternative Control Study⁴ of 60 to 70 percent, and the NESCAUM study of 40 to 60 percent.³ These data are comprised of guaranteed data and not actual test data. Once these units are retrofitted and testing is conducted, the data set will be revisited and reanalyzed.

For the two tangential-fired units retrofitted with the LNB+OFA technology (LNCFS II), the reduction in NO_x is guaranteed to be 64 percent for Site I and 30 percent for Site J. The significant difference in the LNB+OFA technology for the two units is due to the difference in plant size and performance characteristics. In addition, these efficiencies are guaranteed reductions provided by the vendor and not obtained from actual testing. The data will be re-evaluated once data are obtained from actual testing of the retrofits.

Retrofit LNB Costs. A summary of the performance and cost model outputs are provided in Tables 5 and 6. Cost data for the LNB retrofit were available for four wall-fired units.

Retrofit LNB+OFA Costs. Capital cost data for the retrofit LNB+OFA technology were available for eight wall-fired units and two tangential-fired units. Table 6 summarizes the capital cost data used as the model inputs.

Unburned Carbon Levels. For all the tangential-fired units at which LNCFS I was applied, given in Table 1, unburned carbon levels in the flyash increased by four percentage points or greater. Two of the wall-fired units, Site A and Site F, had increases in the flyash unburned carbon level of 7.4 and 2.6 percentage points, respectively. The rest of the wall-fired units retrofitted with the LNB+OFA technology had guarantees which included no increases in the unburned carbon level in the flyash.

Other Model Inputs. The coal used for all the model runs in this study was provided by a power utility. The higher heating value is 12,500 BTU/lb. The ultimate analysis on a dry basis is given below in weight percent.

<u>Component</u>	<u>Weight Percent</u>
Ash	10.70
Sulfur	1.07
Carbon	74.91
Hydrogen	4.92
Oxygen	7.00
Nitrogen	1.40
Moisture	6.50

Model applications were conducted for Sites K, L, R, and X using the input assumptions summarized in Table 4. For Sites A through J, for which no performance data other than plant size were available, a set of assumed performance inputs were applied. These inputs are also summarized in Table 4 in the row labeled "generic". For the cost module, the total capital cost in millions of dollars for the control technology was an input. These values are summarized in Tables 5 and 6, which also report model output results.

Cost estimates were obtained in 1995 dollars with a levelization factor of 1.00 and a capital recovery factor of 10 percent. The opportunity cost of lost electrical power sales was assumed to be 64 mills/kWh and the fuel cost was \$34/ton.

Model Outputs

Performance cost model results for retrofit LNB and LNB+OFA are reported here.

Retrofit LNB Costs. The model results for estimated capital cost including direct and indirect costs ranged from \$2.3/kW to \$10.3/kW. The average value of the estimated costs for these plants is \$6.2/kW. This range of cost values for these LNB retrofits is low compared to values presented in previous studies, which varied from \$15.1/kW to \$29.0/kW when adjusted to 1995 dollars.^{3,7,11} The difference in the modeled costs estimate compared to the values from the previous studies may be due to the fact that the retrofits at these modeled units did not require major modifications. Most of the burners were modified rather than replaced.

An increase of four percentage points in UBC was assumed for each unit, because the unburned carbon data were provided as either increasing by four percentage points or by greater than four percentage points, without specifications as to how much greater. The utility cost for the increase in fuel consumption was then combined with the annualized capital cost to determine the total revenue requirement (TRR) in mills/kWh. The average TRR for these LNB retrofitted tangential-fired boilers was 0.35 mills/kWh. The average TRR for the utility cost is 0.16 mills/kWh. Thus, the loss of plant output due unburned carbon increases is shown in this case to be a substantial contributor to the total costs of the NO_x control.

The Acid Rain Division study assumed O&M costs of 0.04 mills/kWh associated with the increase in unburned carbon levels in LNB retrofitted units.⁴ This O&M cost is much lower than the estimated utility cost. This is due to the fact that: (1) a lower boiler efficiency loss of 0.27 percentage points was assumed for all units in the ARD study; and (2) ARD evaluated the effects of an increase in fuel consumption, whereas here we are evaluating the effect of a loss of electrical revenues. An increase in UBC of four percentage points results in a boiler efficiency loss of 0.36 percentage points, which is 25 percent higher than the loss assumed in the ARD study. The costs calculated for loss of electrical output at constant fuel flow assume that the plant would be dispatched at full load. At partial loads, there would be no loss in revenues, but there would be an increase in fuel cost. Thus, our estimate is an upper bound. The ARD estimate may be representative of a lower bound.

Retrofit LNB+OFA Costs. The range of capital cost results for the wall-fired units is \$15.2/kW to \$28.3/kW with an average of \$19.3/kW. These values are low compared to the ranges given in previous studies,^{3,4} which are \$21/kW to \$42/kW in 1995 dollars. For the tangential-fired units, the cost for Site I is \$15.8/kW while the cost for Site J is \$35.1/kW. The cost estimate for Site J is higher than capital cost data reported in previous studies, which range from \$12/kW to \$24.2/kW when adjusted to 1995 dollars.¹¹

For the retrofit LNB+OFA technology in wall-fired boilers, only two estimates of the increase in unburned carbon in the flyash were given. These estimates were provided for Sites A and F as guarantees from the LNB+OFA technology vendors. The percentage point increases of 2.6 and 7.4 are consistent with increases reported in the open literature.^{3,4} Table 6 includes the utility cost associated with those unburned carbon level increases. The average contributor to the TRR due to the unburned carbon from these two units is 0.22 mills/kWh.

Alternative Methods for Cost Implications of Unburned Carbon. To evaluate the sensitivity of NO_x controls to assumptions regarding how the boiler efficiency impacts of changes in unburned carbon might be handled at various plants, we considered an alternative case study. Instead of penalizing a plant for a derate at a specified fuel flow rate, a case was considered in which fuel flow was increased to maintain plant output at its pre-retrofit level. This analysis assumed that no major modifications were required to accommodate an increase in the gross plant output. Site A was selected since it had the largest impact from unburned carbon. If the fuel consumption is increased to meet the required electricity output, the additional O&M cost for fuel would be 0.10 mills/kWh. This is almost one-third of the utility cost estimated for this unit using the default cost procedure. Therefore, the levelized costs associated with the decrease in boiler efficiency can vary significantly depending upon the method by which these costs are estimated. In extreme cases, these costs are a significant fraction of the total annualized costs for the combustion NO_x control retrofits.

Flyash Saleability. Substantial increased levels of unburned carbon in the flyash can lead to the inability to sell the flyash as a byproduct. Many power plants are able to sell a portion of their flyash and hence avoid some disposal costs. Flyash containing unburned carbon levels higher than the levels specified by users of byproduct flyash, such as four percent, can no longer be sold and must be disposed. To study the cost impacts associated with the disposal of the flyash, as opposed to selling it as a byproduct, plant performance data for 15 plants from the model outputs were used to estimate the O&M costs associated with this issue. The data include the hourly flyash production, annual electricity output and operating hours. The value of the flyash as a byproduct was set at a revenue of \$5/ton, while the cost to dispose of the flyash is assumed to be \$15/ton. The potential inability to sell flyash as a byproduct was assessed by calculating loss in the byproduct revenues for varying percentages of the total flyash stream that would have otherwise been sold.

This flyash saleability analysis was conducted for 17 units assuming that 25 percent of the total ash is flyash and 40 percent of the total flyash is sold as byproduct. The analysis shows that the average cost of disposing the flyash without selling any of the flyash is 0.17 mills/kWh compared to 0.10 mills/kWh when 40 percent of the flyash is sold, a difference of 0.07 mills/kWh. Figure 1 depicts the loss revenue associated with the inability to sell the flyash due to the unburned carbon levels for Site K. For example, if the unit is typically able to sell 40 percent of its flyash as a byproduct, then not selling the flyash would result in a loss of 0.09 mills/kWh. Therefore, the cost impacts associated with the inability to sell flyash due to excessive increases in UBC can be significant compared to costs of NO_x control. Increase in the disposal cost due to the unsaleability of the flyash may result in high O&M costs. Such costs should be charged to the NO_x control technology. The sensitivity analysis here indicates that the loss of flyash revenues can range from 15 to 55 percent of the TRR for the NO_x control equipment itself. Therefore, the costing methodologies should consider the flyash saleability issue when trying to determine the operating and maintenance costs associated with the operation of the technology.

FUTURE WORK

Once more performance and cost data are collected, the following work will be conducted to enhance the performance and cost models:

1. Further develop performance and cost algorithms for LNB and LNB+OFA technologies for different levels of retrofit at wall- and tangential-fired boilers including analysis of data sets to determine whether it is feasible to develop a regression model of capital cost versus plant size.
2. Apply the cost and performance algorithms to new case studies to evaluate the performance, emissions, and cost of NO_x controls.
3. Characterize variability and uncertainty in the model predictions.

CONCLUSIONS

Retrofit of LNB and LNB+OFA technologies at wall- and tangential-fired boilers can result in significant impacts to the base plant performance. These performance impacts are in the form of increased unburned carbon levels in the flyash. This leads to potentially two significant impacts: (1) decrease in plant efficiency; and (2) a potential loss of flyash byproduct revenues.

The variation in capital cost for the control technologies shows that the capital cost depends upon the extent of modifications and the type of boiler being retrofitted.

Alternative approaches to quantifying the effect of unburned carbon on plant operating costs provide bounding estimates for NO_x control costs. These alternatives include derating plant output versus increasing fuel flow. Flyash saleability is also an important issue to consider when attempting to estimate the costs associated with the application of NO_x combustion control technologies. The inability to sell the flyash as a byproduct can lead to substantial disposal costs.

ACKNOWLEDGMENTS

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Table 1. Retrofit LNB Performance Data for Tangential-fired Boilers

Plant/Unit	Boiler Size (MW)	Baseline Emissions (lb/10 ⁶ BTU)	Controlled Emissions (lb/10 ⁶ BTU)	NO _x Reduction (%)
Site K	165	0.73	0.45	38
Site L	270	0.67	0.45	33
Site R	562	0.60	0.41	32
Site W	385	0.57	0.45	21
Site X	660	0.59	0.45	24
Site Y	94	0.65	0.40	38
Site Z	133	0.65	0.40	38

Table 2. Retrofit LNB+OFA Performance Data

Plant/Unit	Boiler Size (MW)	Boiler Type ^a	Baseline Emissions (lb/10 ⁶ BTU)	Controlled Emissions ^b (lb/10 ⁶ BTU)	NO _x Reduction ^b (%)
Site A	390	W	1.32	0.38	71
Site B	750	W	0.62	0.32	48
Site C	200	W	1.03	0.41	60
Site D	257	W	0.92	0.33	64
Site E	194	W	0.89	0.36	60
Site F	710	W	0.55	0.33	40
Site G	416	W	1.17	0.51	56
Site H	715	W	1.43	0.44	69
Site I	390	T	1.32	0.38	71
Site J	715	T	1.43	0.44	69

^aT=Tangential-Fired, W=Wall-Fired^bBased upon vendor guaranteesTable 3. Statistical Summary of NO_x Control Effectiveness for Wall- and Tangential-Fired Boilers^a

Statistical Data	Wall Baseline Emissions (lb/10 ⁶ BTU)	Wall LNB+OFA Controlled Emissions (lb/10 ⁶ BTU)	Wall LNB+OFA Reduction Efficiency (%)	Tangential Baseline Emissions (lb/10 ⁶ BTU)	Tangential LNB Controlled Emissions (lb/10 ⁶ BTU)	Tangential LNB Reduction Efficiency (%)
Mean	0.99	0.39	59	0.62	0.43	32
Standard Deviation	0.31	0.07	10	0.06	0.03	7
Minimum	0.55	0.32	40	0.53	0.40	21
Maximum	1.43	0.51	71	0.73	0.45	38
Count	8	8	8	17	7	7

^aSummary for wall-fired boilers is based upon data in Table 1. Summary for tangential-fired boilers is based upon data in Table 2 combined with additional utility-reported data for baseline emission.

Table 4. Performance Model Inputs

Unit ^a	Gross Capacity (MW)	Net Capacity (MW)	Capacity Factor (%)	Net Heat Rate (BTU/kWh)	Excess Air (%)
Site K	165	158	30	10,337	14.3
Site L	270	259	35	9,946	14.3
Site R	562	540	40	9,870	14.3
Site X	660	635	70	8,970	14.3
Generic unit gross capacity			75	9,400	14.3

^aGeneric assumptions were applied to case studies of units A through J due to the absence of site-specific data.

Table 5. Selected Performance and Cost Model Inputs and Outputs for Retrofit LNB Technology

Unit	Model Inputs ^a			Model Outputs ^b			
	MW	Boiler Type	TCC (\$M)	Heat Rate Change (BTU/kWh)	TCC (\$/kW)	Utility (mills/kWh)	TRR (mills/kWh)
Site K	165	T	1.25	44	8.1	0.19	0.39
Site L	270	T	2.50	42	10.3	0.14	0.30
Site R	562	T	2.20	41	4.2	0.19	0.31
Site X	660	T	1.30	37	2.3	0.13	0.17

^aMW = Plant capacity in megawatts; Boiler Type: T=tangential-fired, W=wall-fired; TCC=total capital cost including indirect costs.

^bTCC=total capital cost; Utility=cost for loss in electricity output due to unburned carbon losses; TRR=total revenue requirement for NO_x control.

Table 6. Selected Performance and Cost Model Inputs and Outputs for Retrofit LNB+OFA Technology

Unit	Model Inputs ^a			Model Outputs ^b			
	MW	Boiler Type	TCC (\$M)	Heat Rate Change (BTU/kWh)	TCC (\$/kW)	Utility (mills/kWh)	TRR (mills/kWh)
Site A	390	W	5.69	70	15.6	0.35	0.50
Site B	750	W	6.60	0	15.8	0	0.15
Site C	200	W	4.43	0	23.5	0	0.37
Site D	257	W	6.85	0	28.3	0	0.45
Site E	194	W	4.19	0	22.9	0	0.36
Site F	710	W	11.04	23	16.6	0.08	0.34
Site G	416	W	5.94	0	15.2	0	0.24
Site H	715	W	11.04	0	16.4	0	0.26
Site I	675	T	10.20	0	15.8	0	0.25
Site J	175	T	5.78	0	35.1	0	0.55

^aMW = Plant capacity in megawatts; Boiler Type: T=tangential-fired, W=wall-fired; TCC=total capital cost including indirect costs.

^bTCC=total capital cost; Utility=cost for loss in electricity output due to unburned carbon losses; TRR=total revenue requirement for NO_x control.

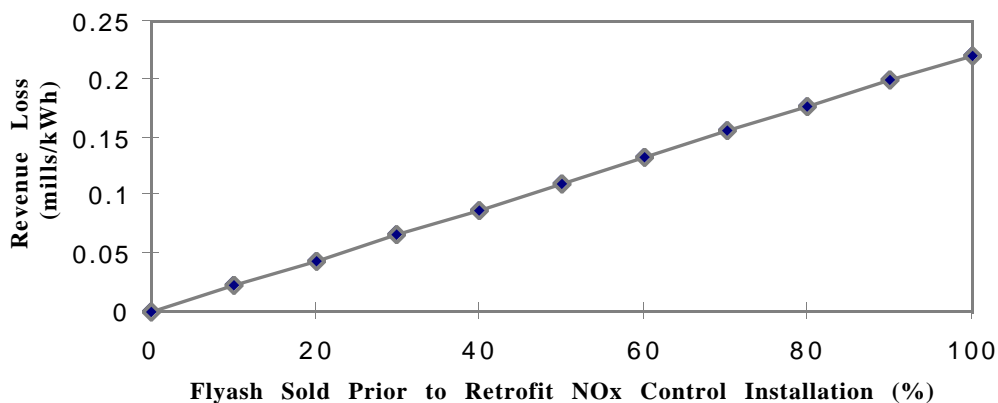


Figure 1. Sensitivity Analysis of Revenue Loss Associated with Inability to Sell Flyash.

Total Capital Investment calculations

CPP Halsey Estimate (including installation labor, materials and subcontracting)	DEQ Estimate (leaving labor, materials and subcontracting to a later step)	
\$128,700	\$128,700	reported purchased equipment cost for LNB FGR on 31 MMBtu/hr boiler
1	1	purchased equipment cost
3.6		labor multiplier
1.3		materials multiplier
2		subcontracting multiplier
7.9	1	sum of multipliers
\$1,016,730	\$128,700	total assumed cost
31	31	boiler size for quote (MMBtu/hr)
236	236	boiler size for this estimate (MMBtu/hr)
7.61	7.61	ratio of boiler sizes
0.6	0.6	
3.380	3.380	ratio of boiler sizes^0.6, the "six tenths rule"
\$3,436,654	\$435,020	estimated LNB/FGR cost for 236 MMBtu/hr boiler

The EPA control cost manual doesn't have an LNB chapter. Here are installation cost calculations from the cost manual for other technologies:

PEC includes equipment cost + sales tax + freight.

Direct and Indirect install costs as ratio of PEC including instrumentation, sales taxes and freight.

TCI = (1+CF)*(DCF+ICF)*PEC

	Direct install cost factor (DCF)	Install Cost	Contingency Factor (CF)	Overall Factor [(1+CF)*(DCF+ICF)]	
carbon adsorber	1.3	0.28	10%	1.738	Contingency between 5 and 15%
refrigerated condenser		1.15		1.15	TCI including direct, indirect and contingency = 1.15 times PEC
flare	1.57	0.32	10%	2.079	Contingency between 5 and 15%
thermal oxidizers	1.3	0.28	10%	1.738	Contingency between 5 and 15%
SNCR		1.3		1.3	TCI including direct, indirect and contingency = 1.3 times (SNCR cost + Balance of Plant cost)
SCR		costs are technology-specific			
				1.601	average

Generally, vendor quotes are “F.O.B.” (free-on-board) for the vendor, meaning that no taxes, freight, or other charges are included. For these equipment, the analyst must take care to identify and include the cost of transportation, taxes, and other necessary charges in the TCI (see Figure 2.1). The costs of freight, instrumentation, and sales tax are calculated differently from the direct and indirect installation costs. These items are developed by multiplying the base equipment cost (F.O.B. the vendor) by an industry-accepted factor. Unlike other estimating factors that differ from system to system, installation factors are essentially equal for all control systems. [10] Table 2.4, below, displays values for these factors.

Table 2.4: Cost Ranges for Freight, Sales Tax, and Instrumentation

% of Total Equipment Cost, FOB		
Cost	Range	Typical
Freight	0.01 - 0.10	0.05
Sales Tax	0 - 0.08	0.03
Instrumentation	0.05- 0.30	0.10

		Current SO2 PSEL (tons/year)					SO2 PSEL after replacing #6 with ULSD (tons/year)					SO2 PSEL reduction	
Emissions Unit	ID	Natural Gas	#6 fuel oil	Black Liquor Solids (BLS)	Lime (CaO)	Non-condensable gases (NCG)	Natural Gas	ULSD	#6 fuel oil	Black Liquor Solids (BLS)	Lime (CaO)	Non-condensable gases (NCG)	
Recovery Furnace	RFEU	0.2	165	288.1			0.2	0.1			288.1		
Smelt Dissolving Tank	SDTEU			0.1						0.1			
Lime Kiln	LKEU		2.2		0.5	65.7		0.0			0.5	65.7	
Power Boiler #1	PB1EU	0.7	68.8			18.6	0.7	0.0				18.6	
Power Boiler #2	PB2EU	0.2					0.2						
		1.1	236	288.2	0.5	84.3	1.1	0.2	0	288.2	0.5	84.3	
		610.1					374					236	

2020 Permit Renewal

kg/y

Emission Unit	Device or Process	Annual Production Rate	Emissions Factor	Emissions (tons/year)
RFEU	Recovery Furnace	514,380 # BLS	1.119 #/T BLS	576.1 (2012 CEMS)
	No. 4 residual oil	1295.84 gal/min	2.15 #/M gal	278.52 (2012 CEMS)
	Natural gas re-propane	260 MMBtu	1.7 #/MMBtu	442.0
SDTEU	Smelt Dissolving Tank	514,380 T BLS	0.0002 #/T BLS	0.103 (2012 CEMS)
LKEU	Lime Kiln	9.125 T CaO	0.011 #/T CaO	0.101 (2012 CEMS)
	No. 4 residual oil	1000 M gal/min	1.44 #/M gal	1440.0
	NCG incineration	8424 hours	15.6 #/hr	131.6
PB1EU	Power Boiler #1	160 M gal/min	2.15 #/M gal	344.0 (2012 CEMS)
	No. 4 residual oil	875 MMBtu	1.7 #/MMBtu	1487.5 (2012 CEMS)
	Natural gas	315 MMBtu	1.7 #/MMBtu	535.5 (2012 CEMS)
PB2EU	Power Boiler #2	421 MMBtu	1.7 #/MMBtu	715.7 (2012 CEMS)

[The source specific SO2 PSEL will be set at 610 kg/year]

	Sulfur Content	EF (lb/1000 gal/percent S)	EF (lb/1000 gal)	MMBTU/1000 gal	lb/MMBtu	ratio
#6	0.0175	157	274.75	150	4312.5	
ULSD	1.5E-05	142	0.213	140	29.82	0.00072

control efficiency

<https://www3.epa.gov/ttn/chief/ap42/ch01/final/c01s03.pdf>

AP-42

Table 1.3-1. CRITERIA POLLUTANT EMISSION FACTORS FOR FUEL OIL COMBUSTION*

Firing Configuration (MW)	NO _x		SO ₂		NO ₂		CO ^b		PM ^c	
	Factor (lb/10 ⁶ gal)	EMF10 (lb/10 ⁶ gal)	Factor (lb/10 ⁶ gal)	EMF10 (lb/10 ⁶ gal)	Factor (lb/10 ⁶ gal)	EMF10 (lb/10 ⁶ gal)	Factor (lb/10 ⁶ gal)	EMF10 (lb/10 ⁶ gal)	Factor (lb/10 ⁶ gal)	EMF10 (lb/10 ⁶ gal)
Residue > 100 Million Btu/hr										
No. 4 fuel, normal firing, 100-1000 Btu/hr	1570	A	5.76	C	47	A	5	A	4.080x10 ⁻²	A
No. 4 fuel, normal firing, 1000-10,000 Btu/hr	1570	A	5.76	C	40	B	3	A	4.080x10 ⁻²	A
No. 4 fuel, normal firing, 10,000-100,000 Btu/hr	1570	A	5.76	C	33	A	3	A	4.080x10 ⁻²	A
No. 4 fuel, normal firing, 100,000-1,000,000 Btu/hr	1570	A	5.76	C	26	B	3	A	4.080x10 ⁻²	A
No. 4 fuel, normal firing, 1,000,000-10,000,000 Btu/hr	1570	A	5.76	C	47	B	3	A	40	B
No. 4 fuel, normal firing, 10,000,000-100,000,000 Btu/hr	1570	A	5.76	C	33	B	3	A	10	B
No. 4 fuel, normal firing, 100,000,000-1,000,000,000 Btu/hr	1570	A	5.76	C	47	B	3	A	7	B
No. 4 fuel, normal firing, 1,000,000,000-10,000,000,000 Btu/hr	1570	A	5.76	C	33	B	3	A	7	B
No. 4 fuel, normal firing, 10,000,000,000-100,000,000,000 Btu/hr	1570	A	5.76	C	33	B	3	A	2	A
No. 4 fuel, normal firing, 100,000,000,000-1,000,000,000,000 Btu/hr	1570	A	5.76	C	33	B	3	A	2	A

- * No comment from the 100,000 gal to 100,000,000 gal range. See 1.3-1, Table 1.3-1, Section 1.3-1.1.
- ^a Reference is 1.5E-05 #/lb. It indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then 0.1570 = 1.570 x 10⁻².
- ^b Reference is 1.5E-05 #/lb. It indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then 0.1570 = 1.570 x 10⁻².
- ^c Reference is 1.5E-05 #/lb. It indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then 0.1570 = 1.570 x 10⁻².
- ^d Reference is 1.5E-05 #/lb. It indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then 0.1570 = 1.570 x 10⁻².
- ^e Reference is 1.5E-05 #/lb. It indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then 0.1570 = 1.570 x 10⁻².
- ^f Reference is 1.5E-05 #/lb. It indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then 0.1570 = 1.570 x 10⁻².
- ^g Reference is 1.5E-05 #/lb. It indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then 0.1570 = 1.570 x 10⁻².
- ^h Reference is 1.5E-05 #/lb. It indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then 0.1570 = 1.570 x 10⁻².
- ⁱ Reference is 1.5E-05 #/lb. It indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then 0.1570 = 1.570 x 10⁻².
- ^j Reference is 1.5E-05 #/lb. It indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then 0.1570 = 1.570 x 10⁻².
- ^k Reference is 1.5E-05 #/lb. It indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then 0.1570 = 1.570 x 10⁻².
- ^l Reference is 1.5E-05 #/lb. It indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then 0.1570 = 1.570 x 10⁻².
- ^m Reference is 1.5E-05 #/lb. It indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then 0.1570 = 1.570 x 10⁻².
- ⁿ Reference is 1.5E-05 #/lb. It indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then 0.1570 = 1.570 x 10⁻².
- ^o Reference is 1.5E-05 #/lb. It indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then 0.1570 = 1.570 x 10⁻².
- ^p Reference is 1.5E-05 #/lb. It indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then 0.1570 = 1.570 x 10⁻².
- ^q Reference is 1.5E-05 #/lb. It indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then 0.1570 = 1.570 x 10⁻².
- ^r Reference is 1.5E-05 #/lb. It indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then 0.1570 = 1.570 x 10⁻².
- ^s Reference is 1.5E-05 #/lb. It indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then 0.1570 = 1.570 x 10⁻².
- ^t Reference is 1.5E-05 #/lb. It indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then 0.1570 = 1.570 x 10⁻².
- ^u Reference is 1.5E-05 #/lb. It indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then 0.1570 = 1.570 x 10⁻².
- ^v Reference is 1.5E-05 #/lb. It indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then 0.1570 = 1.570 x 10⁻².
- ^w Reference is 1.5E-05 #/lb. It indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then 0.1570 = 1.570 x 10⁻².
- ^x Reference is 1.5E-05 #/lb. It indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then 0.1570 = 1.570 x 10⁻².
- ^y Reference is 1.5E-05 #/lb. It indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then 0.1570 = 1.570 x 10⁻².
- ^z Reference is 1.5E-05 #/lb. It indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then 0.1570 = 1.570 x 10⁻².

Tables 1.3-1 and 1.3-2 present emission factors for uncontrolled criteria pollutants from fuel oil combustion. Tables in this section present emission factors on a volume basis (lb/10⁶ gal). To convert to an energy basis (lb/MMBtu), divide by a heating value of 150 MMBtu/10⁶ gal for Nos. 4, 5, 6, and residual fuel oil, and 140 MMBtu/10⁶ gal for No. 2 and distillate fuel oil. Table 1.3-2 presents emissions

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