APPENDIX G-2

Florida Department of Environmental Protection
Division of Air Resource Management

Regional Haze SIP – Reasonable Progress Analysis
Facilities Response Letters

TABLE OF CONTENTS

DUKE ENERGY

Wayne Toms
Station Manager,
Crystal River North & Fuel Operations

August 20, 2020

Mr. Jeff Koerner
Division of Air Resource Management
Florida Department of Environmental Protection
2600 Blair Stone Road, MS #5505
Tallahassee, FL 32399-2000

RE: Regional Haze Rule – Reasonable Progress Analysis
Crystal River Power Plant – Facility I.D. No. 0170004

Dear Mr. Koerner:

In response to the Department's June 22, 2020 request to provide information for the following Crystal River Power Plant (Crystal River) units:

- EU003 – Fossil Fuel Steam Generating Unit 5
- EU004 – Fossil Fuel Steam Generating Unit 4
- EU042 – Citrus Combined Cycle Station Unit 2A
- EU043 – Citrus Combined Cycle Station Unit 2B
- EU051 – Citrus Combined Cycle Station Unit 1A
- EU052 – Citrus Combined Cycle Station Unit 1B

please see below the analysis demonstrating that all these units meet EPA's "effectively-controlled unit" exemption.

Facility Description

The Crystal River facility consists of two coal fired boilers (Units 4 and 5), four combined cycle combustion turbines (Citrus Units 1A, 1B, 2A, and 2B), and miscellaneous small emissions sources.

Unit 4 and Unit 5 are fossil fuel-fired electric utility steam generators, each consisting of a pulverized coal, dry bottom, wall-fired boiler nominally rated at 760 megawatts (MW). Air pollution control equipment includes: low-NOX burners; Selective Catalytic Reduction (SCR) systems; Flue Gas Desulfurization (FGD) systems; Acid Mist Mitigation (AMM) systems; and Electro-static Precipitators (ESP). Units 4 and 5 share a common 550-foot tall chimney with separate internal stack liners with continuous emissions monitoring systems (CEMS) on each stack liner.

The Citrus Combined Cycle units consists of two power blocks. Each power block consists of two natural gas-fired Mitsubishi Power Systems 501GAC combustion turbine-electric generators (CTGs), one steam turbine-electric generator, two heat recovery steam generators (HRSGs) equipped with natural gas-fired duct burners (DB) and selective catalytic reduction (SCR) systems. Emissions from these units are controlled by use of clean fuels, dry low-NOX (DLN) burners, and SCR systems. Each HRSG stack is equipped with a continuous emissions monitoring system (CEMS) to measure and record NOx and carbon dioxide (CO_2).

Regional Haze Requirements
As described in the Department's request, modeling analysis indicated that Crystal River could potentially influence visibility impairment in nearby Class I areas, primarily with respect to SO_2. As such, FDEP is requesting information for the Crystal River units noted above to determine if additional SO_2 emission control and reductions are cost-effective for this implementation period. In accordance with EPA Guidance,[1] states should require such units to submit a four-factor analysis of feasible SO_2 control measures to determine whether additional reductions are cost-effective, but can exempt such units if they are determined to already be "effectively controlled" under an enforceable requirement. The following are two of the bullet points found in the list of options provided in Section II.B.3.f of EPA's Guidance for when it is reasonable for a state to determine that a unit is already "effectively controlled."

- For the purpose of SO_2 control measures, an EGU that has add-on flue gas desulfurization (FGD) and that meets the applicable alternative SO_2 emission limit of the 2012 Mercury Air Toxics Standards (MATS) rule for power plants. The two limits in the rule (0.2 lb/MMBtu for coal-fired EGUs or 0.3 lb/MMBtu for EGUs fired with oil-derived solid fuel) are low enough that it is unlikely that an analysis of control measures for a source already equipped with a scrubber and meeting one of these limits would conclude that even more stringent control of SO_2 is necessary to make reasonable progress.

- For the purpose of SO_2 and PM control measures, fuel combustion units that combust only pipeline natural gas per enforceable requirements. Add-on SO_2 controls or more stringent limits on the sulfur content of the natural gas would very likely not be determined to be necessary to make reasonable progress.

The first bullet point is applicable to Crystal River Units 4 and 5, as noted by the existing permit conditions in the following section. However, since the SO_2 limitation in the MATS rule is based on its use as a surrogate for the HCl limitation requirement, and not specifically required to be used in the current permit condition to limit SO_2 emissions, a permit modification will be requested to incorporate the MATS equivalent SO_2 standard as a permit requirement.

The second bullet point is applicable to Citrus Units 1A, 1B, 2A, and 2B. These units only combust pipeline natural gas, as noted in the following permit condition section.

Permit Conditions

Crystal River Units 4 and 5 meet EPA's exemption criteria because they utilize an add-on FGD system and comply with the MATS SO_2 limit of 0.20. Permit conditions A.5.c and A.15, as found in Section III of Permit No. 0170004-058-AV, as noted below address these items.

> **A.5.c.** *Flue Gas Desulfurization (FGD) Equipment.* The permittee is required to operate and maintain wet flue gas desulfurization systems to reduce SO_2 and other acid gas emissions in order to comply with the emissions standards in **Specific Conditions A.7, A.11, A.15,** and **A16.** A limestone slurry shall be injected into the FGD absorbers at the design feed rate of approximately 352 gallons per minute (gpm).
>
> **A.15.** Hydrogen Chloride (HCl) Emissions – MATS. As determined by EPA Method 26, or EPA Method 26 as modified in accordance with DARM-OGC-20, emissions of HCl shall not exceed either 0.0020 lb/MMBtu heat input or 0.020 lb/MWh on an individual unit basis. As an allowed alternative, these units may comply with the HCl limit through participation in a multi-unit averaging plan on a 30-day rolling average basis, following the requirements of 40 CFR 63.10009. In lieu of an HCl emissions limit, the permittee may choose to meet an alternate SO_2 emissions limit of either 0.20 lb/MMBtu heat input or 1.5 lb/MWh.

Citrus Combined Cycle Units 1A, 1B, 2A, and 2B meet EPA's exemption because they combust only pipeline natural gas, as noted in permit condition E.3 of Section III of Permit No. 0170004-058-AV.

> **E.3.** Methods of Operation – Fuels. The CTGs shall fire only natural gas as a fuel, which shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet (gr/100 SCF) of natural gas.

Conclusion

Based on the information provided, all the applicable Crystal River units meet EPA's "effectively-controlled" exemption from the obligation to submit any further analysis of additional SO_2 emission controls for this Regional Haze implementation period.

Please do not hesitate to contact Jamie Hunter at Jamie.Hunter@duke-energy.com if you have any questions.

Sincerely,

Wayne Toms

C. Wayne Toms
Plant Manager

Via Email: Jeff.Koerner@dep.state.fl.us

Georgia-Pacific

Regional Haze Rule – Reasonable Progress Analysis

for

Foley Cellulose LLC
Facility ID No. 1230001
One Buckeye Drive
Perry, Taylor County, Florida

Submitted to the
Florida Department of Environmental Protection

October 2020

TABLE OF CONTENTS

1. EXECUTIVE SUMMARY

Foley Cellulose LLC, a wholly owned subsidiary of Georgia-Pacific LLC (GP), owns and operates a softwood Kraft pulp mill (referred to as the "Foley Mill" or the "Mill") located in Perry, Taylor County, Florida that manufacturers bleached market, fluff, and specialty dissolving cellulose pulp. The Foley Mill is a major source with respect to the Title V operating permit program and operates under a Title V Major Source Operating Permit (No. 1230001-087-AV), most recently issued by the Florida Department of Environmental Protection (FDEP) on January 6, 2020.

On June 22, 2020, FDEP issued a letter to the Foley Mill requesting an analysis for the following emission units demonstrating that the unit is already effectively-controlled under an enforceable requirement or that the Mill provide a reasonable progress four-factor analysis (FFA) for sulfur dioxide (SO_2) :

- EU002 – No. 1 Power Boiler,
- EU004 – No. 1 Bark Boiler,
- EU006 – No. 2 Recovery Furnace,
- EU007 – No. 3 Recovery Furnace,
- EU011 – No. 4 Recovery Furnace, and
- EU019 – No. 2 Bark Boiler.

The four-factor analyses included in this submittal follow the August 20, 2019 United States Environmental Protection Agency's (EPA) guidance[1] to address regional haze further progress by reviewing:

- The cost of compliance,
- Energy and non-air quality impacts of compliance,
- The time necessary for compliance, and
- Remaining useful life of existing affected sources.

1.1. SOURCE INFORMATION

Details on the sources considered in the analysis are detailed below and summarized in Table 1-1.

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

Table 1-1 Source Summary

Unit ID	Name	3-Year Average SO_2 Emissions (tpy)	Fuels Fired	Controls
EU002	No. 1 Power Boiler	81	Natural Gas, No. 6 FO, Tall Oil, Used Oil, NCGs	TRS pre-scrubber
EU004	No. 1 Bark Boiler	188	Natural Gas, No. 6 FO, Tall Oil, Used Oil, Wood, NCGs	TRS pre-scrubber, Scrubber
EU006	No. 2 Recovery Furnace	307	BLS, No. 6 FO, Tall Oil, Used Oil, No. 2 FO, Natural Gas	ESP
EU007	No. 3 Recovery Furnace	573	BLS, No. 6 FO, Tall Oil, Used Oil, No. 2 FO, Natural Gas	ESP
EU011	No. 4 Recovery Furnace	618	BLS, No. 6 FO, Tall Oil, Used Oil, No. 2 FO, Natural Gas	ESP
EU019	No. 2 Bark Boiler	3	Natural Gas, No. 6 FO, Tall Oil, Used Oil, Wood	Scrubbers

The sources to be evaluated consist of boilers (EUs 002, 004, 019) and Recovery Furnaces (EUs 006, 007, 011), and the analyses are grouped into these two categories.

The No. 1 Power Boiler (EU 002) was built by Babcock and Wilcox in 1953. The boiler fires natural gas, No. 6 fuel oil, tall oil, and on-specification used oil. The No. 1 Power Boiler serves as the secondary control device for low volume, high concentration (LVHC) non-condensable gases (NCGs) up to 2,800 hours per year. The NCGs are routed to the total reduced sulfur (TRS) pre-scrubber before introduction to the boiler. The No. 1 Power Boiler is capable of serving the Mill with 195,000 pounds per hour (lbs/hr) of steam.

The No. 1 Bark Boiler (EU 004) fires carbonaceous fuel, consisting of wood materials such as bark, chips, and sawdust; No. 6 fuel oil; natural gas; tall oil; and on-specification used oil. The boiler serves as the primary control device for LVHC NCGs. The No. 1 Bark Boiler is capable of serving the Mill with 200,000 lbs/hr (24-hour block average basis) of steam and is equipped with a cyclone collector and a wet venturi scrubber.

The No. 2 Bark Boiler (EU 019) fires carbonaceous fuel consisting, of wood materials such as bark, chips, and sawdust; No. 6 fuel oil; natural gas; tall oil; and on-specification used oil. The boiler is capable of serving the Mill with 395,000 lbs/hr (24-hour block average basis) of steam. The flue gases from the No. 2 Bark Boiler are split into two streams: (1) one stream flowing through the economizer to a wet, Venturi scrubber, through the demister, and out the stack and (2) the other stream bypassing the economizer and going directly to a cyclone collector and a second wet, Venturi scrubber.

The Mill's three recovery furnaces (EUs 006, 007, and 011) are nondirect contact evaporator (NDCE) units and burn the organic material present in black liquor (black liquor solids, BLS). In addition to BLS, the Nos. 2, 3, and 4 Recovery Furnaces may also be fired with natural gas, No. 6 fuel oil, No. 2 fuel oil, tall oil, ultra-low sulfur diesel, on-specification used oil, and methanol (only in the Nos. 2 and 4 Recovery

Furnaces). Particulate matter emissions from the recovery furnaces are controlled by dedicated electrostatic precipitators (ESPs).

1.2. No. 2 Bark Boiler

The FDEP letter requests analyses of sources projected to emit more than five tons per year (tpy) in 2028. Based on the last three years of data and operational plans going forward, the Foley Mill does not expect the No. 2 Bark Boiler (EU019) to emit more than five tpy of SO_2 in the future. Emissions for 2017, 2018, and 2019 were 3.8, 2.6, and 2.8 tpy of SO_2, respectively. The No. 2 Bark Boiler primarily fires wood fuel (bark) with natural gas and No. 6 fuel oil as ancillary fuels. SO_2 emissions from the No. 2 Bark Boiler are primarily from the firing of No. 6 fuel oil, which is only fired when there are issues with the natural gas line header pressure. The Mill does not expect to alter the current fuel mix going forward.

Based on discussions with FDEP, the Foley Mill understands that, based on these low emissions, a four-factor analysis is not required for the No. 2 Bark Boiler at this time.

1.3. Report Contents

This four-factor analysis for the Foley Mill includes the following elements:

- Section 2 describes available control technologies,
- Section 3 provides the four-factor analysis for individual emission units,
- Section 4 provides a summary of findings,
- Appendix A contains a review of the RACT/BACT/LAER Clearinghouse (RBLC) for SO_2 controls, and
- Appendix B contains control cost data for individual units at the Foley Mill.

2. AVAILABLE SO_2 CONTROL TECHNOLOGIES

The following sections provide a brief description of potentially applicable control technologies for SO_2 control on the boilers and recovery furnaces.

2.1. CONTROL TECHNOLOGY OVERVIEW

EPA maintains a database of control technologies used at specific sources as part of control technology analyses for air permitting. The database was reviewed to determine available SO_2 controls for biomass combustion, fuel oil combustion, natural gas combustion[2], and recovery furnaces firing BLS over the past 20 years. Details on the RBLC review are provided in Appendix A. Available controls identified include the following:

- Good operating practices,
- Low-sulfur fuels,
- Wet scrubber with caustic addition, and
- Dry sorbent injection (DSI).

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

2.2. GOOD OPERATING PRACTICES

Good operating practices for an industrial boiler are important, but are less likely to impact SO_2 emissions. For a recovery furnace, very low SO_2 emissions may be achieved from a well operated furnace. 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. Most of the sulfur introduced to the recovery furnace leaves in the smelt. Factors that influence SO_2 levels in recovery furnaces include liquor sulfidity, liquor solids content, stack oxygen content, furnace load, auxiliary fuel use, and furnace design. The sodium salt fume in the upper furnace also acts to limit SO_2 emissions. The Nos. 2, 3, and 4 Recovery Furnaces are all NDCE units which typically have lower SO_2 emissions than direct contact evaporator (DCE) units due to improved combustion efficiency.

2.3. LOW-SULFUR FUELS

Fuel switching 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 EPA 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 best available control technology (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]

[2] Although there are entries in the RBLC for SO_2 from natural gas combustion, there are no add-on controls listed for these sources as natural gas is a low-sulfur fuel. For this reason, a list of the RBLC entries for natural gas is not included in the attachment.

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

2.4. WET SCRUBBER WITH CAUSTIC ADDITION

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

Wet scrubbers are considered technically feasible for both industrial boilers and recovery furnaces. However, the only two wet scrubbers used for SO_2 control in recovery furnaces listed in EPA's RBLC Database were not installed to meet a RACT/BACT/LAER requirement. Georgia-Pacific's Camas, Washington facility installed a wet scrubber on the No. 3 and No. 4 Recovery Furnaces (now shut down) for heat recovery purposes and not for SO_2 control. The other entry is for a MeadWestvaco facility in Wickliffe, Kentucky, which put in the scrubber to reduce SO_2 emissions to avoid triggering Prevention of Significant Deterioration (PSD) permitting.

2.5. DRY SORBENT INJECTION

DSI accomplishes removal of acid gases by injecting a dry reagent (*i.e.,* lime or trona) into the flue gas stream and prior to particulate matter (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 disposal of additional dry waste. Dry sorbents can also prove challenging to maintain a very low moisture content and keep flowing. DSI systems are typically used to control SO_2, hydrochloric acid and other acid gas emissions from coal-fired boilers.

DSI is not technically feasible for recovery furnaces because dust from the recovery furnace flue gas is captured by the ESP and returned to the chemical recovery process. Introduction of the lime or trona into the flue gas will disrupt the recycle and chemical balance. There are no known installations of DSI for recovery furnaces. DSI is technically feasible for industrial boilers.

3. FOUR FACTOR ANALYSES

The following sections evaluate the technically feasible control technologies for each source and add-on control technology (wet scrubber with caustic and DSI) based on four factors:

- The cost of compliance,
- Energy and non-air quality impacts of compliance,
- The time necessary for compliance, and
- Remaining useful life of existing affected sources.

For each source/add-on control device option analyzed, cost estimates were based on vendor data for similar sources and EPA guidance. Emissions used for cost effectiveness (cost per ton) analyses were based on the average of the last three years, as the Mill believes this is likely to best represent future (2028) operating conditions. The average actual emissions for the last three years were summarized in Table 1-1. As part of this review, an error was discovered in the reported emissions in 2018 for the No. 4 Recovery Furnace. The unit has an SO_2 continuous emissions monitoring system (CEMS) and emissions were reported based on the sum of the CEMS measurements and fuel oil emissions as calculated from AP-42 emission factors. However, the CEMS data captures all of the sources of emissions, so earlier reported emissions were over-estimated.

Although FDEP has not indicated what additional controls they would consider cost effective, similar analyses performed by EPA and other states were reviewed to get a general idea of the level above which additional controls are not cost effective.

- Texas evaluated visibility impacts for controls with an estimated cost effectiveness of $5,000/ton or less.
- North Carolina has indicated a cost effectiveness threshold of less than $5,000/ton will be used to determine what controls are cost effective for Regional Haze.
- EPA used a cost effectiveness threshold of less than $5,000/ton when determining if it was cost effective to require NO_X controls as part of regional transport rules.
- EPA did not further examine control options above $3,400/ton for the 2016 Cross-State Air Pollution Rule (CSAPR) update rule.
- EPA used $2,000/ton in the NO_X SIP call as the threshold for cost-effective controls.
- The Western Regional Air Partnership (WRAP) Annex to the Grand Canyon Visibility Transport Report (June 1999) indicated that control costs greater than $3,000/ton were high.
- States such as New York and Pennsylvania consider NO_X controls less than approximately $5,000/ton as cost effective for Reasonably Available Control Technology (RACT).

For purposes of this analysis, GP assumes that thresholds used by similar states of more than $5,000 per ton should not be considered cost effective.

3.1. No. 1 Power Boiler

The No. 1 Power Boiler (EU 002) fires natural gas, No. 6 fuel oil, tall oil, used oil, and serves as a backup for the control of NCGs. The primary fuel is natural gas, which results in very low SO_2 emissions. The majority of annual SO_2 emissions from the boiler are due to combustion of the NCGs, converting reduced sulfur compounds to SO_2 and water. When NCGs are routed to the No. 1 Power Boiler, a pre-scrubber is used to assist with reduction of TRS which in turn limits SO_2 production.

3.1.1. Wet Scrubber

GP obtained a cost estimate for a scrubber for a Lime Kiln at one of its Oregon facilities for a regional haze rule analysis earlier this year.[4] As this was the most recent quote for a similar unit available, the Lime Kiln scrubber cost estimate was used for the No. 1 Power Boiler by ratioing the flows to the 0.6 power.[5] Caustic use was based on the molar ratio of sodium hydroxide and SO_2 and an assumed a 10% loss. Electricity requirements, water use, and waste generation costs were based on a detailed vendor quote for a similar system at a GP facility in Georgia. These usage rates were scaled based on air flow. Facility costs for labor, water, waste, and caustic were based on the Mill's site-specific data or data from other similar facilities. The capital costs were annualized based on a 30-year life span and 5% interest rate as outlined in EPA's *DRAFT EPA SO_2 and Acid Gas Control Cost Manual*.[6]

Based on the cost information and emissions, a caustic scrubber would cost approximately $13,500 per ton of SO_2 removed, which is not cost effective.

3.1.2. Dry Sorbent Injection

The capital cost for a system to inject milled trona was estimated using an April 2017 Sargent and Lundy report prepared under a U.S. EPA contract.[7] Facility labor, chemical, and utility costs were used to estimate the annual cost of operating the system. The Sargent and Lundy report indicates that 90% SO_2 control can be achieved when injecting trona prior to a fabric filter. The cost of the DSI system and operation alone, without a fabric filter, is approximately $21,700 per ton of SO_2 removed, which is not cost effective. A new baghouse would also have to be installed to collect the dry by-product, which would be an additive cost. As the costs of DSI alone were not cost effective, the additional cost of a baghouse was not included.

3.2. No. 1 Bark Boiler

The No. 1 Bark Boiler (EU 004) fires carbonaceous fuel, consisting of wood materials such as bark, chips, and sawdust; No. 6 fuel oil; natural gas; tall oil; and on-specification used oil. The boiler serves as the primary control device for NCGs. The No. 1 Bark Boiler is equipped with a cyclone collector and a wet venturi scrubber. When NCGs are vented to the No. 1 Bark Boiler, a pre-scrubber is also utilized. If the pre-scrubber is not operational, caustic is injected into the wet venturi scrubber. As the No. 1 Bark

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[4] Although a lime kiln is very different from a power boiler, this estimate was determined to be conservative (lower than expected actual value) based on the design of the Foley boiler and the details of the lime kiln proposal.

[5] EPA, *DRAFT EPA SO_2 and Acid Gas Control Cost Manual*, July 2020, Chapter 1 Wet and Dry Scrubbers for Acid Gas Control.

[6] *Ibid.*

[7] Sargent & Lundy LLC. 2017. *Dry Sorbent Injection for SO_2/HCl Control Cost Development Methodology*. Project 13527-001, Eastern Research Group, Inc. Chicago, IL.

Boiler is already equipped with a scrubber, only the addition of more caustic is evaluated. DSI is not analyzed as the scrubber would have to be replaced with a dry control device. The DSI costs would be in a similar range as those for the No. 1 Power Boiler, which are not cost effective on their own, in addition to the costs associated with removal of an existing control device.

In addition to caustic addition, anti-scalant must be added to minimize fouling and scaling due to caustic buildup in the boiler. Based on current caustic and anti-scalant prices and the molar ratio of sodium hydroxide and SO_2, additional SO_2 reduction can be achieved at an estimated cost of $2,600/ton by using caustic in the scrubber in place of using the TRS pre-scrubber.

3.3. NOS. 2, 3, AND 4 RECOVERY FURNACES

In the Mill's three recovery furnaces (EUs 006, 007, and 011), the organic material present in black liquor is oxidized as the carbon is burned away and the inorganic compounds are smelted in reduction reactions for reuse in the pulping process. The molten inorganic chemicals, or smelt, consisting primarily of sodium carbonate (Na_2CO_3), collect in the bottom of the recovery furnaces, and pour out of spouts into the associated smelt dissolving tanks (EUs 021, 022, and 023). Salt cake, reclaimed from the economizer and the electrostatic precipitator (operated to control emissions of particulate matter), is mixed with black liquor and recycled back into the liquor system via black liquor/salt cake mix tanks and the precipitator mix tanks. The salt cake/black liquor mixture is either burned in the recovery furnace or sent to a strong black liquor storage tank. In addition to BLS, the Nos. 2, 3, and 4 Recovery Furnaces may also be fired with natural gas, No. 6 fuel oil, No. 2 fuel oil, tall oil, ultra-low sulfur diesel, on-specification used oil, and methanol (only in the Nos. 2 and 4 Recovery Furnaces). Particulate matter emissions from the recovery furnaces are controlled by dedicated ESPs.

As discussed above, a scrubber with caustic addition is the only technically feasible add-on SO_2 control option for recovery furnaces. For the recovery furnaces, GP utilized an American Forest and Paper Association (AF&PA) publication developed by BE&K Engineering, Emission Control Study – Technology Cost Estimates, September 2001.[8] Costs were scaled to 2019[9] dollars and ratioed by the BLS throughputs to the 0.6 power. Caustic use was based on the molar ratio of sodium hydroxide and SO_2 and an assumed 10% loss. Electricity requirements, water use and waste generation costs were based on the AF&PA cost data and scaled based on actual BLS throughput. Facility costs for labor, water, waste, and caustic were based on the Mill's site-specific data or data from other similar facilities. The capital costs were annualized based on a 30-year life span and 5% interest rate as outlined in EPA's DRAFT EPA SO_2 and Acid Gas Control Cost Manual.[10]

Although the AF&PA costs are slightly dated, they were deemed to be the most representative as they were based on costs for a recovery furnace retrofit scrubber after an ESP. In addition, the costs are consistent with data presented in the November 2016 Washington Regional Haze plan[11],which estimates

[8] http://www.nescaum.org/documents/bart-resource-guide/be-k-capital-operating-cost-estimate-9-20-01.pdf/
[9] The most recent complete year of the Chemical Engineering Plant Cost Index (CEPCI) was used.
[10] EPA, *DRAFT EPA SO_2 and Acid Gas Control Cost Manual*, July 2020, Chapter 1 Wet and Dry Scrubbers for Acid Gas Control.
[11] Department of Ecology, *Washington Regional Haze Reasonably Available Control Technology Analysis for Pulp and Paper Mills*, November 2016. https://fortress.wa.gov/ecy/publications/SummaryPages/1602023.html

annual operating costs between $3 and 9 million per year. The costs in the Mill's analysis were between $2.8 and 3.8 million per year.

Based on the cost information and emissions, a caustic scrubber would cost approximately $9,300, $5,100, and $6,300 per ton of SO_2 removed for the Nos. 2, 3, and 4 Recovery Furnaces, respectively. These values are not considered cost effective. Moreover, the Foley Mill believes that the actual value will be significantly higher due to costs associated with retrofitting the scrubber on an existing emissions unit.

3.4. Energy and Non-Air Quality Impacts of Compliance

Use of an SO_2 scrubber requires the use of additional water and generates a wastewater stream that must be treated. Additional electricity is required to power scrubber fans. DSI results in additional waste being generated.

3.5. Time Necessary for Compliance

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 add-on controls that would be feasible, if controls are ultimately required to meet Regional Haze Rule (RHR) requirements, facilities would need at least four to five years to implement add-on controls after final EPA approval of the RHR SIP. The Mill 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, and other critical suppliers. 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. 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.

3.6. Remaining Useful Life

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

4. SUMMARY OF FINDINGS

The Foley Mill analyzed the significant SO_2 emissions sources for additional control utilizing EPA's four-factor method. Based on this analysis, no add-on controls are deemed feasible or cost-effective. The use of caustic in the venturi scrubber for the No. 1 Bark Boiler when combusting NCGs may be considered cost-effective. But the expected amount of emissions reduction by adding caustic is only approximately 96 tpy of SO_2, which is unlikely to have a measurable impact on regional haze at the Okefenokee National Wildlife Refuge.

APPENDIX A

RBLC SEARCH RESULTS

RBLC Entries for SO2, Oil Fired Boilers

Facility Name	ST	Process Name	Primary Fuel	Throughput	Unit	Control Method Description	Emission Limit 1	Unit	Time Condition	Emission Limit 2	Unit	Time Condition
INTERNATIONAL PAPER COMPANY - Rieglewood Mill	NC	RECOVERY BOILER	NO. 6 FUEL OIL	557.00	MMBTU/H	GOOD COMBUSTION PRACTICE	979	LB/H		n/a		
INTERNATIONAL PAPER COMPANY - Rieglewood Mill	NC	SMELT TANKS				FAN IMPINGEMENT-TYPE WET SCRUBBER	6	LB/H		n/a		
INTERNATIONAL PAPER COMPANY - Rieglewood Mill	NC	BOILER, POWER, COAL-FIRED	COAL	249	MMBTU/H	MULTICLONE AND A VARIABLE THROAT VENTURI-TYPE WET SCRUBBER	1	LB/MMBTU		n/a		
INTERNATIONAL PAPER COMPANY - Rieglewood Mill	NC	BOILER, POWER, OIL-FIRED	NO. 6 FUEL OIL	249.0	MMBTU/H	MULTICLONE AND VARIABLE THROAT VENTURI-TYPE WET SCRUBBER	1	LB/MMBTU		n/a		
INTERNATIONAL PAPER COMPANY - Rieglewood Mill	NC	BOILER, POWER, WOODWASTE-FIRED	WOODWASTE	600.0	MMBTU/H	MULTICLONE AND A VARIABLE THROAT VENTURI-TYPE WET SCRUBBER	0.0	LB/MMBTU		n/a		
MILLER BREWING COMPANY -Trenton	OH	BOILER (2), NO. 6 FUEL OIL	NO. 6 FUEL OIL	238	MMBTU/H		1.60	LB/MMBTU		2,758	T/YR	BOTH BOILERS TOGETHER, PER ROLLING 12-MO
MILLER BREWING COMPANY	OH	BOILER (2), NATURAL GAS	NATURAL GAS	238	MMBTU/H		2	LB/MMBTU		2,758	T/YR	BOTH BOILERS TOGETHER, PER ROLLING 12-MO
MILLER BREWING COMPANY	OH	BOILER (2), COAL FIRED	COAL	238.00	MMBTU/H		1.60	LB/MMBTU		2,758	T/YR	BOTH BOILERS TOGETHER, PER ROLLING 12-MO
MILLER BREWING COMPANY	OH	BOILER (2), NO. 2 FUEL OIL	NO. 2 FUEL OIL	238.00	MMBTU/H		1.60	LB/MMBTU		2,758	T/YR	BOTH BOILERS TOGETHER, PER ROLLING 12-MO
VIRGINIA COMMONWEALTH UNIVERSITY	VA	BOILER - NO 6 FUEL OIL	FUEL OIL #6	150.0	MMBTU/H	GOOD COMBUSTION PRACTICES. LOW SULFUR FUELS.	79	LB/H	each unit 3hr rolling avg	n/a		
VIRGINIA COMMONWEALTH UNIVERSITY	VA	BOILER NATUAL GAS	NATURAL GAS	150.0	MMBTU/H	GOOD COMBUSTION PRACTICES. LOW SULFUR FUELS.	0.1	LB/H	each unit 3hr rolling avg	n/a		
VIRGINIA COMMONWEALTH UNIVERSITY	VA	BOILER - DISTILLATE	FUEL OIL #2	150.0	MMBTU	GOOD COMBUSTION PRACTICES. LOW SULFUR FUELS.	78.50	LB/H	each unit 3hr rolling avg	n/a		
VIRGINIA COMMONWEALTH UNIVERSITY	VA	BOILER - OIL OR GAS	GAS OR OIL	150.0	MMBTU	GOOD COMBUSTION PRACTICES. LOW SULFUR FUELS.	196.30	T/YR	combined units	n/a		
Virginia Commonwealth University	VA	BOILER, NATURAL GAS, (3)	NATURAL GAS	150.6	MMBTU/H	LOW SULFUR FUEL	0.10	LB/H		n/a		
Virginia Commonwealth University	VA	BOILER, #6 FUEL OIL, (3)	# 6 FUEL OIL	150.6	MMBTU/H	FUEL SULFUR LIMIT: < 0.5% S BY WT	78.50	LB/H		196.3	T/YR	combined operation, all fuels
Virginia Commonwealth University	VA	BOILER, #2 FUEL OIL, (3)	NO. 2 FUEL OIL	151	MMBTU/H	FUEL SULFUR LIMITS: <0.5% S BY WT.	79	LB/H		n/a		
HERCULES INC	VA	CHEMICAL PREP	NATURAL GAS	90.0	MMBTU/H	CEMS AND GOOD COMBUSTION PRACTICES	0	LB/H		n/a	LB/H	
HERCULES INC	VA	CHEMICAL PREP	DISTILLATE OIL	90	MMBTU	WET OR DRY SCRUBBER AND GOOD COMBUSTION PRACTICES	9	LB/H		9	LB/H	
HERCULES INC	VA	CHEMICAL PREP	RESIDUAL OIL	90	MMBTU	0.5% S AND WET OR DRY SCRUBBER. GOOD COMBUSTION PRACTICES	9.5	LB/H		10	LB/H	
HERCULES INC	VA	CHEMICAL PREP	DISTILLATE OIL	90	MMBTU	.5% S FUEL AND GOOD COMBUSTION PRACTICES	45.40	LB/H		45.40	LB/H	
WEIDMANN ELECTRICAL TECHNOLOGY, INC.	VT	WEST BUILDING BOILER #3	NO.6 FUEL OIL	19.4	MMBTU/H HEAT INPUT	LOW SULFUR FUEL	0.50	% SULFUR CONTENT		n/a		
MIDDLEBURY COLLEGE	VT	Boiler #12	No. 6 fuel oil	57	MMBTU/H	Use of 0.5% (max) sulfur content fuel oil	1	% SULFUR CONTENT		n/a		

RBLC Entries for SO2, Wood Fired Boilers

FACILITY_NAME	ST	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	UNIT	CONTROL_METHOD_DESCRIPTION	EMISSION LIMIT 1	UNIT	TIME CONDITION	EMISSION LIMIT 2	UNIT	TIME CONDITION
CLEWISTON MILL	FL	Boiler No. 9	Bagasse	1077	MMBtu/hr	Inherently low-sulfur fuels and natural alkalinity of bagasse can scrub out sulfur emissions.	0.064	LB/MMBTU	--		--	--
HIGHLANDS ENVIROFUELS	FL	Cogeneration Biomass Boiler	Bagasse	458	MMBtu/hr	--	0.06	LB/MMBTU	30-DAY-ROLLING	0.078	LB/MMBTU	1-HR AVG
WARREN COUNTY BIOMASS ENERGY FACILITY	GA	Boiler, Biomass Wood	Biomass wood	100	MW	Dust sorbent injection system	0.01	LB/MMBTU	30 D ROLLING AV / CONDITION 2.12	56	TONS	12 MONTH ROLLING TOTAL / CONDITION 2.20
ABENGOA BIOENERGY BIOMASS OF KANSAS (ABBK)	KS	biomass to energy cogeneration bioler	different types of biomass	500	MMBtu/hr	Injection of sorbent (lime) in combination with a dry flue gas desulfurization (FGD) system	0.21	LB/MMBTU	30-DAY ROLLING, INCLUDES SSM	110.25	LB/HR	MAX 1-HR, INCLUDES SS, EXCLUDES MALFUNCT
RED RIVER MILL	LA	NO. 2 HOGGED FUEL BOILER	HOGGED FUEL/BARK	992.43	MMBTU/H	Use of low sulfur fuels	60	LB/H	HOURLY MAXIMUM	262.8	T/YR	ANNUAL MAXIMUM
VERSO BUCKSPORT LLC	ME	Biomass Boiler 8	Biomass	814	MMBTU/H	0.7% sulfur when firing oil	0.8	LB/MMBTU	3-HR AVERAGE	651.2	LB/H	--
BERLIN BIOPOWER	NH	EU01 BOILER #1	WOOD	1013	MMBTU/H	Wood Fuel	0.012	LB/MMBTU	STACK TEST		--	--
GP CLARENDON LP	SC	334 MILLION BTU/HR WOOD FIRED FURNACE #2	WOOD	334	MMBTU/H	SO2 Emissions controlled through good combustion practices	28.14	LB/H	--	117.1	T/YR	--
GP CLARENDON LP	SC	197 MILLION BTU/HR WOOD FIRED FURNACE	WOOD	197	MMBTU/H	SO2 Emissions controlled through good combustion practices	28.14	LB/H	--	117.1	T/YR	--
GP CLARENDON LP	SC	334 MILLION BTU/HR WOOD FIRED FURNACE #1	WOOD	334	MMBTU/H	SO2 Emissions controlled through good operating practices	28.14	LB/H	--	117.1	T/YR	--
LINDALE RENEWABLE ENERGY	TX	Wood fired boiler	biomass	73	T/H	--	0.025	LB/MMBTU	ROLLING 30- DAY AVG		--	--
LUFKIN GENERATING PLANT	TX	Wood-fired Boiler	wood	693	MMBtu/H	--	0.025	LB/MMBTU	30 DAY ROLLING AVERAGE		--	--
BEAVER WOOD ENERGY FAIR HAVEN	VT	Main Boiler	wood	482	MMBTU/H	Use of low sulfur fuel (wood)	0.02	LB/MMBTU	HOURLY AVERAGE		--	--
NORTH SPRINGFIELD SUSTAINABLE ENERGY PROJECT	VT	Wood Fired Boiler	wood	464	MMBTU/H	Use of low sulfur fuel (wood)	0.02	LB/MMBTU	HOURLY AVERAGE	10	LB/H	HOURLY AVERAGE

RBLC Entries for SO2, Recovery Furnaces

Facility Name	ST	Process Name	Primary Fuel	Throughput	Unit	Control Method Description	Emission Limit 1	Unit	Time Condition	Emission Limit 2	Unit	Time Condition
ROCK-TENN MILL COMPANY, LLC	AL	RECOVERY FURNACE	--	4.32	mmlb/day	--	100	PPMV @ 8% O2	3 HR	252.9	LB/H	3 HR
ID COURTLAND	AL	NO. 3 RECOVERY FURNACE	BLACK LIQUOR	950	MMBTU/H	--	75	PPM@8% O 2	3HRS	31	PPM@8% O 2	3HRS
BOWATER INC. COOSA PINES OPERATIONS	AL	NO. 3 RECOVERY FURNACE	BLACK LIQUOR	816	MMBTU/H	--	75	PPM@8% O2	3HRS AVG	169.6	LB/H	3HRS
ALABAMA RIVER PULP	AL	RECOVERY FURNACE	BLACK LIQUOR	7.5	MMLB BLS/DAY	--	60	PPMDV		271	LB/H	
GEORGIA-PACIFIC CORPORATION - CROSSETT PAPER OPERATIONS	AR	8R RECOVERY BOILER	BLACK LIQUOR SOLIDS AND NO. 6 FUEL OIL	6.9	MMLB BLS/D	COMBUSTION CONTROL	84.7	LB/H	BLS WITH SUPPLEMENTAL OIL, 3-HR AV	989.1	LB/H	SPEC OIL ONLY, 3-HR AV
MEADWESTVACO KENTUCKY, INC/WICKLIFFE	KY	RECOVERY FURNACE	--	473000	LB/H	WET SCRUBBER	0.29	LB/T ADP	--		--	--
MANSFIELD MILL	LA	RECOVERY BOILER NO.1 AND NO.2	--	71	TBLS/H	GOOD PROCESS CONTROLS	510	LB/H	--	2233.8	T/YR	--
PORT HUDSON OPERATIONS	LA	RECOVERY FURNACE NO. 1	--	2.81	MM LB/D	--	105.91	LB/H	--	463.88	T/YR	--
PORT HUDSON OPERATIONS	LA	RECOVERY FURNACE NO. 2	--	3.96	MM LB/D	--	143.23	LB/H	--	627.35	T/YR	--
RED RIVER MILL	LA	RECOVERY BOILER NO. 3	BLACK LIQUOR	6.4	MM LB/D	PROPER BOILER DESIGN AND OPERATION	20	PPM @ 8% O2*	--		--	--
MANSFIELD MILL	LA	RECOVERY BOILERS NO. 1 &2	--	961.3	MMBTU/H	PROPER DESIGN, GOOD COMBUSTION PRACTICES, FIRING LOW SULFUR FUEL, AND A 10% ANNUAL	217.6	LB/H	HOURLY MAXIMUM	907.9	T/YR	ANNUAL MAXIMUM
GEORGIA PACIFIC CORPORATION, MONTICELLO MILL	MS	RECOVERY BOILER NO. 1	BLACK LIQUOR	861.4	MMBTU/H	--	408.33	LB/H	--	1788.5	T/YR	--
GEORGIA PACIFIC CORPORATION, MONTICELLO MILL	MS	RECOVERY BOILER NO. 2	BLACK LIQUOR	861.4	MMBTU/H	--	408.33	LB/H	--	1788.5	T/YR	--
GEORGIA PACIFIC CORPORATION, MONTICELLO MILL	MS	BOILER, NO. 1 RECOVERY	BLS	861.4	MMBTU/H	COMBUSTION CONTROL AND FURNACE DESIGN	408.33	LB/H	--	1788.5	T/YR	--
GEORGIA PACIFIC CORPORATION, MONTICELLO MILL	MS	BOILER, NO. 2 RECOVERY	BLS	861.4	MMBTU/H	COMBUSTION CONTROL AND FURNACE DESIGN	408.33	LB/H	--	1788.5	T/YR	--
INTERNATIONAL PAPER - ROANOKE RAPIDS MILL	NC	NO. 7 RECOVERY FURNACE	BLACK LIQUOR SOLIDS	3	MMLB/D	FURNACE DESIGN AND COMBUSTION OPTIMIZATION	75	PPM	8% O2 ANNUAL	110	PPM	8% O2 3-HOUR
WEYERHEAUSER COMPANY-MARLBORO PAPER MILL	SC	NO. 1 RECOVERY FURNACE	HEAVY BLACK LIQUOR	4.4	MMLB/D	GOOD COMBUSTION/RECOVERY FURNACE FIRING RATE AND	75	PPM @ 8% O2	--	838	T/YR	--
RESOLUTE FP US INC	SC	NO. 3 RECOVERY FUNRACE	BLACK LIQUOR	2040	T/D BLS	FUEL MONITORING (USE AND SULFUR CONTENT)	50	PPM (DRY BASIS)	--	551	T/YR	12 MONTH ROLLING SUM
INLAND PAPERBOARD AND PACKAGING ORANGE MILL	TX	NO.1 AND NO. 2 RECOVERY FURNACE	NATURAL GAS	--	--	--	915.7	LB/H	--	1372	T/YR	--
INTERNATIONAL PAPER COMPANY PULP AND PAPER MILL	TX	NO 2 RECOVERY FURNACE EAST/WEST STACK	--	--	--	--	375.71	LB/H	--	521.11	T/YR	--
INTERNATIONAL PAPER COMPANY PULP AND PAPER MILL	TX	NO 1 RECOVERY FURNACE NORTH/SOUTH STACK	--	--	--	--	210.94	LB/H	--	307.98	T/YR	--
LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	RECOVERY FURNACE 15	--	1150	TBLS/D	--	60	PPMDV @ 8% O2	3 H AV	365	T/YR	--
LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	RECOVERY FURNACE 18	--	1200	TBLS/D	FACILITY WILL HAVE A FEDERAL LIMIT OF SO2 REPRESENTING A 53% REDUCTION FROM THE	60	PPMDV @ 8% O2	3 H AV	202	T/YR	--
LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	RECOVERY FURNACE 19	--	2000	T BLS/D	FACILITY WILL HAVE A LIMIT ON SO2 REPRESENTING A	60	PPMDV @ 8% O2	3 H AV	301	T/YR	MO AV
LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	RECOVERY FURNACE 22	--	1950	T BLS/D	--	120	PPMDV @ 8% O2	3 H AV	1291	T/YR	
JAMES RIVER CORP (now GP)	WA	RECOVERY FURANCE #4	BLACK LIQUOR	770	MMBTU/H	HEAT RECOVERY SCRUBBER	10	PPM		46	T/YR	
MOSINEE PAPER CORPORATION	WI	RECOVERY BOILER, PROCESS #B21, STACK #S11	BLACK LIQUOR	250	MMBTU/H	--	209.8	T/YR	--		--	--
DOMTAR NEKOOSA MILL	WI	KRAFT BLACK LIQUOR RECOVERY FURNACE, B14	STRONG BLACK LIQUOR	37.5	bl	GOOD OPERATING PRACTICES	60	PPMDV @ 8% O2	--		--	--

APPENDIX B

CONTROL COST ANALYSES

Supporting Data for Control Device Cost Effectiveness Calculations

Parameter	Value		Note(s)
Operating Labor Cost	30.68	$/hr	1
Maintenance Labor Cost	32.15	$/hr	1
Caustic Cost	480	$/ton	1
Electricity Cost	0.0755	$/kWh	1
Water Cost	0.86	$/Mgal	2
Wastewater Treatment Cost	0.64	$/Mgal	1

1. Labor, caustic, electricity, and wastewater based on Foley specific data.
2. Water cost based on data from similar facilities.

Chemical, Energy, Water Use Basis

Amount of NaOH per SO2, based on molar ratio	1.25	lb/lb SO2 Removed		
NaOH solution, 50%	2.5	lb/lb SO2 Removed		
Data for Recovery Furnace				
Electricty per AFPA data	440.92	kW/MMlb BLS		
Freshwater use per AFPA Data	40.00	gpm/(MMlb BLS/day)		
Wastewater disposal per AFPA Data	4.00	gpm/(MMlb BLS/day)		
Data for Boiler	Reference is		420,000	acfm
Electricity per previous BART Control data	0.00175	KWhr/acfm		
Freshwater use per previous BART Data	0.233	Mgal/acfm		
Wastewater disposal per Previous BART data	0.082	Mgal/acfm		

1. Caustic use based on 2NaOH + SO2 → Na2SO3 + H2O
2. Usage of electricity, water, and waste based on reference cost estimates for controls.
   AFPA data basis is http://www.nescaum.org/documents/bart-resource-guide/be-k-capital-operating-cost-estimate-9-20-01.pdf/
   Previous BART Data is based on a 2008 BART control submittal for a similar GP unit.

Foley PB1

Capital and Annual Costs Associated with Trona Injection

Variable	Designation	Units	Value	Calculation
Heat Input		**MMBtu/hr**	**151.3**	
Unit Size	A	MW	13	Based on 3-year average actual, 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	0.124	Based on 3-year average actual
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	1.51E+08	151.33 MMBtu/hr
NSR	K	-	2.61	Milled Trona w/ FF = 0.208e^(0.0281*H)
Sorbent Feed Rate	M	ton/hr	0.20	Trona = (1.2011*10^-06)*K*A*C*D
Estimated HCl Removal	V	%	98.85	Milled or Unmilled Trona w/ FF = 84.598*H^0.0346
Sorbent Waste Rate	N	ton/hr	0.16	Trona = (0.7387+0.00185*H/K)*M
Fly Ash Waste Rate	P	ton/hr	0.00	Ash in Bark = 0.05; Boiler Ash Removal = 0.2; HHV = 4600 (A*C)*Ash*(1-Boiler Ash Removal)/(2*HHV; fires primarily natural gas, set to zero.
Aux Power	Q	%	0.30	Milled Trona M*20/A
Sorbent Cost	R	$/ton	170	Default value in report
Waste Disposal Cost	S	$/ton	100	Default value for disposal without fly ash
Aux Power Cost	T	$/kWh	0.06	Default value in report
Operating Labor Rate	U	$/hr	49.09	Typical labor cost, includes 60% overhead cost

SO_2 Control Efficiency:	90%
Representative Emissions	81.3
Controlled SO_2 Emissions:	73.2

Capital Costs					
Direct Costs					
BM (Base Module) scaled to 2019 dollars		$	$	5,864,531	Milled Trona if(M>25, 820000*B*M, 8300000*B*(M^0.284))
Indirect Costs					
Engineering & Construction Management	A1	$	$	586,453	10% BM
Labor adjustment	A2	$	$	293,227	5% BM
Contractor profit and fees	A3	$	$	293,227	5% BM
Capital, engineering and construction cost subtotal	CECC	$	$	7,037,438	BM+A1+A2+A3
Owner costs including all "home office" costs	B1	$	$	351,872	5% CEC
Total project cost w/out AFUDC	TPC	$	$	7,389,309	B1+CEC
AFUDC (0 for <1 year engineering and construction cycle)	B2	$		0	0% of (CECC+B1)
Total Capital Investment	**TCI**	**$**	**$**	**7,389,309**	CECC+B1+B2

Annualized Costs					
Fixed O&M Cost					
Additional operating labor costs	FOMO	$	$	204,206	(2 additional operator)*2080*U
Additional maintenance material and labor costs	FOMM	$	$	58,645	BM*0.01/B
Additional administrative labor costs	FOMA	$	$	6,830	0.03*(FOMO+0.4*FOMM)
Total Fixed O&M Costs	**FOM**	**$**	**$**	**269,681**	FOMO+FOMM+FOMA
Variable O&M Cost					
Cost for Sorbent	VOMR	$	$	292,753	M*R
Cost for waste disposal that includes both sorbent & fly ash waste not removed prior to sorbent injection	VOMW	$	$	138,202	(N+P)*S
Additional auxiliary power required	VOMP	$	$	113,801	Q*T*10*ton SO_2
Total Variable O&M Cost	**VOM**	**$**	**$**	**544,756**	VOMR+VOMW+VOMP
Indirect Annual Costs					
General and Administrative	2%	of TCI	$	147,786	
Property Tax	1%	of TCI	$	73,893	
Insurance	1%	of TCI	$	73,893	
Capital Recovery	6.51%	x TCI	$	480,685	
Total Indirect Annual Costs			**$**	**776,258**	
Life of the Control:		30 years		5.00%	interest
Total Annual Costs			**$**	**1,590,695**	
Total Annual Costs/SO_2 Emissions			**$**	**21,727**	

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

Capital & Operating Cost Evaluation for SO2 Scrubber for PB1

Cost Category	Value	Notes [1]
Vendor Quoted System Costs ($) =	$7,200,000	Based on 2020 cost estimate for Lime Kiln for similar 4-factor Analysis
Vendor Quoted System (cfm) =	124,500	
CFM analyzed	115,770	
Engineering Factor =	1.0	Vendor quote includes auxiliary costs
Total Capital Investment (TCI)	**$6,892,686**	Prorated from previous vendor quote based on capacity ratio raised to the power of
Capital Recovery		
Capital Recovery Factor (CRF) [2]	0.0651	CRF = 5% interest and 30-yr equipment life based on July 2020 Draft Section 5 Contr
Capital Recovery Cost (CRC)	***$448,714***	***CRC = TCI × CRF***
Operating Costs		
Direct Operating Costs (DOC)		
Operating Labor	$16,797	A = Based on 0.5 hour per shift, 3 shifts per day
Supervisory Labor	$2,520	B = 15% of operating labor
Maintenance Labor	$17,602	C = Based on 0.5 hour per shift, 3 shifts per day
Maintenance Materials	$17,602	D = Equivalent to maintenance labor
Caustic Costs	$105,230	E = Mass of NaOH to neutralize SO2 times chemical cost plus 10% waste (based on example in July 2020 Draft Section 5 Control Cost Manual)
Electricity Usage	202	Power (kWh) ratioed based on similar boiler cost estimate values.
Cost of Electricity Usage	$133,793	F = E × Electricity Cost
Fresh Water	$23,199	G = Freshwater use * water cost
Water Disposal	$6,065	H = Water disposal amount * disposal cost
Total Direct Operating Costs (DOC)	***$322,808***	***DOC = A + B + C + D +E + F + G + H***
Indirect Operating Costs (IOC)		
Overhead	$32,713	H = 60% × (A + B + C + D)
Property Tax	$68,927	I = 1% × TCI
Insurance	$68,927	J = 1% × TCI
Administrative Charges	$137,854	K = 2% × TCI
Total Indirect Operating Costs (IOC)	***$308,420***	***IOC = H + I + J + K***
Total Annualized Cost (AC) =	**$1,079,942**	*AC = CRC + DOC + IOC*
SO_2 Uncontrolled Emissions (tpy)	81.35	
SO_2 Removed (tpy)	79.72	98.0% Removal Efficiency
Cost per ton of SO2 Removed ($/ton)	**$13,547**	**$/ton = AC / Pollutant Removed**

1. TCI per 2020 Envitech estimate for Lime Kiln scrubber at another GP facility.
2. U.S. EPA OAQPS, EPA Air Pollution Control Cost Manual Draft, July 2020, Section 5 SO_2 and Acid Gas Controls.

Operating Cost Evaluation for SO2 Caustic Addition for BB1

Emission Rate with Caustic (lb/ADTUBP)	1.74	
Emission Rate without Caustic and with Pre-scrubber (lb/ADTUBP)	3.54	
% Control - caustic	51%	
Caustic Use	2.5	lb NaOH per lb SO2 removed
Caustic Loss	10%	
Caustic Cost	480	$/ton Caustic
Anti-scaler	$125,000	per year
Cost per ton of SO_2 removed, Caustic	$1,320	$/ton
Cost per ton of SO_2 removed, Anti-Scaler	$1,307	$/ton
Total tons reduced	96	tons
Total cost per ton	$2,627	

1. Emissions rates based on stack test data and % control represents improvement over operation with pre-scrubber.
2. Caustic use based on molar ratio.
3. Anti-scaler based on estimated cost of using caustic full time and improved caustic control.

Capital & Operating Cost Evaluation for SO2 Scrubber for RF2

Cost Category	Value	Notes [1]
Vendor Quoted System Costs ($) =	$19,788,754	AFPA 2001 Data, scaled to 2019 dollars based on CEPCI of 394.3 (2001) and 607.5 (20
Vendor Quoted System BLS (ton BLS/day) =	1,850	AFPA 2001 Data
BLS Analyzed (ton BLS/day) =	1,171	Permitted Capacity
Engineering Factor =	1.0	Vendor quote includes auxiliary costs
Total Capital Investment (TCI)	**$15,041,601**	Prorated from previous vendor quote based on capacity ratio raised to the power of
Capital Recovery		
Capital Recovery Factor (CRF) [2]	0.0651	CRF = 5% interest and 30-yr equipment life based on July 2020 Draft Section 5 Contr
Capital Recovery Cost (CRC)	***$979,208***	***CRC = TCI × CRF***
Operating Costs		
Direct Operating Costs (DOC)		
Operating Labor	$16,797	A = Based on 0.5 hour per shift, 3 shifts per day
Supervisory Labor	$2,520	B = 15% of operating labor
Maintenance Labor	$17,602	C = Based on 0.5 hour per shift, 3 shifts per day
Maintenance Materials	$17,602	D = Equivalent to maintenance labor
Caustic Costs	$397,010	E = Mass of NaOH to neutralize SO2 times chemical cost plus 10% waste (based on example in July 2020 Draft Section 5 Control Cost Manual)
Electricity Usage	1,033 kWh	Power (kWh) ratioed based on AFPA values.
Cost of Electricity Usage	$683,086	F = E × Electricity Cost
Fresh Water	$42,352	G = Freshwater use * water cost
Water Disposal	$3,139	H = Water disposal amount * disposal cost
Total Direct Operating Costs (DOC)	***$1,180,109***	***DOC = A + B + C + D +E + F + G + H***
Indirect Operating Costs (IOC)		
Overhead	$32,713	H = 60% × (A + B + C + D)
Property Tax	$150,416	I = 1% × TCI
Insurance	$150,416	J = 1% × TCI
Administrative Charges	$300,832	K = 2% × TCI
Total Indirect Operating Costs (IOC)	***$634,377***	***IOC = H + I + J + K***
Total Annualized Cost (AC) =	**$2,793,693**	*AC = CRC + DOC + IOC*
SO_2 Uncontrolled Emissions (tpy)	306.90	
SO_2 Removed (tpy)	300.77	98.0% Removal Efficiency
Cost per ton of SO2 Removed ($/ton)	**$9,289**	**$/ton = AC / Pollutant Removed**

1. TCI Per AFPA BE & K Study, 2001 ratioed to 2019 dollars.
2. U.S. EPA OAQPS, EPA Air Pollution Control Cost Manual Draft, July 2020, Section 5 SO_2 and Acid Gas Controls.

Capital & Operating Cost Evaluation for SO2 Scrubber for RF3

Cost Category	Value	Notes [1]
Vendor Quoted System Costs ($) =	$19,788,754	AFPA 2001 Data, scaled to 2019 dollars based on CEPCI of 394.3 (2001) and 607.5 (201
Vendor Quoted System BLS (ton BLS/day) =	1,850	AFPA 2001 Data
BLS Analyzed (ton BLS/day) =	988	Permitted Capacity
Engineering Factor =	1.0	Vendor quote includes auxiliary costs
Total Capital Investment (TCI)	**$13,583,833**	Prorated from previous vendor quote based on capacity ratio raised to the power of 0
Capital Recovery		
Capital Recovery Factor (CRF) [2]	0.0651	CRF = 5% interest and 30-yr equipment life based on July 2020 Draft Section 5 Control
Capital Recovery Cost (CRC)	***$884,308***	***CRC = TCI × CRF***
Operating Costs		
Direct Operating Costs (DOC)		
Operating Labor	$16,797	A = Based on 0.5 hour per shift, 3 shifts per day
Supervisory Labor	$2,520	B = 15% of operating labor
Maintenance Labor	$17,602	C = Based on 0.5 hour per shift, 3 shifts per day
Maintenance Materials	$17,602	D = Equivalent to maintenance labor
Caustic Costs	$741,401	E = Mass of NaOH to neutralize SO2 times chemical cost plus 10% waste (based on example in July 2020 Draft Section 5 Control Cost Manual)
Electricity Usage	871 kWh	Power (kWh) ratioed based on AFPA values.
Cost of Electricity Usage	$576,354	F = E × Electricity Cost
Fresh Water	$35,735	G = Freshwater use * water cost
Water Disposal	$2,648	H = Water disposal amount * disposal cost
Total Direct Operating Costs (DOC)	***$1,410,659***	***DOC = A + B + C + D +E + F + G + H***
Indirect Operating Costs (IOC)		
Overhead	$32,713	H = 60% × (A + B + C + D)
Property Tax	$135,838	I = 1% × TCI
Insurance	$135,838	J = 1% × TCI
Administrative Charges	$271,677	K = 2% × TCI
Total Indirect Operating Costs (IOC)	***$576,066***	***IOC = H + I + J + K***
Total Annualized Cost (AC) =	**$2,871,033**	*AC = CRC + DOC + IOC*
SO_2 Uncontrolled Emissions (tpy)	573.13	
SO_2 Removed (tpy)	561.67	98.0% Removal Efficiency
Cost per ton of SO2 Removed ($/ton)	**$5,112**	**$/ton = AC / Pollutant Removed**

1. TCI Per AFPA BE & K Study, 2001 ratioed to 2019 dollars.
2. U.S. EPA OAQPS, EPA Air Pollution Control Cost Manual Draft, July 2020, Section 5 SO_2 and Acid Gas Controls.

Capital & Operating Cost Evaluation for SO2 Scrubber for RF4

Cost Category	Value	Notes [1]
Vendor Quoted System Costs ($) =	$19,788,754	AFPA 2001 Data, scaled to 2019 dollars based on CEPCI of 394.3 (2001) and 607.5 (20:
Vendor Quoted System BLS (ton BLS/day) =	1,850	AFPA 2001 Data
BLS Analyzed (ton BLS/day) =	1,606	Permitted Capacity
Engineering Factor =	1.0	Vendor quote includes auxiliary costs
Total Capital Investment (TCI)	**$18,178,017**	Prorated from previous vendor quote based on capacity ratio raised to the power of 0
Capital Recovery		
Capital Recovery Factor (CRF) [2]	0.0651	CRF = 5% interest and 30-yr equipment life based on July 2020 Draft Section 5 Control
Capital Recovery Cost (CRC)	***$1,183,389***	***CRC = TCI × CRF***
Operating Costs		
Direct Operating Costs (DOC)		
Operating Labor	$16,797	A = Based on 0.5 hour per shift, 3 shifts per day
Supervisory Labor	$2,520	B = 15% of operating labor
Maintenance Labor	$17,602	C = Based on 0.5 hour per shift, 3 shifts per day
Maintenance Materials	$17,602	D = Equivalent to maintenance labor
Caustic Costs	$799,540	E = Mass of NaOH to neutralize SO2 times chemical cost plus 10% waste (based on example in July 2020 Draft Section 5 Control Cost Manual)
Electricity Usage	1,416 kWh	Power (kWh) ratioed based on AFPA values.
Cost of Electricity Usage	$936,619	F = E × Electricity Cost
Fresh Water	$58,071	G = Freshwater use * water cost
Water Disposal	$4,304	H = Water disposal amount * disposal cost
Total Direct Operating Costs (DOC)	***$1,853,055***	***DOC = A + B + C + D +E + F + G + H***
Indirect Operating Costs (IOC)		
Overhead	$32,713	H = 60% × (A + B + C + D)
Property Tax	$181,780	I = 1% × TCI
Insurance	$181,780	J = 1% × TCI
Administrative Charges	$363,560	K = 2% × TCI
Total Indirect Operating Costs (IOC)	***$759,833***	***IOC = H + I + J + K***
Total Annualized Cost (AC) =	**$3,796,278**	*AC = CRC + DOC + IOC*
SO_2 Uncontrolled Emissions (tpy)	618.07	
SO_2 Removed (tpy)	605.71	98.0% Removal Efficiency
Cost per ton of SO2 Removed ($/ton)	**$6,267**	**$/ton = AC / Pollutant Removed**

1. TCI Per AFPA BE & K Study, 2001 ratioed to 2019 dollars.
2. U.S. EPA OAQPS, EPA Air Pollution Control Cost Manual Draft, July 2020, Section 5 SO_2 and Acid Gas Controls.

GOLDER

REPORT

REASONABLE PROGRESS FOUR-FACTOR ANALYSIS

JEA Northside Generating Station (NGS)

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Table of Contents

1.0 INTRODUCTION

EPA's regional haze program requirements are contained in 40 CFR Part 51.308. The regional haze program requires the States to achieve reasonable progress toward natural visibility conditions in the Class I areas by 2064. Under the program, States must submit a regional haze State Implementation Plan (SIP) every ten years (each implementation period) to protect visibility in Class I areas. SIPs must contain Reasonable Progress Goals (RPGs) expressed in deciviews that provide for reasonable progress towards achieving natural visibility conditions. The RPGs must provide for an improvement in visibility for the most impaired days over each 10-year implementation period and ensure no degradation in visibility for the least impaired days over the same period. The first implementation period ended in December 2017. The second implementation period is from 2018 to 2028 and the SIPs are due to EPA by July 31, 2021.

Per the regional haze rule, States must evaluate progress-to-date from the 2000-2004 baseline visibility conditions and determine whether any cost-effective emission reduction measures and strategies are available to ensure reasonable progress toward natural visibility conditions in the current implementation period. According to the EPA Guidance on Regional Haze SIP for the Second Implementation Period (August 2019), the Florida Department of Environmental Protection (FDEP) must select sources for reasonable progress analysis. FDEP has selected several sources in FL based on regional haze 2028 modeling performed by SESARM/VISTAS and their relative contribution to visibility impairment in Class I areas located both inside and outside FL. The JEA Northside Generating Station (NGS) is one of the selected sources with SO_2 emissions affecting visibility in the Wolf Island National Wildlife Refuge and is subject to reasonable progress analysis.

The main SO_2 and NO_X emissions sources at the NGS are circulating fluidized-bed (CFB) Boiler Nos. 1 and 2 (EUs 026 and 027) and Boiler No. 3 (EU 003). NGS Units 1 and 2 are equipped with selective non-catalytic reduction (SNCR) system to control NO_X emissions and limestone injection and spray dryer absorber (SDA) to control SO_2 emissions. As explained in JEA's August 10, 2020 letter to DEP (incorporated as Attachment A), Units 1 and 2 meet EPA's criteria for being "effectively-controlled," and thus are exempt from the requirement to undergo a four-factor analysis. NGS Unit 3 does not have add-on controls for SO_2. Note that Unit 3 is the only Best Available Retrofit Technology (BART) eligible emission unit at the facility and a BART determination for the unit was performed in 2012. BART eligible emissions units are those that were targeted for the reduction of visibility impairing pollutants in the first regional haze rule implementation period. The BART analysis determined that add-on control technologies for SO_2, NO_X, or PM were not cost effective. This report reiterates the effectively controlled analysis for Units 1 and 2 and provides a four-factor reasonable progress analysis for Unit 3.

As stated in the Clean Air Act (CAA) Section 169A(g)(1), the following four statutory factors are assessed in determining reasonable progress:

- The cost of control
- Time necessary to install controls
- Energy and non-air quality impacts
- Remaining useful life

The projected visibility benefits of a measure may also be considered in determining whether a measure is reasonable, as explained in EPA's 2019 Guidance. Further, in its June 22, 2020 letter to JEA, DEP requested that JEA include the control effectiveness and emission reductions for each technically feasible measure.

These factors were evaluated for possible SO_2 control strategies that could reduce the emissions potential of these pollutants. These factors were previously included in the five-step BART determination analysis performed for Unit 3 in 2012 for SO_2, NO_x, and PM, which also included visibility improvement reasonably expected from the technology. As a result, this current four-factor reasonable progress analysis involves updating the prior five-factor BART analysis, based on current information.

A description of the emissions units at the NGS is presented in Section 2.0. The methodology is presented in Section 3.0 and the four-factor analysis is presented in Section 4.0.

2.0 DESCRIPTION OF EMISSION UNITS

The JEA NGS is currently operating under Title V Air Operating Permit No. 0310045-053-AV and operates the following main SO_2 emissions sources:

- CFB Boiler Nos. 1 and 2 (EUs 027 and 026)
- Boiler No. 3 (EU 003)

CFB Boiler Nos. 1 and 2

CFB Boilers 1 and 2 fire a combination of natural gas, coal, petcoke, and biomass and the emissions are controlled using a combination of add-on control technologies. The SO_2 emissions from the Boilers 1 and 2 are controlled by limestone injection and SDA, and NO_X emissions are controlled by SNCR. As explained in JEA's August 10, 2020 letter to DEP (Attachment A), and in accordance with EPA's 2019 Guidance, Units 1 and 2 meet EPA's criteria for being considered effectively controlled, and thus are exempt from the requirement to conduct a four-factor analysis.

Boiler No. 3

Unit 3 does not have add-on emission controls. NGS Unit 3 began commercial operation in 1977 and has a maximum design heat input of 5,260 MMBtu/hr for firing natural gas and 5,033 MMBtu/hr for firing No. 6 fuel oil. Sulfur content of No. 6 fuel oil is limited to 1.8 percent by weight. Although fuel oil firing is not limited, Unit 3 currently meets the definition of a natural gas-fired electric utility steam generating unit as defined in 40 CFR 63.10042, based on its limited use of oil, and thus is exempt from the requirements of MATS. The current Title V permit has a permitting note stating that if the unit becomes an oil-fired electric utility steam generating unit as defined in 40 CFR 63.10042, it will be subject to the applicable requirements of MATS. An oil-fired electric utility steam generating unit is defined as a unit that burns oil for more than 10.0 percent of the average annual heat input during the 3 previous calendar years or for more than 15.0 percent of the annual heat input during any one of those calendar years. As reflected by the unit's exempt status as related to MATS, oil firing in NGS Unit 3 has been less than 10 percent of the annual heat input on average, which is equivalent to 876 hrs/yr at full capacity.

In 2012, a BART determination was performed for NGS Unit 3 regarding regional haze impacts at the following PSD Class I areas within 300 kilometers (km) of the NGS:

- Okefenokee National Wilderness Area (NWA) – 63 km
- Wolf Island NWA – 100 km
- Chassahowitzka NWA – 217 km
- Saint Marks NWA – 240 km

This BART determination concluded that add-on control technologies were not cost effective and no additional control technologies were installed for the boiler. The BART emissions limits were determined to be the existing emissions limits for the unit, which are:

- NO_X – 0.3 lb/MMBtu
- SO_2 – 1.98 lb/MMBtu and No. 6 fuel oil sulfur content not exceeding 1.8% by weight
- PM – 0.1 lb/MMBtu for normal operation and 0.3 lb/MMBtu for soot-blowing operation

3.0 METHODOLOGY

The CAA and the Regional Haze Rule provide a process for states to follow to determine what is necessary to make reasonable progress in Class I areas towards natural visibility conditions. In general, this process involves a state evaluating what emission control measures are reasonably necessary for its sources in light of the four statutory factors and five additional considerations specified in the Regional Haze Rule (40 CFR 51.308(f)(2)). According to the EPA's 2019 Guidance, key steps in developing the regional haze SIP include:

- Identify the 20 percent most anthropogenically impaired days and the 20 percent clearest days and determine baseline, current, and natural visibility conditions for each Class I area within the state.
- Determine which Class I area(s) in other states may be affected by the state's own emissions.
- Select emissions sources for reasonable progress analysis.

There are three Class I areas in Florida and three Class I areas outside Florida that are most impacted by sources in Florida. EPA has completed regional haze modeling for 2028 and visibility conditions in each Class I area are compared to a uniform rate of progress (URP) from baseline conditions (2000-2004 visibility) to natural visibility conditions in 2064. Based on visibility monitoring data (2017 data), the actual visibility for the 20 percent most impaired days are below the URP, which means the actual visibility is better than the target level to maintain URP. The EPA 2028 modeling results also show that visibility in 2028 for the 20% most impaired days will be below the URP.

The VISTAS is assisting the 10 SEASRM states including Florida to develop the regional haze SIPs for the second implementation period which are due by July 31, 2021. VISTAS has performed regional scale air dispersion modeling to estimate regional haze and progress goals at southeastern state Class I areas in projection year 2028. VISTAS has also performed area of influence analysis to identify visibility impairment contributions from major point sources to Class I areas in the modeling domain and Particulate Matter Source Apportionment Technology (PSAT) modeling to quantify visibility impacts from individual point sources. Results from the VISTAS analysis are used to select sources for reasonable progress analysis, as described further below.

The following steps are used in selecting the sources for reasonable progress analysis:

- Develop area of influence analysis
- Identify sources to tag for PSAT source-apportionment modeling
- Analyze projected visibility impairment of tagged sources
- Identify threshold for selecting sources
- Eliminate "effectively-controlled" sources
- Perform reasonable progress analysis on remaining sources

Based on the source contribution analysis performed by VISTAS, NGS contributes more than 1% of the total sulfate impacts at the Wolf Island NWA Class I area and as a result, NGS has been selected as a source for reasonable progress analysis. NGS Units 1 and 2 are exempt as effectively controlled sources and as a result, a four-factor reasonable progress analysis is only required for NGS Unit 3. The four-factor reasonable progress analysis considers emission reduction measures and strategies against four factors to identify whether any are available for ensuring reasonable progress toward natural visibility conditions. The CAA section 169(A)(g)(1) lists the four factors:

- Cost of compliance
- Time necessary for compliance
- Energy and non-air quality environmental impacts of compliance
- Remaining useful life

In addition, EPA's 2019 Guidance, on page 34, specifically provides that the visibility benefits of a particular measure may also be considered as part of the analysis. These factors are described briefly in the following sections.

Factor 1 – Costs of Compliance

For purposes of the second implementation period, EPA recommends that states follow the source type-relevant recommendations in the EPA Air Pollution Control Cost Manual that are stated in the manual as applying to cost estimates in a permitting context.

Once the control technology alternatives and achievable emissions performance levels have been identified, then the source must develop estimates of capital and annual costs. The basis for equipment cost estimates also should be documented, either with data supplied by an equipment vendor (i.e., budget estimates or bids) or by a referenced source (such as the EPA's Control Cost Manual). To maintain and improve consistency, cost estimates should be based on the Control Cost Manual, where possible. The Control Cost Manual addresses most control technologies in sufficient detail for a reasonable progress analysis. The cost analysis should also take into account any site-specific design or other conditions that affect the cost of a particular BART technology option.

Cost effectiveness, in general, is a criterion used to assess the potential for achieving an objective in the most economical way. For purposes of air pollutant analysis, "effectiveness" is measured in terms of tons of pollutant emissions removed, and "cost" is measured in terms of annualized control costs. The EPA recommends two types of cost effectiveness calculations: average cost effectiveness and incremental cost effectiveness.

Average cost effectiveness means the total annualized costs of control divided by annual emissions reductions (the difference between baseline annual emissions and the estimate of emissions after controls). Because costs are calculated in (annualized) dollars per year and emission rates are calculated in TPY, the result is an average cost effectiveness number in (annualized) dollars per ton of pollutant removed.

The baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source. In general, the anticipated annual emissions will be estimated based upon actual emissions from a baseline period. For air permitting purposes, baseline actual emissions are normally based on the highest consecutive 24-month average emissions that occurred over the last 5 or 10 years.

In addition to the average cost effectiveness of a control option, the incremental cost effectiveness should also be calculated. The incremental cost effectiveness calculation compares the costs and performance level of a control option to those of the next most stringent option, as shown in the following formula (with respect to cost per emissions reduction):

Incremental Cost effectiveness (dollars per incremental ton removed) =

$$\frac{\text{(Total annualized costs of control option)} - \text{(Total annualized costs of next control option)}}{\text{(Control option annual emissions)} - \text{(Next control option annual emissions)}}$$

Factor 2 – Time Necessary for Compliance

This factor involves estimating the time needed for a source to comply with a potential control measure. The time needed to install a control measure should be reasonable and should be accomplished within the 10-year implementation period (absent justification for a longer period). Unlike for BART, there is no requirement in the Regional Haze Rule that emission control measures that have been determined to be necessary to make reasonable progress must be installed as expeditiously as practicable or within 5 years of EPA's approval of the SIP revision.

Factor 3 – Energy and Non-Air Quality Environmental Impacts

The energy requirements of the control technology should be analyzed to determine whether the use of that technology results in energy penalties or benefits. If such benefits or penalties exist, they should be quantified to the extent practicable. Because energy penalties or benefits can usually be quantified in terms of additional cost or income to the source, the energy impact analysis can, in most cases, simply be factored into the cost impacts analysis.

The energy impact analysis should consider only direct energy consumption and not indirect energy impacts. The energy requirements of the control options should be shown in terms of total (and in certain cases, also incremental) energy costs per ton of pollutant removed. These units can then be converted into dollar costs and, where appropriate, factored into the control cost analysis.

Non-air quality related environmental impacts of a particular measure can include solid or hazardous waste generation and discharges to nearby water bodies from a control device. Some control technologies may have potentially significant secondary environmental impacts. Scrubber effluent, for example, may affect water quality and land use. Alternatively, water availability may affect the feasibility and costs of wet scrubbers. Other examples of secondary environmental impacts could include hazardous waste discharges, such as spent catalysts or contaminated carbon.

In general, the analysis need only address those control alternatives with any significant or unusual environmental impacts that have the potential to affect the selection of a control alternative, or elimination of a more stringent control alternative. Thus, any important relative environmental impacts (both positive and negative) of alternatives can be compared with each other.

Factor 4 – Remaining Useful Life

The analysis of the fourth factor involves collecting information on how long the source will remain in operation and the lifetime of potential control measures. The remaining useful life of the source may be treated as one element of the overall cost analysis. The "remaining useful life" of a source, if it represents a relatively short time period, may affect the annualized costs of retrofit controls. For example, the methods for calculating annualized costs in EPA's Control Cost Manual require the use of a specified time period for amortization that varies based upon the type of control.

If a control measure involves only operational changes, there typically will be only small capital costs, if any, and the useful life of the source or control equipment will not materially affect the annualized cost of the measure. The Control Cost Manual provides guidance on typical values for the useful life of various emission control systems used at stationary sources. EPA recommends that states use these values.

Factor 5 – Visibility Benefits (Optional)

Visibility benefits associated with the control measures can also be considered along with the four statutory factors. Visibility benefit of a control measure is expressed in units of light extinction (inverse megameters, Mm-1) and it can be calculated by making two air quality modeling runs, with and without the measure assumed to be in place. However, if a source's impacts on ambient PM species under a particular emissions scenario have been determined through source apportionment/attribution, it is appropriate to estimate the reductions in ambient PM species due to pollutant-specific emission reductions from the source by assuming a proportionality between source emissions of the relevant species precursor and the ambient PM species concentration. The PM species concentrations with and without the measure can then be used to estimate the light extinction benefit of the measure.

4.0 FOUR-FACTOR ANALYSIS

The VISTAS analysis identifies sulfate as the most contributing pollutant to visibility degradation and selected NGS based on it sulfate contribution of 1.29% to the Wolf Island Class I area (slightly more than VISTAS 1% threshold). This reasonable progress analysis therefore focuses on the reduction of SO_2 emissions from Unit 3. Note that on an annual basis, fuel oil is not fired in Unit 3 for more than 10% of the total annual heat input and the unit is considered as a natural gas-fired electric utility steam generating unit.

Based on the AOR data, following are the oil-firing related information for Unit 3 in the period 2011-2019:

- Maximum oil consumed – 1,817,000 gallons or 2.4% of the total annual heat input in 2011 (1,697,000 gallons or 1.35% of the total annual heat input in most recent 5 years)
- Maximum oil sulfur content – 1.7% by weight in 2011 (based on AOR data)

Following are the actual annual SO_2 emissions in tons/yr from oil-firing based on actual oil usage and sulfur content reported in the AORs:

	2011	2012	2013	2014	2015	2016	2017	2018	2019
SO_2 – oil-firing	256.4	85.2	0	83.0	56.1	154.2	4.2	236.6	9.2

The baseline SO_2 emissions and oil usage were estimated from 2-year average of 2018-2019:

- Baseline emissions – 122.9 tpy
- Baseline oil usage – 882,000 gal/yr

Oil-firing in Unit 3 is already a small fraction of the unit's total annual usage. Following is the actual oil usage as a percentage of the total actual annual heat input in the most recent 5-year period:

	Total Annual Heat Input (MMBtu/yr)	Oil-Firing (%)
2019	18,755,650	0.05%
2018	18,671,190	1.35%
2017	13,311,112	0.03%
2016	14,176,553	1.19%
2015	11,641,668	0.53%

4.1 Available SO_2 Control Technologies Considered

The RACT/BACT/LAER Clearinghouse (RBLC) on EPA's webpage has no recent (within the past 10 years) SO_2 RACT/BACT/LAER examples for large size (>250 MMBtu/hr) oil-fired boilers. While there are numerous examples available in the RBLC database for large coal-fired boilers using flue gas desulfurization (FGD) determined as BACT for SO_2 emissions, SO_2 emissions reduction from large utility oil-fired boilers have been largely based on the use of low-sulfur fuels.

Lower Sulfur No. 6 Fuel Oil

Unit 3 currently burns natural gas, landfill gas, and residual (No. 6) fuel oil. Although the sulfur content of natural gas and landfill gas are typically very low, sulfur content of liquid fossil fuels such as No. 6 fuel oil can range from 0.3 percent to more than 2 percent. Unit 3 is currently permitted to fire No. 6 fuel oil with a maximum sulfur content of 1.8 percent. Switching to a lower-sulfur No. 6 fuel oil can reduce SO_2 emissions; however, the cost of compliance depends on the following:

- Cost difference for lower sulfur No. 6 fuel oil
- Difference in delivery cost for the lower-sulfur fuel oil

Lower Sulfur Fuel using No. 2 Fuel Oil

The use of lower sulfur fuel has been recognized by EPA as an available SO_2 emissions control method in the promulgatin of its BART requirements. Low-sulfur No. 2 fuel oil has a sulfur content of 500 ppm or 0.05 percent by weight and ultra low-sulfur diesel fuel has a sulfur content of 15 ppm or 0.0015 percent by weight. Switching to low-sulfur or ultra low-sulfur diesel fuel can also reduce SO2 emissions from the use of residual fuel oil and the cost of compliance will depend on cost difference of the No. 2 fuel, storage of the new fuel, and retrofitting Unit 3 to fire No. 2 fuel oil.

Post Combustion Controls

Post-combustion SO2 controls consist primarily of flue gas desulfurization (FGD) systems, commonly referred to as scrubbers. FGD systems rely on chemical reactions within the control device to reduce the concentration of SO_2 in the flue gas. The chemical reaction with an alkaline chemical, which can be performed in a wet or dry contact system, converts SO_2 to sulfite or sulfate salts. Based on the EPA Fact Sheet on FGD systems, typical industrial applications of FGD systems are stationary coal and oil-fired combustion units such as utility and industrial boilers. As shown by the RBLC database, use of a wet or dry FGD system for oil-fired boilers similar in size to Unit 3 is not common. Post-combustion controls are typically applied to coal-fired boilers. The EPA Fact Sheet also mentions the high capital cost of an FGD system as a disadvantage. Based on the cost range provided by EPA in the Fact Sheet for FGD system (EPA-452/F-03-034), the capital cost of a wet FGD system for Unit 3 may range between $70 million to $180 million (2001 dollars converted into May 2020 dollars using Producer Price Index for Total Manufacturing Industries).

4.2 Control Technology Feasibility

Emissions of SO_2 are directly proportional to fuel oil sulfur content. Unit 3 is currently permitted to fire No. 6 fuel oil with a maximum sulfur content of 1.8 percent. Switching to a lower-sulfur No. 6 fuel oil or No. 2 fuel oil can reduce SO_2 emissions proportional to the magnitude of the sulfur reduction. Based on information from the Energy Information Administration, low sulfur No. 6 fuel oil is defined as having sulfur content of 1.0 percent or less. No. 2 fuel oil has even lower sulfur content of 0.05 percent or 0.0015 percent (ultra-low sulfur diesel).

Although there is a cost premium for low sulfur No. 6 fuel oil or No. 2 fuel oil, both are considered to be technically feasible control technologies.

Since Unit 3 already burns No. 6 fuel oil, switching to a lower sulfur content No. 6 fuel oil option is best suited for the unit and least expensive. Although technically feasible, FGD systems have not been determined as BACT for large fuel oil-fired boilers in the last 10 years.

4.3 Factor 1 – Cost of Compliance

Use of lower sulfur No. 6 fuel oil, switching to No. 2 fuel oil, or use of FGD as an add-on control technology, all are technically feasible options, however none are cost effective. Unit 3 is currently permitted to burn 1.8-percent sulfur No. 6 fuel oil and is expected to have useful remaining life of approximately 20 years. Switching to lower sulfur content No. 6 fuel oil is the least expensive option among the three alternatives since additional design changes would not be necessary, as they would for burning No. 2 fuel oil or installing a FGD system.

The US Energy Information Administration (EIA) provides cost information for residual fuel categories of less than or equal to 1 percent sulfur and greater than 1 percent sulfur. The greater than 1 percent sulfur fuel oil usually has sulfur content in the range between 1.5 and 2 percent. The less than or equal to 1 percent sulfur oil usually has sulfur content in the range 0.7 to 1 percent. Based on latest JEA fuel data, the cost of 1.8% sulfur residual fuel oil is $1.04 per gallon and according to the EIA (Petroleum Marketing Monthly, October 2020) data the 1% or less sulfur residual fuel cost is $1.153 per gallon. The cost of compliance to use reduced sulfur No. 6 fuel oil is represented by the differential cost of these fuel types. Based on EIA information, the cost for ultra low-sulfur diesel (ULSD) is $1.437 per gallon (July 2020 price). After adding a transportation cost of $0.09 per gallon (JEA data), the cost for ULSD is $1.527 per gallon, which is $0.487 more expensive than No. 6 fuel oil with sulfur content higher than 1 percent. The actual fuel usage for the baseline period was estimated based on the 2-year average actual heat input from oil firing for the period 2018-2019.

The cost analysis for switching to either lower sulfur No. 6 or No. 2 fuel oil was prepared following EPA's Control Cost Manual and is presented in Table 1. The 1.0-percent sulfur fuel oil has much less viscosity than the 1.8-percent sulfur fuel oil and therefore, modifications are needed for the unit to accept the lower viscosity fuel. Based on JEA estimate, a modification cost of approximately $1,000,000 will be needed, which includes inspection of burner and booster pumps, burner tuning/optimization, replacement of instrumentation, and test burns to determine boiler performance. For burning No. 2 fuel oil, new burners will be needed for a minimum cost of $1,000,000. A new fuel oil tank will not be needed for lower sulfur No. 6 fuel oil since the facility already burns No. 6 fuel oil and the existing fuel tank can be used to hold the lower sulfur fuel oil. For switching to No. 2 fuel oil, a new tank will be needed. According to JEA estimate a new No. 2 fuel oil tank and associated piping will cost approximately $6,000,000. No operation or maintenance costs were used in the cost analysis because no change is expected to these costs. The direct operating cost associated with the lower sulfur fuel oil usage was estimated based on the cost of the less than 1% sulfur No. 6 oil or ultra low-sulfur No. 2 oil for the amount equal to the baseline fuel oil usage. A 20-year life and 7% interest rate was used for estimating capital recovery cost.

The cost analysis for adding a FGD system is presented in Table 2. The cost calculation was developed using capital, fixed operation and maintenance (O&M) and variable O&M costs that are available on a $/kW basis as part of EPA's Integrated Planning Model (IPM) Base Case v. 4.10 (9-1-2010) for Transport Rule; Documentation; Chapter 5, Emission Control Technologies. These cost models were developed by engineering contractors such as Sargent & Lundy for the wet-FGD cost model. Additionally, cost factors from the EPA Cost Control Manual (EPA, 1996) were used to include those costs not included in the EPA IPM cost model. Annualized costs were developed using the methodology in the EPA Cost Control Manual. As shown in Table 2, the annualized cost was for a FGD system was estimated to be $39.0 million. A 98 percent control efficiency was assumed for the FGD system.

As shown in Tables 1 and 2, the cost effectiveness values were estimated to be as follows:

- Switching to lower sulfur No. 6 fuel oil - $6,969/ton of SO_2 removed
- Switching to No. 2 fuel oil - $19,881/ton of SO_2 removed
- Wet FGD system – $324,141/ton of SO_2 removed

4.4 Factor 2 – Time Necessary for Compliance

Switching to a lower sulfur No. 6 fuel oil or No. 2 fuel oil will require the following major steps:

- Retention of a vendor to inspect the burner and booster pumps
- New burner installation and replacement of instrumentation
- Burner tuning/optimization and test burn
- Burner replacement for No. 2 fuel oil
- Sell the existing high sulfur No. 6 fuel oil and empty the tank
- Tank cleanup and get it filled with low-sulfur No. 6 fuel oil or No. 2 fuel oil
- Air permitting from FDEP for the authorization of the change in the methodology of operation

JEA estimates that the time necessary to complete the fuel switching would be approximately nine months to a year. A boiler outage of approximately two to three months would be necessary to perform the new burner installation. Installing a wet FGD system is expected to take longer due to the need for engineering design, equipment procurement and installation, and installation and testing. EPA IPM model estimates the engineering, procurement and installation would take about 36 months.

4.5 Factor 3 – Energy and Non-Air Quality Environmental Impacts

There are no energy impacts associated with using lower sulfur fuel oil since the heating value is expected to remain the same with lower sulfur content. Use of lower sulfur fuel oil also does not result in any non-air quality environmental impacts.

Wet-FGD has considerable energy penalties due to the pressure drop through the absorbers and the energy usage by auxiliary systems. The latter included limestone preparation, pumps for limestone slurry, fans for forced oxidation, etc. The pressure drop will be about 8 inches, which will require about 0.5 percent of the power generated. The auxiliary systems require about 2.5 percent of the power produced. The total energy impacts would be about 30,000 MWh for the maximum possible operation of Unit 3 currently authorized.

Operation of wet-FGD will also require the delivery, handling and storage of limestone, and the handling and disposal of FGD by-product (i.e., gypsum). In addition, process water is required that results from flue gas quenching, limestone slurry preparation and flue gas saturation. The delivery of limestone and removal of FGD byproducts from the plant would generate significant amount of truck trips in and out of the plant.

4.6 Factor 4 – Remaining Useful Life

JEA is evaluating retirement of Unit 3 but has no definitive plans to shut it down yet. It is however expected to remain in service for no longer than 20 years. A remaining useful life of 20 years was used in estimating annualized cost of switching from the currently permitted 1.8% S No. 6 fuel oil to less than 1% S No. 6 fuel oil or No. 2 fuel oil.

4.7 Visibility Benefits

Based on VISTAS PSAT modeling (April 2020) results, total light extinction (that causes visibility degradation) caused at the Wolf Island NWR due to the SO_2 and sulfate emissions from JEA NGS is 0.163 inverse megameters (Mm-1). VISTAS used a total 14,917 tpy of SO_2 and 6.3 tpy of sulfate emissions from JEA Northside in the modeling for 2011 including 312 tpy of SO_2 from Unit 3 (2.1 percent of total). Other major JEA emissions units included in the 2011 modeling are NGS Units 1 and 2 and SJRPP Units 1 and 2. Although emissions from individual units may not be directly proportional to individual contribution to the total light extinction, it can be estimated that Unit 3 for its 2.1 percent of the total modeled SO_2 emissions, caused a light extinction of approximately 0.0034 Mm-1, which is a negligible contribution. Lowering SO_2 emissions from Unit 3 is therefore, not going to cause a meaningful reduction in light extinction and improve visibility.

4.8 Analysis

JEA expects to maintain the natural gas-firing electric utility steam generating unit status for Unit 3; fuel oil usage in Unit 3 is extremely limited. The almost exclusive use of natural gas effectively controls SO_2 emissions. Within the most recent 5-year period, Unit 3 fired fuel oil for a maximum of only 1.35% of the total annual heat input. In its 2020 Ten Year Site Plan submitted to the Florida Public Service Commission, JEA does not project the use of residual oil to meet generation needs (JEA, 2020). Therefore, the actual SO_2 emissions emitted from Unit 3 are currently low and are expected to remain low through 2029. As shown in Table 1, any further reduction in SO_2 emissions using the most feasible and least expensive option of switching to a lower sulfur No. 6 fuel oil is not cost effective and would have a nominal impact on visibility improvement. Add-on control technologies such as an FGD will have a significant capital cost that is orders of magnitude higher than fuel switching (from none to over $200 million). In addition, add-on SO_2 control is not cost effective even if the percent reduction in SO_2 emissions may be higher ($6,969 and $19,881 per ton of SO_2 removed compared to over $300,000 per ton of SO_2 removed). Based on an analysis of the four statutory factors, plus visibility, the conclusion is that no other measures including add-on controls for Unit 3 are reasonable.

5.0 CONCLUSION

DEP selected JEA NGS Units 1, 2, and 3 for further evaluation as part of DEP's Reasonable Progress submittal for the second Regional Haze implementation period. NGS Units 1 and 2 meet EPA's criteria for being considered effectively controlled, and thus are exempt from the requirement to conduct a four-factor analysis. For NGS Unit 3, JEA identified technically feasible measures such as switching to lower sulfur No. 6 fuel oil, and switching to No. 2 fuel oil, or adding a wet FGD system and analyzed these measures using EPA's four-factor approach. JEA also evaluated the potential improvement in visibility that can be achieved by lowering SO_2 emissions from Unit 3, which appears negligible. Based primarily on the cost and the negligible amount of visibility improvement that can be achieved by lowering SO_2 emissions from Unit 3, none of the control measures are determined to be reasonable for this implementation period.

6.0 REFERENCES

JEA 2020 Ten-Year Site Plan (TYSP).

Florida Department of Environmental Protection (FDEP). Regional Haze Second Implementation Period Outreach Webinar, January 2020.

U.S. Environmental Protection Agency (EPA). Guidance on Regional Haze Implementation Plans for the Second Implementation Period, August 2019.

U.S. Environmental Protection Agency (EPA). 40 CFR Part 51, July 2005. Regional Haze Regulations and Guidelines for Best Available Retrofit (BART) Determinations.

U.S. Environmental Protection Agency (EPA). Cost Control Manual, Fifth Edition, EPA-4531B-96-001. February 1996.

U.S. Environmental Protection Agency (EPA) IPM Model – IPM v6 - Emission Control Technologies Attachment 5-1: Wet FGD Cost Development Methodology; Updates to Cost and Performance for APC Technologies Wet FGD Cost Development Methodology, Final January 2017; Sargent and Lundy.

Visibility Improvement State and Tribal Association of the Southeast (VISTAS) Regional Haze Project Update, April 2020.

Tables

Table 1. Cost Effectiveness of Fuel Switching for NGS Unit 3

Cost Items	Cost Factors	No. 6 Fuel Oil ≤1.0% S Fuel Cost ($)	No. 2 Fuel Oil (0.05%S or ULSD) Cost ($)
DIRECT CAPITAL COSTS (DCC):			
(1) Equipment Cost			
(a) New Fuel Oil Storage tank	New tank will not be needed	0.0	6,000,000.0
(b) Pumps, piping, etc.	NA	0.0	0.0
(c) New oil guns/atomizer sprayer plates	New fuel injectors for No. 2 oil	0.0	1,000,000.0
(3) Sales Tax	NA	0.0	0.0
Subtotal: Total Equipment Cost (TEC)		0.0	7,000,000.0
(4) Direct Installation Costs	NA	0.0	0.0
Total DCC:		0.0	7,000,000.0
INDIRECT CAPITAL COSTS (ICC): [a]			
(1) Indirect Installation Costs			
(a) Engineering	10% of TEC	0.0	700,000.0
(b) Construction & Field Expenses	10% of TEC	0.0	700,000.0
(c) Construction Contractor Fee	10% of TEC	0.0	700,000.0
(d) Contingencies	3% of TEC	0.0	210,000.0
(e) Modifications to Unit 3 [b]	Unit 3 modifications to accept lower sulfur fuel, JEA data	$1,000,000	$1,000,000
(2) Other Indirect Costs			
(a) Startup	1% of TEC	0.0	70,000.0
(b) Performance Test'	1% of TEC	0.0	70,000.0
Total ICC:		1,000,000.0	3,450,000.0
PROJECT CONTINGENCY	15% of (DCC+ICC)	150,000.0	1,567,500.0
TOTAL CAPITAL INVESTMENT (Total Plant Cost) (TCI):	DCC + ICC+Project Contingency	1,150,000.0	12,017,500.0
DIRECT OPERATING COSTS (DOC):			
(1) Variable Operation & Maintenance Cost	Assumed zero	0	0
(3) Fuels			
Differential Fuel Cost (From >1.0%S to ≤1.0%S) [c]	$1.153/gal - $1.04/gal, 1,697,000 gallons/yr	$191,761	--
Differential Fuel Cost (From >1.0%S No. 6 oil to ULSD) [d]	$1.527/gal ULSD - $1.04 high sulfur No. 6, 1,697,000 gallons/yr	--	$826,439
Total DOC:		$191,761	$826,439
INDIRECT OPERATING COSTS (IOC): [a]			
(1) Overhead	60% of oper. labor & maintenance, CCM Chapter 2	0.0	0.0
(2) Property Taxes	1% of total capital investment, CCM Chapter 2	11,500.0	120,175.0
(3) Insurance	1% of total capital investment, CCM Chapter 2	11,500.0	120,175.0
(4) Administration	2% of total capital investment, CCM Chapter 2	23,000.0	240,350.0
Total IOC:	(1) + (2) + (3) + (4)	46,000.0	480,700.0
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	108,560.0	1,134,452.0
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	$346,321	$2,441,591
Baseline Emissions [e]	2-year average for the period 2018-209 (from AOR Data)	122.9	122.9
Projected Future Emission [f]:	2-year average oil usage, 1% S, 8.3 lb/gal	73	--
Projected Future Emission [f]:	2-year average oil usage, 0.0015% S, 7.1 lb/gal	--	0.09
Emissions Reduction (TPY)(AC):	Baseline - Future Emissions (TPY)	50	122.8
Average Cost Effectiveness ($/ton):	AC/Emissions Reduction	$6,969	$19,881

Notes:

[a] Factors and cost estimates reflect OAQPS Cost Manual, 6th Edition, January 2002.

[b] Unit 3 will need to be modified to accept low viscosity ≤1.0 S fuel or No. 2 disel fuel oil.

[c] Based on differential fuel cost of >1% S oil and <1% S oil and projected actual oil usage.
Current fuel cost based on JEA fuel purchase data. Fuel cost for 1% S or less is based on EIA data (July 2020 price).

[d] Cost of ULSD based on EIA Petroleum Marketing Monthly (October 2020) and adding a transportation cost of $0.09/gal.

[e] Maximum 2-year average actual SO_2 emissions for the period 2018-2019.

[f] Maximum 2-year average oil usage for the period 2018-2019, 1% S, 8.3 lb/gal.

Table 2. Cost Effectiveness of Wet-Flue Gas Desulfurization (FGD) for NGS Unit 3

Cost Items	Cost Factors	Wet-FGD Cost ($)
DIRECT CAPITAL COSTS (DCC):		
(1) Equipment Cost		
(a) Limestone FGD	$375/kW Base Cost from EPA IPM Retrot Costs [a]	211,387,500.0
(b)	NA	0.0
(c)	NA	0.0
(3) Sales Tax	Exempt	0.0
Subtotal: Total Equipment Cost (TEC)		211,387,500.0
(4) Direct Installation Costs	Included in EPA IPM	0.0
Total DCC:		211,387,500.0
INDIRECT CAPITAL COSTS (ICC): [b]		
(1) Indirect Installation Costs		
(a) Engineering	Included in EPA IPM	
(b) Construction & Field Expenses	Included in EPA IPM	
(c) Construction Contractor Fee	Included in EPA IPM	
(d) Owner's Costs	Included in EPA IPM	
(2) Other Indirect Costs		
(a) Startup	1% of TEC	2,113,875.0
(b) Performance Test'	1% of TEC	2,113,875.0
Total ICC:		4,227,750.0
PROJECT CONTINGENCY	Included in EPA IPM	
TOTAL CAPITAL INVESTMENT (Total Plant Cost) (TCI):	DCC + ICC+Project Contingency	215,615,250.0
DIRECT OPERATING COSTS (DOC):		
(1) Fixed Operation & Maintenance Cost	$8/MWh estimated from EPA IPM CSPR	9,616,858
(2) Fuels		0
Total DOC:		$9,616,858
INDIRECT OPERATING COSTS (IOC): [b]		
(1) Overhead	60% of operation and maintenance (7.72% of DOC), CCM Chapter 2	445,452.9
(2) Property Taxes	1% of total capital investment, CCM Chapter 2	2,156,152.5
(3) Insurance	1% of total capital investment, CCM Chapter 2	2,156,152.5
(4) Administration	2% of total capital investment, CCM Chapter 2	4,312,305.0
Total IOC:	(1) + (2) + (3) + (4)	9,070,062.9
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	20,354,079.6
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	$39,041,000
Baseline Emissions [c]	Max. 2-year average for the period 2018-209 (from AOR Data)	122.9
Projected Future Emission:	98% SO_2 Removal	2
Emissions Reduction (TPY)(AC):	Baseline - Future Emissions (TPY)	120
Average Cost Effectiveness ($/ton):	AC/Emissions Reduction	$324,141

Notes:

[a] EPA IPM Model – Updates to Cost and Performance for APC Technologies Wet FGD Cost Development Methodology, Final January 2017

[b] Factors and cost estimates reflect OAQPS Cost Manual, 6th Edition, January 2002.

[c] Maximum 2-year average actual SO_2 emissions for the period 2018-2019.

Attachment A

August 10, 2020

Mr. Jeff Koerner
Division of Air Resource Management
Florida Department of Environmental Protection (FDEP)
2600 Blair Stone Road, MS #5505
Tallahassee, FL 32399-2000
Email: Jeff.Koerner@dep.state.fl.us

RE: Regional Haze Rule – Reasonable Progress Analysis
Northside Generation Station (NGS) – 0310045

Dear Mr. Koerner:

In response to the Department's June 22, 2020 request to provide information for Northside Generating Station, EU003 (Boiler No. 3), EU026 (Circulating Fluidized Bed (CFB) Boiler No. 2) and EU027 (CFB Boiler No.1), please see below the analysis demonstrating that EU026 and EU027 meet EPA's "effectively-controlled unit" exemption. JEA will submit additional information regarding EU003 separately, in accordance with the Department's request.

Facility Description

Northside Generating Station (NGS) facility consists of three boilers (Boiler No. 3 and CFB Boiler Nos. 1 and 2) and other miscellaneous small emissions sources.

EU003 is an existing, pre-NSPS boiler coupled to a steam turbine-electrical generator (STEG) with a nominal rating of 564 megawatts (MW). This boiler is fired primarily by natural gas, but is also allowed to burn No. 6 fuel oil and used oil. Nitrogen Oxide (NOx) emissions from EU003 are controlled by low NOx burners.

EU026 and EU027 are fired primarily by coal and, petroleum coke (petcoke), but are also permitted to burn biomass. Each CFB boiler is coupled to a STEG rated at 297.5 MW for a combined generating capacity of 595 MW. CFB combustion technology reduces the formation of NOx while also achieving high combustion efficiency to reduce carbon monoxide (CO) and volatile organic compound (VOC) emissions. Each CFB boiler is equipped with a selective non-catalytic reduction (SNCR) system to reduce NOx emissions, fabric filter to control particulate matter (PM) and particulate matter less than 10 microns in diameter (PM10) emissions, and dry limestone injection as well as a spray dryer absorber (SDA, a Flue Gas Desulfurization (FGD) technology, also known as a polishing scrubber) to minimize Sulfur Dioxide (SO_2) emissions.

Regional Haze Requirements

As described in the Department's request, a VISTA (Visibility Improvement – State and Tribal Association of the Southeast) modeling analysis indicated that NGS could potentially influence visibility impairment in nearby Class I areas, primarily with respect to SO_2. As such, FDEP is requesting information for the three boilers at NGS to determine if additional SO_2 emission control and reductions are cost-effective for this implementation period. In accordance with EPA Guidance,[1] states should require such units to submit a four-factor analysis of feasible SO_2 control measures to determine whether additional reductions are cost-effective, but can exempt such units if they are determined to already be "effectively controlled" under an enforceable requirement. EPA's Guidance states that for electric generating units that have add-on FGD systems and that meet the 0.20 lb SO_2/mmBtu limit in the Mercury and Air Toxics Standard (MATS), it is reasonable for a state to determine that that unit is already "effectively controlled."

Permit Conditions

EU026 and EU027 meet EPA's exemption because they utilize an add-on FGD system (SDA) and meet the MATS SO_2 limit, as well as a more-stringent PSD limit of 0.15. These permit conditions are quoted below and can be found on Page 23 of **Attachment A** of this document (Permit No. 0310045-052-AV).

C.10. Sulfur Dioxide. The permittee shall use an SO_2 CEMS to demonstrate compliance with the following emissions standards:

a. SO_2 emissions from each CFB boiler shall not exceed 0.20 lb/MMBtu (24-hour block average) nor 0.15 lb/MMBtu (30-day rolling average), excluding periods of startup, shutdown and malfunction.

b. SO_2 from CFB Boiler Nos. 1 and 2 and existing Boiler No. 3 (EU No. 003) combined shall not exceed 12,284 tons during any consecutive 12-month period on a rolling basis, including startup, shutdown and malfunction.

c. SO_2 emissions from each CFB boiler shall not exceed the NESHAP Subpart UUUUU limit of 0.20 lb/MMBtu heat input (or 1.5 lb/MWh), based on a 30-boiler operating day rolling average.

[40 CFR 63.9991(a)(1) and Table 2 to Subpart UUUUU; Permit No. 0310045-003-AC/PSD-FL-265; and, JEPB Rule 2, Part IV, 2.401]

Conclusion

Northside units EU026 and EU027 meet EPA's "effectively-controlled" exemption from the obligation to submit an analysis of additional SO_2 emission controls for this Regional Haze implementation period. For EU003, JEA will perform a four-factor technical analysis to evaluate SO_2 control measures and will provide it separately.

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[1] https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.

DRAFT

Please do not hesitate to contact Mr. Daniel Nay Hlaing at (904) 665-6247, or Mr. Kevin Holbrooks at (904) 665-4540, if you have any questions.

Sincerely,

Kelsey Hope

Kelsey Hope, P.E.
Environmental Engineer

cc: K. Holbrooks, JEA
D. Hlaing, JEA

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September 2, 2020

(*via e-mail: Jeff.Koerner@FloridaDEP.gov*)
Mr. Jeff Koerner, Director
Division of Air Resource Management
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399

RE: C.D. McIntosh, Jr. Power Plant
Air Permit 1050004-051-AV
Unit 3 (EU 006)

Subject: Regional Haze Rule – Reasonable Progress Analysis

Dear Mr. Koerner:

In response to the Department's letter dated August 18, 2020 requesting information concerning Regional Haze Rule for McIntosh Power Plant Unit 3 (EU 006), please see below the analysis demonstrating that this unit meets EPA's "effectively controlled unit" exemption.

Facility Description

McIntosh Power Plant consists of one fossil fuel fired steam generator, three gas turbines, and other miscellaneous small emissions sources.

McIntosh Unit 3 is a nominal 364 MW fossil fuel fired steam generator that is primarily fired by coal but also fires natural gas. The unit is also allowed to burn low sulfur fuel oil and propane. Unit 3 is equipped with an electrostatic precipitator, a flue gas desulfurization system, a selective catalytic reduction system, low NO_x burners, and an overfire air system to control emissions.

Regional Haze Requirements

As described in the Department's request, McIntosh Unit 3 has been identified as a source of SO_2 emissions that must undergo a reasonable progress analysis. The Department has requested that Lakeland Electric complete and submit either a reasonable progress four-factor technical analysis, or an analysis demonstrating that a four-factor analysis is not required because the unit meets one of the exemptions in EPA's Regional Haze Guidance. EPA's Guidance states that for an electric generating unit that has add-on flue gas desulfurization and that meets the applicable alternative SO_2 emission limit of the 2012 Mercury Air Toxics Standards (MATS) rule for power plants, it is reasonable for a state to determine that the unit is already "effectively controlled" and is therefore exempt from the requirement to complete a four-factor analysis.

501 E. Lemon St. ✦ Lakeland, Florida 33801
Phone: 863.834.6300 ✦ Fax: 863.834.6344

Permit Condition

McIntosh Unit 3 meets EPA's exemption because it utilizes a flue gas desulfurization system and complies with the MATS SO_2 limit of 0.20 lb/MMBtu. This SO_2 limit can be found in Specific Condition C.12.a. of Title V Air Operation Permit 1050004-051-AV (permit attached), and is also copied below:

C.12. SO_2 Emissions. As determined by a CEMS, emissions of SO_2 shall not exceed the following limits.
a. All Fuels. 0.20 lb/MMBtu, based on a 30-operating day rolling average, except during periods of startup and shutdown. {*Permitting Note: The permittee has elected to meet this SO_2 emission limit with compliance demonstrated by a SO_2 CEMS as a surrogate for the hydrogen chloride (HCl) emission limit.*}
[Rules 62-4.070(1) & (3) F.A.C.; 40 CFR 63.9991(a); and Permit Nos. 1050004-038-AC and 1050004-044-AC]

Conclusion

McIntosh Unit 3 meets EPA's "effectively controlled" exemption from the obligation to submit a reasonable progress four-factor technical analysis for this Regional Haze implementation period.

If you have any questions regarding this submittal, please contact our Environmental Coordinator, Nedin Bahtic, at (863) 834-8180 or nedin.bahtic@lakelandelectric.com.

Sincerely,

Stephen Reinhart
Plant Manager

cc: Hastings Read, FDEP (Hastings.Read@FloridaDEP.gov)

ATTACHMENT

TITLE V AIR OPERATION PERMIT 1050004-051-AV

Lakeland Electric
C.D. McIntosh, Jr. Power Plant

Facility ID No. 1050004
Polk County

Title V Air Operation Permit Revision

Permit No. 1050004-051-AV
(1st Revision of Title V Air Operation Permit No. 1050004-049-AV)

Permitting Authority:
State of Florida
Department of Environmental Protection
Division of Air Resource Management
Office of Permitting and Compliance
2600 Blair Stone Road
Mail Station #5505
Tallahassee, Florida 32399-2400

Telephone: (850) 717-9000
Email: DARM_Permitting@dep.state.fl.us

Compliance Authority:
Southwest District Office
13051 North Telecom Parkway
Temple Terrace, Florida 33637-0926

Telephone: (813) 470-5700
E-mail (preferred): SWD_Air@dep.state.fl.us

Title V Air Operation Permit Revision

Permit No. 1050004-051-AV

Table of Contents

Section **Page Number**

FLORIDA DEPARTMENT OF
Environmental Protection

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2600 Blair Stone Road
Tallahassee, FL 32399-2400

Ron DeSantis
Governor

Jeanette Nuñez
Lt. Governor

Noah Valenstein
Secretary

PERMITTEE:
Lakeland Electric
501 East Lemon Street
Lakeland, Florida 33801-5079

Permit No. 1050004-051-AV
C.D. McIntosh, Jr. Power Plant
Facility ID No. 1050004
Title V Air Operation Permit Revision

The purpose of this permit is to revise the Title V air operation permit for the above referenced facility. The existing C.D. McIntosh, Jr. Power Plant is located in Polk County at 3030 East Lake Parker Drive, Lakeland, Florida. UTM Coordinates are: Zone 17, 409.0 kilometers (km) East and 3,106.2 km North. Latitude is: 28° 04' 50" North; and Longitude is: 81° 55' 32" West.

The Title V air operation permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, 62-213, and 62-214. The above-named permittee is hereby authorized to operate the facility in accordance with the terms and conditions of this permit.

Executed in Tallahassee, Florida.

1050004-049-AV Effective Date: November 26, 2018
1050004-051-AV Effective Date: March 11, 2019
Renewal Application Due Date: April 15, 2023
Expiration Date: November 26, 2023

David Lyle Read, P.E.
Digitally signed by David Lyle Read
Date: 2019.03.11 11:10:28 -04'00'

For:
Syed Arif, P.E., Program Administrator
Office of Permitting and Compliance
Division of Air Resource Management

SA/dlr/ead

SECTION I. FACILITY INFORMATION.

Subsection A. Facility Description.

This facility consists of two fossil fuel fired steam generators, three diesel powered engines, and two gas turbines. McIntosh Unit 2 (EU 005) is a nominal 114.7-megawatt (MW) fossil-fuel-fired steam generator that fires natural gas, propane, No. 2 fuel oil or No. 6 fuel oil, with a maximum heat input rate of 1,184.5 million British thermal units per hour (MMBtu/hour). McIntosh Unit 3 (EU 006) is a nominal 364 MW fossil-fuel-fired steam generator that fires coal, low sulfur fuel oil, propane, and natural gas, with a maximum heat input rate of 3,640 MMBtu/hour. Gas Turbine Peaking Unit 1 (EU 004) is a nominal 20 MW gas turbine that fires natural gas or No. 2 fuel oil. McIntosh Unit 5 is a 370 MW combined cycle stationary combustion turbine (CCCT) with a heat recovery steam generator (HRSG). The CCCT fires natural gas or No. 2 (or superior grade) fuel oil. The three diesel engines (EU 008, EU 010, and EU 011) consist of: a 25-horsepower (HP) non-emergency diesel-fired engine; a 300-HP emergency diesel-fired fire pump; and a 500-HP black-start diesel-fired engine. Also, included in this permit are miscellaneous unregulated/insignificant emissions units and/or activities.

Subsection B. Summary of Emissions Units.

EU No.	Brief Description
Regulated Emissions Units	
004	Gas Turbine Peaking Unit 1
005	McIntosh Unit 2 – Fossil-Fuel-Fired Steam Generator
006	McIntosh Unit 3 – Fossil-Fuel-Fired Steam Generator
008	Diesel Drive Coal Tunnel Sump Engine (25 HP)
010	Fire Water UPS Diesel Engine No. 32 (300 HP)
011	CT Startup Diesel Engine (500 HP)
028	McIntosh Unit 5 - 370 MW CCCT
035	Coal Handling and Storage Activities
Unregulated Emissions Units and Activities *(see Appendix U, List of Unregulated Emissions Units and/or Activities)*	
002	Diesel Engine Peaking Unit 2 (Limited Use Engines under 40 CFR 63 Subpart ZZZZ)
003	Diesel Engine Peaking Unit 3 (Limited Use Engines under 40 CFR 63 Subpart ZZZZ)
007	Tanks with Greater Than 10,000-gallon Capacity Installed Prior to July 23, 1984
014	General Purpose Painting
015	Parts Cleaning
016	Sand Blasting (Maintenance only)
018	Three Cooling Towers (Units 2 and 3)
019	Northside Waste Water Treatment Facility - Wastewater Treatment Processes and Tanks
020	Northside Waste Water Treatment Facility - Four Emergency Diesel Generators
021	Northside Waste Water Treatment Facility - Chemical and Petroleum Storage
022	Northside Waste Water Treatment Facility - Miscellaneous Activities
026	Limestone Handling and Storage System
027	Fly Ash Handling and Storage System
029	1.05-million-gallon Storage Tank for McIntosh Unit 5
030	Mechanical Draft Cooling Tower

033	Portable Pumps and Welding Equipment

Subsection C. Applicable Regulations.

Based on the Title V air operation permit renewal application received May 11, 2018, this facility is a major source of hazardous air pollutants (HAP). The existing facility is a prevention of significant deterioration (PSD) major source of air pollutants in accordance with Rule 62-212.400, F.A.C. A summary of applicable regulations is shown in the following table.

Regulation	**EU Nos.**
Federal Rule Citations	
40 CFR 60, Subpart A, NSPS General Provisions	005, 006, 028 & 035
40 CFR 60, Subpart D, Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971	005 & 006
40 CFR 60, Subpart Y, Standards of Performance for Coal Preparation and Processing Plants	035
40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines	028
40 CFR 63, Subpart A, NESHAP General Provisions	006, 008, 010, & 011
40 CFR 63, Subpart ZZZZ, NESHAP for Stationary Reciprocating Internal Combustion Engines	008, 010, & 011
40 CFR 63, Subpart UUUUU, NESHAP: Coal- and Oil-Fired Electric Utility Steam Generating Units	006
Acid Rain, Phase II	005, 006, & 028
State Rule Citations	
Chapter 62-4, F.A.C., Permits	All
Rule 62-204.800, F.A.C., Federal Regulations Adopted by Reference	004, 005, 006, 008, 010, 011, & 028
Rule 62-210.300, F.A.C., Permits Required	004, 005, 006, 008, 010, 011, & 028
Rule 62-212.400, F.A.C., PSD	006 & 028
Chapter 62-213, F.A.C., Operation Permits for Major Sources of Air Pollution	All
Chapter 62-214, F.A.C., Requirements for Sources Subject to the Federal Acid Rain Program	005, 006, & 028
Rule 62-296.405, F.A.C., Fossil Fuel Steam Generators with More than 250 MMBtu/Hour Heat Input	005 & 006
Rule 62-297.310, F.A.C., General Emissions Test Requirements	004, 005, 006, 008, 010, 011, & 028

Table of Contents.

The following conditions apply facility-wide to all emission units and activities:

FW1. Appendices. The permittee shall comply with all documents identified in Section V, Appendices, listed in the Table of Contents. Each document is an enforceable part of this permit unless otherwise indicated. [Rule 62-213.440, F.A.C.]

Emissions and Controls

FW2. **Not federally Enforceable.** Objectionable Odor Prohibited. No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rule 62-296.320(2) and 62-210.200(Definitions), F.A.C.]

FW3. General Volatile Organic Compounds (VOC) Emissions or Organic Solvents (OS) Emissions. The permittee shall allow no person to store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed-necessary and ordered by the Department. [Rule 62-296.320(1), F.A.C.]

{Permitting Note: Nothing is deemed necessary and ordered at this time.}

FW4. General Visible Emissions. No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20% opacity. This regulation does not impose a specific testing requirement. [Rule 62-296.320(4)(b), F.A.C.]

FW5. Unconfined Particulate Matter (PM). No person shall cause, let, permit, suffer or allow the emissions of unconfined PM from any activity, including vehicular movement; transportation of materials; construction; alteration; demolition or wrecking; or industrially related activities such as loading, unloading, storing or handling; without taking reasonable precautions to prevent such emissions. Reasonable precautions to prevent emissions of unconfined PM at this facility include:

a. Maintenance of paved areas;
b. Regular mowing of grass and care of vegetation; and
c. Limiting access to plant property by unnecessary vehicles.

[Rule 62-296.320(4)(c), F.A.C.; and, proposed by applicant in Title V air operation permit renewal application received May 11, 2018.]

Reports and Fees

See Appendix RR, Facility-wide Reporting Requirements, for additional details and requirements.

FW6. Electronic Annual Operating Report and Title V Annual Emissions Fees. The information required by the Annual Operating Report for Air Pollutant Emitting Facility [Including Title V Source Emissions Fee Calculation] (DEP Form No. 62-210.900(5)) shall be submitted by April 1 of each year, for the previous calendar year, to the Department of Environmental Protection's Division of Air Resource Management. Each Title V source shall submit the annual operating report using the DEP's Electronic Annual Operating Report (EAOR) software, unless the Title V source claims a technical or financial hardship by submitting DEP Form No. 62-210.900(5) to the DEP Division of Air Resource Management instead of using the reporting software. Emissions shall be computed in accordance with the provisions of subsection 62-210.370(2), F.A.C. Each Title V source must pay between January 15 and April 1 of each year an annual emissions fee in an amount determined as set forth in subsection 62-213.205(1), F.A.C. The annual fee shall only apply to those regulated pollutants, except carbon monoxide and greenhouse gases, for which an allowable numeric emission-limiting standard is specified in the source's most recent construction permit or operation permit. Upon completing the required EAOR entries, the EAOR Title V Fee Invoice can be printed by the source showing which of the reported emissions are subject to the fee and the total Title V Annual Emissions Fee that is due. The submission of the annual Title V emissions fee payment is also due (postmarked) by April 1st of each year. A copy of the system-generated EAOR Title V Annual Emissions Fee Invoice and the indicated total fee shall be submitted to: **Major Air Pollution Source Annual Emissions Fee, P.O. Box 3070, Tallahassee, Florida 32315-3070.** Additional information is available by accessing the Title V Annual Emissions Fee On-line Information Center at the following Internet web site: https://floridadep.gov/air/permitting-compliance/content/title-v-fees. [Rules 62-210.370(3), 62-210.900 & 62-213.205, F.A.C.; and, §403.0872(11), Florida Statutes (2013)]

{Permitting Note: Resources to help you complete your AOR are available on the electronic AOR (EAOR) website at: http://www.dep.state.fl.us/air/emission/eaor. If you have questions or need assistance after reviewing the information posted on the EAOR website, please contact the Department by phone at (850) 717-9000 or email at eaor@dep.state.fl.us.}

*{Permitting Note: The Title V Annual Emissions Fee form (DEP Form No. 62-213.900(1)) has been repealed. **A separate Annual Emissions Fee form is no longer required to be submitted by March 1st each year.**}*

FW7. Annual Statement of Compliance. The permittee shall submit an annual statement of compliance to the compliance authority at the address shown on the cover of this permit and to the US. EPA at the address shown below within 60 days after the end of each calendar year during which the Title V air operation permit was effective. (See also Appendix RR, Conditions RR1 and RR7.) [Rules 62-213.440(3)(a)2. & 3. and (b), F.A.C.]

U.S. Environmental Protection Agency, Region 4
Atlanta Federal Center
61 Forsyth Street, SW
Atlanta, Georgia 30303
Attn: Air Enforcement Branch

FW8. Prevention of Accidental Releases (Section 112(r) of CAA).

a. As required by Section 112(r)(7)(B)(iii) of the CAA and 40 CFR 68, the owner or operator shall submit an updated Risk Management Plan (RMP) to the Chemical Emergency Preparedness and Prevention Office (CEPPO) RMP Reporting Center. (See paragraph e., below.)
b. As required under Section 252.941(1)(c), F.S., the owner or operator shall report to the appropriate representative of the Division of Emergency Management, as established by department rule, within one working day of discovery of an accidental release of a regulated substance from the stationary source, if the owner or operator is required to report the release to the United States Environmental Protection Agency under Section 112(r)(6) of the CAA.
c. The owner or operator shall submit the required annual registration fee to the Division of Emergency Management on or before April 1, in accordance with Part IV, Chapter 252, F.S., and Rule 27P-21, F.A.C.
d. Any required written reports, notifications, certifications, and data required to be sent to the Division of Emergency Management, should be sent to: Division of Emergency Management, 2555 Shumard Oak Boulevard, Tallahassee, FL 32399-2100, Telephone: (850) 413-9970, Fax: (850) 488-1739.
e. Any Risk Management Plans, original submittals, revisions, or updates to submittals, should be sent electronically through EPA's Central Data Exchange system at the following address: https://cdx.epa.gov. Information on electronically submitting risk management plans using the Central Data Exchange system is available at: http://www2.epa.gov/rmp. The RMP Reporting Center can be contacted at: RMP Reporting Center, Post Office Box 10162, Fairfax, VA 22038, Telephone: (703) 227-7650.
f. Any required reports to be sent to the National Response Center, should be sent to: U.S. Environmental Protection Agency, Office of Solid Waste and Emergency Response, 1200 Pennsylvania Ave. NW, Mail Code: US EPA (5101T), Washington, DC 20460, Telephone: (800) 424-8802.

g. Send the required annual registration fee using approved forms made payable to: Cashier, Division of Emergency Management, State Emergency Response Commission, 2555 Shumard Oak Boulevard, Tallahassee, FL 32399-2149

[Part IV, Chapter 252, F.S.; and, Rule 27P-21, F.A.C.]

FW9. Semi-Annual Reports. The permittee shall monitor compliance with the terms and conditions of this permit and shall submit reports at least every six months to the compliance office. Each semi-annual report shall cover the 6-month periods of January 1 – June 30 and July 1 – December 31. The reports shall be submitted by the 60th day following the end of each calendar half (i.e., March 1st and August 29th of every year). All instances of deviations from permit requirements (including conditions in the referenced Appendices) must be clearly identified in such reports, including reference to the specific requirement and the duration of such deviation. If there are no deviations during the reporting period, the report shall so indicate. Any semi-annual reporting requirements contained in applicable federal NSPS or NESHAP requirements may be submitted as part of this report. The submittal dates specified above shall replace the submittal dates specified in the federal rules. All additional reports submitted as part of this report should be clearly identified according to the specific federal requirement. All reports shall include a certification by a responsible official, pursuant to subsection 62-213.420(4), F.A.C. (See also Conditions RR2. – RR4. of Appendix RR, Facility-wide Reporting Requirements, for additional reporting requirements related to deviations.) [Rule 62-213.440(1)(b)3.a., F.A.C.; and, 40 CFR 60.19, 40 CFR 61.10 & 40 CFR 63.10]

{Permitting Note: EPA has clarified that, pursuant to 40 CFR 70.6(a)(3), the word "monitoring" is used in a broad sense and means monitoring (i.e., paying attention to) the compliance of the source with all emissions limitations, standards, and work practices specified in the permit.}

Table of Contents.

The specific conditions in this section apply to the following emissions unit:

EU No.	Brief Description
004	Gas Turbine Peaking Unit 1

Gas Turbine Peaking Unit 1 consists of a gas turbine, which drives a generator producing electrical power at a nominal nameplate rating of 20 MW. The gas turbine is fired with natural gas or No. 2 fuel oil with a maximum sulfur content of 0.5% by weight. The maximum fuel firing rate is 320 million cubic feet per hour (MMcf/hour) of natural gas (approximately 330 MMBtu/hour) or 2,310 gallons per hour of No. 2 fuel oil (approximately 320 MMBtu/hour). Gas Turbine Peaking Unit 1 began commercial service in 1973. The stack parameters are: height, 35 feet; diameter (rectangular), 13’2” x 10’11” feet; exit temperature, 900 degrees Fahrenheit (°F); actual stack gas flow rate (while firing gas), 742,174 actual cubic feet per minute (acfm); and actual stack gas flow rate (while firing oil), 682,334 acfm.

{Permitting Note: This emissions unit is regulated under Rule 62-210.300, F.A.C., Permits Required. This unit is not subject to 40 CFR 60, Subpart GG, Standards of Performance for New Stationary Gas Turbines.}

Essential Potential to Emit (PTE) Parameters

A.1. Permitted Capacity.

a. *Heat Input*. The maximum heat input rate of the turbine is 330 MMBtu/hour (lower heating value [LHV]) at 30°F while firing natural gas and 320 MMBtu/hour (LHV) at 30°F while firing No. 2 fuel oil.

b. *Firing Rate*. The maximum firing rate of the turbine is 320 million cubic feet per hour of when firing natural gas or 2,310 gallons per hour when firing No. 2 fuel oil.

[Rules 62-4.160(2), and 62-210.200(PTE), F.A.C.; and Permit No. AO53-244727]

A.2. Emissions Unit Operating Rate Limitation After Testing. See the related testing provisions in Appendix TR, Facility-wide Testing Requirements. [Rule 62-297.310(3), F.A.C.]

A.3. Methods of Operation - Fuels. Only natural gas or distillate (No. 2) fuel oil shall be fired in the combustion turbine. [Rule 62-213.410, F.A.C.; and Permit No. AO53-244727]

A.4. Hours of Operation. This emissions unit may operate continuously (i.e., 8,760 hours/year). [Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; and Permit No. AO53-244727]

Emission Limitations and Standards

A.5. Sulfur Dioxide – Sulfur Content. The sulfur content of the No. 2 fuel oil shall not exceed 0.5%, by weight. [Rule 62-213.440, F.A.C.; and Permit No. AO53-244727]

Monitoring of Operations

A.6. Fuel Sulfur Monitoring. The permittee shall demonstrate compliance with the liquid fuel sulfur limit by means of a fuel analysis provided by the vendor or the permittee upon each fuel delivery. [Rule 62-213.440, F.A.C.; and Permit No. AO53-244727]

Test Methods and Procedures

A.7. Test Methods. When required, tests shall be performed in accordance with the following reference method:

Method	Description of Method and Comments
9	Visual Determination of the Opacity of Emissions from Stationary Sources

The above methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Appendix A of 40 CFR 60]

A.8. Common Testing Requirements. Unless otherwise specified, tests shall be conducted in accordance with the requirements and procedures specified in Appendix TR, Facility-Wide Testing Requirements, of this permit. [Rule 62-297.310, F.A.C.]

A.9. Fuel Sulfur Test Methods. The fuel sulfur content, percent by weight, for liquid fuels shall be evaluated using either ASTM D2622-92, ASTM D4294-90, or both ASTM D4057-88 and ASTM D129-91, or the respective successor ASTM method(s). [Rule 62-213.440, F.A.C.; and Permit No. AO53-244727]

Recordkeeping and Reporting Requirements

A.10. Other Reporting Requirements. See Appendix RR, Facility-wide Reporting Requirements, for additional reporting requirements. [Rule 62-213.440(1)(b), F.A.C.]

A.11. Sulfur Content Records. The permittee shall maintain records of the sulfur content, in percent by weight, of No. 2 fuel oil delivered for use in the gas turbine. These records can be vendor supplied documentation that the delivered fuel oil meets the specification in Condition **A.5**. These records shall be maintained for a minimum of two years and made available to the Department upon request. [Permit No. AO53-244727]

Table of Contents.

The specific conditions in this section apply to the following emissions unit:

EU No.	Brief Description
005	McIntosh Unit 2 – Fossil-Fuel-Fired Steam Generator

McIntosh Unit 2 is a nominal 114.7 MW (electric) fossil-fuel fired steam generator. The unit is fired on low sulfur No. 6 or No. 2 fuel oil with a maximum heat input rate of 1,115 MMBtu/hour, or natural gas with a maximum heat input rate of 1,184.5 MMBtu/hour. The stack parameters are: height, 157 feet; diameter, 10.5 feet; exit temperature, 277°F; and actual stack gas flow rate, 380,200 acfm. McIntosh Unit 2 began commercial service in June 1976.

NO_X control is incorporated by furnace design through the use of flue gas recirculation (FGR).

This emissions unit is equipped with continuous emissions monitoring systems (CEMS) for NO_X and SO_2, a continuous opacity monitoring systems (COMS), a CEMS for carbon dioxide (CO_2), and a CEMS for stack flow rate.

{Permitting Note: This emissions unit is regulated under Acid Rain, Phase II; Rule 62-296.405, F.A.C., Fossil Fuel Steam Generators with More than 250 MMBtu/Hour Heat Input; and NSPS - 40 CFR 60, Subpart A, General Provisions and Subpart D, Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971, both adopted and incorporated by reference in Rule 62-204.800, F.A.C. This emissions unit is <u>not</u> subject to NESHAP 40 CFR 63, Subpart UUUUU, because it does not meet the definition of "oil-fired" electric utility steam generating unit (EGU) as defined in 40 CFR 63.10042.}

<u>Essential Potential to Emit (PTE) Parameters</u>

B.1. <u>Permitted Capacity</u>. The maximum operation heat input rates are as follows:

Unit No.	MMBtu/hour Heat Input	Fuel Type
	1,184.5	Natural Gas
2	1,115	No. 6 Fuel Oil
	1,115	No. 2 Fuel Oil

When a blend of fuel oil and natural gas is fired, the heat input is prorated based on the percent heat input of each fuel. The Acid Rain CEMS will not be a method of compliance for the determination of the heat input rate.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

{Permitting Note: The heat input limitations have been placed in each permit to identify the capacity of each unit for the purposes of confirming that emissions testing is conducted within 90 to 100% of the unit's rated capacity (or to limit future operation to 110% of the test load), to establish appropriate emission limits and to aid in determining future rule applicability. Regular recordkeeping is not required for heat input. Instead the owner or operator is expected to determine heat input whenever emission testing is required, to demonstrate at what percentage of the rated capacity that the unit was tested. Rule 62-297.310(3), F.A.C., included in the permit, requires measurement of the process variables for emission tests. Such heat input determination may be based on measurements of fuel consumption by various methods including but not limited to fuel flow metering or tank drop measurements, using the heat value of the fuel determined by the fuel vendor or the owner or operator, to calculate average hourly heat input during the test.}

B.2. <u>Emissions Unit Operating Rate Limitation After Testing</u>. See the related testing provisions in Appendix TR, Facility-wide Testing Requirements. [Rule 62-297.310(3), F.A.C.]

B.3. <u>Methods of Operation – Fuels</u>. The only fuels allowed to be burned are natural gas, propane, No. 6 fuel oil, No. 2 fuel oil, and combinations of natural gas, propane, No. 6 fuel oil, and No. 2 fuel oil. [Rule 62-213.410, F.A.C.]

B.4. Hours of Operation. This emissions unit may operate continuously (i.e., 8,760 hours/year). [Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

Control Equipment

B.5. Flue Gas Recirculation (FGR). The permittee shall operate and maintain the FGR to reduce emissions of NO_X from the burners. [Rule 62-213.440(1)(b), F.A.C.; and Permit No. AC53-2244]

B.6. Circumvention. No person shall circumvent any air pollution control device, or allow the emission of air pollutants without the applicable air pollution control device operating properly. [Rule 62-210.650, F.A.C.]

Emission Limitations and Standards

Unless otherwise specified, the averaging times for Conditions **B.7 - B.10** are based on the specified averaging time of the applicable test method.

B.7. Visible Emissions. As determined by stack test, visible emissions shall not exceed 20% opacity except for one 6-minute period per hour of not more than 27% opacity. This limitation does not apply when combusting only natural gas. [Rule 62-296.405(2)(a), F.A.C.; and 40 CFR 60.42(a)(2) & (d)]

B.8. PM Emissions. As determined by stack test, PM emissions shall not exceed 0.10 pound per million Btu (lb/MMBtu) heat input derived from fossil fuels. This limitation does not apply when combusting only natural gas. [Rule 62-296.405(2)(b), F.A.C.; and 40 CFR 60.42(a)(1) & (d)]

B.9. SO_2 Emissions. As determined by CEMS, SO_2 emissions shall not exceed 0.80 lb/MMBtu heat input derived from liquid fossil fuels, based on a 3-hour average. Compliance shall be based on the total heat input from all fossil fuels burned, including gaseous fuels. [Rule 62-296.405(2)(c), F.A.C.; and 40 CFR 60.43(a)(1) and 60.43(c)]

B.10. NO_X Emissions. As determined by stack test, NO_X emissions, expressed as nitrogen dioxide (NO_2), shall not exceed the following emission standards:

a. *Gas*. 0.20 lb/MMBtu heat input derived from gaseous fossil fuel; and
b. *Oil*. 0.30 lb/MMBtu heat input derived from liquid fossil fuel.
c. *Combination of Fuels*. When different fossil fuels are burned simultaneously in any combination, the applicable standard (in nanograms per Joule (ng/J)) is determined by proration using the following formula:

$$PS_{NO_X} = \frac{w(260) + x(86) + y(130) + z(300)}{w + x + y + z}$$

where:

PS_{NO_x} = the prorated standard for nitrogen oxides when burning different fuels simultaneously, in ng/J heat input, derived from all fossil fuels fired or from all fossil fuels and wood residue fired;
w = the percentage of total heat input derived from lignite;
x = the percentage of total heat input derived from gaseous fossil fuel;
y = the percentage of total heat input derived from liquid fossil fuel; and
z = the percentage of total heat input derived from solid fossil fuel (except lignite).

[Rule 62-296.405(2)(d), F.A.C.; and 40 CFR 60.44(a)(1) & (2) and 60.44(b)]

Excess Emissions

Rule 62-210.700 (Excess Emissions), F.A.C. cannot vary any requirement of an NSPS, NESHAP, or Acid Rain program provision.

B.11. Excess Emissions Allowed. Excess emissions resulting from startup, shutdown, or malfunction of any emissions unit shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]

B.12. Excess Emissions Prohibited. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited. [Rule 62-210.700(1), F.A.C.]

B.13. NSPS Subpart D Excess Emissions. Excess emissions under NSPS 40 CFR 60, Subpart D are defined for applicable limits as follows.

a. *Opacity*. Excess emissions are defined as any 6-minute period during which the average opacity of emissions exceeds 20% opacity, except that one 6-minute period per hour of up to 27% opacity.

b. *SO_2 Emissions*. Excess emissions are defined as any 3-hour period during which the average emissions (arithmetic average of three contiguous 1-hour periods) as measured by a CEMS exceed the standard in Condition **B.9**.

[40 CFR 60.45(g)]

Continuous Monitoring Requirements

B.14. Continuous Monitoring Systems.

a. *COMS*. The permittee shall certify, operate, calibrate, and maintain a continuous monitoring system for continuous monitoring of opacity. The COMS shall meet the design, installation, equipment, and performance specifications in Performance Specification 1 in Appendix B of 40 CFR 60.

b. *NO_X CEMS*. The permittee shall certify, operate, calibrate, and maintain a continuous monitoring system for continuously monitoring NO_X (expressed as NO_2) in accordance with 40 CFR 75. A NO_X-diluent CEMS (consisting of a NO_X pollutant concentration monitor and an O_2 or CO_2-diluent gas monitor) shall have an automated data acquisition and handling system for measuring and recording NO_X concentration (in parts per million (ppm)), CO_2 concentration (in percent CO_2), and NO_X emissions rate (in lb/MMBtu) discharged to the atmosphere, except as provided in 40 CFR 75.12 and 75.17 and Subpart E of Part 75. The permittee shall account for total NO_X emissions, both NO and NO_2, either by monitoring for both NO and NO_2 or by monitoring for NO only and adjusting the emissions data to account for NO_2.

c. *SO_2 CEMS*. The permittee shall certify, operate, and maintain, in accordance with all the requirements of 40 CFR 75, a SO_2 CEMS and a flow monitoring system with an automated data acquisition and handling system for measuring and recording SO_2 concentration (in ppm), volumetric gas flow (in standard cubic feet per hour (scfh)), and SO_2 mass emissions (in lb/hour) discharged to the atmosphere, except as provided in 40 CFR 75.11 and 75.16 and Subpart E.

d. *CO_2 CEMS*. The permittee shall certify, operate, and maintain CO_2 CEMS, in accordance with all the requirements of 40 CFR 75.

[40 CFR 60.45(a) and 40 CFR 75]

Test Methods and Procedures

B.15. Test Methods. When required, tests shall be performed in accordance with the following reference methods:

Method	Description of Method and Comments
1-4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content
5, 5B, 5F, 17	Methods for Determining PM Emissions
6, 6A - 6C	Methods for Determining SO_2 Emissions
7, 7A, 7C - 7E	Determination of NO_X Emissions
9	Visual Determination of the Opacity of Emissions
19	Determination of SO_2 Removal Efficiency and PM, SO_2, and NO_X Emission Rates (Optional F-factor method may be used to determine flow rate and gas analysis to calculate mass emissions in lieu of Methods 1-4.)

The above methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Appendix A of 40 CFR 60]

B.16. Compliance Tests. During each calendar year (January 1st to December 31st), this emissions unit shall be tested to demonstrate compliance with the emission limitations and standards for PM, NO_X, and VE. In addition to the annual compliance tests, this emissions unit shall be tested prior to permit renewal to demonstrate compliance with the emission limitations for SO_2. The NO_X and SO_2 relative accuracy test audit (RATA) data and the COMS data may be used to demonstrate compliance with the testing requirements, provided the testing requirements (notification, procedures & reporting) of Chapter 62-297, F.A.C., 40 CFR 60, and 40 CFR 75, are met. An annual emissions test shall not be required for any emissions unit with emissions generated solely from the combustion of fuel, provided that the emissions unit does not burn any liquid fuel or solid fuel or fuel blend for more than 400 hours combined, other than during startup, during the calendar year. If an emissions unit's liquid fuel or solid fuel or fuel blend burning exceeds 400 hours combined during the calendar year, other than during startup, an emissions test shall be completed no later than 60 days after the emissions unit's liquid fuel or solid fuel or fuel blend burning exceeds 400 hours combined, or by the end of the calendar year, whichever is later. [Rules 62-297.310(8)(a) & (b), F.A.C.]

B.17. Common Testing Requirements. Unless otherwise specified, tests shall be conducted in accordance with the requirements and procedures specified in Appendix TR, Facility-Wide Testing Requirements, of this permit. [Rule 62-297.310, F.A.C.]

Recordkeeping and Reporting Requirements

B.18. Reporting Schedule. The following reports and notifications shall be submitted to the Compliance Authority:

Report	Reporting Deadline	Related Condition(s)
Excess Emissions	Quarterly	**B.19.**
NSPS Subpart D Excess Emissions	Semi-Annually	**B.20.**

[Rule 62-213.440(1)(b), F.A.C.]

B.19. Quarterly Excess Emissions Report. In the case of excess emissions resulting from malfunctions, the owner or operator shall notify the Compliance Authority in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(5), F.A.C.]

B.20. NSPS Subpart D Semi-Annual Reports. The permittee shall submit excess emission and monitoring system performance reports to the Compliance Authority semi-annually for each 6-month period in each calendar year. All reports shall be postmarked by the 30th day following the end of each 6-month period. Each report shall include the information required in 40 CFR 60.7(c). Periods of excess emissions are defined in Condition **B.13**. [40 CFR 60.45(g)]

B.21. SSM Records. The owner or operator shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction (SSM) in the operation of this emissions unit, any malfunction of the air pollution control equipment, or any periods during which a CMS or monitoring device is inoperative. [40 CFR 60.7(b)]

B.22. Other Reporting Requirements. See Appendix RR, Facility-wide Reporting Requirements, for additional reporting requirements. [Rule 62-213.440(1)(b), F.A.C.]

B.23. Fuel Use Records. The permittee shall keep records of monthly fuel use by the EGU, including the types of fuel and the amounts used to demonstrate that the EGU is not "oil-fired" and is not subject to 40 CFR 63, Subpart UUUUU. The permittee is required to evaluate applicability based on oil usage from the three previous calendar years on an annual rolling basis. [Rule 62-213.440(1)(b), F.A.C.; and 40 CFR 63.10042]

Miscellaneous Requirements

B.24. NSPS Requirements – Subpart A. This emissions unit shall comply with all applicable requirements of 40 CFR 60, Subpart A, General Provisions, which have been adopted and incorporated by reference in Rule 62-204.800, F.A.C. Subpart A is attached as an appendix to this permit. [40 CFR 60.1(a)]

B.25. NSPS Requirements – Subpart D. This emissions unit shall comply with all applicable requirements of 40 CFR 60, Subpart D, Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971, which have been adopted and incorporated by reference in Rule 62-204.800, F.A.C. Subpart D is attached as an appendix to this permit. [40 CFR 60.40]

Table of Contents.

Subsection C. The specific conditions in this section apply to the following emissions unit:

EU No.	Brief Description
006	McIntosh Unit 3 – Fossil-Fuel-Fired Steam Generator

McIntosh Unit 3 is a nominal 364-megawatt (electric) dry bottom wall-fired fossil-fuel-fired steam generator. The unit is fired on coal, natural gas, low sulfur fuel oil, and propane. The maximum heat input rate is 3,640 MMBtu/hour. Unit 3 is equipped with an electrostatic precipitator (ESP), a flue gas desulfurization system (FGD), a selective catalytic reduction (SCR) system, low NO_X burners (LNB), and an overfire air (OFA) system to control emissions. Dibasic acid or other organic acids may be used in the FGD system to enhance SO_2 removal efficiency. McIntosh Unit 3 began commercial service in September 1982. The FGD is exempted from CAM because the Acid Rain SO_2 CEMS will be used to demonstrate continuous compliance. The stack parameters are: height, 250 feet; diameter, 18 feet; exit temperature, 125°F; and, actual stack gas flow rate, 1,260,536 acfm.

This emissions unit has CEMS for SO_2 emissions, NO_X emissions, PM emissions, CO_2 emissions, stack flow rate, CO emissions, and mercury (Hg) emissions (sorbent trap). The CEMS for PM emissions has been certified in accordance with Performance Specification 11 of Appendix B of 40 CFR 60.

{Permitting Note: This emissions unit is regulated under Acid Rain, Phase II; Rule 62-296.405, F.A.C., Fossil Fuel Steam Generators with More than 250 MMBtu/hour Heat Input; 40 CFR 60, Subpart A, NSPS General Provisions and Subpart D, Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Commenced After August 17, 1971, both adopted and incorporated by reference in Rule 62-204.800, F.A.C.; 40 CFR 63, Subpart A, NESHAP General Provisions and Subpart UUUUU, NESHAP: Coal- and Oil-Fired Electric Utility Steam Generating Units, both adopted and incorporated by reference in Rule 62-204.800, F.A.C.; and Rule 62-212.400, F.A.C., PSD and Best Available Control Technology (BACT).}

<u>Essential Potential to Emit (PTE) Parameters</u>

C.1. <u>Capacity</u>. The maximum heat input rate is 3,640 MMBtu/hour. The Acid Rain CEMS will not be a method of compliance for the determination of the heat input rate. [Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

{Permitting Note: The heat input limitations have been placed in each permit to identify the capacity of each unit for the purposes of confirming that emissions testing is conducted within 90 to 100% of the unit's rated capacity (or to limit future operation to 110% of the test load), to establish appropriate emission limits and to aid in determining future rule applicability. Regular recordkeeping is not required for heat input. Instead the owner or operator is expected to determine heat input whenever emission testing is required, to demonstrate at what percentage of the rated capacity that the unit was tested. Rule 62-297.310(3), F.A.C., included in the permit, requires measurement of the process variables for emission tests. Such heat input determination may be based on measurements of fuel consumption by various methods including but not limited to fuel flow metering or tank drop measurements, using the heat value of the fuel determined by the fuel vendor or the owner or operator, to calculate average hourly heat input during the test.}

C.2. <u>Emissions Unit Operating Rate Limitation After Testing</u>. See the related testing provisions in Appendix TR, Facility-wide Testing Requirements. [Rule 62-297.310(3), F.A.C.]

C.3. <u>Methods of Operation – Fuels</u>. The only fuels allowed to be burned are:

a. Coal only;
b. Low sulfur fuel oil only (≤0.5% sulfur by weight ; and
c. Natural gas or propane only, or in combination with any of the other fuels or fuel combinations listed above.

[Rules 62-4.160(2), 62-210.200(PTE), and 62-213.440(1), F.A.C.; and Permit Nos. PSD-FL-008B and 1050004-041-AC]

{Permitting Note: U.S. EPA approved Florida's Regional Haze State Implementation plan on March 10, 2015. Therefore, this condition supersedes the authority to fire petcoke authorized by Permit No. PSD-FL-008B, issued December 11, 1995, which was a revision to the original PSD permit issued by EPA in 1978.}

C.4. Hours of Operation. This emissions unit may operate continuously (i.e., 8,760 hours/year). [Rule 62-210.200(PTE), F.A.C.]

Control Equipment

C.5. ESP System. The permittee shall operate and maintain the ESP system to reduce emissions of PM. [Rule 62-213.440(1)(b), F.A.C.]

C.6. SCR System. The permittee shall tune, operate, and maintain the SCR system to reduce emissions of NO_X as needed to comply with the NO_X emission standard in Specific Condition **C.13.b**. [Permit Nos. 1050004-019-AC & 026-AC]

C.7. FGD System. The permittee shall tune, operate, and maintain the FGD system to reduce emissions of SO_2. [Permit No. 1050004-038-AC]

C.8. LNB and OFA System. The permittee shall tune, operate, and maintain the LNB and the OFA systems to reduce emissions of NO_X. [Permit No. 1050004-018-AC (PSD-FL-387)]

C.9. Circumvention. No person shall circumvent any air pollution control device, or allow the emission of air pollutants without the applicable air pollution control device operating properly. [Rule 62-210.650, F.A.C.]

C.10. Control Equipment/Measures: The permittee shall notify the Department if they desire to remove the sorbent injection system. [Permit No. 1050004-035-AC]

Emissions Limitations and Standards

Unless otherwise specified, the averaging times for Conditions **C.11 - C.16** are based on the specified averaging time of the applicable test method

C.11. PM Emissions. As determined by a CEMS, emissions of PM shall not exceed the following limits.

a. *Coal/Oil*. Filterable PM shall not exceed 0.030 lb/MMBtu on a 30-operating day rolling average, except during periods of startup and shutdown. *{Permitting Note: For informational purposes only, the filterable PM limit of 0.030 lb/MMBtu equates to 109.2 lb/hour and 478.3 tons/year. The permittee has elected to meet the 40 CFR 63 Subpart UUUUU PM emission limit of 0.030 lb/MMBtu with compliance shown by a PM CEMS. Note that NESHAP Subpart UUUUU allows alternatives to this method for demonstrating compliance.}* [40 CFR 63.9991(a)]

b. *Coal*. 0.044 lb/MMBtu, based on a 3-hour average, except during periods of startup and shutdown. [Permit No. PSD-FL-008B]

c. *Oil*. 0.070 lb/MMBtu, based on a 3-hour average, except during periods of startup and shutdown. [Permit No. PSD-FL-008B]

d. *Fossil Fuels*. 0.03 lb/MMBtu heat input, based on a daily average, except during periods of startup, shutdown, or malfunction. [Rule 62-296.405(2)(b), F.A.C.; 40 CFR 60.42(c) & 40 CFR 60.42Da(a); and Permit No. 1050004-050-AC] {*Permitting Note: The permittee has requested to comply with the PM limit of 0.03 lb/MMBtu from 40 CFR 60.42Da(a) in lieu of the 0.10 lb/MMBtu PM limit and opacity limit from 40 CFR 60.42(a), as allowed by 40 CFR 60.42(c).}*

C.12. SO_2 Emissions. As determined by a CEMS, emissions of SO_2 shall not exceed the following limits.

a. *All Fuels*. 0.20 lb/MMBtu, based on a 30-operating day rolling average, except during periods of startup and shutdown. *{Permitting Note: The permittee has elected to meet this SO_2 emission limit with compliance demonstrated by a SO_2 CEMS as a surrogate for the hydrogen chloride (HCl) emission limit.}* [Rules 62-4.070(1) & (3) F.A.C.; 40 CFR 63.9991(a); and Permit Nos. 1050004-038-AC and 1050004-044-AC]

b. *Oil*. 0.80 lb/MMBtu heat input, based on a 3-hour average. [Rule 62-296.405(2)(c), F.A.C.; and 40 CFR 60.43(a)(1)]

c. *Coal*.
   (1) 1.2 lb/MMBtu heat input, based on a 3-hour average. [Rule 62-296.405(2)(c), F.A.C.; and 40 CFR 60.43(a)(2)]
   (2) A FGD system will be operated and maintained to treat exhaust gases and will operate such that whenever coal is burned, SO_2 gases discharged to the atmosphere from the boiler shall not exceed 10% of the potential combustion concentration (90% reduction), or 35% of the potential combustion concentration (65% reduction) when emissions are less than 0.75 lb/MMBtu heat input. Compliance with the percent reduction requirement shall be determined on a 30-day rolling average. This compliance information shall be retained for a period of five years and made available upon request of the Department. [Permit No. PSD-FL-008B]

d. *Combination of Fuels*. When different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) shall be determined by proration using the following formula:

$$PS_{SO_2} = \frac{y(340) + z(520)}{(y + z)}$$

where:
   PS_{SO2} = prorated standard for SO_2 when burning different fuels simultaneously, in ng/J heat input derived from all fossil fuels or from all fossil fuels and wood residue fired;
   y = percentage of total heat input derived from liquid fossil fuel; and
   z = percentage of total heat input derived from solid fossil fuel.

Compliance shall be based on the total heat input from all fossil fuels burned, including gaseous fuels. [Rule 62-296.405(2)(c), F.A.C.; and 40 CFR 60.43(b) & (c)]

e. *Natural Gas/Oil*. Continuous burning of natural gas, low sulfur fuel oil (≤0.5% sulfur by weight), or combinations of these two fuels with or without the use of the SO_2 scrubber will be allowed. [Permit No. PSD-FL-008B]

C.13. NO_X Emissions.

a. As determined by stack test, emissions of NO_X shall not exceed the following limits.
   (1) *Natural Gas*. 0.20 lb/MMBtu heat input, expressed as NO_2;
   (2) *Oil*. 0.30 lb/MMBtu heat input, expressed as NO_2; and
   (3) *Coal*. 0.70 lb/MMBtu heat input, expressed as NO_2.

   [Rule 62-296.405(2)(d), F.A.C.; and 40 CFR 60.44(a)(1), (2), & (3)]

   (4) *Combination of Fuels*. Except as provided under 40 CFR 60.44(c) and (d), when different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) is determined by proration using the following formula:

$$PS_{NO_X} = \frac{w(260) + x(86) + y(130) + z(300)}{(w + x + y + z)}$$

where:
   PS_{NOx} = prorated standard for NO_X when burning different fuels simultaneously, in ng/J heat input, derived from all fossil fuels fired or from all fossil fuels and wood residue fired;
   w = the percentage of total heat input derived from lignite;
   x = the percentage of total heat input derived from gaseous fossil fuel;
   y = the percentage of total heat input derived from liquid fossil fuel; and
   z = the percentage of total heat input derived from solid fossil fuel (except lignite).

[Rule 62-296.405(2)(d), F.A.C.; and 40 CFR 60.44(b)]

b. *All Fuels*. As determined by CEMS, NO_X emissions from Unit 3 shall not exceed 0.22 lb/MMBtu of heat input, based on a calendar year average of all periods of operation, including startup, shutdown, and malfunction. [Permit No. 1050004-026-AC]

C.14. CO Emissions. As demonstrated by CEMS, emissions of carbon monoxide (CO) from Unit 3 shall not exceed 0.20 lb/MMBtu on a 30-day rolling average. [Rule 62-212.400(BACT), F.A.C.; and Permit Nos. 1050004-018-AC (PSD-FL-387), 1050004-019-AC, and 1050004-026-AC]

C.15. Ammonia Emissions (Slip). Subject to the requirements of Condition **C.35**, the SCR system shall be operated for an ammonia slip target of less than 5 parts per million by volume (ppmv), based on the average of three 1-hour test runs. [Rule 62-4.070, F.A.C.; and Permit No. 1050004-026-AC]

C.16. Mercury Emissions. Emissions of mercury shall not exceed 1.2 pounds per trillion British thermal units (lb/TBtu), based on a 30-operating day rolling average. [40 CFR 63.9991(a); and Permit No. 1050004-038-AC]

Work Practice Standards

C.17. Tune-Ups. The permittee must conduct a tune-up of the electrical generating unit (EGU) burner and combustion control at least each 36 calendar months, as specified in 40 CFR 63.10021(e). [40 CFR 63.9991(a)(1) & 63.10021(e)]

C.18. Startup and Shutdown. This emissions unit must comply with the applicable work practice standards for periods of startup and shutdown as described in Table 3 to Subpart UUUUU. [40 CFR 63.9991(a)(1) & 63.10021]

Excess Emissions

Rule 62-210.700 (Excess Emissions), F.A.C. cannot vary any requirement of an NSPS, NESHAP, or Acid Rain program provision.

C.19. Excess Emissions Allowed. Excess emissions resulting from startup, shutdown, or malfunction of any emissions unit shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]

C.20. Excess Emissions Prohibited. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited. [Rule 62-210.700(1), F.A.C.]

C.21. NSPS Subpart D Excess Emissions. Excess emissions under NSPS 40 CFR 60, Subpart D are defined for applicable limits as follows.

a. *SO_2 Emissions*. Excess emissions are defined as any 3-hour period during which the average emissions (arithmetic average of three contiguous 1-hour periods) as measured by a CEMS exceed an applicable standard in Condition **C.12**.
b. *PM Emissions*. Excess emissions are defined as any boiler operating day period during which the average emissions (arithmetic average of all operating 1-hour periods) as measured by a CEMS exceed the applicable standard in Condition **C.11**.

[40 CFR 60.45(g)]

C.22. NEHSAP Subpart UUUUU Startup and Shutdown.

a. *Startup*. Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on-site use). Any fraction of an hour in which startup occurs constitutes a full hour of startup;
b. *Shutdown*. Shutdown means the period in which cessation of operation of an EGU is initiated for any purpose. Shutdown begins when the EGU no longer generates electricity or makes useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes or when no coal, liquid oil, syngas, or solid oil-derived fuel is being fired in the EGU, whichever is earlier. Shutdown ends when the EGU no longer generates electricity or makes useful thermal energy (such as steam or heat) for

industrial, commercial, heating, or cooling purposes, and no fuel is being fired in the EGU. Any fraction of an hour in which shutdown occurs constitutes a full hour of shutdown.
[40 CFR 63.10042]

Continuous Monitoring Requirements

C.23. NO_X CEMS. The permittee shall certify, operate, calibrate, and maintain a continuous monitoring system for continuously monitoring NO_X (expressed as NO_2) in accordance with 40 CFR 75 in a manner sufficient to demonstrate compliance with the emission limit specified in paragraph b of Condition **C.13**. A NO_X-diluent CEMS (consisting of a NO_X pollutant concentration monitor and an O_2 or CO_2-diluent gas monitor) shall have an automated data acquisition and handling system for measuring and recording NO_X concentration (in ppm), CO_2 concentration (in percent CO_2), and NO_X emission rate (in lb/MMBtu) discharged to the atmosphere, except as provided in 40 CFR 75.12 and 75.17 and Subpart E of Part 75. The permittee shall account for total NO_X emissions, both NO and NO_2, either by monitoring for both NO and NO_2, or by monitoring for NO only and adjusting the emissions data to account for NO_2. [40 CFR 60.45(a) and 40 CFR 75]

C.24. SO_2 CEMS. The permittee shall certify, operate, and maintain, in accordance with all the requirements of 40 CFR 75, a SO_2 CEMS and a flow monitoring system with an automated data acquisition and handling system for measuring and recording SO_2 concentration (in ppm), volumetric gas flow (in scfh), and SO_2 mass emissions (in lb/hour) discharged to the atmosphere, except as provided in 40 CFR 75.11 and 75.16 and Subpart E of Part 75. [40 CFR 60.45(a) and 40 CFR 75]

a. Continuous monitors shall be installed and operated in accordance with 40 CFR 60.45 and 60.13. In addition, an ASTM-certified automatic solid fossil fuel sampler shall be installed which produces a representative daily sample for analysis of sulfur, moisture, heating value, and ash. The solid fossil fuel data shall be used in conjunction with emissions factors and the continuous monitoring data to calculate SO_2 reduction. [PSD-FL-008B]
b. Pursuant to 40 CFR 64.2(b)(1)(vi), the permittee has elected to use the existing Acid Rain SO_2 CEMS for continuous compliance in order to be exempted from the Compliance Assurance Monitoring (CAM) requirements contained in 40 CFR 64. [40 CFR 64.2(b)(1)(vi)]

C.25. PM CEMS. Continuous compliance with the PM emission standards and limits shall be with the PM CEMS in order to be exempted from the CAM requirements contained in 40 CFR 64. The permittee shall certify, operate, and maintain the PM CEMS on Unit 3 in order to be exempted from the NSPS Subpart D requirement to have a continuous opacity monitoring system (COMS). The PM CEMS shall be certified in accordance with Performance Specification 11 of Appendix B of 40 CFR 60 and operated and maintained in accordance with Procedure 2 of Appendix F of 40 CFR 60. [40 CFR 64.2(b)(1)(i) & (vi) and 40 CFR 63.10010(i)]

C.26. CO CEMS. The permittee shall certify, operate, calibrate, and maintain a continuous monitoring system for continuously monitoring CO emissions.

a. *Performance Specifications and Quality Assurance*. The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F. The required RATA shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately, considering the expected range of emissions and corresponding emission standards.
b. *CEMS Data Requirements for CO BACT Standard.*
   (1) *Data Collection.* The CO CEMS shall monitor and record emissions during all operations and whenever emissions are being generated, including during episodes of startup, shutdown, and malfunction. All data shall be used, except for invalid measurements taken during monitor system breakdowns, repairs, calibration checks, zero adjustments, and span adjustments.
   (2) *Operating Hours and Operating Days.* An hour is the 60-minute period beginning at the top of each hour. Any hour during which an emissions unit is in operation for more than 15 minutes is an

operating hour for that emissions unit. A day is the 24-hour period from midnight to midnight. Any day with at least one operating hour for an emissions unit is an operating day for that emissions unit.

(3) *Valid Hourly Averages*. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over the hour at a minimum of one measurement per minute. All valid measurements collected during an hour shall be used to calculate a 1-hour block average that begins at the top of each hour.
   (a) Hours that are not operating hours are not valid hours.
   (b) For each operating hour, the 1-hour block average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, there is insufficient data, the 1-hour block average is not valid, and the hour is considered as "monitor unavailable."

(4) *Rolling 30-Day Average*. Compliance shall be determined after each operating day by calculating the arithmetic average of all the valid hourly averages from that operating day and the prior 29 operating days.

(5) *Monitor Availability*. The quarterly excess emissions report shall identify monitor availability for each quarter in which the unit operated. Monitor availability for the CEMS shall be 95% or greater in any calendar quarter in which the unit operated for more 760 hours. In the event the applicable availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving the required availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit.

c. *CEMS Annual Emissions Requirement*. The owner or operator shall use data from the CO CEMS when calculating annual emissions for purposes of computing actual emissions, baseline actual emissions, and net emissions increase, as defined at Rule 62-210.200, F.A.C., and for purposes of computing emissions pursuant to the reporting requirements of Rule 62-210.370(3), F.A.C. In computing the emissions of a pollutant, the owner or operator shall account for the emissions during periods of startup and shutdown of the emissions unit.

[Permit No. 1050004-018-AC (PSD-FL-387)]

C.27. Mercury Sorbent Trap. If this emissions unit does not qualify as a low emitting EGU (LEE), then compliance must be demonstrated through the use of a Hg CEMS or sorbent trap monitoring system, in accordance with Appendix A of 40 CFR 63.

a. Separate sorbent trap monitoring systems may be used to demonstrate compliance with Hg emissions—one sorbent trap monitoring system to demonstrate compliance with the numeric Hg emission limit during periods other than startup or shutdown, and one sorbent trap monitoring system to report average Hg concentration during startup or shutdown periods.

b. A single sorbent trap monitoring system may be used to demonstrate compliance with the Hg emission limit at all times (including periods of startup and shutdown) and to report average Hg concentration. The startup and shutdown requirements given in Table 3 to Subpart UUUUU must be followed.

c. A site-specific monitoring plan for the sorbent trap monitoring system(s) shall be developed and submitted in accordance with 40 CFR 63.10000(d)(5) unless the sorbent trap monitoring system is certified, maintained, operated, quality-assured, and recordkeeping and reporting requirements that pertain to the CMS are met according to 40 CFR 75 or 40 CFR 63 Appendix A or B.

[40 CFR 63.10000(c)(1)(vi) & (d)]

C.28. Ammonia Monitoring Requirements. In accordance with the manufacturer's specifications, the permittee shall calibrate, operate, and maintain an ammonia flow meter to measure and record the ammonia injection rate to the SCR system. [Permit No. 1050004-019-AC]

Test Methods and Procedures

C.29. Test Methods. When required, tests shall be performed in accordance with the following reference methods:

Method	Description of Method and Comments
1-4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content
5, 5B, 5F, or 17	Methods for Determining PM Emissions
6, 6A - 6C	Methods for Determining SO_2 Emissions
7, 7A, 7C - 7E	Determination of NO_X Emissions
9	Visual Determination of the Opacity of Emissions
10	Determination of CO Emissions
19	Determination of SO_2 Removal Efficiency and PM, SO_2, and NO_X Emission Rates (Optional F-factor method may be used to determine flow rate and gas analysis to calculate mass emissions in lieu of Methods 1-4.)
30B	Determination of Total Vapor Phase Mercury Emissions from Coal-Fired Combustion Sources Using Carbon Sorbent Traps
320	Measurement of Vapor Phase Organic and Inorganic Emissions by Extractive Fourier Transform Infrared (FTIR) Spectroscopy
CTM-027	Procedure for Collection and Analysis of Ammonia in Stationary Sources

The above methods are described in 40 CFR 60, Appendix A, and 40 CFR 63, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Appendix A of 40 CFR 60 and Appendix A of 40 CFR 63]

C.30. Annual Compliance Tests. During each calendar year (January 1st to December 31st), this emissions unit shall be tested to demonstrate compliance with the emission limitations and standards for NO_X. The NO_X RATA test data may be used to demonstrate compliance with the annual testing requirements, provided the testing requirements (notification, procedures & reporting) of Chapter 62-297, F.A.C., 40 CFR 60, and 40 CFR 75, are met. An annual emissions test shall not be required for any emissions unit with emissions generated solely from the combustion of fuel, provided that the emissions unit does not burn any liquid fuel or solid fuel or fuel blend for more than 400 hours combined, other than during startup, during the calendar year. If an emissions unit's liquid fuel or solid fuel or fuel blend burning exceeds 400 hours combined during the calendar year, other than during startup, an emissions test shall be completed no later than 60 days after the emissions unit's liquid fuel or solid fuel or fuel blend burning exceeds 400 hours combined, or by the end of the calendar year, whichever is later. If this emissions unit qualifies as a low emitting EGU for Hg, then an annual compliance test for Hg shall be conducted according to Condition **C.36**. [Rule 62-297.310(8), F.A.C.; and 40 CFR 63.10000(c)(1)(ii)]

C.31. Common Testing Requirements. Unless otherwise specified, tests shall be conducted in accordance with the requirements and procedures specified in Appendix TR, Facility-Wide Testing Requirements, of this permit. [Rule 62-297.310, F.A.C.]

C.32. SO_2 Compliance Requirements. The existing FGD and SO_2 CEMS shall be operated at all times, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities. Compliance with the SO_2 emissions limit shall be met at all times, except during periods of startup and shutdown. During startup and shutdown, work practice standards in accordance with NESHAP 40 CFR 63 Subpart UUUUU shall apply. [40 CFR 63.9991(a)(1); and Permit No. 1050004-044-AC]

C.33. PM Compliance Requirements. The PM CEMS shall be operated at all times, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities. Compliance with the PM emissions limit shall be met at all times, except during periods of startup and shutdown. During startup and shutdown, work practice standards in accordance with NESHAP 40 CFR 63 Subpart UUUUU shall apply. [Rule 62-4.070(3) F.A.C.; and 40 CFR 63.9991(a)(1)]

C.34. Hg Compliance Requirements.

a. *Compliance for Units that Qualify as an LEE*. An existing EGU may qualify as an LEE for Hg emissions if the following requirements are met.
   (1) The permittee may elect this compliance option unless prohibited pursuant to 40 CFR 63.10000(c)(1)(i).
   (2) Based on collected performance test or continuous monitoring data, one of the following conditions must be met.
      (a) The average Hg emissions must be less than 10% of the Hg emission limit (expressed in units of lb/TBtu) in Condition **C.16**.
      (b) The Hg mass emissions from the EGU must be 29.0 or fewer pounds per year, and compliance with the Hg emission limit (expressed in units of lb/TBtu) in Condition **C.16** must be achieved.
   (3) The permittee must conduct a 30-boiler operating day performance test using EPA Method 30B in Appendix A to 40 CFR 60 to determine whether the EGU qualifies for LEE status. Follow the procedures in 40 CFR 63.10005(h)(3) and 63.10007(e).
   (4) For a qualifying LEE for Hg emissions, the permittee must conduct a 30-day performance test using EPA Method 30B at least once every 12 calendar months to demonstrate continued LEE status.
   [40 CFR 63.10000(c)(1)(ii) & 63.10005(h)]

b. *Loss of LEE Status*. If LEE status is lost, the unit must comply via sorbent trap (see Condition **C.27**) within 6 calendar months of losing LEE eligibility. Until the sorbent trap system is installed, certified, and operating, Hg emissions testing must be conducted quarterly. From the time of loss of LEE eligibility, there must be three calendar years of testing and sorbent trap monitoring system data that satisfy the above requirements to reestablish LEE status. [40 CFR 63.10006(b)]

C.35. Ammonia Slip Tests. Annual compliance with the ammonia (NH_3) slip target in Condition **C.14** shall be determined using EPA Conditional Test Method 27 (CTM-027), EPA Method 320, or other methods approved by the Department. If the tested NH_3 slip rate exceeds 5 ppmv during the test, the permittee shall:

a. Begin testing and reporting the NH_3 slip for each subsequent calendar quarter;
b. Before the NH_3 slip exceeds 7 ppmv, take corrective actions that result in lowering the NH_3 slip to less than 5 ppmv; and
c. Test and demonstrate that the NH_3 slip is less than 5 ppmv within 30 days after completing the corrective actions.

Corrective actions may include, but are not limited to, adding catalyst, replacing catalyst, or other SCR system maintenance or repair. After demonstrating that the NH_3 slip level is less than 5 ppmv, testing and reporting shall resume on an annual basis.
[Permit No. 1050004-026-AC]

Recordkeeping and Reporting Requirements

C.36. Other Reporting Requirements. See Appendix RR, Facility-wide Reporting Requirements, for additional reporting requirements. [Rule 62-213.440(1)(b), F.A.C.]

C.37. Reporting Schedule. The following reports and notifications shall be submitted to the Compliance Authority:

Report	Reporting Deadline	Related Condition
Deviation and Malfunction Excess Emissions	Quarterly	**C.38.**

SIP Quarterly Excess Emissions	Quarterly	**C.38.**
NSPS Subpart D Excess Emissions	Semi-Annually	**C.38.**
Notification of Compliance Status	60 days after compliance demonstration	**C.39.**
NESHAP Subpart UUUUU Compliance	Semi-Annually	**C.40.**
PM CEMS	Quarterly	**C.41.b.**

[Rule 62-213.440(1)(b), F.A.C.]

C.38. Excess Emissions Reporting.

a. *Malfunctions*. In the case of excess emissions resulting from malfunctions, the owner or operator shall notify the Compliance Authority in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(5), F.A.C.]

b. *State Implementation Plant (SIP) Quarterly Report*. Within 30 days following the end of each calendar quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of CO emissions in excess of the BACT permit standard following the NSPS format in 40 CFR 60.7(c). The report shall summarize the CO CEMS system monitor availability for the previous quarter. In addition to the requirements of 40 CFR 60.7, each excess emissions report shall include the periods of oil consumption due to FGD system malfunction. [Permit Nos. PSD-FL-008 and 1050004-018-AC (PSD-FL-387)]

c. *NSPS Subpart D Semi-Annual Reports*. The owner or operator shall submit excess emission and monitoring system performance reports to the Compliance Authority semi-annually for each 6-month period in each calendar year. All reports shall be postmarked by the 30th day following the end of each 6-month period. Each report shall include the information required in 40 CFR 60.7(c). Periods of excess emissions are defined in Condition **C.21**. [40 CFR 60.45(g)]

C.39. Notification of Compliance Status. When there will be a change in the method of compliance (e.g., complying on a heat input basis versus a gross output basis) and an initial compliance demonstration is necessary, the permittee must submit a Notification of Compliance Status according to the following requirements. The notification shall be submitted by 60 days following the completion of the relevant compliance demonstration, unless otherwise indicated in the below paragraphs.

a. *NESHAP Subpart A Requirements.*

(1) The notification shall be signed by the responsible official who shall certify its accuracy, attesting to whether the source has complied with NESHAP Subpart UUUUU.

(2) The notification shall list:

(a) Methods that were used to determine compliance;

(b) Results of any performance tests, CMS performance evaluations, and/or other methods that were conducted;

(c) Methods that will be used for determining continuing compliance, including a description of monitoring and reporting requirements and test methods;

(d) Type and quantity of HAP emitted by the source, reported in units in accordance with the test methods specified in Subpart UUUUU;

(e) Description of the air pollution control equipment (or method) for each emission point, including each control device for each HAP and the control efficiency of each device; and

(f) A statement by the owner or operator as to whether the unit has complied with the requirements of Subpart UUUUU.

[40 CFR 63.9(h)(2)]

b. *NESHAP Subpart UUUUU Requirements.*

(1) Description of the unit, including identification of the subcategory of the unit, its design capacity, its add-on controls, and fuel(s) burned.
(2) Summary of the results of all performance tests, fuel analyses, and calculations used to demonstrate initial compliance, including all established operating limits.
(3) Identification of the chosen method of compliance (e.g., CEMS, fuel analysis, performance testing).
(4) Identification of whether emissions averaging will be used for compliance.
(5) A signed certification that the unit has met all applicable emission limits and work practice standards.
(6) If there were any deviations from any emission limit, work practice standard, or operating limit, a brief description of the deviation, its duration, emission point identification, and cause of the deviation.
(7) In addition to the information required by paragraph a of this condition:
    (a) A summary of the results of annual performance tests and documentation of any operating limits that were reestablished during the test, if applicable.
    (b) A certification of compliance, signed by the responsible official stating, “this EGU complies with the requirements in [40 CFR] 63.10021(a) to demonstrate continuous compliance.”
(8) Identification of which definition of “startup” in Condition **C.22** upon which the permittee shall rely.

[40 CFR 63.10030(e)(1) - (6), (7)(i) & (ii), and (8)]

c. *Emission Limit Switch*. For an existing EGU (i.e., Unit 3), the permittee must identify each applicable emissions limit with which the unit will comply. The permittee may switch from a mass per heat input to a mass per gross output limit (or vice-versa), provided that:
(1) The permittee submits a request that identifies both the current and proposed emission limit;
(2) The request arrives to the Department at least 30 calendar days prior to the date that the switch is proposed to occur;
(3) The request demonstrates, through performance test results completed within 30 days prior to the submission, compliance for the EGU with both the mass per heat input and mass per gross output limits;
(4) The permittee revises and submits all other applicable plans (e.g., monitoring) with the request;
(5) The permittee maintains records of all information regarding the choice of emission limits;
(6) The permittee shall begin to use the revised emission limits starting in the next reporting period, after receipt of written acknowledgment from the Department of the switch; and
(7) From submission of the request until the start of the next reporting period after receipt of written acknowledgment from the Department of the switch, the unit must demonstrate compliance with both the mass per heat input and mass per gross output emission limits for each applicable pollutant for the unit.

[40 CFR 63.10030(e)(7)(iii)]

C.40. NESHAP Subpart UUUUU Semi-Annual Compliance Reports.

a. *Report Content*. Each compliance report must contain the information required by 40 CFR 63.10031(c), as applicable to this emissions unit.

b. *Deviations and Malfunctions*.
(1) If there are no deviations from any emission limitation, operating limit, or work practice standard that applies to this emissions unit, include a statement that there were no deviations during the reporting period.
(2) If there was a deviation from any emission limitation, operating limit, or work practice standard that applies to this emissions unit during the reporting period, the report must contain the information in 40 CFR 63.10031(d). If there were periods during which a CMS, including CEMS and CPMS, were out-of-control, as specified in 40 CFR 63.8(c)(7), the report must contain the information in 40 CFR 63.10031(e).
(3) If there was a malfunction during the reporting period, the report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded.

[40 CFR 63.10031]

C.41. Electronic Reporting Requirements. Prior to July 1, 2020, the reports required by paragraphs a, b, and d of this condition shall be submitted to the EPA at the frequency specified in those paragraphs in electronic PDF using the ECMPS Client Tool. Each PDF version of a submitted report must include sufficient information to assess compliance and to demonstrate that the testing was done properly. The data elements contained in 40 CFR 63.100031(f)(6)(i) through (xii) must be entered into the ECMPS Client Tool at the time of submission of each PDF file.

a. *Performance Tests and CEMS RATA*. On or after July 1, 2020, within 60 days after the date of completing each performance test or CEMS performance evaluation test, the permittee must submit the performance test reports or RATA data required by this section to EPA's WebFIRE database using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). Performance test and RATA data shall be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (*http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using those test methods and only RATA data compounds listed on the ERT website are subject to this requirement for submitting reports electronically to WebFIRE. The permittee must also submit these reports to the Compliance Authority in portable document format (PDF).

b. *Quarterly Reports*. On or after July 1, 2020, for a unit equipped with a PM CEMS, within 60 days after the reporting periods ending on March 31, June 30, September 30, and December 31, the permittee must submit quarterly reports to the EPA's WebFIRE database using the CEDRI that is accessed through the EPA's CDX. The permittee must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with EPA's reporting form output format. For each reporting period, the quarterly reports must include all of the calculated 30-boiler operating day rolling average values derived from the PM CEMS.

c. *SO_2 CEMS and Hg Sorbent Trap*. Reports for an SO_2 CEMS, a Hg sorbent trap monitoring system, and any supporting monitors for such systems (such as a diluent monitor or moisture monitor) shall be submitted using the EPA's Emissions Collection and Monitoring Plan System (ECMPS) Client Tool, as provided for in Appendices A and B to 40 CFR 63 Subpart UUUUU and 40 CFR 63.10021(f).

d. *Compliance Reports*. On or after July 1, 2020, the permittee must submit the compliance reports required in Condition **C.40** and the notification of compliance status required in Condition **C.39** to the EPA's WebFIRE database using the CEDRI that is accessed through the EPA's CDX. The permittee must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with EPA's reporting form output format.

[40 CFR 63.10031(f)(1) through (6)]

C.42. SSM Records. The permittee shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of this emissions unit, any malfunction of the air pollution control equipment, or any periods during which a CMS or monitoring device is inoperative. [40 CFR 60.7(b); and 40 CFR 63.100032(g)]

C.43. NESHAP Subpart UUUUU Records. The permittee shall maintain records for the EGU according to the following requirements. These records shall be kept for five years following the date of each record.

a. *Fuel Use*. Records of monthly fuel use by the EGU, including the types and amounts of fuel used.

b. *LEE Status*. For an EGU that qualifies as an LEE under Condition **C.34**, annual records that document that the emissions from previous stack tests continue to qualify the EGU for LEE status, and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions to increase within the past year.

c. *Startup and Shutdown*.

(1) Records of the occurrence and duration of each startup or shutdown.

(2) Records of the types and amounts of fuel used during each startup or shutdown.

d. *Corrective Actions*. Records of actions taken during periods of malfunctions to minimize emissions in accordance with 40 CFR 63.10000(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

[40 CFR 63.10032(d)(1) & (3), (f)(1), (h), and (i); and 40 CFR 63.10033(b)]

Miscellaneous Requirements

C.44. NSPS Requirements – Subpart A. This emissions unit shall comply with all applicable requirements of 40 CFR 60, Subpart A, General Provisions, which have been adopted and incorporated by reference in Rule 62-204.800, F.A.C. Subpart A is attached as an appendix to this permit. [40 CFR 60.1(a)]

C.45. NSPS Requirements – Subpart D. This emissions unit shall comply with all applicable requirements of 40 CFR 60, Subpart D, Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971, which have been adopted and incorporated by reference in Rule 62-204.800, F.A.C. Subpart D is attached as an appendix to this permit. [40 CFR 60.40]

C.46. NESHAP Requirements – Subpart A. This emissions unit shall comply with all applicable requirements of 40 CFR 63, Subpart A, General Provisions, which have been adopted and incorporated by reference in Rule 62-204.800, F.A.C. Subpart A is attached as an appendix to this permit. [40 CFR 63.1(4)]

C.47. NESHAP Requirements – Subpart UUUUU. This emissions unit shall comply with all applicable requirements of 40 CFR 63, Subpart UUUUU, NESHAP: Coal- and Oil-Fired Electric Utility Steam Generating Units, which have been adopted and incorporated by reference in Rule 62-204.800, F.A.C. Subpart UUUUU is attached as an appendix to this permit. Compliance with any applicable emission limit in Conditions **C.11** through **C.16** shall be demonstrated pursuant to one of the available options specified in Subpart UUUUU and in accordance with any notification submitted pursuant to Condition **C.39**. [40 CFR 63.9981; and Permit No. 1050004-038-AC]

Table of Contents.

Subsection D. The specific conditions in this section apply to the following emissions unit:

EU No.	Brief Description
028	McIntosh Unit 5 – 370 MW Combined Cycle Stationary Combustion Turbine

McIntosh Unit 5 is a nominal 250-megawatt (MW) Westinghouse 501G combustion turbine (CT) operating in combined cycle mode with a heat recovery steam generator (HRSG) and 120 MW steam electric turbine. The total combined nominal output of the unit is 370 MW. The CT is fired with natural gas or No. 2 (or superior grade) distillate fuel oil with a maximum of 0.05% sulfur content, by weight. Emissions of NO_X are controlled by dry low NO_X combustors (DLN), water injection (for oil firing), and a SCR system (for gas firing). An oxidation catalyst was installed in 2003 to control emissions of CO and volatile organic compounds (VOC). The stack parameters are: height, 300 feet; diameter, 20 feet; exit temperature, 187°F; actual stack gas flow rate (for gas firing), 1,271,428 acfm; and actual stack gas flow rate (for oil firing), 1,291,502 acfm.

This emissions unit has a CEMS for NO_X emissions. Combined cycle operation began in January 2002.

{Permitting Note: This emissions unit is regulated under Acid Rain, Phase II; 40 CFR 60, Subpart A, NSPS General Provisions, and Subpart GG, Standards of Performance for Stationary Gas Turbines, both adopted and incorporated by reference in Rule 62-204.800, F.A.C.; and Rule 62-212.400, F.A.C. (PSD and BACT).

This emissions unit is subject to the federal Acid Rain provisions. However, it is not required to operate and maintain continuous monitoring devices for opacity or SO_2 because it is defined as a "gas-fired" unit under 40 CFR 72.2. There are no opacity monitoring requirements, but the permittee must follow procedures in Appendix D of 40 CFR 75 to estimate hourly SO_2 mass emissions.}

Essential Potential to Emit (PTE) Parameters

D.1. Permitted Capacity. The maximum heat input rates, based on the lower heating values (LHV) of each fuel to Unit 5 at ambient conditions of 59°F, 60% relative humidity, 100% load, and 14.7 pounds per square inch (psi) pressure shall not exceed:

a. 2,407 MMBtu/hour when firing natural gas; nor
b. 2,236 MMBtu/hour when firing No. 2 (or superior grade) distillate fuel oil.

These maximum heat input rates will vary depending upon ambient conditions and the CT characteristics. Manufacturer's curves approved by the Department, attached in Appendix W501G McIntosh #5, Lakeland FL – Maximum Heat Input as a Function of Compressor Inlet Temperature (dated 01/05/2001), for the heat input correction to other temperatures may be utilized to establish heat input rates over a range of temperatures for compliance determination. Monitoring required under 40 CFR 60.334(a) shall satisfy periodic monitoring requirements for heat input. [Rules 62-4.160(2), 62-210.200(PTE) & 62-213.440(1)(b)1b, F.A.C.; and Permit No. 1050004-010-AC (PSD-FL-245C)]

D.2. Emissions Unit Operating Rate Limitation After Testing. See the related testing provisions in Appendix TR, Facility-wide Testing Requirements. [Rule 62-297.310(3), F.A.C.]

D.3. Methods of Operation – Fuels. Only pipeline natural gas or No. 2 (or superior grade) distillate fuel oil, with a maximum sulfur content of 0.05% by weight, shall be fired in this emissions unit. [Permit No. 1050004-004-AC (PSD-FL-245)]

D.4. Hours of Operation. This emissions unit may operate continuously (i.e., 8,760 hours/year). [Rule 62-210.200(PTE), F.A.C.; and Permit No. 1050004-004-AC (PSD-FL-245)]

D.5. Fuel Usage as Heat Input – Fuel Oil. Fuel usage as heat input from fuel oil shall not exceed 599 x 10^9 Btu (LHV) per year (rolled monthly). [Permit No. 1050004-004-AC (PSD-FL-245)]

Control Technology

D.6. DLN Combustors. The permittee shall tune, operate, and maintain DLN combustors to reduce emissions of NO_X while firing natural gas. [Permit No. 1050004-004-AC (PSD-FL-245)]

D.7. SCR System and Oxidation Catalyst. The permittee shall tune, operate, and maintain the SCR equipment and operate an oxidation catalyst. The oxidation catalyst shall be designed for a minimum 90% destruction efficiency at base load. [Permit No. 105004-014-AC (modification to PSD-FL-245)]

D.8. Water Injection for Oil Firing. A water injection system shall be used for control of NO_X emissions when firing No. 2 (or superior grade) distillate fuel oil. [Permit No. 1050004-004-AC (PSD-FL-245)]

D.9. Circumvention. No person shall circumvent any air pollution control device, or allow the emission of air pollutants without the applicable air pollution control device operating properly. [Rule 62-210.650, F.A.C.]

Emission Limitations and Standards

Unless otherwise specified, the averaging times for Conditions **D.10 – D.14** are based on the specified averaging time of the applicable test method.

D.10. Visible Emissions. Visible emissions shall not exceed 10% opacity. [Permit No. 1050004-004-AC (PSD-FL-245)]

D.11. NO_X Emissions. NO_X emissions shall not exceed 7.5 parts per million by volume, dry, corrected to 15% oxygen (ppmvd @ 15% O_2) when firing natural gas and 15 ppmvd @ 15% O_2 when firing fuel oil, on the basis of a 3-hour average, as measured by the CEMS. In addition, NO_X emissions calculated as nitrogen dioxide (NO_2) (at ISO conditions) shall not exceed 71.1 lb/hour when firing natural gas and 148 lb/hour when firing fuel oil, to be demonstrated by stack tests. [Permit No. 1050004-004-AC (PSD-FL-245)]

D.12. CO Emissions. The concentration of CO in the exhaust gas shall be additionally controlled by the use of an oxidation catalyst with a minimum of 90% CO removal efficiency (based upon design at base load). The CO emissions shall be tested annually at full load and shall not exceed 2 ppmvd @ 15% O_2 when firing natural gas, as measured by EPA Method 10. The oxidation catalyst shall be maintained according to manufacturer's recommendations. However, in the event that CO emissions exceed 2 ppmvd @ 15% O_2 (as demonstrated by annual testing below), the permittee shall implement a remedy and re-test within 90 days of operation. Should the re-test in CO emissions exceed 2 ppmvd @ 15% O_2, the remedy shall be to completely replace the oxidation catalyst. [Permit No. 1050004-014-AC (modification to PSD-FL-245)]

D.13. SO_2 Emissions. SO_2 emissions (at ISO conditions) shall not exceed 8 lb/hour when firing pipeline natural gas and 127 lb/hour when firing No. 2 (or superior grade) distillate fuel oil with a maximum sulfur content of 0.05% by weight, as measured by applicable compliance methods. Emissions of SO_2 shall not exceed 38.4 tons/year. [Permit No. 1050004-010-AC (PSD-FL-245C)]

D.14. VOC Emissions. VOC emissions shall be additionally controlled through the use of an oxidation catalyst. CO emissions shall be employed as a surrogate for VOC emissions and no further annual testing will be required. [Permit No. 1050004-014-AC (modification to PSD-FL-245)]

Excess Emissions

Rule 62-210.700 (Excess Emissions), F.A.C. cannot vary any requirement of an NSPS, NESHAP, or Acid Rain program provision.

D.15. Excess Emissions Allowed. Excess emissions from this emissions unit resulting from startup, shutdown, malfunction, or fuel switching shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized. Excess emissions shall in no case exceed four hours in any 24-hour period for cold startup or two hours in any 24-hour period for other reasons unless specifically authorized by the Department for longer duration. During any calendar day in which a startup, shutdown, or fuel change occurs, the following alternative NO_X limit applies:

a. 100 lb/hour on the basis of a 24-hour average; and
b. 200 lb/hour on the basis of a 24-hour average if fuel oil is fired during a startup or shutdown within the 24-hour period.

[Rule 62-210.700(1), F.A.C.; and Permit No. 1050004-014-AC (modification to PSD-FL-245)]

D.16. Excess Emissions Prohibited. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited. [Rule 62-210.700(1), F.A.C.]

Monitoring of Operations

D.17. Fuel Oil Monitoring Schedule. The following monitoring schedule for No. 2 (or superior grade) fuel oil shall be followed. For all bulk shipments of No. 2 (or superior grade) fuel oil received at the C.D. McIntosh, Jr. Power Plant, an analysis which reports the sulfur content and the nitrogen content of the fuel shall be provided by the vendor. The analysis shall also specify the methods by which the analysis was conducted and shall comply with the requirements of 40 CFR 60.335(b)(9)(i) and (10)(i). [Permit No. 1050004-004-AC (PSD-FL-245)]

D.18. Natural Gas Monitoring Schedule. The following custom monitoring schedule for natural gas is approved in lieu of the daily sampling requirements of 40 CFR 60.334(i)(2):

a. Monitoring of natural gas nitrogen content shall not be required.
b. Analysis of the sulfur content of natural gas shall be conducted using one of the EPA-approved ASTM reference methods for the measurement of sulfur in gaseous fuels, or an approved alternate method. Monitoring of the sulfur content of the natural gas shall be conducted semiannually.
c. Should any sulfur analysis indicate noncompliance with 40 CFR 60.333, the permittee shall notify the Department of such excess emissions and the custom fuel monitoring schedule shall be reexamined. The sulfur content of the natural gas will be monitored weekly during the interim period while the monitoring schedule is reexamined.
d. The permittee shall notify the Department of any change in natural gas supply for reexamination of this monitoring schedule. A substantial change in natural gas quality (i.e., sulfur content variation of greater than one grain per 100 cubic feet of natural gas) shall be considered as a change in the natural gas supply. Sulfur content of the natural gas will be monitored weekly by the natural gas supplier during the interim period when this monitoring schedule is being reexamined.
e. Records of sampling analyses and natural gas supply pertinent to this monitoring schedule shall be retained by the permittee for a period of 5 years, and shall be made available for inspection by the appropriate regulatory personnel.
f. The permittee may obtain the sulfur content of the natural gas from the fuel supplier (Florida Gas Transmission or Gulfstream), provided the approved test methods are used.

[Permit No. 1050004-004-AC (PSD-FL-245)]

Continuous Monitoring Requirements

D.19. NO_X CEMS. The permittee shall certify, operate, calibrate, and maintain a continuous monitoring system for continuously monitoring NO_X (expressed as NO_2) in accordance with 40 CFR 75 in a manner sufficient to demonstrate compliance with the emission limits of this permit. A NO_X-diluent CEMS (consisting of a NO_X pollutant concentration monitor and an O_2-diluent gas monitor) shall have an automated data acquisition and handling system for measuring and recording NO_X concentration (in ppm), O_2 concentration (in percent O_2), and NO_X emission rate (in lb/MMBtu) discharged to the atmosphere, except as provided in 40 CFR 75.12 and 75.17 and Subpart E of Part 75. The permittee shall account for total NO_X emissions, both NO and NO_2, either by monitoring for both NO and NO_2, or by monitoring for NO only and adjusting the emissions data to account for NO_2. Periods when NO_X emissions (ppmvd @ 15% O_2) are above the BACT standards listed in Condition **D.11** shall be reported to the Department's Southwest District Office pursuant to Rule 62-4.160(8), F.A.C. Following the format of 40 CFR 60.7, periods of startup, shutdown, malfunction, and fuel switching shall be monitored, recorded, and reported as excess emissions when emission levels exceed the BACT standards listed in Condition **D.11**. [40 CFR 60.7 and 40 CFR 75; and Permit No. 1050004-004-AC (PSD-FL-245)]

D.20. CEMS In Lieu of Water-to-Fuel Ratio. The NO_X CEMS shall be used in lieu of the water/fuel monitoring system for reporting excess emissions in accordance with 40 CFR 60.334(j)(1). Calibration of the water/fuel monitoring device required in 40 CFR 60.334(b)(4) will be replaced by the 40 CFR 75 certification tests of the NO_X CEMS. Upon request from the Department, the CEMS emissions rates for NO_X on Unit 5 shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332. [Permit No. 1050004-004-AC (PSD-FL-245)]

D.21. Missing Data Substitution. When NO_X monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate any specified average time. [Permit No. 1050004-004-AC (PSD-FL-245)]

D.22. Continuous Monitoring System. The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of 40 CFR 60.13, including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60.7(a)(5) or 40 CFR 75. Quality assurance procedures must conform to all applicable sections of 40 CFR 60, Appendix F or 40 CFR 75. [Permit No. 1050004-004-AC (PSD-FL-245)]

Test Methods and Procedures

D.23. Test Methods. When required, tests shall be performed in accordance with the following reference methods:

Method	Description of Method and Comments
1-4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content
7E	Determination of Nitrogen Oxide Emissions
9	Visual Determination of the Opacity of Emissions
10	Determination of Carbon Monoxide Emissions
18, 25 and/or 25A	Determination of Volatile Organic Concentrations
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines
ASTM D2880-71 or D4294 (or latest version) for the sulfur content of liquid fuels and D1072-80, D3031-81, D4084-82 or D3246-81 (or latest version)	Methods for Evaluating Fuel Sulfur Content

The above methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Appendix A of 40 CFR 60]

D.24. Annual Compliance Tests. During each calendar year (January 1st to December 31st), this emissions unit shall be tested to demonstrate compliance with the emission limitations and standards for VE, NO_X, and CO. The NO_X RATA test data may be used to demonstrate compliance with the annual testing requirements, provided the testing requirements (notification, procedures & reporting) of Chapter 62-297, F.A.C., 40 CFR 60, and 40 CFR 75, are met. In addition to the annual compliance tests, this emissions unit shall be tested prior to permit renewal to demonstrate compliance with the emission limitations for these pollutants. [Rule 62-297.310(8), F.A.C.]

D.25. Common Testing Requirements. Unless otherwise specified, tests shall be conducted in accordance with the requirements and procedures specified in Appendix TR, Facility-Wide Testing Requirements, of this permit. [Rule 62-297.310, F.A.C.]

D.26. Compliance with the Allowable Emission Limiting Standards – Each Fuel. Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate, for each fuel, at which this unit will be operated, but not later than 180 days after initial operation of the unit for that fuel, and annually thereafter as indicated in this permit, by using the reference methods as described in the latest edition of 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. [Permit No. 1050004-004-AC (PSD-FL-245)]

D.27. Compliance Testing. Initial (I) performance tests shall be performed on Unit 5 while firing natural gas as well as while firing fuel oil. Initial tests shall also be conducted after any modifications (and shakedown period not to exceed 100 days after restarting the CT) of air pollution control equipment, including installation of Ultra-Low NO_X burners (ULN) or hot SCR. [Permit No. 1050004-004-AC (PSD-FL-245)]

D.28. Continuous Compliance with the NO_X Emission Limits. Continuous compliance with the NO_X emission limits shall be demonstrated with the CEMS, based on the applicable averaging time of 24-hour block average (DLN or ULN technology) or a 3-hour average (if SCR is used). Based on CEMS data, a separate compliance determination is conducted at the end of each operating day (or 3-hour period when applicable) and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous operating day (or 3-hour period when applicable). Valid hourly emission rates shall not include periods of startup (including fuel switching), shutdown, or malfunction as defined in Rule 62-210.200, F.A.C., where emissions exceed the applicable NO_X standard. These excess emissions periods shall be reported as required. A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart. [Permit No. 1050004-004-AC (PSD-FL-245)]

D.29. Compliance with the SO_2 and PM/PM_{10} Emission Limits. The use of pipeline natural gas and No. 2 (or superior grade) distillate fuel oil with maximum sulfur content of 0.05% (by weight), is the method for determining compliance for SO_2 and PM/PM_{10}. For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard and the 0.05% sulfur limit, fuel oil analysis using ASTM D2880-71, or D4294 (or latest version) for the sulfur content of liquid fuels and D1072-80, D3031-81, D4084-42, or D3246-81 (or latest version) for sulfur content of gaseous fuels shall be utilized in accordance with the EPA-approved custom fuel monitoring schedule in Conditions **D.17** and **D.18**. The applicant is responsible for ensuring that the procedures above are used for determination of fuel sulfur content. Analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(b)(11). [Permit No. 1050004-004-AC (PSD-FL-245)]

D.30. Compliance with CO Emissions/Performance Criteria. Annual compliance testing for CO may be conducted concurrently with the annual RATA testing for NO_X required pursuant to 40 CFR 75 (required for gas only). [Permit No. 1050004-004-AC (PSD-FL-245)]

D.31. Compliance with the VOC Emissions/Performance Criteria. The CO emission limit will be employed as a surrogate and no annual testing for VOC emissions is required. [Permit No. 1050004-004-AC (PSD-FL-245)]

Recordkeeping and Reporting Requirements

D.32. Other Reporting Requirements. See Appendix RR, Facility-wide Reporting Requirements, for additional reporting requirements. [Rule 62-213.440(1)(b), F.A.C.]

D.33. Reporting Schedule. The following reports and notifications shall be submitted to the Compliance Authority:

Report	Reporting Deadline	Related Condition
Excess Emissions	Quarterly	**D.34.**

Report	Reporting Deadline	Related Condition
NSPS 40 CFR 60.7(c)	Semi-Annually	**D.35.**

[Rule 62-213.440(1)(b), F.A.C.]

D.34. Quarterly Excess Emissions Report. In the case of excess emissions resulting from malfunctions, the owner or operator shall notify the Compliance Authority in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(5), F.A.C.]

D.35. NSPS Excess Emissions. The owner or operator shall submit excess emission and monitoring system performance reports to the Compliance Authority semi-annually for each 6-month period in each calendar year. All reports shall be postmarked by the 30^{th} day following the end of each 6-month period. Each report shall include the information required in 40 CFR 60.7(c). [40 CFR 60.7(c)]

D.36. SSM Records. The owner or operator shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of this emissions unit, any malfunction of the air pollution control equipment, or any periods during which a CMS or monitoring device is inoperative. [40 CFR 60.7(b)]

Miscellaneous Requirements

D.37. Operating Procedures. Operating procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices shall meet the guidelines and procedures as established by the equipment manufacturers. All operators (including supervisors) of air pollution control devices shall be properly trained in plant-specific equipment. [Permit No. 1050004-004-AC (PSD-FL-245)]

D.38. Compliance Plan. Based on the application for Permit No. 1050004-016-AV, initial compliance has been demonstrated for natural gas firing, but not for distillate fuel oil firing. **Appendix CP**, **Compliance Plan**, for McIntosh Unit 5 is attached as a part of this permit. [Rule 62-213.440(2), F.A.C.]

D.39. NSPS Requirements – Subpart A. This emissions unit shall comply with all applicable requirements of 40 CFR 60, Subpart A, General Provisions, which have been adopted and incorporated by reference in Rule 62-204.800, F.A.C. Subpart A is attached as an appendix to this permit. [40 CFR 60.1(a)]

D.40. NSPS Requirements – Subpart GG. This emissions unit shall comply with all applicable requirements of 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, which have been adopted and incorporated by reference in Rule 62-204.800, F.A.C. Subpart GG is attached as an appendix to this permit. [40 CFR 60.330(a)]

Table of Contents.

Subsection E. The specific conditions in this section apply to the following emissions unit:

EU No.	Brief Description
008	Diesel-Drive Coal Tunnel Sump Engine

This emissions unit consists of a Lister diesel engine-driven non-emergency sump pump. The following table provides important details for the engine. This emissions unit is an existing stationary reciprocating internal combustion engine (RICE) based on its manufacture date.

Engine Brake HP	Date of Construction	Primary Fuel	Type of Engine	Displacement (liters/cylinder)	Model No. / Serial No.	Date of Last Modification or Reconstruction
25	1981	Diesel	Non-Emergency Compression Ignition	<10	HS-468 / 25M55A1C20	N/A

{Permitting Note: This compression ignition (CI) RICE is regulated under 40 CFR 63, Subpart A, NESHAP General Provisions, and Subpart ZZZZ, NESHAP for Stationary RICE, both adopted and incorporated by reference in Rule 62-204.800, F.A.C. This RICE is not used for fire pumps. This RICE is exempted from regulation under 40 CFR 60, Subpart IIII, based on manufacture date. This is an existing stationary RICE less than or equal to 500 horsepower (HP), with a displacement of less than 10 liters per cylinder that is located at a major source of HAP and that has not been modified or reconstructed after June 12, 2006.}

Essential Potential to Emit (PTE) Parameters

E.1. Hours of Operation.

a. *Normal Operation*. This emissions unit may operate continuously (i.e., 8,760 hours/year). [Rule 62-210.200(PTE), F.A.C.]

b. *Engine Startup*. During periods of startup, the owner or operator must minimize the engine's time spent at idle and minimize the engine's time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply. [40 CFR 63.6625(h)]

Emission Limitations and Operating Requirements

E.2. Work or Management Practice Standards.

a. *Oil*. Change oil and filter every 1,000 hours of operation or annually, whichever comes first, unless allowed to be extended by paragraph e of this condition.

b. *Air Cleaner*. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first and replace as necessary.

c. *Hoses and Belts*. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first and replace as necessary.
[40 CFR 63.6602 & Table 2c to Subpart ZZZZ of Part 63]

d. *Operation and Maintenance*. Operate and maintain the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions or develop and follow your own maintenance plan which must provide, to the extent practicable, for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions. [40 CFR 63.6625(e) & 63.6640(a)]

e. *Oil Analysis*. The owner or operator has the option of using an oil analysis program to extend the oil change requirement. The oil analysis must be performed at the same frequency specified for changing the oil in paragraph a of this condition. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30% of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20% from the viscosity of the oil when new, or percent water content (by volume) is greater than 0.5%. If all of these condemning limits are not exceeded, the owner or operator is not required to change the oil. If any of the limits are exceeded, the owner or operator must change the oil within two days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the owner or operator must change the oil within two days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be a part of the maintenance plan for the engine. [40 CFR 63.6625(i)]

Monitoring of Operations

E.3. RESERVED.

Compliance Requirements

E.4. Continuous Compliance. This emissions unit shall be in compliance with the emissions limitations and operating standards in this section at all times. [40 CFR 63.6605(a)]

E.5. Operation and Maintenance of Equipment. At all times, the owner or operator must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Compliance Authority which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. [40 CFR 63.6605(b)]

Recordkeeping and Reporting Requirements

E.6. Other Reporting Requirements. See Appendix RR, Facility-wide Reporting Requirements, for additional reporting requirements. [Rule 62-213.440(1)(b), F.A.C.]

E.7. Notification, Performance, and Compliance Records. The owner or operator must keep:

a. A copy of each notification and report that the owner or operator submitted to comply with this section, including all documentation supporting any initial notification or notification of compliance status that the owner or operator submitted;
b. Records of the occurrence and duration of each malfunction;
c. Records of actions taken during periods of malfunction to minimize emissions in accordance with Condition **E.5**, including corrective actions to restore malfunctioning process and monitoring equipment to its normal or usual manner of operation;
d. Records of the actions required in Condition **E.2d** to show continuous compliance with each operating requirement;
e. Records required by the oil analysis program (if utilized) as detailed in Condition **E.2e**;
f. Records of the work or management practice standards specified in Condition **E.2**; and
g. Records of the maintenance conducted in order to demonstrate that the RICE was operated and maintained according to your own maintenance plan (if applicable).

[40 CFR 63.6655]

E.8. Record Retention.

a. The owner or operator must keep records in a suitable and readily available form for expeditious reviews.
b. The owner or operator must keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record.

[40 CFR 63.6660 & 63.10(b)(1)]

General Provisions

E.9. 40 CFR 63 Subpart A - General Provisions. The permittee shall comply with the following applicable requirements of 40 CFR 63, Subpart A - General Provisions, which have been adopted by reference in Rule 62-204.800(11)(d)1., F.A.C., except that the Secretary is not the Administrator for purposes of 40 CFR 63.5(e), 40 CFR 63.5(f), 40 CFR 63.6(g), 40 CFR 63.6(h)(9), 40 CFR 63.6(j), 40 CFR 63.13, and 40 CFR 63.14. Link to 40 CFR 63, Subpart A - General Provisions

General Provisions Citation	Subject of Citation
§63.1	General applicability of the General Provisions
§63.2	Definitions (additional terms defined in 43 CFR 63.6675)
§63.3	Units and abbreviations
§63.4	Prohibited activities and circumvention
§63.5	Construction and reconstruction
§63.6(a)	Applicability
§63.6(c)(1)-(2)	Compliance dates for existing sources
§63.9(a)	Applicability and State delegation of notification requirements
§63.9(b)(1)-(5)	Initial notifications (except that §63.9(b)(3) is reserved)
§63.9(i)	Adjustment of submittal deadlines
§63.9(j)	Change in previous information
§63.10(a)	Administrative provisions for recordkeeping/reporting
§63.10(b)(1)	Record retention
§63.10(b)(2)(vi)–(xi)	Records
§63.10(b)(2)(xii)	Record when under waiver
§63.10(b)(2)(xiv)	Records of supporting documentation
§63.10(b)(3)	Records of applicability determination
§63.10(d)(1)	General reporting requirements
§63.10(f)	Waiver for recordkeeping/reporting
§63.12	State authority and delegations
§63.13	Addresses
§63.14	Incorporation by reference
§63.15	Availability of information

[40 CFR 63.6645(a), 63.6665, & Table 8 to Subpart ZZZZ of Part 63]

Table of Contents.

Subsection F. The specific conditions in this section apply to the following emissions unit:

EU No.	Brief Description
010	Fire Water UPS Diesel Engine No. 32

This emissions unit consists of a Cummins diesel engine-driven emergency fire pump. The following table provides important details for this engine.

Engine Brake HP	Date of Construction	Primary Fuel	Type of Engine	Displacement (liters/cylinder)	Model No. / Serial No.	Date of Last Modification or Reconstruction
300	April 1989	Diesel	Emergency Compression Ignition	14	NT 885-F3 / 69827	N/A

{Permitting Note: This emissions unit is regulated under 40 CFR 63, Subpart A, NESHAP General Provisions, and Subpart ZZZZ, NESHAP for Stationary RICE, both adopted and incorporated by reference in Rule 62-204.800, F.A.C. This permit section addresses an existing emergency stationary CI RICE fire pump engine less than or equal to 500 HP that is located at a major source of HAP and that has not been modified or reconstructed after June 12, 2006.}

Essential Potential to Emit (PTE) Parameters

F.1. Hours of Operation.

a. *Emergency Situations*. There is no time limit on the use of emergency stationary RICE in emergency situations. [40 CFR 63.6640(f)(1)]

b. *Maintenance and Testing*. This unit is authorized to operate for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by federal, state, or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. The owner or operator may petition the Department for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per year. [40 CFR 63.6640(f)(2)(i)]

c. *Non-Emergency Situations*. This unit is authorized to operate up to 50 hours per year in non-emergency situations, but those 50 hours are counted towards the 100 hours per year provided for maintenance checks and readiness testing. [40 CFR 63.6640(f)(3)]

Emission Limitations and Operating Requirements

F.2. Work or Management Practice Standards.

a. *Oil*. Change oil and filter every 500 hours of operation or annually, whichever comes first, unless allowed to be extended by paragraph f of this condition.

b. *Air Cleaner*. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first and replace as necessary.

c. *Hoses and Belts*. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first and replace as necessary.

[40 CFR 63.6602 & Table 2c to Subpart ZZZZ of Part 63]

d. *Operation and Maintenance*. Operate and maintain the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions or develop and follow your own maintenance plan which must provide, to the extent practicable, for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions. [40 CFR 63.6625(e) & 63.6640(a)]

e. *Engine Startup*. During periods of startup, the owner or operator must minimize the engine's time spent at idle and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes. [40 CFR 63.6625(h)]

f. *Oil Analysis*. The owner or operator has the option of using an oil analysis program to extend the oil change requirement. The oil analysis must be performed at the same frequency specified for changing the oil in paragraph a of this condition. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30% of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20% from the viscosity of the oil when new, or percent water content (by volume) is greater than 0.5%. If all of these condemning limits are not exceeded, the owner or operator is not required to change the oil. If any of the limits are exceeded, the owner or operator must change the oil within two days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the owner or operator must change the oil within two days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be a part of the maintenance plan for the engine. [40 CFR 63.6625(i)]

Monitoring of Operations

F.3. Hour Meter. The owner or operator must install a non-resettable hour meter if one is not already installed. [40 CFR 63.6625(f)]

Compliance Requirements

F.4. Continuous Compliance. This emissions unit shall be in compliance with the emissions limitations and operating standards in this section at all times. [40 CFR 63.6605(a)]

F.5. Operation and Maintenance of Equipment. At all times, the owner or operator must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Compliance Authority which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. [40 CFR 63.6605(b)]

Recordkeeping and Reporting Requirements

F.6. Other Reporting Requirements. See Appendix RR, Facility-wide Reporting Requirements, for additional reporting requirements. [Rule 62-213.440(1)(b), F.A.C.]

F.7. Notification, Performance, and Compliance Records. The owner or operator must keep:

a. A copy of each notification and report that the owner or operator submitted to comply with this section, including all document supporting any initial notification or notification of compliance status that the owner or operator submitted;
b. Records of the occurrence and duration of each malfunction of operation;
c. Records of all required maintenance performed on the hour meter;
d. Records of actions taken during periods of malfunction to minimize emissions in accordance with Condition **F.5.** including corrective actions to restore malfunctioning process and monitoring equipment to its normal or usual manner of operation;
e. Records of the actions required in Condition **F.2. d** to show continuous compliance with each emission limitation or operating requirement;
f. Records required by the oil analysis program (if utilized) as detailed in Condition **F.2. f**;
g. Records of the work or management practice standards specified in Condition **F.2.** ;

h. Records of the maintenance conducted in order to demonstrate that the RICE was operated and maintained according to your own maintenance plan; and
i. Records of the hours of operation of the engine that are recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation.

[40 CFR 63.6655]

F.8. Record Retention.
a. The owner or operator must keep records in a suitable and readily available form for expeditious reviews.
b. The owner or operator must keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record.

[40 CFR 63.6660 and 63.10(b)(1)]

F.9. Delay of Performing Work Practice Requirements. If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in Condition **F.2.** , or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under federal, state, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under federal, state, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under federal, state, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the federal, state, or local law under which the risk was deemed unacceptable. [40 CFR 63.6640 & footnote 1 to Table 2c to Subpart ZZZZ of Part 63]

General Provisions

F.10. 40 CFR 63 Subpart A - General Provisions. The permittee shall comply with the following applicable requirements of 40 CFR 63, Subpart A - General Provisions, which have been adopted by reference in Rule 62-204.800(11)(d)1., F.A.C., except that the Secretary is not the Administrator for purposes of 40 CFR 63.5(e), 40 CFR 63.5(f), 40 CFR 63.6(g), 40 CFR 63.6(h)(9), 40 CFR 63.6(j), 40 CFR 63.13, and 40 CFR 63.14. Link to 40 CFR 63, Subpart A - General Provisions

General Provisions Citation	Subject of Citation
§63.1	General applicability of the General Provisions
§63.2	Definitions (additional terms defined in 43 CFR 63.6675)
§63.3	Units and abbreviations
§63.4	Prohibited activities and circumvention
§63.5	Construction and reconstruction
§63.6(a)	Applicability
§63.6(c)(1)-(2)	Compliance dates for existing sources
§63.9(a)	Applicability and State delegation of notification requirements
§63.9(b)(1)-(5)	Initial notifications (except that §63.9(b)(3) is reserved)
§63.9(i)	Adjustment of submittal deadlines
§63.9(j)	Change in previous information
§63.10(a)	Administrative provisions for recordkeeping/reporting
§63.10(b)(1)	Record retention
§63.10(b)(2)(vi)–(xi)	Records
§63.10(b)(2)(xii)	Record when under waiver
§63.10(b)(2)(xiv)	Records of supporting documentation
§63.10(b)(3)	Records of applicability determination

General Provisions Citation	Subject of Citation
§63.10(d)(1)	General reporting requirements
§63.10(f)	Waiver for recordkeeping/reporting
§63.12	State authority and delegations
§63.13	Addresses
§63.14	Incorporation by reference
§63.15	Availability of information

[40 CFR 63.6645(a), 63.6665, & Table 8 to Subpart ZZZZ of Part 63]

Table of Contents.

Subsection G. The specific conditions in this section apply to the following emissions unit:

EU No.	Brief Description
011	CT Startup Diesel Engine

This emissions unit consists of a Detroit Diesel engine that is used as a startup engine for the combustion turbine in Subsection A of this permit. The following table provides important details for this engine.

Engine Brake HP	Date of Construction	Primary Fuel	Type of Engine	Displacement (liters/cylinder)	Model No. / Serial No.	Date of Last Modification or Reconstruction
500	1969	Diesel	CI Black Start Non-Emergency	<10	V-71 / CH8118	N/A

{Permitting Note: This compression ignition (CI) RICE is regulated under 40 CFR 63, Subpart A, NESHAP General Provisions, and Subpart ZZZZ, NESHAP for Stationary RICE, both adopted and incorporated by reference in Rule 62-204.800, F.A.C. This RICE is not used for fire pumps. This RICE is exempted from regulation under 40 CFR 60, Subpart IIII, based on manufacture date. This permit section addresses and existing stationary CI RICE less than or equal to 500 HP that is located at a major source of HAP and that has not been modified or reconstructed after June 12, 2006.}

Essential Potential to Emit (PTE) Parameters

G.1. Hours of Operation. This emissions unit may operate continuously (i.e., 8,760 hours/year). [Rule 62-210.200(PTE), F.A.C.]

Emission Limitations and Operating Requirements

G.2. Work or Management Practice Standards.

a. *Oil*. Change oil and filter every 500 hours of operation or annually, whichever comes first, unless allowed to be extended by paragraph f of this condition.

b. *Air Cleaner*. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first and replace as necessary.

c. *Hoses and Belts*. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first and replace as necessary.

[40 CFR 63.6602 & Table 2c to Subpart ZZZZ of Part 63]

d. *Operation and Maintenance*. Operate and maintain the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions or develop and follow your own maintenance plan which must provide, to the extent practicable, for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions. [40 CFR 63.6625(e)(2) & 63.6640(a)]

e. *Engine Startup*. During periods of startup, the owner or operator must minimize the engine's time spent at idle and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes. [40 CFR 63.6625(h)]

f. *Oil Analysis*. The owner or operator has the option of using an oil analysis program to extend the oil change requirement. The oil analysis must be performed at the same frequency specified for changing the oil in paragraph a of this condition. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30% of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20% from the viscosity of the oil when new, or percent water content (by volume) is greater than 0.5%. If all of these condemning limits are not exceeded, the owner or operator is not required to change the oil. If any of the limits are exceeded, the owner or operator must change the oil within two days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the owner or operator must change the oil within two days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be a part of the maintenance plan for the engine. [40 CFR 63.6625(i)]

Compliance Requirements

G.3. Continuous Compliance. This emissions unit shall be in compliance with the emissions limitations and operating standards in this section at all times. [40 CFR 63.6605(a)]

G.4. Operation and Maintenance of Equipment. At all times, the owner or operator must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Compliance Authority which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. [40 CFR 63.6605(b)]

Recordkeeping and Reporting Requirements

G.5. Other Reporting Requirements. See Appendix RR, Facility-wide Reporting Requirements, for additional reporting requirements. [Rule 62-213.440(1)(b), F.A.C.]

G.6. Notification, Performance, and Compliance Records. The owner or operator must keep:

a. A copy of each notification and report that the owner or operator submitted to comply with this section, including all document supporting any initial notification or notification of compliance status that the owner or operator submitted;
b. Records of the occurrence and duration of each malfunction of operation;
c. Records of actions taken during periods of malfunction to minimize emissions in accordance with Condition **G.4**, including corrective actions to restore malfunctioning process and monitoring equipment to its normal or usual manner of operation;
d. Records of the actions required in Condition **G.2d** to show continuous compliance with each emission limitation or operating requirement;
e. Records required by the oil analysis program (if utilized) as detailed in Condition **G.2f**;
f. Records of the work or management practice standards specified in Condition **G.2**; and
g. Records of the maintenance conducted in order to demonstrate that the RICE was operated and maintained according to your own maintenance plan.

[40 CFR 63.6655]

G.7. Record Retention.

a. The owner or operator must keep records in a suitable and readily available form for expeditious reviews.
b. The owner or operator must keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record.

[40 CFR 63.6660 and 63.10(b)(1)]

General Provisions

G.8. 40 CFR 63 Subpart A - General Provisions. The permittee shall comply with the following applicable requirements of 40 CFR 63, Subpart A - General Provisions, which have been adopted by reference in Rule 62-204.800(11)(d)1., F.A.C., except that the Secretary is not the Administrator for purposes of 40 CFR 63.5(e), 40 CFR 63.5(f), 40 CFR 63.6(g), 40 CFR 63.6(h)(9), 40 CFR 63.6(j), 40 CFR 63.13, and 40 CFR 63.14. Link to 40 CFR 63, Subpart A - General Provisions

General Provisions Citation	Subject of Citation
§63.1	General applicability of the General Provisions
§63.2	Definitions (additional terms defined in 43 CFR 63.6675)
§63.3	Units and abbreviations
§63.4	Prohibited activities and circumvention
§63.5	Construction and reconstruction
§63.6(a)	Applicability
§63.6(c)(1)-(2)	Compliance dates for existing sources
§63.9(a)	Applicability and State delegation of notification requirements
§63.9(b)(1)-(5)	Initial notifications (except that §63.9(b)(3) is reserved)
§63.9(i)	Adjustment of submittal deadlines
§63.9(j)	Change in previous information
§63.10(a)	Administrative provisions for recordkeeping/reporting
§63.10(b)(1)	Record retention
§63.10(b)(2)(vi)–(xi)	Records
§63.10(b)(2)(xii)	Record when under waiver
§63.10(b)(2)(xiv)	Records of supporting documentation
§63.10(b)(3)	Records of applicability determination
§63.10(d)(1)	General reporting requirements
§63.10(f)	Waiver for recordkeeping/reporting
§63.12	State authority and delegations
§63.13	Addresses
§63.14	Incorporation by reference
§63.15	Availability of information

[40 CFR 63.6645(a), 63.6665, & Table 8 to Subpart ZZZZ of Part 63]

Table of Contents.

Subsection H. The specific conditions in this section apply to the following emissions unit:

EU No.	Brief Description
035	Coal Handling and Storage Activities

Emissions Unit 035 is the coal handling and storage activities for McIntosh Unit 3 (EU 006). This emissions unit began operation on September 1, 1982. The maximum annual throughput of coal is 1,398,121 tons.

Fugitive emissions of PM are controlled through a combination of bag filters, enclosures, and moisture/watering.

This emissions unit consists of the following emission points:

Emission Point ID	Emission Point Description
F-090	Active Coal Storage Yard
V-074	Conveyor C3 Baghouse
V-075	Conveyor C2 Baghouse

{Permitting Note: This emissions unit is regulated under NSPS 40 CFR 60, Subpart A, General Provisions, and Subpart Y, Standards of Performance for Coal Preparation and Processing Plants, adopted and incorporated by reference in Rule 62-204.800, F.A.C.}

Essential Potential to Emit (PTE) Parameters

H.1. Hours of Operation. This emissions unit may operate continuously (i.e., 8,760 hours/year). [Rule 62-210.200(PTE), F.A.C.]

Emission Limitations

H.2. Visible Emissions (VE). Visible emissions from this emissions unit shall not equal or exceed 20% opacity. [40 CFR 60.254(a)]

Test Methods and Procedures

H.3. Test Methods. When required, tests shall be performed in accordance with the following reference methods:

Method	Description of Method and Comments
9	Visual Determination of the Opacity of Emissions

The above methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Appendix A of 40 CFR 60]

H.4. Additional Method 9 Requirements. The permittee shall conform to the following requirements when determining compliance of this emissions unit through EPA Method 9.

a. Method 9 of 40 CFR 60, Appendix A, and the procedures in 40 CFR 60.11 must be used to determine opacity, with the exceptions specified in subparagraphs a(1) and a(2).
   (1) The duration of the Method 9 performance test shall be one hour (10 6-minute averages).
   (2) If, during the initial 30 minutes of the observation of a Method 9 performance test, all of the 6-minute average opacity readings are less than or equal to half the applicable opacity limit, then the observation period may be reduced from one hour to 30 minutes.

b. To determine opacity for fugitive coal dust emissions sources, the additional requirements in subparagraphs b(1) through b(3) must be used.
   (1) The minimum distance between the observer and the emission source shall be 5.0 meters (16 feet), and the sun shall be oriented in the 140-degree sector of the back.

(2) The observer shall select a position that minimizes interference from other fugitive coal dust emissions sources and make observations such that the line of vision is approximately perpendicular to the plume and wind direction.
(3) The observer shall make opacity observations at the point of greatest opacity in that portion of the plume where condensed water vapor is not present. Water vapor is not considered a visible emission.

c. A visible emissions observer may conduct visible emission observations for up to three fugitive, stack, or vent emission points within a 15-second interval if the following conditions in subparagraphs c(1) through c(3) are met.
(1) No more than three emissions points may be read concurrently.
(2) All three emissions points must be within a 70-degree viewing sector or angle in front of the observer such that the proper sun position can be maintained for all three points.
(3) If an opacity reading for any one of the three emissions points is within 5% opacity from the applicable standard (excluding readings of zero opacity), then the observer must stop taking readings from the other two points and continue reading just that single point.

[40 CFR 60.257(a)]

H.5. Annual Compliance Tests. During each calendar year (January 1st to December 31st), this emissions unit shall be tested to demonstrate compliance with the emission limitation for VE. [Rule 62-297.310(8)(a)3, F.A.C.]

H.6. Common Testing Requirements. Unless otherwise specified, tests shall be conducted in accordance with the requirements and procedures specified in Appendix TR, Facility-Wide Testing Requirements, of this permit. [Rule 62-297.310, F.A.C.]

Recordkeeping and Reporting Requirements

H.7. Other Reporting Requirements. See Appendix RR, Facility-wide Reporting Requirements, for additional reporting requirements. [Rule 62-213.440(1)(b), F.A.C.]

H.8. SSM Records. The permittee shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility, any malfunction of the air pollution control equipment, or any periods during which a continuous monitoring system or monitoring device is inoperative. [40 CFR 60.7(b)]

Miscellaneous Requirements

H.9. NSPS Requirements – Subpart A. This emissions unit shall comply with all applicable requirements of 40 CFR 60, Subpart A, General Provisions, which have been adopted and incorporated by reference in Rule 62-204.800, F.A.C. Subpart A is attached as an appendix to this permit. [40 CFR 60.1(a)]

H.10. NSPS Requirements – Subpart Y. This emissions unit shall comply with all applicable requirements of 40 CFR 60, Subpart Y, Standards of Performance for Coal Preparation and Processing Plants, which have been adopted and incorporated by reference in Rule 62-204.800, F.A.C. Subpart Y is attached as an appendix to this permit. [40 CFR 60.250]

Table of Contents.

Federal Acid Rain Provisions

C.D. McIntosh, Jr. Power Plant
Operated by: Lakeland Electric
ORIS Code: 0676

The emissions units listed below are regulated under Acid Rain, Phase II.

E.U. ID No.	Brief Description
005	McIntosh Unit 2 – Fossil-Fuel-Fired Steam Generator
006	McIntosh Unit 3 – Fossil-Fuel-Fired Steam Generator
028	McIntosh Unit 5 – 370 MW Combined Cycle Stationary Combustion Turbine

A.1. The Phase II Acid Rain Part application submitted for this facility, as approved by the Department, is a part of this permit. The owners and operators of these Phase II acid rain units must comply with the standard requirements and special provisions set forth in the application listed below:
a. DEP Form No. 62-210.900(1)(a), dated 05/08/2018, received 05/11/2018.
[Chapter 62-213, F.A.C. and Rule 62-214.320, F.A.C.]

A.2. Nitrogen oxide (NO_X) requirements for each Acid Rain Phase II unit are as follows:

E.U. ID No.	EPA ID	NO_X Limit
006	**03**	The Florida Department of Environmental Protection approves a NO_X compliance plan for this unit. The compliance plan is effective for calendar year 2019 through calendar year 2023. This unit's applicable emission limitation for each year of the plan, is 0.46 lb/MMBtu from 40 CFR 76.7(a)(2) for dry bottom wall-fired boilers.

Additional Requirements (for units in a NO_X averaging plan)

a. Under the plan (NO_X Phase II averaging plan), the actual Btu-weighted annual average NO_X emission rate for the units in the plan shall be less than or equal to the Btu-weighted annual average NO_X emission rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emission limitations under 40 CFR 76.5, 76.6, or 76.7, except that for any early election units, the applicable emission limitations shall be under 40 CFR 76.7. If the designated representative demonstrates that the requirement of the prior sentence (as set forth in 40 CFR 76.11(d)(1)(ii)(A)) is met for a year under the plan, then this unit shall be deemed to be in compliance for that year with its alternative contemporaneous annual emission limitation and annual heat input limit.
b. In addition to the described NO_X compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NO_X compliance plan and requirements covering excess emissions.

A.3. Sulfur Dioxide (SO_2) Emission Allowances. SO_2 emissions from sources subject to the Federal Acid Rain Program (Title IV) shall not exceed any allowances that the source lawfully holds under the Federal Acid Rain Program. Allowances shall not be used to demonstrate compliance with a non-Title IV applicable requirement of the Act.
a. No permit revision shall be required for increases in emissions that are authorized by allowances acquired pursuant to the Federal Acid Rain Program, provided that such increases do not require a permit revision pursuant to Rule 62-213.400(3), F.A.C.
b. No limit shall be placed on the number of allowances held by the source under the Federal Acid Rain Program.
c. Allowances shall be accounted for under the Federal Acid Rain Program.
[Rule 62-213.440(1)(c)1., 2. & 3., F.A.C.]

A.4. Comments, Notes, and Justifications: None.

Table of Contents.

Acid Rain Part Application

For more information, see instructions and refer to 40 CFR 72.30, 72.31, and 74; and Chapter 62-214, F.A.C.

This submission is: ☐ New ☐ Revised ■ Renewal

STEP 1

Identify the source by plant name, state, and ORIS or plant code.

Plant name	State	ORIS/Plant Code
C.D. McIntosh, Jr. Power Plant	FL	0676

STEP 2
Enter the unit ID# for every Acid Rain unit at the Acid Rain source in column "a."

If unit a SO_2 Opt-in unit, enter "yes" in column "b".

For new units or SO_2 Opt-in units, enter the requested information in columns "d" and "e."

a	b	c	d	e
Unit ID#	SO_2 Opt-in Unit? (Yes or No)	Unit will hold allowances in accordance with 40 CFR 72.9(c)(1)	New or SO_2 Opt-in Units Commence Operation Date	New or SO_2 Opt-in Units Monitor Certification Deadline
EU 005	No	Yes	N/A	N/A
EU 006	No	Yes	N/A	N/A
EU 028	No	Yes	N/A	N/A

DEP Form No. 62-210.900(1)(a) – Form
Effective: 3/16/08 1

Federal Acid Rain Provisions

C.D. McIntosh, Jr. Power Plant
Plant Name (from STEP 1)

STEP 3

Read the standard requirements.

Acid Rain Part Requirements.

(1) The designated representative of each Acid Rain source and each Acid Rain unit at the source shall:
(i) Submit a complete Acid Rain Part application (including a compliance plan) under 40 CFR Part 72 and Rules 62-214.320 and 330, F.A.C., in accordance with the deadlines specified in Rule 62-214.320, F.A.C.; and
(ii) Submit in a timely manner any supplemental information that the DEP determines is necessary in order to review an Acid Rain Part application and issue or deny an Acid Rain Part;
(2) The owners and operators of each Acid Rain source and each Acid Rain unit at the source shall:
(i) Operate the unit in compliance with a complete Acid Rain Part application or a superseding Acid Rain Part issued by the DEP; and
(ii) Have an Acid Rain Part.

Monitoring Requirements.

(1) The owners and operators and, to the extent applicable, designated representative of each Acid Rain source and each Acid Rain unit at the source shall comply with the monitoring requirements as provided in 40 CFR Part 75, and Rule 62-214.420, F.A.C.
(2) The emissions measurements recorded and reported in accordance with 40 CFR Part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.
(3) The requirements of 40 CFR Part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.
(4) For applications including a SO_2 Opt-in unit, a monitoring plan for each SO_2 Opt-in unit must be submitted with this application pursuant to 40 CFR 74.14(a). For renewal applications for SO_2 Opt-in units include an updated monitoring plan if applicable under 40 CFR 75.53(b).

Sulfur Dioxide Requirements.

(1) The owners and operators of each source and each Acid Rain unit at the source shall:
(i) Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)), or in the compliance subaccount of another Acid Rain unit at the same source to the extent provided in 40 CFR 73.35(b)(3), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and
(ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.
(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.
(3) An Acid Rain unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
(i) Starting January 1, 2000, an Acid Rain unit under 40 CFR 72.6(a)(2); or
(ii) Starting on the later of January 1, 2000, or the deadline for monitor certification under 40 CFR Part 75, an Acid Rain unit under 40 CFR 72.6(a)(3).
(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain Part application, the Acid Rain Part, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements. The owners and operators of the source and each Acid Rain unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Excess Emissions Requirements.

(1) The designated representative of an Acid Rain unit that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR Part 77.
(2) The owners and operators of an Acid Rain unit that has excess emissions in any calendar year shall:
(i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR Part 77; and
(ii) Comply with the terms of an approved offset plan, as required by 40 CFR Part 77.

Recordkeeping and Reporting Requirements.

(1) Unless otherwise provided, the owners and operators of the source and each Acid Rain unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the EPA or the DEP:
(i) The certificate of representation for the designated representative for the source and each Acid Rain unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with Rule 62-214.350, F.A.C.; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
(ii) All emissions monitoring information, in accordance with 40 CFR Part 75, provided that to the extent that 40 CFR Part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply;
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,

DEP Form No. 62-210.900(1)(a) – Form
Effective: 3/16/08 2

C.D. McIntosh, Jr. Power Plant
Plant Name (from STEP 1)

STEP 3, Continued.

Recordkeeping and Reporting Requirements (cont)

(iv) Copies of all documents used to complete an Acid Rain Part application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.

(2) The designated representative of an Acid Rain source and each Acid Rain unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR Part 72, Subpart I, and 40 CFR Part 75.

Liability.

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain Part application, an Acid Rain Part, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each Acid Rain source and each Acid Rain unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an Acid Rain source (including a provision applicable to the designated representative of an Acid Rain source) shall also apply to the owners and operators of such source and of the Acid Rain units at the source.
(6) Any provision of the Acid Rain Program that applies to an Acid Rain unit (including a provision applicable to the designated representative of an Acid Rain unit) shall also apply to the owners and operators of such unit. Except as provided under 40 CFR 72.44 (Phase II repowering extension plans) and 40 CFR 76.11 (NO_X averaging plans), and except with regard to the requirements applicable to units with a common stack under 40 CFR Part 75 (including 40 CFR 75.16, 75.17, and 75.18), the owners and operators and the designated representative of one Acid Rain unit shall not be liable for any violation by any other Acid Rain unit of which they are not owners or operators or the designated representative and that is located at a source of which they are not owners or operators or the designated representative.
(7) Each violation of a provision of 40 CFR Parts 72, 73, 74, 75, 76, 77, and 78 by an Acid Rain source or Acid Rain unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Effect on Other Authorities.

No provision of the Acid Rain Program, an Acid Rain Part application, an Acid Rain Part, or an exemption under 40 CFR 72.7or 72.8 shall be construed as:
(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an Acid Rain source or Acid Rain unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;
(2) Limiting the number of allowances a unit can hold; *provided*, that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Act;
(3) Requiring a change of any kind in any state law regulating electric utility rates and charges, affecting any state law regarding such state regulation, or limiting such state regulation, including any prudence review requirements under such state law;
(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
(5) Interfering with or impairing any program for competitive bidding for power supply in a state in which such program is established.

STEP 4
For SO_2 Opt-in units only.

In column "f" enter the unit ID# for every SO_2 Opt-in unit identified in column "a" of STEP 2.

For column "g" describe the combustion unit and attach information and diagrams on the combustion unit's configuration.

In column "h" enter the hours.

f	g	h (not required for renewal application)
Unit ID#	Description of the combustion unit	Number of hours unit operated in the six months preceding initial application
N/A	N/A	N/A

DEP Form No. 62-210.900(1)(a) – Form
Effective: 3/16/08
3

C.D. McIntosh, Jr. Power Plant
Plant Name (from STEP 1)

STEP 5

For SO_2 Opt-in units only.

(Not required for SO_2 Opt-in renewal applications.)

In column "i" enter the unit ID# for every SO_2 Opt-in unit identified in column "a" (and in column "f").

For columns "j" through "n," enter the information required under 40 CFR 74.20-74.25 and attach all supporting documentation required by 40 CFR 74.20-74.25.

i	j	k	l	m	n
Unit ID#	Baseline or Alternative Baseline under 40 CFR 74.20 (mmBtu)	Actual SO_2 Emissions Rate under 40 CFR 74.22 (lbs/mmBtu)	Allowable 1985 SO_2 Emissions Rate under 40 CFR 74.23 (lbs/mmBtu)	Current Allowable SO_2 Emissions Rate under 40 CFR 74.24 (lbs/mmBtu)	Current Promulgated SO_2 Emissions Rate under 40 CFR 74.25 (lbs/mmBtu)
N/A	N/A	N/A	N/A	N/A	N/A

STEP 6

For SO_2 Opt-in units only.

Attach additional requirements, certify and sign.

A. If the combustion source seeks to qualify for a transfer of allowances from the replacement of thermal energy, a thermal energy plan as provided in 40 CFR 74.47 for combustion sources must be attached.
B. A statement whether the combustion unit was previously an affected unit under 40 CFR 74.
C. A statement that the combustion unit is not an affected unit under 40 CFR 72.6 and does not have an exemption under 40 CFR 72.7, 72.8, or 72.14.
D. Attach a complete compliance plan for SO_2 under 40 CFR 72.40.
E. The designated representative of the combustion unit shall submit a monitoring plan in accordance with 40 CFR 74.61. For renewal application, submit an updated monitoring plan if applicable under 40 CFR 75.53(b).
F. The following statement must be signed by the designated representative or alternate designated representative of the combustion source: "I certify that the data submitted under 40 CFR Part 74, Subpart C, reflects actual operations of the combustion source and has not been adjusted in any way."

Signature N/A | Date N/A

STEP 7

Read the certification statement; provide name, title, owner company name, phone, and e-mail address; sign, and date.

Certification (for designated representative or alternate designated representative only)

I am authorized to make this submission on behalf of the owners and operators of the Acid Rain source or Acid Rain units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Subject: Acid Rain Part Application (C.D.McIntosh, Jr. Power Plant)

Name Mr. Michael Lunday	Title Plant Manager
Owner Company Name Lakeland Electric	
Phone (863) 834-6691	E-mail address michael.lunday@lakelandelectric.com
Signature M S Lunday	Date 5-8-18

DEP Form No. 62-210.900(1)(a) – Form
Effective: 3/16/08

4

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258

Phase II NO_x Compliance Plan

Page 1 of 2

For more information, see instructions and refer to 40 CFR 76.9

This submission is : [X] New [ ] Revised

Step 1
Indicate plant name, State, and ORIS code from NADB, if applicable

Plant Name	State	ORIS Code
C.D. McIntosh, Jr. Power Plant	FL	0676

Step 2

Identify each affected Group 1 and Group 2 boiler using the boiler ID# from NADB, if applicable. Indicate boiler type: "GB" for cell burner, "CY" for cyclone, "DBW" for dry bottom wall fired, "T" for tangentially fired, "V" for vertically fired, and "WB" for wet bottom. Indicate the compliance option selected for each unit.

	ID# 03 (EU006) Type DBW	ID# Type	ID# Type	ID# Type	ID# Type	ID# Type
(a) Standard annual average emission limitation of 05.0 lb/mmBtu (for Phase I dry bottom wall-fired boilers)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
(b) Standard annual average emission limitation of 0.45 lb/mmBtu (for Phase I tangentially fired boilers)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
(c) EPA-approved early election plan under 40 CFR 76.8 through 12/31/07 (also indicate above emission limit specified in	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
(d) standard annual average emission limitation of 0.46 lb/mmBtu (for Phase II dry bottom wall-fired boilers)	[X]	[ ]	[ ]	[ ]	[ ]	[ ]
(e) Standard annual average emission limitation of 4.0 lb/mmBtu (for Phase II tangentially fired boilers)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
(f) Standard annual average emission limitation of 0.68 lb/mmBtu (for cell burner boilers)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
(g) Standard annual average emission limitation of .086 lb/mmBtu (for cyclone boilers)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
(h) Standard annual average emission limitation of 0.80 lb/mmBtu (for vertically fired boilers)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
(i) Standard annual average emission limitation of 0.84 lb/mmBtu (for wet bottom boilers)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
(j) NO_x Averaging Plan (include NO_x Averaging form)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
(k) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(A)(check the standard emission limitation applicable to any unit utilizing stack)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
(l) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(B) with NOX Averaging (check the NOX Averaging Plan box and include NOX Averaging form)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]

EPA Form 7610-28 (3-97)

C.D. McIntosh, Jr. Power Plant

Plant Name (from Step 1)

NOX Compliance – Page 2

Page 2 of 2

Step 2, cont'd

	ID# Type	ID# Type	ID# Type	ID# Type	ID# Type	ID# Type
(m) EPA-approved common stack apportionment method pursuant to 40 CFR 75.17 (a)(2)(i)(C), (a)(2)(iii)(B), or (b)(2)						
(n) AEL (include Phase II AEL Demonstration Period, Final AEL Petition, or AEL Renewal form as appropriate)	☐	☐	☐	☐	☐	☐
(o) Petition for AEL demonstration period or final AEL under review by U.S. EPA or demonstration period ongoing	☐	☐	☐	☐	☐	☐
(p) Repowering extension plan approved or under review	☐	☐	☐	☐	☐	☐

Step 3
Read the standard requirements and certification, enter the name of the designated representative, sign &

Standard Requirements

General. This source is subject to the standard requirement in 40 CFR 72.9 (consistent with 40 CFR 76.8(e)(1)(i)). These requirements are listed in this source's Acid Rain Permit.

Special Provisions for Early Election Units

Nitrogen Oxides. A unit that is governed by approved early election plan shall be subject to an emissions limitation for NO_x as provided under 40 CFR 76.8(a)(2) except as provided under 40 CFR 76.8(e)(3)(ii).
Liability. The owners and operators of a unit governed by an approved early election plan shall be liable for any violation of the plan or 40 CFR 76.8 at that unit. The owners and operators shall be liable, beginning January 1,200, for fulfilling the obligations specified in 40 CFR part 77.
Termination. An approved early election plan shall be in effect only until the earlier of January 1, 2008 or january1 of the calendar year for which a termination of the plan takes effect. If the designated representative of the unit under an approved early election plan fails to demonstrate compliance with the applicable emissions limitation under 40 CFR 76.5 for any year during the period beginning January 1 of the first year the early election takes effect and ending December 31, 2007, the permitting authority will terminate the plan. The termination will take effect beginning January 1 of the year for which there is a failure to demonstrate compliance, and the designated representative may no submit a new early election plan. The designated representative of the unit under an approved early election plan may terminate the plan any year prior to 2008 but may not submit a new early election plan. In order to terminate the plan, the designated reprsentive must submit a notice under 40 CFR 72.40(d) by January 1 of the year for which the termination is to take effect. If an early election plan is terminated any year prior to 2000, the unit shall meet, beginning January 1, 2000, the applicable emissions limitation for NO_x for phase II units with Group 1boilers under 40 CFR 76.7 If an early election plan is terminated on or after 2000,the unit shall meet, beginning on the effective date of the termination, the applicable emissions limitation for NO_x for Phase II units with Group 1 boilers under 40 CFR 76.7.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Subject: C.D. McIntosh, Jr. Power Plant Renewal Phase II NOx Compliance Plan Form

Name Timothy Bachand, P. E.

Signature [signature] Date 6/16/08

EPA Form 7610-28 (3-97)

Table of Contents.

Mosaic Fertilizer, LLC
Bartow Facility
13830 Circa Crossing Drive
Lithia, FL 33547

August 20, 2020 **ELECTRONIC SUBMITTAL**

Mr. Hastings Read
Florida Department of Environmental Protection
Division of Air Resources Management
2600 Blairstone Road
Tallahassee, FL 32399

RE: **Response to June 22, 2020 Regional Haze Rule Reasonable Progress Analysis Request Letter**
Mosaic Bartow Facility
Permit No. 1050046-065-AV

Dear Mr. Read:

This submittal serves as the Regional Haze Rule Reasonable Progress Analysis for the Mosaic Fertilizer, LLC (Mosaic) Bartow facility in response to the June 22, 2020 request letter to complete and submit to the Florida Department of Environmental Protection (Department) an analysis regarding the availability of emission controls needed to ensure reasonable progress to visibility goals at Class I areas in and around the State of Florida. The June 22, 2020 Regional Haze Rule Reasonable Progress Analysis request letter includes background on the U.S. Environmental Protection Agency's (U.S. EPA's) Regional Haze Rule, the second implementation period (2018-2028), and the Department's SIP development process.

The Bartow facility is located in Polk County and is currently operating under Title V Air Operation Permit No. 1050046-065-AV. The Bartow facility is a phosphate fertilizer manufacturing complex which processes phosphate rock into several different fertilizer products. The process begins with the manufacture of sulfuric acid (H_2SO_4) in the sulfuric acid plants (SAPs). Phosphate rock (P_2O_5) is reacted with H_2SO_4 to produce phosphoric acid, which is then ammoniated and granulated to produce fertilizers.

Based on projected 2028 sulfur dioxide (SO_2) emissions, the Department identified Bartow as a source that contributes sulfates at the Everglades National Park that must undergo a reasonable progress analysis for SO_2 emissions. The units listed below are projected to emit more than 5 tons per year of SO_2 in 2028, and the Department requested that Mosaic provide either a reasonable progress four-factor technical analysis or an analysis demonstrating that the unit meets the "effectively controlled unit" exemption at the facility:

- EU 012 – No. 4 Sulfuric Acid Plant
- EU 032 – No. 6 Sulfuric Acid Plant
- EU 033 – No. 5 Sulfuric Acid Plant

Mosaic has determined that a full four-factor technical analysis would likely result in the conclusion that no further controls are necessary at all three SAPs, and this response provides the analysis demonstrating that the SAPs at the Bartow facility meet the "effectively controlled unit" exemption.

Regional Haze Rule Reasonable Progress Analysis Subject Emission Units
Within the process at the three SAPs at the Bartow facility, molten sulfur is combusted (oxidized) with dry air in the sulfur furnace. The resulting SO_2 gas is catalytically converted (further oxidized) to sulfur trioxide (SO_3) over a catalyst bed in a converter tower. The SO_3 is then absorbed in sulfuric acid. The remaining SO_2, not previously oxidized, is passed over a final converter bed of catalyst and the SO_3 produced is then absorbed in H_2SO_4. The remaining gases exit to the atmosphere through a high-efficiency mist eliminator. The current permit production capacities and SO_2 emission limits are presented in Table 1.

Table 1: Bartow SAP Production Capacities & SO_2 Emission Limits

	No. 4 SAP (EU 012)	No. 5 SAP (EU 033)	No. 6 SAP (EU 032)
Maximum Production Rate TPD of 100% H_2SO_4	2,600	2,600	2,600
SO_2 Emission Limit lb/ton of 100% H_2SO_4	4	4	4
SO_2 Emission Limit lb/hr of 100% H_2SO_4	433.3	433.3	433.3
SO_2 Emission Limit ton/year	1,898	1,898	1,898
SO_2 Emission Limit lb/hr CAP	1,100[a] CAP, 24-hour block average (6:00 a.m. to 6:00 a.m.)		

[a]Construction Permit Nos. 1050046-050-AC and 1050046-063-AC

Effectively Controlled Units
Mosaic has determined that the Regional Haze Rule Reasonable Progress Analysis subject emission units (all three SAPs) at the Bartow facility are already effectively controlled with respect to SO_2 emissions and, therefore, they are not subject to a reasonable progress four-factor technical analysis. As outlined below, Mosaic has recently made significant expenditures to effectively control SO_2 emissions at each unit.

The three SAPs at the Bartow facility are double absorption sulfuric acid systems equipped with two absorption towers in series to react sulfur trioxide (SO_3) with water to generate sulfuric acid. The SO_2 generated in a double absorption system's sulfur furnace is catalytically oxidized to SO_3 over catalyst beds at a very high rate of 99.7% or greater, resulting in relatively low SO_2 emissions when compared to a single absorption system. A design feature that limits the overall SO_2-to-SO_3 conversion in a single absorption system is the fact that the reaction of SO_2 to SO_3 becomes less favorable as the SO_3 concentration in the system increases with SO_2 conversion efficiencies ranging from only 95% to 98%. The double absorption design improves SO_2-to-SO_3 conversion by using the first absorption tower, a heat recovery system (HRS) absorption tower, to remove SO_3, thereby bringing about a considerable shift in the SO_2-to-SO_3 reaction equilibrium towards the formation of SO_3 in the converter bed(s) located after the first absorption tower, which results in a very high overall SO_2-to-SO_3 conversion efficiency.

During the 2016-2020 time period, Mosaic replaced the fourth SO_2-to-SO_3 converter bed with cesium-promoted catalyst at each of the three SAPs at the Bartow facility to further reduce each unit's SO_2 emissions to comply with the U.S. EPA's 2010 1-hour SO_2 National

Ambient Air Quality Standard (NAAQS) final rule. Permit Nos. 1050046-050-AC and 1050046-063-AC added a SO_2 lb/hr 24-hour block average cap at each facility based on allowable SO_2 emission rates that demonstrate compliance with the U.S. EPA's 2010 1-hour SO_2 NAAQS final rule. The standard catalysts used in sulfuric acid unit SO_2-to-SO_3 converter beds are comprised of potassium and vanadium salts supported on a silica carrier. Cesium-promoted catalysts are like these standard potassium-promoted catalysts, but the potassium promoter is replaced with cesium. The cesium helps to promote SO_2-to-SO_3 conversion at lower temperatures. In the three SAPs at the Bartow facility, a cesium-promoted catalyst is used in the SO_2-to-SO_3 converter bed located between each unit's two absorption columns because it promotes a high SO_2-to-SO_3 conversion rate at the lower inlet temperature that may occur at this converter bed. By using a cesium-promoted catalyst in the last converter bed, the overall SO_2-to-SO_3 conversion rate is increased, resulting in lower SO_2 emissions from the plant. Appendix 1 provides a summary per SAP of the amount, manufacturer, and type of catalyst installed during the 2016-2020 time period.

A search of sulfuric acid plant (Process Code 62.015) entries dating back to January 1, 2000 in EPA's RACT/BACT/LAER Clearinghouse (RBLC) database indicates that the combination of dual absorption design and cesium-promoted catalysts represents the BACT for sulfur burning, non-single absorption column sulfuric acid plants. Appendix 2 is a compilation of the results of our search of the RBLC database for sulfur burning, non-single absorption column sulfuric acid plants. BACT determinations have been in the range of 3.0 to 4.0 lb/ton for SO_2 emissions.

Additionally, Mosaic has replaced several major components within the three SAPs during the last decade. These comprehensive replacement activities reduced the SAPs' SO_2 emissions by renovating the units with gastight, more efficient components which improved its overall SO_2-to-SO_3 conversion efficiency. The construction permits authorizing improvements to overall SO_2-to-SO_3 conversion efficiency are presented in Table 2.

Table 2. Construction Permits Authorizing Overall SO_2-to-SO_3 Conversion Efficiency Improvements

Emission Unit	Construction Permit
No. 4 SAP (EU 012)	1050046-044-AC
	1050046-048-AC
	1050046-069-AC
No. 5 SAP (EU 033)	1050046-039-AC
	1050046-040-AC
	1050046-055-AC/1050046-062
	1050046-058-AC
	1050046-071-AC
No. 6 SAP (EU 032)	1050046-049-AC

In summary, sulfur dioxide emissions from the three SAPs at the Bartow facility are effectively controlled by the 1,100 lb SO_2/hour, 24-hour block average (6:00 a.m. to 6:00 a.m.) cap, double absorption system technologies with vanadium catalyst for the 1st, 2nd, and 3rd beds and cesium catalyst for the 4th bed in the converters, the use of good combustion practices, and best operational practices to minimize excess emissions during startup and shutdown. Since Mosaic has recently made significant catalyst expenditure that has resulted in significant reductions of visibility impairing pollutions at all three SAPs to meet the 1,100 lb SO_2/hour, 24-hour block average (6:00 a.m. to 6:00 a.m.) cap, additional controls for the three SAP units are unlikely to be reasonable for the upcoming implementation period.

If you have any questions regarding this correspondence please do not hesitate to contact me at 863-800-9283, or email me at Veronica.Figueroa@Mosaicco.com.

Sincerely,

Veronica Figueroa

Veronica K. Figueroa, PE
Senior Engineer, Air Permitting & Compliance

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Appendix 1
2016-2020 Catalyst Improvement Summary

No. 4 SAP (EU 012) Catalyst Conversion Completion Dates: October 2016 & February 2020

No. 1 SAP (EU 002) Bed Number	Catalyst Amount (Liters)	Manufacturer and Type
1st	94,400	MECS, GR-330
2nd	116,000	MECS, XLP-110
3rd	112,800	MECS, XLP-110
4th	138,000	Haldor Topsoe, VK-69

No. 5 SAP (EU 033) Catalyst Conversion Completion Date: October 2018

No. 2 SAP (EU 003) Bed Number	Catalyst Amount (Liters)	Manufacturer and Type
1st	94,400	MECS, GR-330
2nd	116,000	MECS, XLP-110
3rd	112,800	MECS, XLP-110
4th	138,000	Haldor Topsoe, VK-69

No. 6 SAP (EU 032) Catalyst Conversion Completion Date: November 2017

No. 3 SAP (EU 004) Bed Number	Catalyst Amount (Liters)	Manufacturer and Type
1st	94,400	MECS, GR-330
2nd	116,000	MECS, XLP-110
3rd	112,800	MECS, XLP-110
4th	138,000	Haldor Topsoe, VK-69

Appendix 2
EPA RBLC Table for Sulfuric Acid Plants (Process Code 62.015)

RBLC Search Results - Process 62.015; Sulfuric Acid Plants; Sulfur Burning Double Absorption Sulfuric Acid Trains
Sulfur Dioxide

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT		POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT		CASE-BY-CASE BASIS	POLLUTANT COMPLIANCE NOTES
FL-0253	NEW WALES PLANT/MULBERRY	IMC PHOSPHATES MP, INC	7/12/2002	ABSORBER		3,400	T/D	Sulfur Dioxide (SO2)	DOUBLE ABSORPTION PROCESS	3.5	LB/T	BACT-PSD	
FL-0260	PLANT CITY PHOSPHATE COMPLEX	CF INDUSTRIES, INC.	6/1/2004	ABSORBER		3,000	T/D	Sulfur Dioxide (SO2)	DOUBLE ABSORPTION PROCESS IS CONSIDERED AN INHERENT CONTROL TECHNOLOGY SINCE IT CONTROLS EMISSIONS OF SO2.	401	LB/H	BACT-PSD	3.2 LB/T
ID-0015	J R SIMPLOT COMPANY - DON SIDING PLANT	J R SIMPLOT COMPANY	4/5/2004	400 SULFURIC ACID PLANT		2,500	T/D	Sulfur Dioxide (SO2)	DOUBLE-CONTACT PROCESS	999	LB/3 H PERIOD	RACT	3.2 LB/T
MS-0090	MISSISSIPPI PHOSPHATES CORPORATION	MISSISSIPPI PHOSPHATES CORPORATION	11/9/2010	No. 2 Sulfuric Acid Plant (Emission Point AA-001)					ıbsorption plant with a 2-2 ign. MPC will replace the ılyst with cesium catalyst in :h passes of the converter.	3	LB/T OF 100% H2SO4	BACT-PSD	
MS-0090	MISSISSIPPI PHOSPHATES CORPORATION	MISSISSIPPI PHOSPHATES CORPORATION	11/9/2010	No. 3 Sulfuric Acid Plant (Emission Point AA-017)					›n. Replacing vanadium :esium catalyst in 3rd and 4th 2/2 converter.	3	LB/T OF 100% H2SO4	BACT-PSD	
NC-0088	PCS PHOSPHATE COMPANY	PCS PHOSPHATE COMPANY	9/24/2003	SULFURIC ACID PLANT NO. 4					'TION CATALYST	3.7	LB/T	BACT-PSD	
NC-0099	PCS PHOSPHATE	PCS PHOSPHATE	7/14/2000	SULFURIC ACID PLANT NO. 3					›tion sulfuric acid plant	4	LB/T	BACT-PSD	
TX-0519	AGRIFOS SULFURIC ACID PLANT	AGRIFOS FERTILIZER	11/10/2005	H2SO4 PLANT STACK (INCLUDING MSS)						525	LB/H	BACT-PSD	

Mosaic Fertilizer, LLC
New Wales Facility
13830 Circa Crossing Drive
Lithia, FL 33547

August 20, 2020

ELECTRONIC SUBMITTAL

Mr. Hastings Read
Florida Department of Environmental Protection
Division of Air Resources Management
2600 Blairstone Road
Tallahassee, FL 32399

RE: **Response to June 22, 2020 Regional Haze Rule Reasonable Progress Analysis Request Letter**
Mosaic New Wales Facility
Permit No. 1050059-125-AV

Dear Mr. Read:

This submittal serves as the Regional Haze Rule Reasonable Progress Analysis for the Mosaic Fertilizer, LLC (Mosaic) New Wales facility in response to the June 22, 2020 request letter to complete and submit to the Florida Department of Environmental Protection (Department) an analysis regarding the availability of emission controls needed to ensure reasonable progress to visibility goals at Class I areas in and around the State of Florida. The June 22, 2020 Regional Haze Rule Reasonable Progress Analysis request letter includes background on the U.S. Environmental Protection Agency's (U.S. EPA's) Regional Haze Rule, the second implementation period (2018-2028), and the Department's SIP development process.

The New Wales facility is located near Mulberry in Polk County and is currently operating under Title V Air Operation Permit No. 1050059-125-AV. The New Wales facility is a phosphate fertilizer manufacturing complex which processes phosphate rock into several different fertilizer products and animal feed ingredients. The process begins with the manufacture of sulfuric acid (H_2SO_4) in the sulfuric acid plants (SAPs). Phosphate rock (P_2O_5) is reacted with H_2SO_4 to produce phosphoric acid, which is then ammoniated and granulated to produce fertilizers.

Based on projected 2028 sulfur dioxide (SO_2) emissions, the Department identified New Wales as a source that contributes sulfates at the Everglades National Park that must undergo a reasonable progress analysis for SO_2 emissions. The units listed below are projected to emit more than 5 tons per year of SO_2 in 2028, and the Department requested that Mosaic provide either a reasonable progress four-factor technical analysis or an analysis demonstrating that the unit meets the "effectively controlled unit" exemption at the facility:

- EU 002 – No. 1 Sulfuric Acid Plant
- EU 003 – No. 2 Sulfuric Acid Plant
- EU 004 – No. 3 Sulfuric Acid Plant
- EU 042 – No. 4 Sulfuric Acid Plant
- EU 044 – No. 5 Sulfuric Acid Plant

Mosaic has determined that a full four-factor technical analysis would likely result in the conclusion that no further controls are necessary at all five SAPs, and this response provides the analysis demonstrating that the SAPs at the New Wales facility meet the “effectively controlled unit” exemption.

Regional Haze Rule Reasonable Progress Analysis Subject Emission Units

Within the process at the five SAPs at the New Wales facility, molten sulfur is combusted (oxidized) with dry air in the sulfur furnace. The resulting SO_2 gas is catalytically converted (further oxidized) to sulfur trioxide (SO_3) over a catalyst bed in a converter tower. The SO_3 is then absorbed in sulfuric acid. The remaining SO_2, not previously oxidized, is passed over a final converter bed of catalyst and the SO_3 produced is then absorbed in H_2SO_4. The remaining gases exit to the atmosphere through a high-efficiency mist eliminator.

The current permit production capacities and SO_2 emission limits are presented in Table 1. The production capacity of SAP Nos. 1, 2, and 3 were increased in 2002 from 2,900 TPD to 3,400 TPD per construction permit No. 1050059-036-AC (PSD-FL-325) and a SO_2 Best Available Control Technology (BACT) emission limit of 3.5 lb/ton of H_2SO_4, 24-hour average, was established for each unit. Under Permit No. 1050059-061-AC, Best Available Retrofit Technology (BART) Exemption Project, the SO_2 BACT emission limit of 3.5 lb/ton of H_2SO_4, 24-hour average became the BART SO_2 emission limit. Under the open construction permit 1050059-124-AC (PSD-FL-170B) the production capacity at SAP No. 4 is authorized to increase from 2,900 TPD to 3,200 TPD once the converter, waste heat boilers, and cold pass heat exchanger are replaced with larger vessels (work scheduled for August 2020). Mosaic is in the process of preparing a construction permit application to request a similar production capacity increase at SAP No. 5 from 2,900 TPD to 3,200 TPD and intends to submit the application to the Department in August 2020. Similar SO_2 emission limits as to those established for SAP No. 4 under the open construction permit 1050059-124-AC (PSD-FL-170B) are expected for SAP No. 5.

Table 1: New Wales SAP Production Capacities & SO_2 Emission Limits

	No.1 SAP (EU 002)	No. 2 SAP (EU 003)	No. 3 SAP (EU 004)	No. 4 SAP (EU 042)	No. 5 SAP (EU 044)
Maximum Production Rate TPD of 100% H_2SO_4	3,400	3,400	3,400	2,900 *3,200*[c]	2,900
SO_2 Emission Limit lb/ton of 100% H_2SO_4	3.5[a], 24-hr rolling average 4.0, 3-hr rolling average			4 *3.5*[c]*, 24-hr rolling average* *3.0*[c]*, 3-hr rolling average*	4
SO_2 Emission Limit lb/hr of 100% H_2SO_4	496[a], 24-hr daily block CEM average			483.3 *400*[c]*, 24-hr daily block average*	483.3
SO_2 Emission Limit ton/year	2,172 (each)			2,117 *1,752*[c]	2,117
SO_2 Emission Limit lb/hr CAP	1,090[b] CAP, 24-hour block average (6:00 a.m. to 6:00 a.m.)				

[a]Construction Permit 1050059-036-AC (PSD-FL-325) and Permit No. 1050059-061-AC, BART Exemption Project, Specific Condition 3.A.9

[b]Construction Permit Nos. 1050059-106-AC and 1050059-114-AC

[c] Open Construction Permit 1050059-124-AC (PSD-FL-170B), work scheduled for August 2020

Effectively Controlled Units

Mosaic has determined that the Regional Haze Rule Reasonable Progress Analysis subject emission units (all five SAPs) at the New Wales facility are already effectively controlled with respect to SO_2 emissions and, therefore, they are not subject to a reasonable progress four-factor technical analysis. As outlined below, Mosaic has recently made significant expenditures to effectively control SO_2 emissions at each unit.

The five SAPs at the New Wales facility are double absorption sulfuric acid systems equipped with two absorption towers in series to react sulfur trioxide (SO_3) with water to generate sulfuric acid. The SO_2 generated in a double absorption system's sulfur furnace is catalytically oxidized to SO_3 over catalyst beds at a very high rate of 99.7% or greater, resulting in relatively low SO_2 emissions when compared to a single absorption system. A design feature that limits the overall SO_2-to-SO_3 conversion in a single absorption system is the fact that the reaction of SO_2 to SO_3 becomes less favorable as the SO_3 concentration in the system increases with SO_2 conversion efficiencies ranging from only 95% to 98%. The double absorption design improves SO_2-to-SO_3 conversion by using the first absorption tower, the interpass absorption (IPA) tower, to remove SO_3, thereby bringing about a considerable shift in the SO_2-to-SO_3 reaction equilibrium towards the formation of SO_3 in the converter bed(s) located after the first absorption tower, which results in a very high overall SO_2-to-SO_3 conversion efficiency. New Wales SAP Nos. 2, 3 and 4 each utilize a heat recovery system (HRS) absorption tower instead of a traditional IPA tower for steam generation, however from a SO_2 emission standpoint, there is no functional difference between the IPA tower and the HRS tower.

During the 2017-2019 time period, Mosaic replaced the fourth SO_2-to-SO_3 converter bed with cesium-promoted catalyst at each of the five SAPs at the New Wales facility to further reduce each unit's SO_2 emissions to comply with the U.S. EPA's 2010 1-hour SO_2 National Ambient Air Quality Standard (NAAQS) final rule. Permit Nos. 1050059-106-AC and 1050059-114-AC added a SO_2 lb/hr 24-hour block average cap at each facility based on allowable SO_2 emission rates that demonstrate compliance with the U.S. EPA's 2010 1-hour SO_2 NAAQS final rule. In addition to the SO_2 lb/hr 24-hour block average cap, the New Wales facility has completed ambient air boundary improvements by installing additional fencing, gates, and security cameras at the ambient air boundary to restrict access to the public. The standard catalysts used in sulfuric acid unit SO_2-to-SO_3 converter beds are comprised of potassium and vanadium salts supported on a silica carrier. Cesium-promoted catalysts are like these standard potassium-promoted catalysts, but the potassium promoter is replaced with cesium. The cesium helps to promote SO_2-to-SO_3 conversion at lower temperatures. In the five SAPs at the New Wales facility, a cesium-promoted catalyst is used in the SO_2-to-SO_3 converter bed located between each unit's two absorption columns because it promotes a high SO_2-to-SO_3 conversion rate at the lower inlet temperature that may occur at this converter bed. By using a cesium-promoted catalyst in the last converter bed, the overall SO_2-to-SO_3 conversion rate is increased, resulting in lower SO_2 emissions from the plant. Appendix 1 provides a summary per SAP of the amount, manufacturer, and type of catalyst installed during the 2017-2019 time period.

A search of sulfuric acid plant (Process Code 62.015) entries dating back to January 1, 2000 in EPA's RACT/BACT/LAER Clearinghouse (RBLC) database indicates that the combination of dual absorption design and cesium-promoted catalysts represents the BACT for sulfur burning, non-single absorption column sulfuric acid plants. Appendix 2 is a compilation of the results of our search of the RBLC database for sulfur burning, non-single absorption column sulfuric acid plants. BACT determinations have been in the range of 3.0 to 4.0 lb/ton for SO_2 emissions.

Additionally, Mosaic has replaced several major components within the five SAPs during the last decade. These comprehensive replacement activities reduced the SAPs' SO_2 emissions by renovating the units with gastight, more efficient components which improved its overall SO_2-to-SO_3 conversion efficiency. The construction permits authorizing improvements to overall SO_2-to-SO_3 conversion efficiency are presented in Table 2.

Table 2. Construction Permits Authorizing Overall SO_2-to-SO_3 Conversion Efficiency Improvements

Emission Unit	Construction Permit
No. 1 SAP (EU 002)	1050059-070-AC
	1050059-093-AC
No. 2 SAP (EU 003)	1050059-070-AC
	1050059-082-AC
	1050059-118-AC
	1050059-119-AC
No. 3 SAP (EU 004)	1050059-063-AC
	1050059-070-AC
	1050059-095-AC
	1050059-108-AC & 1050059-117-AC
No. 4 SAP (EU 042)	1050059-080-AC & 1050059-084-AC
	1050059-113-AC
	1050059-120-AC & 1050059-124-AC (work scheduled for August 2020)
No. 5 SAP (EU 044)	1050059-073-AC
	1050059-112-AC

In summary, sulfur dioxide emissions from the five SAPs at the New Wales facility are effectively controlled by the 1,090 lb SO_2/hour, 24-hour block average (6:00 a.m. to 6:00 a.m.) cap, double absorption system technologies with vanadium catalyst for the 1st, 2nd, and 3rd beds and cesium catalyst for the 4th bed in the converters, the use of good combustion practices, and best operational practices to minimize excess emissions during startup and shutdown. Since Mosaic has recently made significant catalyst expenditure that has resulted in significant reductions of visibility impairing pollutions at all five SAPs to meet the 1,090 lb SO_2/hour, 24-hour block average (6:00 a.m. to 6:00 a.m.) cap, additional controls for the five SAP units are unlikely to be reasonable for the upcoming implementation period.

If you have any questions regarding this correspondence please do not hesitate to contact me at 863-800-9283, or email me at Veronica.Figueroa@Mosaicco.com.

Sincerely,

Veronica Figueroa

Veronica K. Figueroa, PE
Senior Engineer, Air Permitting & Compliance

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Appendix 1
2017-2019 Catalyst Improvement Summary

No. 1 SAP (EU 002) Catalyst Conversion Completion Date: February 2018

No. 1 SAP (EU 002) Bed Number	Catalyst Amount (Liters)	Manufacturer and Type
1st	123,732	MECS, XLP-220 / GR-330
2nd	153,192	MECS, XLP-110
3rd	159,084	MECS, XLP-110
4th	219,968	Haldor Topsoe, VK-69

No. 2 SAP (EU 003) Catalyst Conversion Completion Date: January 2017

No. 2 SAP (EU 003) Bed Number	Catalyst Amount (Liters)	Manufacturer and Type
1st	126,720	MECS, GR-330
2nd	130,680	MECS, XLP-110
3rd	186,120	MECS, XLP-110
4th	235,500	Haldor Topsoe, VK-69

No. 3 SAP (EU 004) Catalyst Conversion Completion Date: April 2019

No. 3 SAP (EU 004) Bed Number	Catalyst Amount (Liters)	Manufacturer and Type
1st	139,712	MECS, XLP-220/GR-330
2nd	162,000	MECS, GR-310/GR-330
3rd	157,580	MECS, GR-310/GR-330
4th	189,864	Haldor Topsoe, VK-69

No. 4 SAP (EU 042) Catalyst Conversion Completion Date: February 2019

No. 4 SAP (EU 042) Bed Number	Catalyst Amount (Liters)	Manufacturer and Type
1st	99,400	MECS ,GR-330
2nd	117,680	MECS, GR-310
3rd	132,000	MECS, GR-310
4th	164,200	Haldor Topsoe, SCX-2000

No. 5 SAP (EU 044) Catalyst Conversion Completion Date: September 2018

No. 5 SAP (EU 044) Bed Number	Catalyst Amount (Liters)	Manufacturer and Type
1st	101,600	MECS ,GR-330
2nd	119,156	MECS, XLP-110
3rd	123,704	MECS, XLP-110
4th	139,567	Haldor Topsoe, VK-69

Appendix 2
EPA RBLC Table for Sulfuric Acid Plants (Process Code 62.015)

RBLC Search Results - Process 62.015; Sulfuric Acid Plants; Sulfur Burning Double Absorption Sulfuric Acid Trains
Sulfur Dioxide

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT		POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT		CASE-BY-CASE BASIS	POLLUTANT COMPLIANCE NOTES
FL-0253	NEW WALES PLANT/MULBERRY	IMC PHOSPHATES MP, INC	7/12/2002	ABSORBER		3,400	T/D	Sulfur Dioxide (SO2)	DOUBLE ABSORPTION PROCESS	3.5	LB/T	BACT-PSD	
FL-0260	PLANT CITY PHOSPHATE COMPLEX	CF INDUSTRIES, INC.	6/1/2004	ABSORBER		3,000	T/D	Sulfur Dioxide (SO2)	DOUBLE ABSORPTION PROCESS IS CONSIDERED AN INHERENT CONTROL TECHNOLOGY SINCE IT CONTROLS EMISSIONS OF SO2.	401	LB/H	BACT-PSD	3.2 LB/T
ID-0015	J R SIMPLOT COMPANY - DON SIDING PLANT	J R SIMPLOT COMPANY	4/5/2004	400 SULFURIC ACID PLANT		2,500	T/D	Sulfur Dioxide (SO2)	DOUBLE-CONTACT PROCESS	999	LB/3 H PERIOD	RACT	3.2 LB/T
MS-0090	MISSISSIPPI PHOSPHATES CORPORATION	MISSISSIPPI PHOSPHATES CORPORATION	11/9/2010	No. 2 Sulfuric Acid Plant (Emission Point AA-001)					ıbsorption plant with a 2-2 ign. MPC will replace the ılyst with cesium catalyst in :h passes of the converter.	3	LB/T OF 100% H2SO4	BACT-PSD	
MS-0090	MISSISSIPPI PHOSPHATES CORPORATION	MISSISSIPPI PHOSPHATES CORPORATION	11/9/2010	No. 3 Sulfuric Acid Plant (Emission Point AA-017)					›n. Replacing vanadium :esium catalyst in 3rd and 4th 2/2 converter.	3	LB/T OF 100% H2SO4	BACT-PSD	
NC-0088	PCS PHOSPHATE COMPANY	PCS PHOSPHATE COMPANY	9/24/2003	SULFURIC ACID PLANT NO. 4					TION CATALYST	3.7	LB/T	BACT-PSD	
NC-0099	PCS PHOSPHATE	PCS PHOSPHATE	7/14/2000	SULFURIC ACID PLANT NO. 3					›tion sulfuric acid plant	4	LB/T	BACT-PSD	
TX-0519	AGRIFOS SULFURIC ACID PLANT	AGRIFOS FERTILIZER	11/10/2005	H2SO4 PLANT STACK (INCLUDING MSS)						525	LB/H	BACT-PSD	

REASONABLE PROGRESS ANALYSIS AS REQUIRED BY THE US EPA REGIONAL HAZE RULE NUTRIEN, LTD - WHITE SPRINGS AGRICULTURAL CHEMICALS, INC.

INTRODUCTION

Nutrien Ltd (Nutrien) operates the White Springs Agricultural Chemical (WSAC) phosphate fertilizer chemical complex in Hamilton County, Florida. The UTM coordinates of the facility are Zone 17, 321,000m E, 3,369,000m N. The facility processes phosphate rock to produce several phosphate-based fertilizer products and animal feed supplements at the Suwannee River/Swift Creek Chemical Complexes (two plants). The combined facility consists of two sulfuric acid plants, two phosphoric acid plants, one monocal/dical plant, two monoammonium/diammonium phosphate (MAP/DAP) plants, three superphosphoric acid plants, one green superphosphoric plant, and supporting facilities. The facility is permitted by the Florida Department of Environmental Protection (FDEP) with facility ID No. 0470002. The primary regulated air pollutants from the facility are SO2 (primarily from the two sulfuric acid plants), fluorides (a naturally occurring constituent of phosphate rock), and particulate matter.

On June 22, 2020, Nutrien received notice from the FDEP that the facility was subject to a Reasonable Progress Analysis required by the US Environmental Protection Agency (EPA) Regional Haze Rule. This rule requires states to periodically submit State Implementation Plan (SIP) updates to protect visibility in national parks and wilderness areas defined as Federal Class I PSD areas. Florida's Regional Haze SIP for the second implementation period (2018-2028) is due July 31, 2021. To allow the state to develop an effective SIP, Nutrien was requested to determine whether or not there are any cost-effective emission reduction measures available to reduce emissions from affected sources at the facility, or to demonstrate that the affected sources at the facility are already "effectively controlled". The information provided herein represents Nutrien's response to this request.

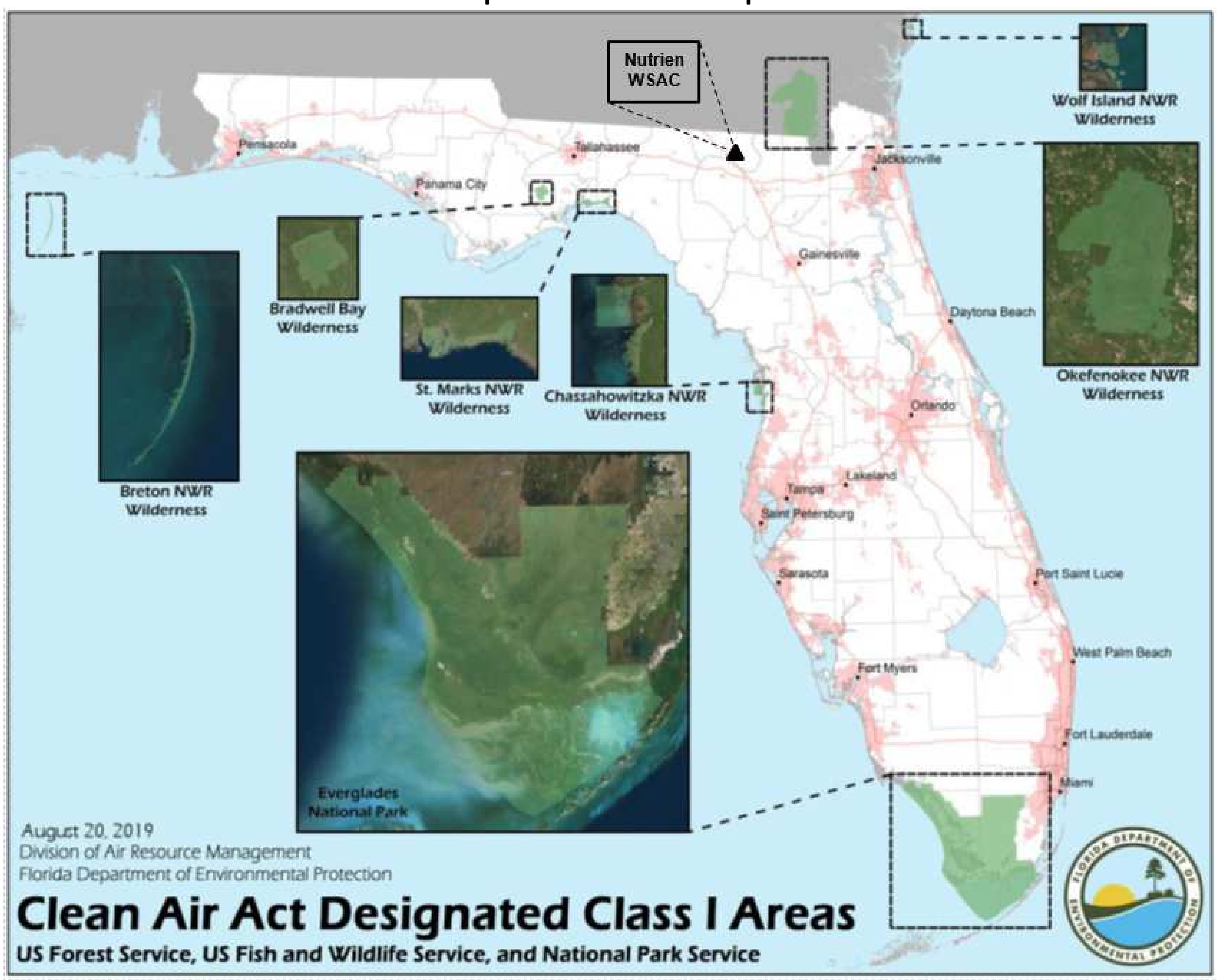
As described herein, Nutrien's options for addressing Reasonable Progress are (1) to conduct a four-factor analysis to determine whether or not there are any cost-effective emission reduction measures available to reduce emissions from affected sources, or (2) to demonstrate that the affected sources are already "effectively controlled". Based on the information provided herein, Nutrien has concluded that the affected sources at the Swift Creek/Suwanee River chemical complexes are "effectively controlled", and hence should be exempt from further Reasonable Progress emission reduction measures.

BACKGROUND

At Part 51 of Title 40 of the Code of Federal Regulation (40 CFR 51), the US Environmental Protection Agency (EPA) sets forth the requirements that states must follow in the preparation, adoption, and submittal of SIPs necessary to protect air quality, and at Subpart P of this rule, the requirements for Protection of Visibility in Class I PSD areas are set forth. EPA further requires that the SIP, as it applies to the protection of visibility in Class I PSD areas, be updated every 10 years (See 40 CFR 51.308(f)).

Class I PSD areas in the state of Florida and in neighboring states that may be affected by anthropogenic emissions from Florida sources of directly emitted and secondarily formed particulate matter are Chassahowitzka (FL), Everglades (FL), St. Marks (FL), Breton (LA), Okefenokee (GA), and Wolf Island (GA). These Class I PSD areas are shown in Figure 1, which was prepared by FDEP[1]. The location of the Nutrien facility has been superimposed on this figure.

Figure 1 - Class I Areas Potentially Impacted by Visibility Impairing Emissions from Florida Sources and the Location of the Nutrien White Springs Agricultural Chemicals Phosphate Fertilizer Complex



Visibility impairment, or Regional Haze, as referenced in 40 CFR 51, Subpart P, is defined at 40 CFR 51.301 as "visibility impairment that is caused by the emission of air pollutants from numerous anthropogenic sources located over a wide geographic area. Such sources include, but

[1] Regional Haze Second Implementation Period Outreach Webinar, contact Hastings Read, FDEP, Tallahassee, Florida

are not limited to, major and minor stationary sources, mobile sources, and area sources." In its guidance document entitled *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period,* EPA further defines visibility impairment to be the result of anthropogenic emissions of directly emitted and secondarily formed particles in the atmosphere that scatter and/or absorb light, thus acting to reduce overall visibility. Sources emitting SO2, which contributes to secondarily formed sulfates, have been determined to have the most significant impact on visibility impairment. In an out-reach webinar on Regional Haze[1], FDEP reported that sulfates contribute, on average, 75 percent of the impairment to visibility on the 20 percent most impaired days.

In the required update to the SIPs, states must evaluate and determine whether any cost-effective emission reduction measures and/or strategies are available to reduce emissions from affected anthropogenic sources, thus ensuring reasonable progress toward natural visibility conditions in Class I areas (See 40 CFR 51.308(f)(2)(i)). To assist states in developing approvable regional haze SIPs, the EPA provided the above referenced guidance dated August 20, 2019. In addition to this guidance, EPA, and individual states (largely through outside contractors) have conducted air quality modeling to identify the anthropogenic sources significantly contributing to regional haze, and thus impairing the visibility and in affected Class I PSD areas.

This modeling, referred to as Source Apportionment Modeling, tracks directly emitted particulate matter, and gaseous pollutants resulting in the secondary formation of small particles, to determine individual source contribution to visibility impairment in Class I areas. The gaseous pollutants responsible for the secondary formation of small particles include SO2 (responsible for the formation of sulfate particles) and NOx (responsible for the formation of nitrate particles). As stated above, FDEP has determined that the sulfate particles secondarily formed from anthropogenic SO2 emissions are the most significant contributor to visibility impairment. The FDEP has defined a threshold of 1.0 percent contribution to visibility impairment from sulfates as an appropriate threshold that would subject a SO2 emitting facility to a Reasonable Progress Analysis.

The modeling conducted for FDEP identified the Nutrien White Springs Agricultural Chemicals phosphate fertilizer complex as a source of SO2 emissions contributing 2.77 percent to the sulfate visibility impairment in the Okefenokee National Wildlife Refuge; the Class I area closest to the Nutrien facility (See Figure 1). The SO2 emitting sources at the Nutrien facility identified as the major contributors to the sulfate visibility impairment are Sulfuric Acid Plant (SAP) E (Emission Unit-066) and SAP F (Emission Unit-067).

NUTRIEN'S REASONABLE PROGRESS ANALYSIS

As a result of this impact, FDEP requested that Nutrien conduct a Reasonable Progress Analysis to determine whether or not there are any cost-effective emission reduction measures and/or strategies available to reduce SO2 emissions from the two SAPs. In accordance with the afore mentioned EPA guidance document on Regional Haze, the Reasonable Progress Analysis could either be a four-factor technical analysis of SO2 emission reduction measures/strategies or a demonstration that SO2 emissions from the two SAPs are already "effectively controlled".

The four-factor analysis is analogous to a Best Available Control Technology analysis; however, the four-factor analysis considers only:

- Cost of SO2 emission reduction,
- The time required to implement the emission reduction measures/strategies,
- Energy requirements and non-air quality environmental impacts, and
- The remaining useful life of the affected emission units.

As an alternative to the four-factor analysis, the EPA guidance referenced above suggests that if a source is already "effectively controlled", there may be a low likelihood of a significant technology advancement that could provide further reasonable emission reductions; and in such cases, it may be reasonable to assume that additional controls are unlikely to be reasonable for the upcoming implementation period. If it is presumed that sources, such as Nutrien's E and F SAPs, are effectively controlled, the rationale for such presumption must be explained.

In its guidance document (beginning Page 22), EPA suggests a non-exhaustive list of scenarios that might be used to demonstrate that a source is already effectively controlled; and therefore should not be subject to further Reasonable Progress emission reductions. The scenarios presented by EPA that are potentially applicable to the E and F SAPs include:

- Being subject to a Federal New Source Performance Standard (NSPS) that was promulgated or reviewed subsequent to July 31, 2013, or
- Being subject to a BACT determination made subsequent to July 31, 2013.

The NSPS scenario is clearly not applicable as the standards for sulfuric acid plants (40 CFR 60, Subpart H) were last reviewed in 1985, and the SO2 emission limit in the standards was set in 1974. Regarding the BACT scenario, the E and F SAPs were constructed in 1979 with the SO2 emission limit set at the NSPS limit of 4.0 pounds per ton of 100 percent acid, and the plants have not been subject to a BACT determination subsequent to July 31, 2013. However, both plants are subject to the terms of a Consent Decree between the US EPA and White Springs Agricultural Chemicals, Inc., et al dated February 26, 2014. This Consent Decree (14-707-BAJ-SCR) imposes SO2 emission limiting standards on both the E and F SAPs of 2.3 pounds of SO2 per ton of 100 percent acid (annual) and 2.6 pounds SO2 per ton of 100 percent acid (3-hour average).

The SO2 emission limiting standards imposed on the E and F SAPs by the Consent Decree are equivalent to a BACT determination that would have been made at the point in time (February 2014) that the Consent Decree was entered into. As a result of these limits, it is the opinion of Nutrien that the E and F SAPs are "effectively controlled" and should therefore be exempt from further Reasonable Progress Analyses. The rationale for this opinion is set forth in the following paragraphs.

The EPA RACT/BACT/LAER Clearinghouse (RBLC) was reviewed for BACT determinations made on sulfur-burning sulfuric acid plants over the past several years. The findings were:

RBLC ID: MS-0090

Date: November 2010

Company: Mississippi Phosphates Corp.

Project: Two 1800 tpd double-absorption, sulfur-burning sulfuric acid plants. SO2 emissions limited to 3.0 pounds per ton of acid by catalyst enhancement.

RBLC ID: TX-0534

Date: January 2008

Company: Rhodia, Inc.

Project: A single 2600 tpd single-absorption, sulfur-burning sulfuric acid plant. SO2 emissions limited to 1.7 pounds per ton of acid by caustic scrubbing.

RBLC ID: LA-0220

Date: June 2007

Company: E.I. DuPont de Nemours

Project: A single 2300 tpd double, sulfur-burning sulfuric acid plant. SO2 emissions limited to 2.4 pounds per ton of acid by catalyst enhancement.

RBLC ID: TX-0519

Date: November 2005

Company: Agrifos Fertilizer.

Project: A greenfield double-absorption, sulfur-burning sulfuric acid plants. Plant capacity and SO2 emission limit (pounds per ton of acid) not provided.

RBLC ID: FL-0260

Date: June 2004

Company: CF Industries, Inc.

Project: Production rate increase up to 2750 tpd for two double-absorption, sulfur-burning sulfuric acid plants. SO2 emissions limited to 3.0 pounds per ton of acid by catalyst enhancement.

It should be noted that the BACT determined SO2 emission limits on all plants using catalyst enhancement ranged from 2.4-3.0 pounds per ton of 100 percent sulfuric acid, and it should also be noted that Rhodia, Inc., the plant with the lowest BACT determined SO2 emission limit, is located on the densely populated Houston Ship Channel within five miles of the city-center of Houston, Texas.

Based on these determinations, the SO2 emission limits imposed on the 2500 tons per day E and F SAPs of 2.3 pounds of SO2 per ton of 100 percent sulfuric acid (annual limit) are certainly consistent with, and equivalent to the most recent BACT determinations made for similar double-absorption, sulfur-burning sulfuric acid plants. Regarding the effect of dates of these BACT determinations, it should be noted that there have been no new developments in catalyst technology and/or strategies for operating SAPs since these BACT determinations have been made; and hence no reason to believe that a BACT determination made at this point in time would be significantly different from those documented above.

To achieve the SO2 emission limits imposed by the Consent Decree, Nutrien applied to FDEP for an Air Construction permit to change catalyst loadings. Pursuant to this application, FDEP issued permit 0470002-107-AC on March 31, 2017. The substance of this permit is summarized as follows:

<u>PERMIT 0470002-107-AC - 03/31/2017</u>

PROPOSED PROJECT

The purpose of this project is to authorize the changing and augmentation of the converter catalyst along with other work for SAPs E and F in forthcoming scheduled turnarounds. In addition, new SO2 emission limits will be established for the two SAPs. These new SO2 emission limits are the result of a Federal Consent Decree No. 14-707-BAJ-SCR [February 26, 2014] entered between White Springs Agricultural Chemicals, Inc. dba PCS Phosphate, White Springs, and the Environmental Protection Agency (EPA). To meet the new emission standards and maintain currently permitted operating rates, some process and equipment changes will also be required in each of the two SAPs.

AUTHORIZED PHYSICAL CHANGES - Permit Condition 2

*SAPs E and F: In accordance with the work schedule given in **Specific Condition 3** of this subsection, the following work shall be accomplished on SAPs E and F. The permitted capacity of each SAP after the change/augmentation of the converter catalyst and other work authorized by this permit shall remain unchanged and no emission limits shall be increased. Within 45 days of commencing operation following the turnaround (including catalyst installation and arrangement for each SAP), the permittee shall provide the following information to the Division and the Compliance Authority: the type of catalyst; the amount of catalyst and the catalyst arrangement within the convertor.*

a. *Catalyst. The permittee is authorized to change out and augment the converter catalyst as well as a change the type of catalyst in the SAPs. In addition, minor changes to the converter to include, but are not limited to, modified inlet nozzle diffusers are authorized.*
b. *Acid Coolers. The permittee is authorized, as needed, change out the acid cooler to allow operating at higher temperatures and with greater cooling capacity. The coolers to be replaced include, but are not limited to, the existing drying and interpass coolers. Minor changes to the piping, pumps and foundations are also be authorized.*

c. Acid Tower. The permittee is authorized, as needed, to do maintenance and/or replacement the acid tower and interpass mist eliminators.
d. SO2 Monitoring System. The permittee shall install a dual range SO2 monitoring system on each SAP.
e. Flow Meters. If needed, the permittee is authorized to install, maintain, and/or replace the existing product flow meters.,

NEW EMISSION LIMITS - Permit Condition 4

SO2 Emission Limits: The new SO2 emission limits along with the required compliance date required by the CD for each SAP are given below:

SAP	***Emission Limit***	***CD Compliance Date***
Phase 1 – SAP F	*2.6 lb/ton, 3-hr rolling average* [1]	*January 1, 2018*
Phase 1 – SAP F	*2.3 lb/ton, 365 day rolling average* [2]	*January 1, 2018*
Phase 2 – SAP E	*2.6 lb/ton, 3-hr rolling average* [1]	*January 1, 2020*
Phase 2 – SAP E	*2.3 lb/ton, 365 day rolling average* [2]	*January 1, 2020*

1. Not including startup and shutdown periods.
2. Including startup and shutdown periods.

The tasks carried out under this permit on both the E and F SAPs included topping off catalyst beds A, B, and C with vanadium catalyst (XLP-110), and converting bed D from a vanadium catalyst to a vanadium/cesium-based catalyst (SCX-2000). The resulting catalyst loadings in the four beds are:

- A - 89,000 liters of XLP-110 catalyst,
- B - 93,000 liters of XLP-110 catalyst,
- C - 119,000 liters of XLP-110 catalyst, and
- D - 141,000 liters of SCX-2000 catalyst.

As a result of these catalyst changes, the heat distribution (resulting from the exothermic conversion of SO2 to SO3 in the catalyst beds) in both plants changed, resulting in an application for a second Air Construction permit to address the heat distribution and to address other issues related to the efficient operation of the two SAPs; thus assuring long-term compliant operation of the two plants. Pursuant to this application, FDEP issued Air Construction permit 0470002-111-AC on December 1, 2017. This second permit did not affect the SO2 emission limits established by permit 0470002-107-AC, nor did it affect the permitted production rates of the two plants. The substance of this second permit is summarized as follows:

PERMIT 0470002-111-AC - 12/01/2017
PROPOSED PROJECT
Air construction permit, which authorizes the repair/replacement and maintenance for the existing sulfuric acid plants "E" and "F".

The list of items for both EU066 "E" and EU067 "F" Sulfuric Acid Plants includes the following components along with associated pumps, piping, instrumentation, and ductwork:

- *Sulfur Tank*
- *Boiler Feedwater Preheater*
- *Drying Tower Cooler*
- *Inter-Pass Absorption Tower Cooler*
- *96% Pump Tanks*
- *Salvage Water Tank*
- *SO2 Emissions Monitoring Equipment*
- *Secondary Economizer*
- *Waste Heat Boiler (Heat exchanger)*
- *Acid Cooler*
- *Inter-Pass Absorption Tower*

This work was carried out as planned and the E and F SAPs are operating normally and as expected. The actual SO2 emissions from the two plants are typically in the range of 1.1-1.5 pounds of SO2 per ton of 100 percent sulfuric acid.

CONCLUSION
As a result of the SO2 emission limits of 2.3 pounds per ton 100 percent sulfuric acid (annual) and 2.6 pounds per ton of 100 percent sulfuric acid (3-hour average) imposed by Consent Decree 14-707-BAJ-SCR, effective February 26, 2014, and the actual SO2 emissions from the two plants subsequent to catalyst and other changes to the plants necessary to assure compliance with the conditions of the Consent Decree, Nutrien is of the opinion that the E and F SAPs are "effectively controlled" as defined by the aforementioned EPA Guidance, and hence should be exempt from further Reasonable Progress emission reduction measures.

If there are questions regarding the information provided herein, the technical contact, authorized by Nutrien to prepare the information provided herein, is Dr. John Koogler, PE of Koogler and Associates Inc. (jkoogler@kooglerassociates.com), and the site representative for Nutrien is Stan Posey (Stan.Posey@nutrien.com).

[end]

October 23, 2020

Mr. Jeff Koerner, Director
Division of Air Resource Management
Florida Department of Environmental Protection
2600 Blair Stone Road, #5505
Tallahassee, FL 32399-2000

Sent via email: jeff.koerner@dep.state.fl.us

Re: Seminole Generating Station -- Regional Haze Reasonable Progress Analysis

Dear Mr. Koerner:

On August 18, 2020, the Department requested a reasonable progress analysis for Seminole Generating Station (SGS) Units 1 and 2 (EU ID Nos. 001 and 002). Seminole Electric Cooperative, Inc. (SECI) provides the following response.

Background

SGS Units 1 and 2 are described in the Title V Permit No. 1070025-034-AV, along with the major regulations they are subject to, as follows:

> The two-fossil fuel fired steam generators, designated as "Electric Utility Steam Generating Units 1 and 2," are coal-fired, dry-bottom wall-fired utility boilers. Each unit has maximum heat input rate of 7,172 MMBtu per hour and a nominal gross generator rating of 735.9 megawatts (MW). Each unit is equipped with the following air pollution control equipment: an electrostatic precipitator (ESP) to control particulate matter (PM) emissions; an upgraded wet limestone flue gas desulphurization (FGD) system to control sulfur dioxide (SO_2) emissions; a low-NOx burner (LNB) system, low excess air firing and an selective catalytic reduction (SCR) system to control NOx emissions; and, an alkali injection system. The alkali injection system is not required to meet current sulfuric acid mist (SAM) emissions limits but will be available for use if needed. Each unit is equipped with continuous emission monitoring systems (CEMS) to measure and record SO_2, NOx, & carbon dioxide (CO_2) emissions as well as a continuous opacity monitoring system (COMS) to measure and record the opacity of the exhaust gas.

Each unit has its own stack, with emissions exhausting through 695 foot stacks with exit diameters of 26.5 feet, 128 °F exit temperatures, and stack gas flow rates of 1,987,064 acfm as referenced in the original air construction permit application. Unit 1 began commercial operation in 1984 and Unit 2 began commercial operation in 1985.

{Permitting note(s): These emissions units are regulated under: Acid Rain, Phase II; 40 CFR 60 Subpart Da, Standards of Performance for Fossil-Fuel Fired Steam Generators; 40 CFR 63, Subpart UUUUU- National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units; Rule 62-296.405(2), F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input; Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD) [PSD-FL-018, as amended & PSD-FL-372/1070025-004-AC, as amended]; and, Rule 62-212.400(6), F.A.C., Best Available Control Technology (BACT) Determination.}

Regional Haze Requirements

As described in the Department's August 18, 2020 request, a VISTA (Visibility Improvement – State and Tribal Association of the Southeast) modeling analysis indicated that SGS could potentially influence visibility impairment in nearby Class I areas, specifically Okefenokee National Wildlife Refuge, and primarily with respect to SO_2. As such, FDEP is requesting information for the two boilers at SGS to determine if additional SO_2 emission control and reductions are cost-effective for this implementation period. In accordance with EPA Guidance[1], states should require such units to submit a four-factor analysis of feasible SO_2 control measures to determine whether additional reductions are cost-effective, but can exempt such units if they are determined to already be "effectively controlled" under an enforceable requirement. EPA's Guidance states that for electric generating units that have add-on FGD systems and that meet the 0.20 lb SO_2/mmBtu limit in the Mercury and Air Toxics Standard (MATS), it is reasonable for a state to determine that that unit is already "effectively controlled."

Permit Conditions

Specific Condition A.33. of Permit No. 1070025-034-AV is quoted below, which requires SGS Units 1 and 2 to comply with MATS and includes the option of complying with either an HCl limit or a SO_2 limit. In accordance with Seminole's most recent MATS Semi-Annual Compliance Reports (dated July 24, 2020), SGS has elected to comply with the MATS SO_2 limit. Note that the revised Notification of Compliance Status (NOCS) submitted per MATS on December 15, 2016 presents initial compliance test results of 0.154 SO_2 lb/mmBtu for Unit 1 and 0.161 lb SO_2/mmBtu for Unit 2.

NESHAP 40 CFR 63 Requirements – Subpart UUUUU. These emission units shall comply with all applicable provisions of 40 CFR 63, Subpart UUUUU, National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

[1] https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.

{also known as "MATS"}. This federal regulation has not been adopted by reference in Rule 62-204.800, F.A.C. Each emissions unit shall comply with Appendix 40 CFR 63 Subpart UUUUU attached to this permit no later than April 16, 2015. Each emissions unit is classified as an "existing" unit since each was constructed prior to May 3, 2011 and has not been reconstructed. In addition, each emissions unit is considered a coal-fired unit not using low rank virgin coal. Subpart UUUUU applies the following emission limits to each emissions unit:

1. Filterable Particulate Matter (PM). Emissions of PM shall not exceed either 0.030 pound/million British thermal unit (lb/MMBtu) or 0.30 pound per megawatt-hour (lb/MWh). In lieu of the filterable PM emission limit, the permittee may select to meet a total non-Hg HAP metals emission limit of either 5.0 x 10-5 lb/MMBtu or 0.50 pounds per gigawatt-hour (lb/GWH). Finally, in lieu of ether filterable PM or total non-Hg HAP metals emission limits the permittee my meet the following individual HAP metal emission limits:

a. Antimony (Sb) - 0.80 pounds per terra Btu (lb/TBtu) or 8.0 x 10-3 lb/GWh.
b. Arsenic (As) - 1.1 lb/TBtu or 0.020 lb/GWh.
c. Beryllium (Be) - 0.20 lb/TBtu or 2.0 x 10-3 lb/GWh.
d. Cadmium (Cd) - 0.30 lb/TBtu or 3.0 x 10-3 lb/GWh.
e. Chromium (Cr) - 2.8 lb/TBtu or 0.030 lb/GWh.
f. Cobalt (Co) - 0.80 lb/TBtu or 8.0 x 10-3 lb/GWh.
g. Lead (Pb) - 1.2 lb/TBtu or 0.020 lb/GWh.
h. Manganese (Mn) - 4.0 lb/TBtu or 0.050 lb/GWh.
i. Nickel (Ni) - 3.5 lb/TBtu or 0.040 lb/GWh.
j. Selenium (Se) - 5.0 lb/TBtu or 0.060 lb/GWh.

2. Hydrogen Chloride (HCl). Emissions of HCl shall not exceed either 2.0 x 10-3 lb/MMBtu or 0.020 lb/MWh. In lieu of HCl emission limit, the permittee may select to meet a SO_2 emission limit of either 0.20 lb/MMBtu or 1.5 lb/GWH.

3. Mercury (Hg). Emissions of Hg shall not exceed either 1.2 lb/TBtu or 0.013 lb/GWh. Compliance with the above emissions limits shall be demonstrated pursuant to one of the available options specified in 40 CFR 63, Subpart UUUUUU which is included as an appendix in the renewed Title V air operation permit. The permittee shall also comply with the recordkeeping and reporting requirements specified in the appendix.

[40 CFR 63, Subpart UUUUU.]

Conclusion

SGS Units 1 and 2 meet EPA's exemption from conducting a four-factor reasonable progress analysis, because they are subject to MATS, have add-on FGD systems, and are in compliance with the MATS SO_2 limit of 0.20 lb/mmBtu. Because MATS allows compliance with the SO_2 limit as a surrogate for compliance with the HCl limit, SECI will submit a permit application soon to expressly impose the 0.20 SO_2 limit on SGS Units 1 and 2.

If you have any questions regarding the information in this letter, or need any additional information, please contact me at (813) 440-8289 or cweber@seminole-electric.com.

Sincerely,

Chris Weber
Senior Environmental Regulatory Specialist – Air Quality Lead

cc: Lewis Snyder, SECI
Luis Guilbe, SECI
Micheal Rogero, SECI
John Townsend, SECI
Stuart Bartlett, FDEP

August 21, 2020

Jeff Koerner
Director - Air Resource Management
Florida Department of Environmental Protection
Division of Air Resource Management
Office of Air Permitting and Compliance
2600 Blair Stone Road, M.S. 5505
Tallahassee, Florida 32399-2400

Email Notification
Jeff.Koerner@FloridaDEP.gov

RE: Tampa Electric Company - Big Bend Station
Response to Regional Haze Request for Reasonable Progress Analysis
Air Construction Permit No. 0570039-129-AC
Title V Air Operating Permit No. 0570039-128-AV
Facility ID No. 0570039
E.U. ID Nos. -003, -004

Dear Mr. Koerner:

On June 22, 2020, the Florida Department of Environmental Protection ("Department"), Division of Air Resource Management requested Tampa Electric Company ("Tampa Electric") provide either a reasonable progress four-factor technical analysis or an analysis demonstrating that the unit meets the "effectively controlled unit." This request was based on recent SO_2 apportionment model results that showed Big Bend Station Units No. 3 and No. 4 exceeded the 5 percent contribution threshold at the Chassahowitzka National Wildlife Refuge. The response below demonstrates that Big Bend Station Units No. 3 and No. 4 meet the "effectively controlled unit" exemption pursuant to EPA guidance[1].

Regional Haze Requirements

The Department must submit a Regional Haze State Implementation Plan ("SIP") revision to the Environmental Protection Agency ("EPA") by July 31, 2021 pursuant to 40 CFR 51.308(f)(2)(i). The SIP revision must evaluate and determine whether any cost-effective emission reduction measures and strategies are available to ensure reasonable progress toward natural visibility conditions in each Class I area in the current implementation period (2018 – 2028).

In accordance with EPA Guidance, states should require such units to submit a four-factor analysis of feasible SO_2 control measures to determine whether additional reductions are cost-effective, but can exempt such units if they are determined to already be "effectively controlled"

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[1] https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.

under an enforceable requirement. EPA's Guidance states that for electric generating units that have add-on FGD systems and that meet the 0.20 lb SO_2/MMBtu limit in the Mercury and Air Toxics Standard (MATS), it is reasonable for a state to determine that the unit is already "effectively controlled."

Regional Haze Analysis

On July 10, 2020, the Department contacted Tampa Electric and indicated that Big Bend Station Units No. 3 and No. 4 can be deemed to have met the "effectively controlled unit" exemption by complying with a federally enforceable commitment to the MATS SO_2 limit pursuant to EPA guidance. To implement the commitment, the Department requested that Tampa Electric incorporate federally enforceable permit conditions in draft air construction permit no. 0570039-129-AC. As summarized below, these federally enforceable conditions were finalized in air construction permit no. 0570039-129-AC, issued on August 11, 2020.

Section 3.B, Air Construction Permit No. 0570039-129-AC

1. Unit 3 Regional Haze SO_2 Emission Limit: As determined by CEMS, the SO_2 emission rate shall not exceed 0.20 lb/MMBtu based on a heat input-weighted 30-boiler operating day rolling average. Compliance shall be demonstrated as determined in §63.10021(a) and (b) of the MATS rule. [Compliance with the Regional Haze Rule]

{*Permitting Note: this federally enforcement condition satisfies the "effectively controlled emission unit" criteria for the Regional Haze Rule.*}

2. Compliance Requirements: To show compliance with the SO_2 emission limit given in Specific Condition 1 of this subsection the testing, monitoring, recordkeeping, etc., shall be conducted in accordance with the requirements of 40 CFR 63, Subpart UUUUU. [Compliance with the Regional Haze Rule]

Section 3.C, Air Construction Permit No. 0570039-129-AC

12. Unit 4 Regional Haze SO_2 Emission Limit: As determined by CEMS, the SO_2 emission rate shall not exceed 0.20 lb/MMBtu based on a heat input-weighted 30-boiler operating day rolling average. Compliance shall be demonstrated as determined in §63.10021(a) and (b) of the MATS rule. [Compliance with the Regional Haze Rule]

{*Permitting Note: this federally enforcement condition satisfies the "effectively controlled emission unit" criteria for the Regional Haze Rule.*}

13. Compliance Requirements: To show compliance with the SO_2 emission limit given in Specific Condition 12 of this subsection the testing, monitoring, recordkeeping, etc., shall be conducted in accordance with the requirements of 40 CFR 63, Subpart UUUUU. [Compliance with the Regional Haze Rule]

Conclusion

Bend Station Units No. 3 and No. 4 meet EPA's "effectively-controlled" exemption from the obligation to submit an analysis of additional SO_2 emission controls for this Regional Haze implementation period.

Please contact me at (813) 228-4232, if you have any questions regarding this response.

Sincerely,

Robert A. Velasco, P.E., BCEE, QEP
Air Programs, Environmental Services
Peoples Gas System/Tampa Electric Company

ENV/dmf/ RAV476 Regional Haze Rule Response Letter

cc: Hastings Read,
Hastings.Read@FloridaDEP.gov

Regional Haze Rule Four-Factor Analysis for the WestRock Fernandina Beach Mill

October 2020

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TABLE OF CONTENTS

Section Name **Page Number**

TABLE OF CONTENTS

Section Name **Page Number**

LIST OF TABLES

LIST OF APPENDICES

1. INTRODUCTION

The Florida Department of Environmental Protection (FDEP) Division of Air Resource Management is in the process of developing a State Implementation Plan (SIP) revision for the second implementation 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 manmade emissions of visibility impairing pollutants. The U.S. EPA developed the RHR to meet the Clean Air Act (CAA) requirements for the protection of visibility in 156 scenic areas, called Mandatory Class I Federal areas, across the United States. The RHR requires states to submit periodic SIPs demonstrating how they have and will continue to make progress towards achieving the national visibility goal by 2064. The first Regional Haze SIPs were due in 2007 and were required to include a long-term strategy and reasonable progress goals. Regional Haze SIPs must be updated in 2021, 2028, and every 10 years thereafter.

FDEP is required to submit its Regional Haze SIP for the second implementation period by July 31, 2021. The long-term strategy in the SIP submittal must include enforceable emission limitations, compliance schedules and other measures necessary to make reasonable progress toward the national visibility goal. In determining the emissions reduction measures necessary to make reasonable progress, the RHR requires states to consider four factors, i.e., to conduct a four-factor analysis (FFA). Using the results of a screening analysis and source apportionment modeling, FDEP has identified the facilities in the state for which an FFA of emission controls is required and requested their cooperation in conducting the FFA for their facilities. FDEP will use the FFAs to determine the emission controls necessary for making reasonable further progress under the RH program and include those emission controls in its RH SIP.

FDEP has requested that WestRock provide an FFA of SO_2 emission control measures for the emission units at the Fernandina Beach Mill (the Mill) that are projected to emit more than 5 tons per year of SO_2 in 2028, specifically, the following emission units:

- No. 5 Power Boiler
- No. 7 Power Boiler
- No. 4 Recovery Boiler
- No. 5 Recovery Boiler

This report provides the requested FFA for each unit in Sections 2 through 5. Appendix A presents the control cost calculations and Appendix B presents supporting information.

1.1 FOUR-FACTOR ANALYSIS METHODOLOGY

FDEP has requested that the Mill address the following four factors specified in the Clean Air Act at Section 169A(g)(1) for technically feasible SO_2 emission control measures identified for the two power boilers and two recovery boilers at the Mill:

- Cost of compliance;
- Time necessary for compliance;
- Energy and non-air quality environmental impacts of compliance;
- Remaining useful life.

FDEP asked that WestRock also provide the control effectiveness and expected emissions reductions that would be achieved by implementation of each technically feasible emission control measure, and that if a control measure is not technically feasible, WestRock should provide justification for that determination. FDEP further specified that WestRock should consult the August 2019 U.S. EPA Regional Haze Guidance in determining which emission control measures to consider and in developing the FFA of those control measures.

WestRock has addressed the four statutory factors in the FFA for each of the included emission units. WestRock has performed the cost analysis for the FFA using available site-specific data, capital costs of controls from vendor estimates, 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 Mill has not performed a significant degree of site-specific engineering analyses for this study due to the time constraints for this process but has used readily available information and sound engineering judgement to determine if additional emission 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 expected actual emissions in 2028.

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 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 utility costs are based on mill-specific values.

1.2 SUMMARY OF SOURCES EVALUATED AND EXISTING REGULATORY REQUIREMENTS

Table 1-1 lists the SO_2 emission units included in the FFA with their installation dates, fuels, existing emission control technology, expected 2028 SO_2 emissions, and applicable major air regulations. 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). Power boilers and recovery 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 criteria pollutant emissions and promote good combustion practices. Actual emissions are based on 2019 values.

Table 1-1
Summary of Emission Sources Evaluated

Emission Unit Description	Year Installed	Fuels Fired	Air Pollution Control Device	Actual SO_2 Emissions, tpy	Major Regulatory Programs
No. 5 Power Boiler (EU006)	1968	Biomass, wastewater treatment plant residuals*, ultra-low-sulfur diesel (ULSD)	Electrostatic precipitator (ESP)	17	MACT DDDDD
No. 7 Power Boiler (EU015)	1983	Coal, No. 5 Power Boiler bark ash, ULSD, natural gas	ESP	1,031	NSPS D MACT DDDDD PSD BACT
No. 4 Recovery Boiler (EU007)	1969	ULSD, natural gas, and black liquor	ESP	15	MACT MM
No. 5 Recovery Boiler (EU011)	1978	ULSD, natural gas, and black liquor	ESP	25	NSPS BB MACT MM

*No. 5 Power Boiler is permitted to burn wastewater treatment plant residuals but does not currently burn them.

1.3 SUMMARY OF RECENT EMISSIONS REDUCTIONS

Since 2010, the Mill has made emissions reductions for a variety of reasons. As shown in Table 1-1, the Mill 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. Emissions standards for HCl also serve to limit emissions of SO_2.

The mill conducted projects totaling $15.9 million in capital costs in 2016 and 2017 to reduce both actual and allowable SO_2 emissions so that modeled allowable emissions would demonstrate compliance with the 1-hour National Ambient Air Quality Standard (NAAQS) for SO_2. These projects included air system changes and installation of a liquor heater for the No. 4 Recovery Boiler, combustion control automation and conversion of auxiliary fuel from No. 6 fuel oil to ULSD for both recovery boilers, elimination of the use of the No. 5 Power Boiler as a backup control device for pulp mill non-condensable gases, and installation of a white liquor scrubber to reduce the sulfur content of the NCGs prior to combustion in the No. 7 Power Boiler, which became the backup NCG control device in place of the No. 5 Power Boiler. With these projects, the SO_2 emission limit for the No. 5 Power Boiler was reduced from 550 pounds per hour (lb/hr) to 15 lb/hr. Additionally, the mill implemented an evaporator project in 2020 to increase black liquor solids content, which helps stabilize operation of the recovery boilers, allowing for improved SO_2 emissions.

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 No. 7 Power Boiler:** provides the FFA for the No. 7 Power Boiler.
- **Section 3 – Four-Factor Analysis for No. 5 Power Boiler:** provides the FFA for the No. 5 Power Boiler.
- **Section 4 – Four-Factor Analysis for No. 4 Recovery Boiler:** provides the FFA for the No. 4 Recovery Boiler.
- **Section 5 – Four-Factor Analysis for No. 5 Recovery Boiler:** provides the FFA for the No. 5 Recovery Boiler.
- **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 NO. 7 POWER BOILER

This section of the report presents the FFA for SO_2 control alternatives for the No. 7 Power Boiler at the WestRock Fernandina Beach Mill. Using the four factors specified in the Clean Air Act and FDEP's instructions, the analysis consists of the following steps:

- Identification of available control measures
- Elimination of technically infeasible options
- Selection of control measures for analysis
- Assessment of the cost of compliance for the selected control measures (statutory factor 1)
- Assessment of the time necessary for compliance (statutory factor 2)
- Assessment of the energy and non-air quality environmental impacts of compliance (statutory factor 3)
- Assessment of the remaining useful life of the emission unit (statutory factor 4)

2.1 AVAILABLE CONTROL MEASURES

Air pollution control measures (including lower-emitting processes and practices) that have the potential for practical application to the emission unit and pollutant under evaluation were considered. The scope of possible control options for the No. 7 Power Boiler was determined based on a review of the RBLC database[1] and knowledge of typical controls used on boilers. RBLC entries that were not representative of the type of emission unit or fuel being fired were excluded from further consideration. Table 2-1 summarizes the available SO_2 control technologies for industrial boilers.

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[1] 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
SO_2	Low-sulfur fuels Wet scrubbers Dry scrubbing systems

The available control measures for reducing emissions of SO_2 from industrial boilers are discussed in detail below.

Low-sulfur Fuels

Uncontrolled emissions of SO_2 are proportional to the amount of sulfur in the fuel being fired. Combustion of natural gas, clean biomass, and ULSD all produce negligible SO_2 emissions. The No. 7 Power Boiler already fires two of these low-sulfur fuels, specifically natural gas and ULSD. It was designed to be a coal-fired boiler and fires coal with a sulfur content not exceeding 1%.

Acid Gas Scrubbers

<u>Wet Scrubbers</u>

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 (physical or chemical). Wet scrubbing involves a mass transfer operation in which one or more soluble components of an acid gas are dissolved in a liquid that has low volatility under process conditions. For SO_2 control, the absorption process is chemical-based and uses an alkali solution (*i.e.*, sodium hydroxide, sodium carbonate, sodium bicarbonate, calcium hydroxide, etc.) as a sorbent or reagent in combination with water. Removal efficiencies are affected by the chemistry of the absorbing solution as it reacts with the pollutant and the design of the wet scrubber. Most wet scrubbers have SO_2 removal efficiencies of at least 90 percent. Wet scrubbers may take the form of a variety of different configurations, including packed columns, plate or tray columns, spray chambers, and venturi scrubbers.

<u>Dry Scrubbing Systems</u>

Types of dry scrubbing systems include spray dryer absorbers (SDA), circulating dry scrubbers (CDS), and dry sorbent injection systems (DSI). SDA systems are gas absorption systems that inject hydrated sorbent, typically lime (CaO) or hydrated lime ($Ca(OH)_2$), into the flue gas after a boiler's air heater. The hydrated sorbent chemically reacts with acid gas compounds and the fly ash in the gas stream to form calcium based salts while absorbing a portion of the residual heat in the flue gas to dry the resultant particles that are later removed in the downstream particulate control device. The July 2020 draft Section 5, Chapter 1, Section 1.2.2 of the U.S. EPA's OAQPS Air Pollution Control Cost Manual indicates that removal efficiencies for SO_2 of up to 95% are achievable for coal-fired power plants. However, the highest removal efficiencies are achievable only where a fabric filter is utilized for the particulate control device as is common in the utility industry (it is noted in July 2020 draft Cost Manual Section 5 that the filter cake of a fabric filter removes SO_2 from the gases, and reference 14 indicates that the removal across the filter can be significant).

Unlike an SDA system, a CDS operates like a circulating fluidized bed that the combustion gases pass through following a boiler's air heater section. In this type of system, the flue gas leaving the air heater section is wetted as it passes through a venturi section and enters upwards into the absorber body. Inside the absorber, water is added to reduce the flue gas temperature which aids in the chemical reaction with the hydrated lime and fly ash to form calcium salts. Particulates from the absorber are captured in the downstream control device. Flue gas flow rate is controlled to maintain the fluidized effect inside the absorber. The July 2020 draft Section 5, Chapter 1, Section 1.2.2 of the U.S. EPA's OAQPS Air Pollution Control Cost Manual indicates that removal efficiencies for SO_2 of up to 98% are achievable for coal-fired power plants. However, as with the SDA technology described above, some of the removal occurs in the filter cake of the fabric filter control devices employed by many coal-fired power plants for particulate removal and the highest removal efficiencies are likely achievable only where a fabric filter is used.

A DSI system controls acid gases by injecting a dry reagent (*i.e.*, lime or trona) into the flue gas stream prior to PM air pollution control equipment. A reaction takes place in the flue gas between the reagent and the acid gases, producing neutral salts that must be removed by the PM air pollution control equipment located downstream. The process is totally "dry," meaning it produces a dry disposal product and introduces the reagent as a dry powder. The benefits of this type of system include the elimination of liquid handling equipment requiring routine maintenance such as pumps, agitators, and atomizers. The drawbacks to using this type of system are the costs associated with the installation of a dry PM control device to collect the dry by-product, as well as ongoing operating costs to procure the sorbent material and dispose of additional dry waste. Dry sorbents can also prove challenging to maintain a very low moisture content and keep flowing. DSI systems are typically used to control SO_2 and other acid gases on coal-fired boilers. The July 2020 draft Section 5, Chapter 1, Section 1.2.1.3 of the U.S. EPA's Air Pollution Control Cost Manual for SO_2 Control indicates that DSI systems can be expected to achieve control efficiencies ranging from 50-70%.

2.2 ELIMINATION OF TECHNICALLY INFEASIBLE OPTIONS

An available control measure could be technically infeasible for a particular emission unit based on physical, chemical, or engineering principles that preclude its successful use for that emission unit. A technology is generally considered technically feasible if it has been demonstrated and operated successfully on the same or similar type of emission unit under review or is available and applicable to the emission unit type under review.

The No. 7 Power Boiler is a tangentially-fired boiler that burns pulverized coal and No. 5 Power Boiler's bark fly ash, as well as natural gas and ULSD. Replacement of some of the coal with a lower sulfur fuel would be an available control measure for the No. 7 Power Boiler. However, as explained in the next paragraph, implementation of this option such that the annual heat input from coal is less than 10% (but greater than 0%) of the total heat input from all fuels is not considered an available option.

Although the No. 7 Power Boiler has been equipped with natural gas load burners and is capable of operating at 100% capacity utilizing only natural gas, it is by design a tangentially-fired pulverized coal boiler and is currently regulated as a pulverized coal unit under the Boiler MACT.[2] The unit must combust at least 10 percent coal on an annual heat input basis to retain this subcategory. If it were to combust primarily natural gas with ULSD backup and a small amount (less than 10 percent of annual heat input) of pulverized coal, it would fall under the Gas 2 subcategory. Because Boiler MACT requires performance tests to be conducted while firing the fuel mix with the highest fuel input of mercury and chlorine, coal would have to be fired during the Gas 2 subcategory performance testing, and the boiler would not meet the Gas 2 subcategory emission limits for HCl (and possibly PM)[3] while burning coal. Therefore, coal replacement such that the annual heat input from coal is less than 10% (and greater than 0%) of the total annual heat input would fundamentally change this boiler, which was designed as a pulverized coal unit, and is not considered an available control measure for the No. 7 Power Boiler.

This boiler also serves as the backup control device for low-volume, high-concentration (LVHC) NCGs, which contain sulfur. However, the NCGs are scrubbed via a white liquor scrubber prior to combustion in the No. 7 Power Boiler so that their impact on SO_2 emissions is minimal.

WestRock evaluated the following SO_2 control measures for the No. 7 Power Boiler: use of a lower sulfur fuel in place of some[4] of the coal currently burned, installation of a wet scrubber, or installation of a dry scrubbing system. Space is limited in the area surrounding the No. 7 Power Boiler, so adding a wet or dry scrubbing system could be challenging, and a detailed engineering study would have to be conducted in order to conclude that a wet or dry scrubbing system could be successfully sited and installed for the No. 7 Power Boiler.

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[2] 40 CFR Part 63, Subpart DDDDD: National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters.

[3] The Gas 2 HCl emission limit is 1.7E-03 lb/MMBtu and the PM limit is 6.7E-03 lb/MMBtu, versus the currently applicable limits of 0.022 lb/MMBtu for HCl and 0.04 lb/MMBtu for PM.

[4] Replacement of coal with natural gas and ULSD such that the annual heat input from coal was greater than 0% but less than 10% is not an available option due to the Gas 2 subcategory Boiler MACT requirements applicable to that fuel mix.

2.3 SELECTION OF CONTROL MEASURES FOR ANALYSIS

FDEP's request for an FFA states that WestRock should utilize the U.S. EPA's Regional Haze Guidance in determining which emission control measures to consider. With respect to determining which emission control measures to consider in the FFA, that guidance states the following on page 29: "A state must reasonably pick and justify the measures that it will consider, recognizing that there is no statutory or regulatory requirement to consider all technically feasible measures or any particular measures. A range of technically feasible measures available to reduce emissions would be one way to justify a reasonable set." WestRock selected at least one specific control measure from each of the control measure categories that were identified as available and technically feasible for application to the No. 7 Power Boiler.

Low-Sulfur Fuels

Reducing coal usage to no more than 125 tons/day on an annual average basis and no less than 10% of annual heat input was identified as a technically feasible low-sulfur fuel alternative. Use of 125 tons/day of coal was selected because this is the lowest rate that can be sustained continuously utilizing one pulverizer, which prevents the need to landfill the No. 5 Power Boiler bark ash.[5] Additionally, the mill's coal handling system must run on a routine basis in order to remain reliably operational. Infrequently used coal handling systems are extremely difficult to maintain, especially in coastal areas where salt corrosion is significant.

This operating rate also allows the mill to take advantage of the significant BTU content of the ash generated by the No. 5 Power Boiler. At typical coal heating values, ash is approximately 13.2% of the heat input capacity of the No. 7 Power Boiler.

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[5] The No. 5 Power Boiler bark ash is fed to the No. 7 Power Boiler through the coal pulverizers. When none of the pulverizers are operating, the bark ash cannot be fed to the No. 7 Power Boiler and must be landfilled. The mill does not have its own landfill, so all ash that cannot be fed to the No. 7 Power Boiler must be transported off-site, which would raise the mill's operating costs, increase truck traffic in and around the mill, and consume valuable commercial landfill space.

Further, this operating rate on coal also provides a comfortable operating margin above the 10% threshold below which it would fall under the Boiler MACT Gas 2 subcategory. As discussed above, Boiler MACT requires HCl and mercury performance tests to be conducted while firing the worst case fuel mix, and the boiler would not meet the Gas 2 subcategory emission limits for HCl (and possibly PM) using this fuel mix.

For the reasons described above, WestRock did not select the complete replacement of coal with low-sulfur fuel as one of the control alternatives for the FFA for the No. 7 Power Boiler. 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 this source, which is a tangentially-fired pulverized coal boiler.

Other low sulfur fuel alternatives also were considered and determined to be infeasible, as discussed below.

<u>Natural gas as primary fuel in place of coal</u>: Although the boiler is currently capable of operating at full load using natural gas, it would not have full back-up fuel capability if coal were eliminated as a permitted fuel. The existing ULSD burners in No. 7 Power Boiler are only rated at a total of 470 MMBtu/hr of heat input, which is 46% of full load. The capital cost for adding full load ULSD burners is estimated to be approximately \$18.8 million. Also, eliminating coal as a permitted fuel would require landfilling of the No. 5 Power Boiler bark ash, consuming landfill capacity better used for materials that cannot be disposed of by other means, eliminating a source of heat input to the unit, and potentially causing more truck traffic in and around the residential neighborhood surrounding the mill.

<u>Biomass as primary fuel in place of coal</u>: a fundamental change to the design of the boiler would be required in order to be able to burn biomass in place of coal (e.g., addition of a firing grate, conversion to a bubbling or fluidized bed). The capital cost of such a conversion would likely be on the order of magnitude of \$50 million to \$100 million.

Wet Scrubbers

Wet scrubbers were identified as available and are expected to be technically feasible for application to the No. 7 Power Boiler. WestRock selected the following wet scrubber alternative for inclusion in the FFA:

- Wet scrubber: install and operate a wet scrubber designed for 98% SO_2 removal using sodium hydroxide as the scrubbing liquid.

Dry Scrubbing Systems

Dry scrubbing systems were identified as available and are expected to be technically feasible for application to the No. 7 Power Boiler. In this category, DSI systems are most commonly applied to industrial boilers. SDAs and CDSs are less common and typically utilize a fabric filter control device for particulate, which increases the SO_2 reduction associated with the dry scrubber because SO_2 is removed across the filter cake in the fabric filter. The No. 7 Power Boiler is equipped with an ESP for particulate removal, so the cost of adding an SDA includes the cost of a fabric filter to replace the ESP.

WestRock selected the following dry scrubbing alternatives for inclusion in the FFA:

- Dry sorbent injection (DSI): install and operate a DSI system designed to achieve 60% SO_2 reduction utilizing unmilled trona as the sorbent.
- Spray dry absorber (SDA): install and operate an SDA (with fabric filter to replace the ESP) designed for 95% SO_2 removal and utilizing hydrated lime as the sorbent.

WestRock selected an unmilled trona-based DSI system for analysis in part because we have facility- and boiler-specific information for that system. Specifically, in 2013, WestRock obtained vendor quotations and conducted DSI trials for the Mill's No. 7 Power Boiler for purposes of determining the best compliance alternative for Boiler MACT HCl compliance.

WestRock also selected an SDA system for analysis since SDAs typically achieve a higher SO_2 reduction than DSI systems. WestRock chose an SDA rather than CDS for analysis because we have some experience operating an SDA system at another WestRock mill and we have a recent vendor quotation that indicates that SDA system can be upgraded to achieve 95% control.

2.4 COST OF COMPLIANCE

Cost analyses were developed for the selected control alternatives. 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, vendor estimates, previously developed company project costs, and/or EPA costing methodologies. The cost effectiveness for each selected 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. Projected maximum actual 2028 emissions were used as the basis for emissions reductions (2019 actual emissions scaled up to reflect a maximum coal sulfur specification of 1%). The actual 2019 operating rate is a reasonable estimate of 2028.

Table 2-2 summarizes the control technologies for which costs were estimated for the No. 7 Power Boiler.

Table 2-2
Control Technologies Evaluated for No. 7 Power Boiler

Fuels Fired	Existing SO_2 Control Technology	Additional SO_2 Control Technology Costed
Coal, No. 5 Power Boiler bark ash, ULSD, natural gas	Some low-sulfur fuels are fired, white liquor scrubber on LVHC NCG stream	Reduce coal usage to 125 tons/day Wet scrubber after existing ESP DSI with existing ESP SDA with new fabric filter

Capital, operating, and total annual cost estimates and the assumed control efficiency and estimated emissions reduction for each control alternative are presented in Appendix A and summarized in Table 2-3. It should be noted that these are screening level cost estimates and are not based on detailed site-specific engineering studies. Site-specific factors such as space constraints, utility limitations (need for utility upgrades) or the ability to achieve the estimated emission reductions with a retrofitted control device could significantly impact the actual cost of implementing controls.

Table 2-3
No. 7 Power Boiler Additional Control Measures Cost Summary

Control Measure	Capital Cost ($)	Annual Cost ($/yr)	SO_2 Control Efficiency Assumed	Annual SO_2 Emissions Reduction (tpy)	Cost Effectiveness of Controls ($/Ton SO_2)
Reduce coal usage to 125 tons/day	NA	Cost savings of $211 thousand	9%	113	-$1,868/ton
Install a wet scrubber	$24.4 million	$8.2 million	98%	1,222	$6,681/ton
Install a wet scrubber with stack liner	$30.1 million	$8.9 million	98%	1,222	$7,311
Install DSI	$3.4 million	$6.7 million	60%	748	$8,938/ton
Install an SDA and FF	$74.4 million	$22.1 million	95%	1,184	$18,652

Low-Sulfur Fuels

No capital is required to implement the coal reduction control alternative for No. 7 Power Boiler. The estimated annual cost and cost effectiveness are based on operating data, current fuel costs (which vary based on the amount of gas consumed) and projected 2028 actual emissions.

Wet Scrubber

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 7.3 presents the costs associated with installing a wet scrubber for SO_2 control on a coal/wood boiler producing 300,000 lb/hr of steam. The equipment cost was scaled using an engineering cost scaling factor of 0.6 and the ratio of the No. 7 Power Boiler's size to the size of the boiler evaluated in the BE&K report. The capital cost was scaled to 2019 dollars using the Chemical Engineering Plant Cost Index (CEPCI). Operating costs were estimated using the factors in the OAQPS Cost Manual, Section 5, Chapter 1. Mill-specific labor, chemical, and utility costs were used to estimate the annual cost of operating the system. Additional studies are required to determine whether the existing brick-lined stack would be suitable for the wet plume that would result from use of a wet scrubber or if the stack would need to be replaced or lined. As such, the cost of the wet scrubber option was analyzed with and without the cost of a stack liner.

DSI

The capital cost for a system to inject unmilled trona prior to the boiler's ESP was estimated using a 2013 quote from Southern Environmental, Inc. (SEI) for an unmilled trona injection system, scaled to reflect the sorbent injection rate determined to be necessary to achieve 60% control during a trial. Operating costs are based on the trial injection rate and an April 2017 Sargent and Lundy report prepared under a U.S. EPA contract.[6] Mill-specific labor, chemical, and utility costs were used to estimate the annual cost of operating the system.

SDA

The capital and operating costs for an SDA system, including a fabric filter, were estimated using a January 2017 Sargent and Lundy report prepared under a U.S. EPA contract[7] and mill-specific

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[6] Sargent & Lundy LLC. 2017. *Dry Sorbent Injection for SO_2/HCl Control Cost Development Methodology.* Project 13527-001, Eastern Research Group, Inc. Chicago, IL.

[7] Sargent & Lundy LLC. 2017. *SDA FGD Cost Development Methodology.* Project 13527-001, Eastern Research Group, Inc. Chicago, IL.

cost data. These equations are also included in the draft update to the OAQPS Control Cost Manual, Section 5, SO_2 and Acid Gas Controls.

2.5 ENERGY AND NON-AIR RELATED IMPACTS

Low-sulfur Fuels

No significant energy or non-air related impacts have been identified for the coal reduction control measure.

Install a Wet Scrubber

Installation of a wet scrubber would increase water and electricity usage and wastewater generation.

Install a DSI System

Installation of a DSI system would increase solid waste and electricity usage. The No. 7 Power Boiler fly ash is currently used in cement manufacturing but would have to be landfilled if contaminated with sorbent.

Install an SDA System

Installation of an SDA system would increase solid waste and electricity usage. The No. 7 Power Boiler fly ash is currently used in cement manufacturing but would have to be landfilled if contaminated with sorbent.

2.6 TIME NECESSARY FOR COMPLIANCE

If installation of controls is ultimately required to meet RHR requirements, the Mill would need a minimum of four years to implement them after final EPA approval of the RHR SIP. At least four years would be required because the process to undertake a retrofitting project is complex, involving design, engineering, permitting, procurement, and installation to name only some of the necessary work streams. Also, since the start of the COVID pandemic, the time necessary to implement construction projects has increased considerably. Lead times for obtaining critical parts and equipment are much longer and the ability to bring outside skilled labor on site has become more difficult than in pre-COVID times. To implement one of the control alternatives, the Mill would need time to obtain corporate approvals for capital funding. Once funding was secured, the design, permitting, procurement, installation, and shakedown of a retrofit emission control project could consume four years. The Mill would need to engage engineering consultants, equipment vendors, construction contractors, financial institutions, and other critical suppliers. 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. The Mill would need to continue to operate as much as possible while retrofitting to meet any new requirements.

The Mill would need until 2022 to implement the coal reduction option, as it is contractually obligated to purchase a set amount of coal through 2021.

2.7 REMAINING USEFUL LIFE OF NO. 7 POWER BOILER

The No. 7 Power Boiler is assumed to have a remaining useful life of twenty years or more.

3. FOUR-FACTOR ANALYSIS FOR NO. 5 POWER BOILER

This section of the report presents the FFA for SO_2 control alternatives for the No. 5 Power Boiler at the WestRock Fernandina Beach Mill. Using the four factors specified in the Clean Air Act and FDEP's instructions, the analysis consists of the following steps:

- Identification of available control measures
- Elimination of technically infeasible options
- Selection of control measures for analysis
- Assessment of the cost of compliance for the selected control measures (statutory factor 1)
- Assessment of the time necessary for compliance (statutory factor 2)
- Assessment of the energy and non-air quality environmental impacts of compliance (statutory factor 3)
- Assessment of the remaining useful life of the emission unit (statutory factor 4)

3.1 AVAILABLE CONTROL MEASURES

Air pollution control measures (including lower-emitting processes and practices) that have the potential for practical application to the emission unit and pollutant under evaluation were considered. The scope of possible control options for the No. 5 Power Boiler was determined based on a review of the RBLC database and knowledge of typical controls used on boilers. RBLC entries that were not representative of the type of emission unit or fuel being fired were excluded from further consideration. Table 3-1 summarizes the available SO_2 control technologies for industrial boilers.

Table 3-1
Control Technology Summary

Pollutant	Controls on Industrial Boilers
SO_2	Low-sulfur fuels Wet scrubbers Dry scrubbing systems

The available control measures for reducing emissions of SO_2 from industrial boilers are discussed in detail below.

Low-sulfur Fuels

Uncontrolled emissions of SO_2 are proportional to the amount of sulfur in the fuel being fired. Combustion of natural gas, clean biomass, and ULSD all produce negligible SO_2 emissions. The No. 5 Power Boiler already fires only low-sulfur fuels (biomass, natural gas, and ULSD).

Acid Gas Scrubbers

<u>Wet Scrubbers</u>

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 (physical or chemical). Wet scrubbing involves a mass transfer operation in which one or more soluble components of an acid gas are dissolved in a liquid that has low volatility under process conditions. For SO_2 control, the absorption process is chemical-based and uses an alkali solution (*i.e.*, sodium hydroxide, sodium carbonate, sodium bicarbonate, calcium hydroxide, etc.) as a sorbent or reagent in combination with water. Removal efficiencies are affected by the chemistry of the absorbing solution as it reacts with the pollutant and the design of the wet scrubber. Most wet scrubbers have SO_2 removal efficiencies of at least 90 percent. 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 Scrubbing Systems

Types of dry scrubbing systems include SDA, CDS, and DSI. SDA systems are gas absorption systems that inject hydrated sorbent, typically lime (CaO) or hydrated lime ($Ca(OH)_2$), into the flue gas after a boiler's air heater. The hydrated sorbent chemically reacts with acid gas compounds and the fly ash in the gas stream to form calcium based salts while absorbing a portion of the residual heat in the flue gas to dry the resultant particles that are later removed in the downstream particulate control device. The July 2020 draft Section 5, Chapter 1, Section 1.2.2 of the U.S. EPA's OAQPS Air Pollution Control Cost Manual indicates that removal efficiencies for SO_2 of up to 95% are achievable for coal-fired power plants. However, the highest removal efficiencies are likely achievable only where a fabric filter is utilized for the particulate control device as is common in the utility industry (it is noted in July 2020 draft Cost Manual Section 5 that the filter cake of a fabric filter removes SO_2 from the gases, and reference 14 indicates that the removal across the filter can be significant).

Unlike an SDA system, a CDS operates like a circulating fluidized bed that the combustion gases pass through following a boiler's air heater section. In this type of system, the flue gas leaving the air heater section is wetted as it passes through a venturi section and enters upwards into the absorber body. Inside the absorber, water is added to reduce the flue gas temperature which aids in the chemical reaction with the hydrated lime and fly ash to form calcium salts. Particulates from the absorber are captured in the downstream control device. Flue gas flow rate is controlled to maintain the fluidized effect inside the absorber. The July 2020 draft Section 5, Chapter 1, Section 1.2.2 of the U.S. EPA's OAQPS Air Pollution Control Cost Manual indicates that removal efficiencies for SO_2 of up to 98% are achievable for coal-fired power plants. However, as with the SDA technology described above, some of the removal occurs in the filter cake of the fabric filter control devices employed by many coal-fired power plants for particulate removal and the highest removal efficiencies are likely achievable only where a fabric filter is used.

A DSI system controls acid gases by injecting a dry reagent (*i.e.*, lime or trona) into the flue gas stream prior to PM air pollution control equipment. A reaction takes place in the flue gas between the reagent and the acid gases, producing neutral salts that must be removed by the PM air pollution control equipment located downstream. The process is totally "dry," meaning it produces a dry disposal product and introduces the reagent as a dry powder. The benefits of this type of system include the elimination of liquid handling equipment requiring routine maintenance such as pumps, agitators, and atomizers. The drawbacks to using this type of system are the costs associated with the installation of a dry PM control device to collect the dry by-product, as well as ongoing operating costs to procure the sorbent material and dispose of additional dry waste. Dry sorbents can also prove challenging to maintain a very low moisture content and keep flowing. DSI systems are typically used to control SO_2 and other acid gases on coal-fired boilers. The July 2020 draft Section 5, Chapter 1, Section 1.2.1.3 of the U.S. EPA's Air Pollution Control Cost Manual for SO_2 Control indicates that DSI systems can be expected to achieve control efficiencies ranging from 50-70%.

3.2 ELIMINATION OF TECHNICALLY INFEASIBLE OPTIONS

An available a control measure could be technically infeasible for a particular emission unit based on physical, chemical, or engineering principles that preclude its successful use for that emission unit. A technology is generally considered technically feasible if it has been demonstrated and operated successfully on the same or similar type of emission unit under review or is available and applicable to the emission unit type under review.

The No. 5 Power Boiler burns only low-sulfur fuels and has actual emissions of only 17 tpy. Both actual and allowable emissions from this boiler were reduced in order to model compliance with the 1-hour SO_2 NAAQS for the SIP.

WestRock expects that it would be technically feasible to apply either of the following available SO_2 control measures identified above to the No. 5 Power Boiler: installation of a wet scrubber or installation of a dry scrubbing system. Space is limited in the area surrounding the No. 5 Power Boiler, so adding a wet or dry scrubbing system could be challenging. A detailed engineering study would need to be conducted in order to confirm with certainty that a wet or dry scrubbing system could be successfully sited and installed for the No. 5 Power Boiler.

3.3 SELECTION OF CONTROL MEASURES FOR ANALYSIS

FDEP's request for a four-factor analysis states that WestRock should utilize the U.S. EPA's Regional Haze Guidance in determining which emission control measures to consider. With respect to determining which emission control measures to consider in the four-factor analysis, that guidance states the following on page 29: "A state must reasonably pick and justify the measures that it will consider, recognizing that there is no statutory or regulatory requirement to consider all technically feasible measures or any particular measures. A range of technically feasible measures available to reduce emissions would be one way to justify a reasonable set." WestRock selected at least one specific control measure from each of the control measure categories that were identified as available and technically feasible for application to the No. 5 Power Boiler.

Wet Scrubbers

Wet scrubbers were identified as available and are expected to be technically feasible for application to the No. 5 Power Boiler. WestRock selected the following wet scrubber alternative for inclusion in the FFA:

- Wet scrubber: install and operate a wet scrubber designed for 98% SO_2 removal using sodium hydroxide as the scrubbing liquid.

Dry Scrubbing

Dry scrubbing was identified as available and is expected to be technically feasible for application to the No. 5 Power Boiler. In this category, DSI systems are most commonly applied to industrial boilers. SDAs and CDSs are less common and typically utilize a fabric filter control device for particulate, which increases the SO_2 reduction associated with the dry scrubber because SO_2 is removed across the filter cake in the fabric filter. The No. 5 Power Boiler is equipped with an ESP for particulate removal and an SDA or CDS system is not likely to be cost effective at the current emissions level, either with or without a fabric filter, based on our experience.

WestRock selected the following dry scrubbing alternative for inclusion in the FFA:

- Dry sorbent injection (DSI): install and operate a DSI system designed to achieve 60% SO_2 reduction utilizing unmilled trona as the sorbent.

WestRock selected an unmilled trona-based DSI system for analysis in part because we have facility-specific information for that type of system. Specifically, in 2013, WestRock obtained vendor quotations and conducted DSI trials for the Mill's No. 7 Power Boiler for purposes of determining the best compliance alternative for Boiler MACT compliance. Based on the boiler's low emission rate and the high cost of the two other scrubbing systems, the cost of an SDA or CDS system was not evaluated for No. 5 Power Boiler.

3.4 COST OF COMPLIANCE

Cost analyses were developed for the selected control alternatives. 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, vendor estimates, previously developed company project costs, and/or EPA costing methodologies. The cost effectiveness for each selected 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. Actual emissions were used as the basis for emissions reductions. The actual 2019 emissions are a reasonable estimate of 2028 actual emissions.

Table 3-2 summarizes the control technologies for which costs were estimated for the No. 5 Power Boiler.

Table 3-2
Control Technologies Evaluated for No. 5 Power Boiler

Fuels Fired	Existing SO_2 Control Technology	Additional SO_2 Control Technology Costed
Biomass and ULSD	Low-sulfur fuels	Wet scrubber DSI

Capital, operating, and total annual cost estimates and the assumed control efficiency and calculated emissions reduction for each control alternative are presented in Appendix A and summarized in Table 3-3. It should be noted that these are screening level cost estimates and are not based on detailed site-specific engineering studies. Site-specific factors such as space constraints, utility limitations (need for utility upgrades), or the ability to achieve the estimated emission reductions with a retrofitted control device could significantly impact the actual cost of implementing controls.

Table 3-3
No. 5 Power Boiler Additional Control Measures Cost Summary

Control Measure	Capital Cost ($)	Annual Cost ($/yr)	SO_2 Control Efficiency Assumed	Annual SO_2 Emissions Reduction (tpy)	Cost Effectiveness of Controls ($/Ton SO_2)
Install a wet scrubber	$18.8 million	$5.7 million	98%	16.7	$344,472
Install a wet scrubber with stack liner	$18.8 million	$5.7 million	98%	16.7	$365,464
Install DSI	$2.2 million	$2.5 million	60%	10.2	$284,922

Wet Scrubber

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 7.3 presents the costs associated with installing a wet scrubber for SO_2 control on a coal/wood boiler producing 300,000 lb/hr of steam. The equipment cost was scaled using an engineering cost scaling factor of 0.6 and the ratio of the No. 5 Power Boiler's size to the size of the boiler evaluated in the BE&K report. The capital cost was scaled to 2019 dollars using the CEPCI. Operating costs were estimated using the factors in the OAQPS Cost Manual, Section 5, Chapter 1. Mill-specific labor, chemical, and utility costs were used to estimate the annual cost of operating the system. Additional studies are required to determine whether the existing stack would be suitable for the wet plume that would result from use of a wet scrubber or whether the stack would need to be replaced or lined. As such, the cost of the wet scrubber option was analyzed with and without the cost of a stack liner.

DSI

The capital cost for a system to inject trona prior to the boiler's ESP was estimated using a 2013 quote from SEI for a DSI system on the Mill's No. 7 Power Boiler and scaled to 2019 dollars using the CEPCI. Operating costs were estimated using an April 2017 Sargent and Lundy report prepared under a U.S. EPA contract.[8] Mill-specific labor, chemical, and utility costs were used to estimate the annual cost of operating the system.

3.5 ENERGY AND NON-AIR RELATED IMPACTS

Install a Wet Scrubber

Installation of a wet scrubber would increase water and electricity usage and wastewater generation.

Install a DSI System

Installation of a DSI system would increase solid waste (including landfilling the No. 5 Power Boiler flyash contaminated with sorbent) and electricity usage.

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[8] Sargent & Lundy LLC. 2017. *Dry Sorbent Injection for SO_2/HCl Control Cost Development Methodology.* Project 13527-001, Eastern Research Group, Inc. Chicago, IL.

3.6 TIME NECESSARY FOR COMPLIANCE

If installation of controls is ultimately required to meet RHR requirements, the Mill would need a minimum of four years to implement them after final EPA approval of the RHR SIP. At least four years would be required because the process to undertake a retrofitting project is complex, involving design, engineering, permitting, procurement, and installation to name only some of the necessary work streams. Also, since the start of the COVID pandemic, the time necessary to implement construction projects has increased considerably. Lead times for obtaining critical parts and equipment are much longer and the ability to bring outside skilled labor on site has become more difficult than in pre-COVID times. To implement one of the control alternatives, the Mill would need time to obtain corporate approvals for capital funding. Once funding was secured, the design, permitting, procurement, installation, and shakedown of a retrofit emission control project could consume four years. The Mill would need to engage engineering consultants, equipment vendors, construction contractors, financial institutions, and other critical suppliers. 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. The Mill would need to continue to operate as much as possible while retrofitting to meet any new requirements.

3.7 REMAINING USEFUL LIFE OF NO. 5 POWER BOILER

The No. 5 Power Boiler is assumed to have a remaining useful life of twenty years or more.

4. FOUR-FACTOR ANALYSIS FOR NO. 4 RECOVERY BOILER

This section of the report presents the FFA for SO_2 control alternatives for the No. 4 Recovery Boiler at the WestRock Fernandina Beach Mill. Using the four factors specified in the Clean Air Act and FDEP's instructions, the analysis consists of the following steps:

- Identification of available control measures
- Elimination of technically infeasible options
- Selection of control measures for analysis
- Assessment of the cost of compliance for the selected control measures (statutory factor 1)
- Assessment of the time necessary for compliance (statutory factor 2)
- Assessment of the energy and non-air quality environmental impacts of compliance (statutory factor 3)
- Assessment of the remaining useful life of the emission unit (statutory factor 4)

4.1 AVAILABLE CONTROL TECHNOLOGIES

Air pollution control technologies or techniques (including lower-emitting processes and practices) that have the potential for practical application to the emission unit and pollutant under evaluation were evaluated. The scope of possible control options for recovery boilers was determined based on a review of the RBLC database and knowledge of typical controls used on recovery boilers in the pulp and paper industry. RBLC entries that are not representative of the type of emission unit or fuel being fired were excluded from further consideration. Table 4-1 summarizes the available SO_2 control technologies for recovery boilers.

Table 4-1
Control Technology Summary

Pollutant	Controls on Recovery Boilers
SO_2	Good operating practices Low-sulfur fuel for startup Wet scrubber

The available control measures for reducing emissions of SO_2 emissions from recovery boilers are discussed in detail below.

Good Operating Practices

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

Low-Sulfur Startup Fuel

Fossil fuel is used to start up a recovery boiler prior to introducing black liquor. Emissions of SO_2 during a cold startup are proportional to the amount of sulfur in the fossil fuel being fired. Natural gas and ULSD are considered low sulfur fossil fuels and produce negligible SO_2 emissions when combusted.

Wet Scrubbers

In wet scrubbing processes for gaseous control, a liquid is used to remove pollutants from an exhaust stream. The removal of pollutants in the gaseous stream is done by absorption. Wet scrubbers used for this type of pollutant control are often referred to as absorbers. Wet scrubbing involves a mass transfer operation in which one or more soluble components of an acid gas are dissolved in a liquid that has low volatility under process conditions. For SO_2 control, the absorption process is chemical-based and uses an alkali solution (*i.e.*, sodium hydroxide, sodium carbonate, sodium bicarbonate, calcium hydroxide, etc.) as a sorbent or reagent in combination with water. Removal efficiencies are affected by the chemistry of the absorbing solution as it reacts with the pollutant. Most wet scrubbers have SO_2 removal efficiencies of at least 90 percent. Wet scrubbers may take the form of a variety of different configurations, including plate or tray columns, spray chambers, and venturi scrubbers.

4.2 ELIMINATION OF TECHNICALLY INFEASIBLE OPTIONS

An available control measure could be technically infeasible for a specific emission unit based on physical, chemical, or engineering principles that would preclude its successful use for that emission unit. A technology is generally technically feasible if it has been demonstrated and operated successfully on the same or similar type of emission unit under review or is available and applicable to the emission unit type under review.

The No. 4 Recovery Boiler is not equipped with add-on SO_2 control technology. Good combustion practices and low-sulfur startup fuels (ULSD and natural gas) are already utilized to minimize SO_2 emissions. As described in Section 1.3, the Mill implemented several projects over the past 5 years to improve combustion conditions and reduce actual and allowable SO_2 emissions from the Recovery Boilers. Although SO_2 emissions from recovery boilers can be inherently low, addition of a wet scrubber to further reduce SO_2 emissions is likely technically feasible. Note that only three currently operating recovery boilers in the U.S. have wet scrubbers installed after their ESPs, and these units are higher-emitting direct contact evaporator (DCE) units, unlike No. 4 Recovery Boiler, which is a lower-emitting non-direct contact evaporator (NDCE) unit. Space is limited in the area surrounding the No. 4 Recovery Boiler, so adding a wet scrubber could be challenging. A detailed engineering study would need to be conducted in order to confirm with certainty that a wet scrubber could be successfully sited and installed for the No. 4 Recovery Boiler.

4.3 SELECTION OF CONTROL MEASURES FOR ANALYSIS

Three control measures were identified as available for reducing SO_2 emissions from recovery boilers. Two of them are already used by the No. 4 Recovery Boiler and do not present opportunities for SO_2 reductions. The third control measure, a wet scrubber system, was therefore selected for inclusion in the FFA. The following specific wet scrubber alternative was utilized:

- Wet scrubber: install and operate a wet scrubber designed for 98% SO_2 removal using sodium hydroxide as the scrubbing liquid.

4.4 COST OF COMPLIANCE

Cost analyses were developed for the selected control alternative. Budgetary estimates of capital and operating costs were determined and used to estimate the annualized costs considering existing equipment design and exhaust characteristics. The capital cost was based on company-specific data, vendor estimates, previously developed company project costs, and/or EPA costing methodologies. The cost effectiveness 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. Actual emissions were used as the basis for emissions reductions. The actual 2019 emissions are a reasonable estimate of 2028 actual emissions.

The selected control technology was evaluated for cost effectiveness for No. 4 Recovery Boiler as summarized in Table 4-2.

Table 4-2
Control Technologies Evaluated for No. 4 Recovery Boiler

Emission unit	Existing SO_2 Control Technology	Additional SO_2 Control Technology Costed
No. 4 Recovery Boiler (EU007)	Low-sulfur startup fuel Proper operation	Wet Scrubber

The capital, operating, and total annual cost estimates are presented in Appendix A and summarized in the table below. These are screening level cost estimates and are not based on detailed site-specific engineering studies.

Table 4-3
No. 4 Recovery Boiler Wet Scrubber Cost Summary

Capital Cost ($)	Annual Cost ($/yr)	SO_2 Control Efficiency Assumed	Annual SO_2 Emissions Reduction (tpy)	Cost Effectiveness of Control ($/Ton SO_2)
$27 million	$5.6 million	98%	14.7	$378,013

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. Sections 7.1 and 7.2 present the costs associated with installing a wet scrubber for SO_2 control on an NDCE recovery boiler 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 the recovery boiler's throughput to the throughput of the boiler evaluated in the BE&K report. Operating costs were estimated using the factors in the OAQPS Cost Manual, Section 5, Chapter 1.

4.5 ENERGY AND NON-AIR RELATED IMPACTS

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

4.6 TIME NECESSARY FOR COMPLIANCE

If controls are ultimately required to meet RHR requirements, the Mill would need a minimum of four years to implement them after final EPA approval of the RHR SIP. At least four years would be required because the process to undertake a retrofitting project is complex, involving design, engineering, permitting, procurement, and installation to name only some of the necessary work streams. Also, since the start of the COVID pandemic, the time necessary to implement construction projects has increased considerably. Lead times for obtaining critical parts and equipment are much longer and the ability to bring outside skilled labor on site has become more difficult than in pre-COVID times. To implement he control alternative, the Mill would need time to obtain corporate approvals for capital funding. Once funding was secured, the design, permitting, procurement, installation, and shakedown of a retrofit emission control project could consume four years. The Mill would need to engage engineering consultants, equipment vendors, construction contractors, financial institutions, and other critical suppliers. 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. The Mill would need to continue to operate as much as possible while retrofitting to meet any new requirements.

4.7 REMAINING USEFUL LIFE OF NO. 4 RECOVERY BOILER

The No. 4 Recovery Boiler is assumed to have a remaining useful life of twenty years or more.

5. FOUR-FACTOR ANALYSIS FOR NO. 5 RECOVERY BOILER

This section of the report presents the FFA for SO_2 control alternatives for the No. 5 Recovery Boiler at the WestRock Fernandina Beach Mill. Using the four factors specified in the Clean Air Act and FDEP's instructions, the analysis consists of the following steps:

- Identification of available control measures
- Elimination of technically infeasible options
- Selection of control measures for analysis
- Assessment of the cost of compliance for the selected control measures (statutory factor 1)
- Assessment of the time necessary for compliance (statutory factor 2)
- Assessment of the energy and non-air quality environmental impacts of compliance (statutory factor 3)
- Assessment of the remaining useful life of the emission unit (statutory factor 4)

5.1 AVAILABLE CONTROL TECHNOLOGIES

Air pollution control technologies or techniques (including lower-emitting processes and practices) that have the potential for practical application to the emission unit and pollutant under evaluation were evaluated. The scope of possible control options for recovery boilers was determined based on a review of the RBLC database and knowledge of typical controls used on recovery boilers in the pulp and paper industry. RBLC entries that are not representative of the type of emission unit or fuel being fired were excluded from further consideration. Table 5-1 summarizes the available SO_2 control technologies for recovery boilers.

Table 5-1
Control Technology Summary

Pollutant	Controls on Recovery Boilers
SO_2	Good operating practices Low-sulfur fuel for startup Wet scrubber

The available control measures for reducing emissions of SO_2 emissions from recovery boilers are discussed in detail below.

Good Operating Practices

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

Low-Sulfur Startup Fuel

Fossil fuel is used to start up a recovery boiler prior to introducing black liquor. Emissions of SO_2 during a cold startup are proportional to the amount of sulfur in the fossil fuel being fired. Natural gas and ULSD are considered low sulfur fossil fuels and produce negligible SO_2 emissions when combusted.

Wet Scrubbers

In wet scrubbing processes for gaseous control, a liquid is used to remove pollutants from an exhaust stream. The removal of pollutants in the gaseous stream is done by absorption. Wet scrubbers used for this type of pollutant control are often referred to as absorbers. Wet scrubbing involves a mass transfer operation in which one or more soluble components of an acid gas are dissolved in a liquid that has low volatility under process conditions. For SO_2 control, the absorption process is chemical-based and uses an alkali solution (*i.e.*, sodium hydroxide, sodium carbonate, sodium bicarbonate, calcium hydroxide, etc.) as a sorbent or reagent in combination with water. Removal efficiencies are affected by the chemistry of the absorbing solution as it reacts with the pollutant. Most wet scrubbers have SO_2 removal efficiencies of at least 90 percent. Wet scrubbers may take the form of a variety of different configurations, including plate or tray columns, spray chambers, and venturi scrubbers.

5.2 ELIMINATION OF TECHNICALLY INFEASIBLE OPTIONS

An available control measure could be technically infeasible for a specific emission unit based on physical, chemical, or engineering principles that would preclude its successful use for that emission unit. A technology is generally technically feasible if it has been demonstrated and operated successfully on the same or similar type of emission unit under review or is available and applicable to the emission unit type under review.

The No. 5 Recovery Boiler is not equipped with add-on SO_2 control technology. Good combustion practices and low-sulfur startup fuels (ULSD and natural gas) are already utilized to minimize SO_2 emissions. As described in Section 1.3, the Mill implemented several projects over the past 5 years to improve combustion conditions and reduce actual and allowable SO_2 emissions from the Recovery Boilers. Although SO_2 emissions from recovery boilers can be inherently low, addition of a wet scrubber to further reduce SO_2 emissions is likely technically feasible. Note that only three currently operating recovery boilers in the U.S. have wet scrubbers installed after their ESPs, and these units are higher-emitting DCE units, unlike No. 5 Recovery Boiler, which is a lower-emitting NDCE unit. A detailed engineering study would need to be conducted in order to confirm with certainty that a wet scrubber could be successfully sited and installed for the No. 5 Recovery Boiler.

5.3 SELECTION OF CONTROL MEASURES FOR ANALYSIS

Three control measures were identified as available for reducing SO_2 emissions from recovery boilers. Two of them are already used by the No. 5 Recovery Boiler and do not present opportunities for SO_2 reductions. The third control measure, a wet scrubber system, was therefore selected for inclusion in the FFA. The following specific wet scrubber alternative was utilized:

- Wet scrubber: install and operate a wet scrubber designed for 98% SO_2 removal using sodium hydroxide as the scrubbing liquid.

5.4 COST OF COMPLIANCE

Cost analyses were developed for the selected control alternative. Budgetary estimates of capital and operating costs were determined and used to estimate the annualized costs considering existing equipment design and exhaust characteristics. The capital cost was based on company-specific data, vendor estimates, previously developed company project costs, and/or EPA costing methodologies. The cost effectiveness 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. Actual emissions were used as the basis for emissions reductions. The actual 2019 emissions are a reasonable estimate of 2028 actual emissions.

The selected control technology for the No. 5 Recovery Boiler was evaluated for cost effectiveness as summarized in Table 5-2.

Table 5-2
Control Technologies Evaluated for No. 5 Recovery Boiler

Emission unit	Existing SO_2 Control Technology	Additional SO_2 Control Technology Costed
No. 5 Recovery Boiler (EU011)	Low-sulfur startup fuel Proper operation	Wet Scrubber

The capital, operating, and total annual cost estimates are presented in Appendix A and summarized in the table below. These are screening level cost estimates and are not based on detailed site-specific engineering studies.

Table 5-3
No. 5 Recovery Boiler Wet Scrubber Cost Summary

Capital Cost ($)	Annual Cost ($/yr)	SO_2 Control Efficiency Assumed	Annual SO_2 Emissions Reduction (tpy)	Cost Effectiveness of Control ($/Ton SO_2)
$27 million	$5.6 million	98%	24.5	$226,808

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. Sections 7.1 and 7.2 present the costs associated with installing a wet scrubber for SO_2 control on an NDCE recovery boiler 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 the recovery boiler's throughput to the throughput of the boiler evaluated in the BE&K report. Operating costs were estimated using the factors in the OAQPS Cost Manual, Section 5, Chapter 1.

5.5 ENERGY AND NON-AIR RELATED IMPACTS

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

5.6 TIME NECESSARY FOR COMPLIANCE

If controls are ultimately required to meet RHR requirements, the Mill would need a minimum of four years to implement them after final EPA approval of the RHR SIP. At least four years would be required because the process to undertake a retrofitting project is complex, involving design, engineering, permitting, procurement, and installation to name only some of the necessary work streams. Also, since the start of the COVID pandemic, the time necessary to implement construction projects has increased considerably. Lead times for obtaining critical parts and equipment are much longer and the ability to bring outside skilled labor on site has become more difficult than in pre-COVID times. To implement he control alternative, the Mill would need time to obtain corporate approvals for capital funding. Once funding was secured, the design, permitting, procurement, installation, and shakedown of a retrofit emission control project could consume four years. The Mill would need to engage engineering consultants, equipment vendors, construction contractors, financial institutions, and other critical suppliers. 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. The Mill would need to continue to operate as much as possible while retrofitting to meet any new requirements.

5.7 REMAINING USEFUL LIFE OF NO. 5 RECOVERY BOILER

The No. 5 Recovery Boiler is assumed to have a remaining useful life of twenty years or more.

6. SUMMARY OF FINDINGS AND PROPOSED DETERMINATION

In response to a request from FDEP, WestRock conducted an FFA to evaluate whether additional emission controls for SO_2 are feasible for the Fernandina Beach Mill's power boilers and recovery boilers, and to estimate the cost of those controls. 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 to perform the analyses was used given the time allowed for the analysis.

FDEP's request for the FFA states that WestRock should provide a proposed determination of whether it is reasonable to require any control measure(s) for each unit. FDEP did not provide any specific guidance on the criteria to be used for determining what would be reasonable, including what FDEP would consider cost effective for purposes of making reasonable progress under the Regional Haze Rule. We believe that the cost effectiveness threshold for reasonable progress under the RHR second implementation period should be less than the threshold for BACT, and therefore less than \$5,000/ton.

Our analysis shows that it would not be cost effective to implement additional SO_2 control measures for the No. 5 Power Boiler, No. 4 Recovery Boiler, or the No. 5 Recovery Boiler. As such, we believe it would not be reasonable to require SO_2 controls during the second implementation period for these emissions units and are proposing a no control determination.

Although we believe it can be concluded that no control measures are reasonable based solely on cost effectiveness, we also considered the other three statutory factors—energy and non-air impacts, time necessary for compliance, and remaining useful life of the emission units—and do not find that they provide any compelling case for determining controls are reasonable. The energy and non-air impacts analyses show that implementing additional control measures would increase energy usage, water usage, wastewater generation, and/or solid waste generation. All of the emission units are presumed to have a remaining useful life exceeding 20 years and the time necessary to implement any of the control measures would be at least four years. Given the four factors, adding SO_2 control measures to No. 5 Power Boiler, No. 4 Recovery Boiler, or the No. 5 Recovery Boiler would not be reasonable for purposes of making further progress in reducing regional haze.

For the No. 7 Power Boiler, our analysis shows that it would not be cost effective to install a wet or dry scrubbing system, and we do not consider them to be reasonable control options. Our analysis indicates that it may be cost effective to reduce coal usage to a maximum of 125 tons/day, assuming current fuel costs do not change significantly.

As noted previously, any determination that additional controls are reasonable for any of the four emissions units evaluated would need to be justified based on a more detailed evaluation that fully considers site-specific factors.

APPENDIX A -
CONTROL COST ESTIMATES

NO. 7 POWER BOILER
CONTROL COST ESTIMATES

Table A-1a
Fuel Switching Cost (125 tons per day Solid Fuel) - WestRock Fernandina Beach No. 7 Power Boiler

ANNUALIZED COSTS				
	COST ITEM	COST FACTOR	UNIT COST	COST ($)
Fuel				
(a)	Natural gas cost - Tier 2 usage rate	[redacted]	[redacted]	*$559,732*
	Coal cost savings	[redacted]	[redacted]	*-$770,672*
	Total Annualized Costs:		***DAC***	***-$210,940***
(b)	SO_2 Reduction	9.1%		
	Pre-retrofit SO_2	1,247 tons SO_2/yr		
	Post-retrofit SO_2	1,134 tons SO_2/yr		
	SO_2 Removed	113 tons SO_2/yr		
	Annual Cost/Ton Removed:			***-$1,868***

(a) 2019 WestRock Fernandina Beach fuel cost.
(b) Pre-retrofit SO_2 emissions estimated based on projected 2028 actual throughput/fuel usage. Post-retrofit SO_2 emissions estimated based on equivalent heat input of pre-retrofit SO_2 emissions when limited to a max of 125 tpd pulverized coal.

Table A-1b

SO_2 Fuel Switching Emissions Calculations - WestRock Fernandina Beach No. 7 Power Boiler

Projected 2028 Actual Throughput/Fuel Usage			Projected 2028 Actual SO_2 Emissions	
Current SO_2				
Bark Ash	14,591	tpy	234	tpy
	2.66E+05	MMBtu/yr		
Coal	51,572	tpy	980	tpy
	1.34E+06	MMBtu/yr		
Natural Gas	5.81E+03	MMscf/yr	1.7	tpy
	6.08E+06	MMBtu/yr		
LVHC NCG	4.18E+04	ADTUBP	31	tpy
Total Emissions			1,247	tpy
Post-change SO_2 (125 tons per day Coal)				
Bark Ash	14,591	tpy	234	tpy
	2.66E+05	MMBtu/yr		
Coal	45,625	tpy	867	tpy
	1.19E+06	MMBtu/yr		
Natural Gas	5.96E+03	MMscf/yr	1.8	tpy
	6.24E+06	MMBtu/yr		
LVHC NCG	4.18E+04	ADTUBP	31	tpy
Total Emissions			1,134	tpy
SO_2 Removed			113	tpy

Heat Content		
Bark Ash[1]	9,100	Btu/lb
Coal[1]	13,000	Btu/lb
Natural Gas[1]	1,047	Btu/scf

1 - Mill Specific Information

Bark Ash Emissions Factor[2]		
Bark Ash Emission Factor	1.77	lb/MMBtu

2 - Calculated from 2019 SO2 CEMS data:
(total SO2 emissions measured by the CEMS minus the SO2 emissions attributable to coal, natural gas and NCG) / (heat input from bark ash)

Coal Emissions Factor[3]		
Coal Sulfur Content	1	% weight Fuel Spec.
Coal Emissions Factor	38.0	lb/ton

3 - AP-42 Section 1.1

Natural Gas Emissions Factor[4]		
Natural Gas Emissions Factor	0.6	lb/MMscf

4 - AP-42 Section 1.4

NCG Emisions Factor[5]		
Emission factor for combustion of scrubbed NCG	1.46	lb/ADTUBP

5 - Calculated from the amount of TRS in LVHC NCG per NCASI Technical Bulletin 1050, Section 4.2.5 and white liquor scrubber control efficiency of 99% for H2S and 80% for methyl mercaptan (NCG passes through the white liquor scrubber prior to combustion in No. 7 Power Boiler).

Table A-2a
Wet Scrubber Cost - WestRock Fernandina Beach No. 7 Power Boiler

CAPITAL COSTS[a]

		COST ITEM	COST FACTOR	COST ($)
		Direct Costs		
		Purchased Equipment Costs		
(a)	***A***	Equipment Costs		***$9,404,704***
(b)		Instrumentation	0.10 A	$940,470
(b)		Sales Tax	0.03 A	$282,141
(b)		Freight	0.05 A	$470,235
	B	***Total Purchased Equipment Cost***		***$11,097,551***
		Direct Installation Costs		
(b)		Foundations and Supports	0.12 B	$1,331,706
(b)		Handling and erection	0.40 B	$4,439,020
(b)		Electrical	0.01 B	$110,976
(b)		Piping	0.30 B	$3,329,265
(b)		Insulation for ductwork	0.01 B	$110,976
(b)		Painting	0.01 B	$110,976
		Direct Installation Cost		***$9,432,918***
		Total Direct Costs		***$20,530,469***
		Indirect Costs		
(b)		Engineering	0.10 B	$1,109,755
(b)		Construction Management	0.10 B	$1,109,755
(b)		Contractor fees	0.10 B	$1,109,755
(b)		Start-up	0.01 B	$110,976
(b)		Performance test	0.01 B	$110,976
(b)		Contingencies	0.03 B	$332,927
		Total Indirect Costs		***$3,884,143***
		Total Capital Investment (TCI)		***$24,414,612***

ANNUALIZED COSTS

	COST ITEM	COST FACTOR	RATE	COST ($)
	Direct Annual Costs			
	Operating Labor			
(b)	Operator[c]	[redacted]	[redacted] (d)	$21,079
(b)	Supervisor	15% of operator labor		$3,162
	Maintenance			
(b)	Maintenance labor[c]	[redacted]	[redacted] (d)	$20,230
(b)	Maintenance materials	100% of maintenance labor		$20,230
	Utilities			
	Electricity	[redacted]	[redacted] (d)	$2,054,915
	Chemicals	[redacted]	[redacted] (d)	$2,636,410
	Fresh water usage	[redacted]	[redacted]	$70,824
	Wastewater disposal	[redacted]	[redacted] (d)	$7,082
	Total Direct Annual Costs			***$4,833,932***
	Indirect Annual Costs			
(b)	Overhead	60% Labor and Material Costs		$38,820
(b)	General and administrative	2% of TCI		$488,292
(b)	Property taxes	1% of TCI		$244,146
(b)	Insurance	1% of TCI		$244,146
(b)	Capital recovery	0.095 x TCI		$2,312,580
	Life of the control:	15 years at	4.75% interest	
	Total Indirect Annual Costs			***$3,327,985***
	Total Annual Costs			***$8,161,917***
	Cost Effectiveness ($/ton)			
	SO_2 Control Efficiency[e]:	98%		
	SO_2 Emissions[f]:	1,247 tpy		Total Annual Costs/Controlled SO_2 Emissions:
	Controlled SO_2 Emissions:	1,222 tons of SO_2 removed annually		***$6,681***

[a] Wet scrubber capital cost based on Section 7.3 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 coal/wood boiler was scaled based on maximum continuous rating steam flow. 2001 dollars were scaled to 2019 dollars based on the 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 WestRock Fernandina Beach rates.

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

[f] Projected actual SO_2 emissions.

Table A-2b

Wet Scrubber Cost with Stack - WestRock Fernandina Beach No. 7 Power Boiler

CAPITAL COSTS[a]

		COST ITEM	COST FACTOR	COST ($)
		Direct Costs		
		Purchased Equipment Costs		
(a)	***A***	Equipment Costs		***$11,604,704***
(b)		Instrumentation	0.10 A	$1,160,470
(b)		Sales Tax	0.03 A	$348,141
(b)		Freight	0.05 A	$580,235
	B	***Total Purchased Equipment Cost***		***$13,693,551***
		Direct Installation Costs		
(b)		Foundations and Supports	0.12 B	$1,643,226
(b)		Handling and erection	0.40 B	$5,477,420
(b)		Electrical	0.01 B	$136,936
(b)		Piping	0.30 B	$4,108,065
(b)		Insulation for ductwork	0.01 B	$136,936
(b)		Painting	0.01 B	$136,936
		Direct Installation Cost		***$11,639,518***
		Total Direct Costs		***$25,333,069***
		Indirect Costs		
(b)		Engineering	0.10 B	$1,369,355
(b)		Construction Management	0.10 B	$1,369,355
(b)		Contractor fees	0.10 B	$1,369,355
(b)		Start-up	0.01 B	$136,936
(b)		Performance test	0.01 B	$136,936
(b)		Contingencies	0.03 B	$410,807
		Total Indirect Costs		***$4,792,743***
		Total Capital Investment (TCI)		***$30,125,812***

ANNUALIZED COSTS

	COST ITEM	COST FACTOR	RATE	COST ($)
	Direct Annual Costs			
	Operating Labor			
(b)	Operator[c]	[redacted]	[redacted] [d]	$21,079
(b)	Supervisor	15% of operator labor		$3,162
	Maintenance			
(b)	Maintenance labor[c]	[redacted]	[redacted] [d]	$20,230
(b)	Maintenance materials	100% of maintenance labor		$20,230
	Utilities			
	Electricity	[redacted]	[redacted] [d]	$2,054,915
	Chemicals	[redacted]	[redacted] [d]	$2,636,410
	Fresh water usage	[redacted]	[redacted] [d]	$70,824
	Wastewater disposal	[redacted]	[redacted] [d]	$7,082
	Total Direct Annual Costs			***$4,833,932***
	Indirect Annual Costs			
(b)	Overhead	60% Labor and Material Costs		$38,820
(b)	General and administrative	2% of TCI		$602,516
(b)	Property taxes	1% of TCI		$301,258
(b)	Insurance	1% of TCI		$301,258
(b)	Capital recovery	0.095 x TCI		$2,853,551
	Life of the control:	15 years at	4.75% interest	
	Total Indirect Annual Costs			***$4,097,404***
	Total Annual Costs			***$8,931,336***
	Cost Effectiveness ($/ton)			
	SO_2 Control Efficiency[e]:	98%		
	SO_2 Emissions[f]:	1,247 tpy	Total Annual Costs/Controlled SO_2 Emissions:	
	Controlled SO_2 Emissions:	1,222 tons of SO_2 removed annually		***$7,311***

[a] Wet scrubber capital cost based on Section 7.3 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 coal/wood boiler was scaled based on maximum continuous rating steam flow. 2001 dollars were scaled to 2019 dollars based on the CEPCI. The addition of a wet scrubber may require an upgrade to the existing stack to accomodate the wet caustic plume. An estimated cost has been included based on costing for a similar stack liner installed at another WestRock Facility.

[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 WestRock Fernandina Beach rates.

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

[f] Projected actual SO_2 emissions.

Table A-3
WestRock Fernandina Beach No. 7 Power Boiler
Capital and Annual Costs Associated with Trona Injection

Variable	Designation	Units	Value	Calculation
Unit Size	A	MW	90	1021 MMBtu/hr heat input, assumes 30% efficiency to convert to equivalent MW output
Retrofit Factor	B	-	1	Average retrofit
Gross Heat Rate	C	Btu/kWh	11,383	Assumes 30% efficiency
SO_2 Rate (uncontrolled)	D	lb/MMBtu	0.32	Actual SO_2 emissions divided by actual fuel use.
Type of Coal	E	-	Bituminous	
Particulate Capture	F	-	ESP	
Sorbent	G	-	Unmilled Trona	
Removal Target	H	%	60	Achieved during WestRock trial
Heat Input	J	Btu/hr	1.02E+09	1021 MMBtu/hr
NSR	K	-	2.79	Unmilled Trona w/ ESP
Sorbent Feed Rate	M	ton/hr	2.00	Based on trial usage, achieved 60% removal at this rate
Estimated HCl Removal	V	%	94.74	Unmilled Trona w/ ESP = 60.86*H^0.1081
Sorbent Waste Rate	N	ton/hr	1.56	Trona = (0.7387+0.00185*H/K)*M
Fly Ash Waste Rate for Coal	P_C	ton/hr	0.57	Ash in Coal = 0.12; Boiler Ash Removal = 0.2; HHV = 13,000 BTU/hr from coal*Ash % in coal*(1-Boiler Ash Removal)/(BTU/lb)/(2000 lb/ton)
Fly Ash Waste Rate for Wood Ash	P_W	ton/hr	0.53	Ash in Bark Ash = 0.40; Boiler Ash Removal = 0.2; HHV = 9,100 BTU/hr from bark ash*Ash % in bark ash*(1-Boiler Ash Removal)/(BTU/lb)/(2000 lb/ton)
Total Fly Ash Waste Rate	P	ton/hr	1.10	$P = P_C + P_W$
Aux Power	Q	%	0.40	Unmilled Trona M*18/A
Sorbent Cost	R	$/ton	[redacted]	
Waste Disposal Cost	S	$/ton	[redacted]	
Aux Power Cost	T	$/kWh	[redacted]	
Operating Labor Rate	U	$/hr	[redacted]	

SO_2 Control Efficiency:	60%
Actual Emissions, tpy	1,247
SO_2 Emissions Removed:	748

Capital Costs [(a)]					
Direct Costs					
BM (Base Module)		$	$	2,678,153	Trona system base cost from SEI quote, scaled to increase size and injection rate based on trial with unmilled trona. Converted from 2013 dollars to 2019 dollars using the CEPCI.
Indirect Costs					
Engineering & Construction Management	A1	$	$	267,815	10% BM
Labor adjustment	A2	$	$	133,908	5% BM
Contractor profit and fees	A3	$	$	133,908	5% BM
Capital, engineering and construction cost subtotal	CECC	$	$	3,213,784	BM+A1+A2+A3
Owner costs including all "home office" costs	B1	$	$	160,689	5% CEC
Total project cost w/out AFUDC	TPC	$	$	3,374,473	B1+CEC
AFUDC (0 for <1 year engineering and construction cycle)	B2	$		0.00	0% of (CECC+B1)
Total Capital Investment	**TCI**	**$**	**$**	**3,374,473**	CECC+B1+B2

Annualized Costs [(a)]					
Fixed O&M Cost					
Additional operating labor costs	FOMO	$	$	1.79	(2 additional operator)*2080*U/(A*1000)
Additional maintenance material and labor costs	FOMM	$	$	0.30	BM*0.01/(B*A*1000)
Additional administrative labor costs	FOMA	$	$	0.06	0.03*(FOMO+0.4*FOMM)
Total Fixed O&M Costs	**FOM**	$/MWh	$	2.14	FOMO+FOMM+FOMA
		$/yr	**$**	**1,682,513**	(FOM x A x 8760)
Variable O&M Cost					
Costs for Sorbent	VOMR	$	$	5.02	M*R/A
Costs for waste disposal that includes both sorbent & fly ash waste not removed prior to sorbent injection	VOMW	$	$	0.60	(N+P)*S/A
Additional auxiliary power required	VOMP	$	$	0.24	Q*T*10
Total Variable O&M Cost	**VOM**	$/MWh	$	5.86	VOMR+VOMW+VOMP
		$/yr	**$**	**4,602,214**	(VOM x A x 8760)
Indirect Annual Costs					
General and Administrative	2%	of TCI	$	67,489	
Property Tax	1%	of TCI	$	33,745	
Insurance	1%	of TCI	$	33,745	
Capital Recovery	7.86%	x TCI	$	265,066	
Total Indirect Annual Costs			**$**	**400,045**	
Life of the Control:	20	years		4.75%	interest
Total Annual Costs			**$**	**6,684,773**	
Total Annual Costs/SO_2 Emissions Removed			**$**	**8,938**	

[(a)]Cost information based on the April 2017 "Dry Sorbent Injection for SO_2/HCl Control Cost Development Methodology" study by Sargent & Lundy for an unmilled Trona system, a quote provided to WestRock by SEI, and a trial with unmilled trona.

Table A-4
WestRock Fernandina Beach No. 7 Power Boiler
Capital and Annual Costs Associated with SDA System

Variable	Designation	Units	Value	Calculation
Unit Size	A	MW	90	1021 MMBtu/hr heat input, assumes 30% efficiency to convert to equivalent MW output
Retrofit Factor	B	-	1	Average retrofit
Gross Heat Rate	C	Btu/kWh	11,383	Assumes 30% efficiency
SO_2 Rate (uncontrolled)	D	lb/MMBtu	0.32	Actual SO_2 emissions divided by actual fuel use.
Type of Coal	E	-	Bituminous	
Coal Factor	F	-	1	
Heat Rate Factor	G	-	1.13832	C/10000
Heat Input	H	Btu/hr	1.02E+09	A*C*1000
Operating SO_2 Removal	J	-	95	Default value in Sargent and Lundy document.
Design Lime Rate	K	ton/hr	0.23	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 removal)
Design Waste Rate	L	ton/hr	0.52	(0.8016*(D^2)+31.1971*D)*A*G/2000 (Based on 95% SO_2 removal)
Aux Power	M	%	1.482	(0.000547*D^2+0.00649*D+1.3)*F*G
Makeup Water Rate	N	kgph	5.65	(0.04898*(D^2)+0.5925*D+55.11)*A*F*G/1000
Lime Cost	P	$/ton	189	WestRock Charleston cost
Waste Disposal Cost	Q	$/ton	[redacted]	
Aux Power Cost	R	$/kWh		
Makeup Water Cost	S	$/kgal		
Operating Labor Rate	T	$/hr		

SO_2 Control Efficiency:	95%
Actual Emissions, tpy	1,247
SO_2 Emissions Removed:	1,184

Capital Costs [(a)]					
Direct Costs					
Base module absorber island cost (includes baghouse)	BMR		$	16,794,357	637000*(A^0.716))*B*(F*G)^0.6*(D/4)^0.01
Base module reagent prep/waste handling cost	BMF		$	6,926,637	338000*(A^0.716))*B*(D*G)^0.2
Base module balance of plant costs	BMB		$	23,683,320	899000*(A^0.716))*B*(F*G)^0.4
	BM		$	47,404,314	
Indirect Costs					
Engineering & Construction Management	A1	$	$	4,740,431	10% BM
Labor adjustment	A2	$	$	4,740,431	10% BM
Contractor profit and fees	A3	$	$	4,740,431	10% BM
Capital, engineering and construction cost subtotal	CECC	$	$	61,625,609	BM+A1+A2+A3
Owner costs including all "home office" costs	B1	$	$	3,081,280	5% CEC
Total project cost w/out AFUDC	TPC	$	$	64,706,889	B1+CEC
AFUDC (0 for <1 year engineering and construction cycle)	B2	$	$	9,706,033	15% of (CECC+B1)
Total Project Cost	**TCI**	**$**	**$**	**74,412,922**	

Annualized Costs [(a)]					
Fixed O&M Cost					
Additional operating labor costs	FOMO	$	$	7.14	(8 additional operators)*2080*T/(A*1000)
Additional maintenance material and labor costs	FOMM	$	$	7.93	BM*0.015/(B*A*1000)
Additional administrative labor costs	FOMA	$	$	0.31	0.03*(FOMO+0.4*FOMM)
Total Fixed O&M Costs	**FOM**	$/MWh	$	15.38	FOMO+FOMM+FOMA
		$/yr	**$**	**12,084,041**	(FOM x A x 8760)
Variable O&M Cost					
Costs for lime reagent	VOMR	$	$	0.48	K*P/A*J/95
Costs for waste disposal	VOMW	$	$	0.12	L*Q/A*J/95
Additional auxiliary power required	VOMP	$	$	0.89	M*R*10
Costs for makeup water	WOMM	$	$	0.02	N*S/A
Total Variable O&M Cost	**VOM**	$/MWh	$	1.51	VOMR+VOMW+VOMP
		$/yr	**$**	**1,183,075**	(VOM x A x 8760)
Indirect Annual Costs					
General and Administrative	2%	of TCI	$	1,488,258	
Property Tax	1%	of TCI	$	744,129	
Insurance	1%	of TCI	$	744,129	
Capital Recovery	7.86%	x TCI	$	5,845,170	
Total Indirect Annual Costs			**$**	**8,821,687**	
Life of the Control:		20 years		4.75%	interest
Total Annual Costs			**$**	**22,088,803**	
Total Annual Costs/SO_2 Emissions Removed			**$**	**18,652**	

[(a)]Cost information based on the January 2017 "SDA FGD Cost Development Methodology" study by Sargent & Lundy.

NO. 5 POWER BOILER
CONTROL COST ESTIMATES

Table A-5a

Wet Scrubber Cost - WestRock Fernandina Beach No. 5 Power Boiler

CAPITAL COSTS[a]

		COST ITEM	COST FACTOR	COST ($)
		Direct Costs		
		Purchased Equipment Costs		
(a)	***A***	Equipment Costs		***$7,258,263***
(b)		Instrumentation	0.10 A	$725,826
(b)		Sales Tax	0.03 A	$217,748
(b)		Freight	0.05 A	$362,913
	B	***Total Purchased Equipment Cost***		***$8,564,750***
		Direct Installation Costs		
(b)		Foundations and Supports	0.12 B	$1,027,770
(b)		Handling and erection	0.40 B	$3,425,900
(b)		Electrical	0.01 B	$85,648
(b)		Piping	0.30 B	$2,569,425
(b)		Insulation for ductwork	0.01 B	$85,648
(b)		Painting	0.01 B	$85,648
		Direct Installation Cost		***$7,280,038***
		Total Direct Costs		***$15,844,788***
		Indirect Costs		
(b)		Engineering	0.10 B	$856,475
(b)		Construction Management	0.10 B	$856,475
(b)		Contractor fees	0.10 B	$856,475
(b)		Start-up	0.01 B	$85,648
(b)		Performance test	0.01 B	$85,648
(b)		Contingencies	0.03 B	$256,943
		Total Indirect Costs		***$2,997,663***
		Total Capital Investment (TCI)		***$18,842,451***

ANNUALIZED COSTS

	COST ITEM	COST FACTOR	RATE	COST ($)
	Direct Annual Costs			
	Operating Labor			
(b)	Operator[c]	[redacted]	[redacted] [d]	$21,079
(b)	Supervisor	15% of operator labor		$3,162
	Maintenance			
(b)	Maintenance labor[c]	[redacted]	[redacted] [d]	$20,230
(b)	Maintenance materials	100% of maintenance labor		$20,230
	Utilities			
	Electricity	[redacted]	[redacted] [d]	$1,334,360
	Chemicals	[redacted]	[redacted] [d]	$1,711,954
	Fresh water usage	[redacted]	[redacted] [d]	$45,990
	Wastewater disposal	[redacted]	[redacted] [d]	$4,599
	Total Direct Annual Costs			***$3,161,604***
	Indirect Annual Costs			
(b)	Overhead	60% Labor and Material Costs		$38,820
(b)	General and administrative	2% of TCI		$376,849
(b)	Property taxes	1% of TCI		$188,425
(b)	Insurance	1% of TCI		$188,425
(b)	Capital recovery	0.095 x TCI		$1,784,778
	Life of the control:	15 years at	4.75% interest	
	Total Indirect Annual Costs			***$2,577,297***
	Total Annual Costs			***$5,738,901***
	Cost Effectiveness ($/ton)			
	SO_2 Control Efficiency[e]:	98%		
	SO_2 Emissions[f]:	17.0 tpy	Total Annual Costs/Controlled SO_2 Emissions:	
	Controlled SO_2 Emissions:	16.7 tons of SO_2 removed annually		***$344,472***

[a] Wet scrubber capital cost based on Section 7.3 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 coal/wood boiler was scaled based on maximum continuous rating steam flow. 2001 dollars were scaled to 2019 dollars based on the 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 WestRock Fernandina Beach rates.

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

[f] Projected actual SO_2 emissions.

Table A-5b

Wet Scrubber Cost with Stack - WestRock Fernandina Beach No. 5 Power Boiler

CAPITAL COSTS[a]

		COST ITEM	COST FACTOR	COST ($)
Direct Costs				
	Purchased Equipment Costs			
(a)	***A***	Equipment Costs		***$8,258,263***
(b)		Instrumentation	0.10 A	$825,826
(b)		Sales Tax	0.03 A	$247,748
(b)		Freight	0.05 A	$412,913
	B	***Total Purchased Equipment Cost***		***$9,744,750***
	Direct Installation Costs			
(b)		Foundations and Supports	0.12 B	$1,169,370
(b)		Handling and erection	0.40 B	$3,897,900
(b)		Electrical	0.01 B	$97,448
(b)		Piping	0.30 B	$2,923,425
(b)		Insulation for ductwork	0.01 B	$97,448
(b)		Painting	0.01 B	$97,448
		Direct Installation Cost		***$8,283,038***
	Total Direct Costs			***$18,027,788***
Indirect Costs				
(b)		Engineering	0.10 B	$974,475
(b)		Construction Management	0.10 B	$974,475
(b)		Contractor fees	0.10 B	$974,475
(b)		Start-up	0.01 B	$97,448
(b)		Performance test	0.01 B	$97,448
(b)		Contingencies	0.03 B	$292,343
	Total Indirect Costs			***$3,410,663***
Total Capital Investment (TCI)				***$21,438,451***

ANNUALIZED COSTS

	COST ITEM	COST FACTOR	RATE	COST ($)
Direct Annual Costs				
	Operating Labor			
(b)	Operator[c]	[redacted]	[redacted] (d)	$21,079
(b)	Supervisor	15% of operator labor		$3,162
	Maintenance			
(b)	Maintenance labor[c]	[redacted]	[redacted] (d)	$20,230
(b)	Maintenance materials	100% of maintenance labor		$20,230
	Utilities			
	Electricity	[redacted]	[redacted] (d)	$1,334,360
	Chemicals	[redacted]	[redacted] (d)	$1,711,954
	Fresh water usage	[redacted]	[redacted] (d)	$45,990
	Wastewater disposal	[redacted]	[redacted] (d)	$4,599
	Total Direct Annual Costs			***$3,161,604***
Indirect Annual Costs				
(b)	Overhead	60% Labor and Material Costs		$38,820
(b)	General and administrative	2% of TCI		$428,769
(b)	Property taxes	1% of TCI		$214,385
(b)	Insurance	1% of TCI		$214,385
(b)	Capital recovery	0.095 x TCI		$2,030,674
	Life of the control:	15 years at	4.75% interest	
	Total Indirect Annual Costs			***$2,927,033***
Total Annual Costs				***$6,088,637***
Cost Effectiveness ($/ton)				
	SO_2 Control Efficiency[e]:	98%		
	SO_2 Emissions[f]:	17.0 tpy	Total Annual Costs/Controlled SO_2 Emissions:	
	Controlled SO_2 Emissions:	16.7 tons of SO_2 removed annually		***$365,464***

[a] Wet scrubber capital cost based on Section 7.3 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 coal/wood boiler was scaled based on maximum continuous rating steam flow. 2001 dollars were scaled to 2019 dollars based on the CEPCI. The addition of a wet scrubber may require an upgrade to the existing stack to accomodate the wet caustic plume. An estimated cost has been included based on costing for a similar stack liner installed at another WestRock Facility.

[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 WestRock Fernandina Beach rates.

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

[f] Projected actual SO_2 emissions.

Table A-6a
WestRock Fernandina Beach No. 5 Power Boiler
Capital and Annual Costs Associated with Trona Injection

Variable	Designation	Units	Value	Calculation
Unit Size	A	MW	71	805 MMBtu/hr heat input, assumes 30% efficiency to convert to equivalent MW output
Retrofit Factor	B	-	1.2	space constaints for additonal equipment
Gross Heat Rate	C	Btu/kWh	11,383	Assumes 30% efficiency
SO_2 Rate (uncontrolled)	D	lb/MMBtu	0.01	Actual SO_2 emissions divided by actual fuel use.
Type of Coal	E	-	NA	
Particulate Capture	F	-	ESP	
Sorbent	G	-	Unmilled Trona	
Removal Target	H	%	60	Achieved during WestRock trial.
Heat Input	J	Btu/hr	8.05E+08	805 MMBtu/hr
NSR	K	-	2.79	Unmilled Trona w/ ESP
Sorbent Feed Rate	M	ton/hr	0.27	1.2011x10^-06*K*A*C*D
Estimated HCl Removal	V	%	94.74	Unmilled Trona w/ ESP = 60.86*H^0.1081
Sorbent Waste Rate	N	ton/hr	0.21	Trona = (0.7387+0.00185*H/K)*M
Fly Ash Waste Rate	P	ton/hr	2.72	Ash in Bark = 0.038; Boiler Ash Removal = 0.2; HHV = 4500 (A*C)*Ash*(1-Boiler Ash Removal)/(2*HHV)
Aux Power	Q	%	0.07	Unmilled Trona M*20/A
Sorbent Cost	R	$/ton	[redacted]	
Waste Disposal Cost	S	$/ton	[redacted]	
Aux Power Cost	T	$/kWh	[redacted]	
Operating Labor Rate	U	$/hr	[redacted]	

SO_2 Control Efficiency:	60%
Actual Emissions, tpy	17.0
SO_2 Emissions Removed:	10.2

Capital Costs [(a)]				
Direct Costs				
BM (Base Module)[(b)]		$	$ 1,766,922	Trona system base cost. Converted from 2013 dollars to 2019 dollars using the CEPCI.
Indirect Costs				
Engineering & Construction Management	A1	$	$ 176,692	10% BM
Labor adjustment	A2	$	$ 88,346	5% BM
Contractor profit and fees	A3	$	$ 88,346	5% BM
Capital, engineering and construction cost subtotal	CECC	$	$ 2,120,307	BM+A1+A2+A3
Owner costs including all "home office" costs	B1	$	$ 106,015	5% CEC
Total project cost w/out AFUDC	TPC	$	$ 2,226,322	B1+CEC
AFUDC (0 for <1 year engineering and construction cycle)	B2	$	0	0% of (CECC+B1)
Total Capital Investment	**TCI**	**$**	**$ 2,226,322**	CECC+B1+B2

Annualized Costs [(a)]					
Fixed O&M Cost					
Additional operating labor costs	FOMO	$	$	2.26	(2 additional operator)*2080*U/(A*1000)
Additional maintenance material and labor costs	FOMM	$	$	0.21	BM*0.01/(B*A*1000)
Additional administrative labor costs	FOMA	$	$	0.07	0.03*(FOMO+0.4*FOMM)
Total Fixed O&M Costs	**FOM**	$/kW yr	$	2.54	FOMO+FOMM+FOMA
		$/yr	**$**	**1,575,625**	(FOM x A x 8760)
Variable O&M Cost					
Costs for Sorbent	VOMR	$	$	0.84	M*R/A
Costs for waste disposal that includes both sorbent & fly ash waste not removed prior to sorbent injection	VOMW	$	$	0.84	(N+P)*S/A
Additional auxiliary power required	VOMP	$	$	0.04	Q*T*10
Total Variable O&M Cost	**VOM**	$/MWh	$	1.72	VOMR+VOMW+VOMP
		$/yr	**$**	**1,066,652**	(VOM x A x 8760)
Indirect Annual Costs					
General and Administrative	2%	of TCI	$	44,526	
Property Tax	1%	of TCI	$	22,263	
Insurance	1%	of TCI	$	22,263	
Capital Recovery	7.86%	x TCI	$	174,879	
Total Indirect Annual Costs			**$**	**263,932**	
Life of the Control:	20	years		4.75%	interest
Total Annual Costs			**$**	**2,906,208**	
Total Annual Costs/SO_2 Emissions Removed			**$**	**284,922**	

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

[(b)]3-8-08 quote from SEI for trona system.

NO. 4 RECOVERY BOILER
CONTROL COST ESTIMATES

Table A-7a
Wet Scrubber Cost - WestRock Fernandina Beach No. 4 Recovery Boiler

CAPITAL COSTS[a]

		COST ITEM	COST FACTOR	COST ($)
		Direct Costs		
		Purchased Equipment Costs		
(a)	***A***	Equipment Costs		***$10,406,616***
(b)		Instrumentation	0.10 A	$1,040,662
(b)		Sales Tax	0.03 A	$312,198
(b)		Freight	0.05 A	$520,331
	B	***Total Purchased Equipment Cost***		***$12,279,807***
		Direct Installation Costs		
(b)		Foundations and Supports	0.12 B	$1,473,577
(b)		Handling and erection	0.40 B	$4,911,923
(b)		Electrical	0.01 B	$122,798
(b)		Piping	0.30 B	$3,683,942
(b)		Insulation for ductwork	0.01 B	$122,798
(b)		Painting	0.01 B	$122,798
		Direct Installation Cost		***$10,437,836***
		Total Direct Costs		***$22,717,643***
		Indirect Costs		
(b)		Engineering	0.10 B	$1,227,981
(b)		Construction Management	0.10 B	$1,227,981
(b)		Contractor fees	0.10 B	$1,227,981
(b)		Start-up	0.01 B	$122,798
(b)		Performance test	0.01 B	$122,798
(b)		Contingencies	0.03 B	$368,394
		Total Indirect Costs		***$4,297,932***
		Total Capital Investment (TCI)		***$27,015,575***

ANNUALIZED COSTS

	COST ITEM	COST FACTOR	RATE	COST ($)
	Direct Annual Costs			
	Operating Labor			
(b)	Operator[c]	[redacted]	[redacted] [d]	$21,079
(b)	Supervisor	15% of operator labor		$3,162
	Maintenance			
(b)	Maintenance labor[c]	[redacted]	[redacted] [d]	$20,230
(b)	Maintenance materials	100% of maintenance labor		$20,230
	Utilities			
	Electricity	[redacted]	[redacted]	$695,070
	Chemicals	[redacted]	[redacted] [d]	$1,093,106
	Fresh water usage	[redacted]	[redacted] [d]	$23,179
	Wastewater disposal	[redacted]	[redacted] [d]	$2,349
	Total Direct Annual Costs			***$1,878,405***
	Indirect Annual Costs			
(b)	Overhead	60% Labor and Material Costs		$38,820
(b)	General and administrative	2% of TCI		$540,312
(b)	Property taxes	1% of TCI		$270,156
(b)	Insurance	1% of TCI		$270,156
(b)	Capital recovery	0.095 x TCI		$2,558,946
	Life of the control:	15 years at	4.75% interest	
	Total Indirect Annual Costs			***$3,678,389***
	Total Annual Costs			***$5,556,795***
	Cost Effectiveness ($/ton)			
	SO_2 Control Efficiency[e]:	98%		
	SO_2 Emissions[f]:	15 tpy	Total Annual Costs/Controlled SO_2 Emissions:	
	Controlled SO_2 Emissions:	14.7 tons of SO_2 removed annually		***$378,013***

[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 Boiler was scaled based on furnace BLS throughput capacity. 2001 dollars were scaled to 2019 dollars based on the 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 WestRock Charleston rates.

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

[f] Projected actual SO_2 emissions.

NO. 5 RECOVERY BOILER
CONTROL COST ESTIMATES

Table A-8a
Wet Scrubber Cost - WestRock Fernandina Beach No. 5 Recovery Boiler

CAPITAL COSTS[a]

		COST ITEM	COST FACTOR	COST ($)
		Direct Costs		
		Purchased Equipment Costs		
(a)	***A***	Equipment Costs		***$10,406,616***
(b)		Instrumentation	0.10 A	$1,040,662
(b)		Sales Tax	0.03 A	$312,198
(b)		Freight	0.05 A	$520,331
	B	***Total Purchased Equipment Cost***		***$12,279,807***
		Direct Installation Costs		
(b)		Foundations and Supports	0.12 B	$1,473,577
(b)		Handling and erection	0.40 B	$4,911,923
(b)		Electrical	0.01 B	$122,798
(b)		Piping	0.30 B	$3,683,942
(b)		Insulation for ductwork	0.01 B	$122,798
(b)		Painting	0.01 B	$122,798
		Direct Installation Cost		***$10,437,836***
		Total Direct Costs		***$22,717,643***
		Indirect Costs		
(b)		Engineering	0.10 B	$1,227,981
(b)		Construction Management	0.10 B	$1,227,981
(b)		Contractor fees	0.10 B	$1,227,981
(b)		Start-up	0.01 B	$122,798
(b)		Performance test	0.01 B	$122,798
(b)		Contingencies	0.03 B	$368,394
		Total Indirect Costs		***$4,297,932***
		Total Capital Investment (TCI)		***$27,015,575***

ANNUALIZED COSTS

	COST ITEM	COST FACTOR	RATE	COST ($)
	Direct Annual Costs			
	Operating Labor			
(b)	Operator[c]	[redacted]	[redacted] [redacted] [redacted] [d]	$21,079
(b)	Supervisor	15% of operator labor		$3,162
	Maintenance			
(b)	Maintenance labor[c]	[redacted]	[redacted] [redacted] [redacted] [d]	$20,230
(b)	Maintenance materials	100% of maintenance labor		$20,230
	Utilities			
	Electricity	[redacted]	[redacted] [redacted] [d]	$695,070
	Chemicals	[redacted]	[redacted] [redacted] [redacted] [d]	$1,093,106
	Fresh water usage	[redacted]	[redacted] [redacted] [redacted] [d]	$23,179
	Wastewater disposal	[redacted]	[redacted] [redacted] [redacted] [d]	$2,349
	Total Direct Annual Costs			***$1,878,405***
	Indirect Annual Costs			
(b)	Overhead	60% Labor and Material Costs		$38,820
(b)	General and administrative	2% of TCI		$540,312
(b)	Property taxes	1% of TCI		$270,156
(b)	Insurance	1% of TCI		$270,156
(b)	Capital recovery	0.095 x TCI		$2,558,946
	Life of the control:	15 years at	4.75% interest	
	Total Indirect Annual Costs			***$3,678,389***
	Total Annual Costs			***$5,556,795***
	Cost Effectiveness ($/ton)			
	SO_2 Control Efficiency[e]:	98%		
	SO_2 Emissions[f]:	25 tpy	Total Annual Costs/Controlled SO_2 Emissions:	
	Controlled SO_2 Emissions:	24.5 tons of SO_2 removed annually		***$226,808***

[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 Boiler was scaled based on furnace BLS throughput capacity. 2001 dollars were scaled to 2019 dollars based on the 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 WestRock Charleston rates.

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

[f] Projected actual SO_2 emissions.

APPENDIX B - SUPPORTING INFORMATION

IPM Model – Updates to Cost and Performance for APC Technologies

Dry Sorbent Injection for SO_2/HCl Control Cost Development Methodology

Final

April 2017

Project 13527-001

Eastern Research Group, Inc.

Prepared by

Sargent & Lundy LLC

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DSI Cost Methodology

Purpose of Cost Algorithms for the IPM Model

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

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

Technology Description

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

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

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

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

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

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

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

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

DSI Cost Methodology

Establishment of the Cost Basis

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

Methodology

Inputs

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

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

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

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

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

DSI Cost Methodology

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

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

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

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

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

Outputs

Total Project Costs (TPC)

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

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

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

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

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

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

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

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

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

Fixed O&M (FOM)

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

The following factors and assumptions underlie calculations of the FOM:

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

DSI Cost Methodology

Variable O&M (VOM)

Variable O&M is a function of the following:

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

The following factors and assumptions underlie calculations of the VOM:

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

DSI Cost Methodology

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

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

The variables that contribute to the overall VOM are:

VOMR = Variable O&M costs for reagent

VOMW = Variable O&M costs for waste disposal

VOMP = Variable O&M costs for additional auxiliary power

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

DSI Cost Methodology

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

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

Costs are all based on 2016 dollars

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

DSI Cost Methodology

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

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

Costs are all based on 2016 dollars

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

DSI Cost Methodology

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

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

Costs are all based on 2016 dollars

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

DSI Cost Methodology

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

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

Costs are all based on 2016 dollars

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

DSI Cost Methodology

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

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

Costs are all based on 2016 dollars

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

DSI Cost Methodology

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

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

Costs are all based on 2016 dollars

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

IPM Model – Updates to Cost and Performance for APC Technologies

SDA FGD Cost Development Methodology

Final

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Project 13527-001

Eastern Research Group, Inc.

Prepared by

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SDA FGD Cost Development 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 impact costs, such as flue gas volume or 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 a facility would incur to install a retrofit control such as project contingency.

Establishment of the Cost Basis

Cost data for the SDA FGD systems based on actual installations were more limited than those for the wet FGD systems until 2012. However, since 2012 the market trend has shifted toward the installation of dry FGD/CDS technology. Even with the new data, a similar trend of capital cost with generating capacity (MW size) is generally seen between the wet and SDA system. The same least-square curve fit power relationship for capital costs as a function of generating capacity, up to 600 MW, was used for the wet and SDA cost estimation with the constant multiplier adjusted to ensure that the curve represented the data available.

The curve fit was set to represent proprietary in-house cost data of a "typical" SDA FGD retrofit for removal of 95% of the inlet sulfur. It should be noted that the lowest available SO_2 emission guarantees, from the original equipment manufactures of SDA FGD systems, are 0.06 lb/MMBtu. The typical SDA FGD retrofit was based on:

- Retrofit Difficulty = 1 (Average retrofit difficulty);
- Gross Heat Rate = 9800 Btu/kWh;
- SO_2 Rate = 2.0 lb/MMBtu;
- Type of Coal = PRB;

SDA FGD Cost Development Methodology

- Project Execution = Multiple lump-sum contracts; and
- Recommended SO_2 emission floor = 0.08 lb/MMBtu.

A dry FGD system designed to treat 100% of the flue gas is capable of meeting Mercury Air Toxics Standards (MATS) limits for HCl of 0.002 lb/MBtu. Dry FGDs can remove up to 99% HCl in the flue gas.

Based on the recently acquired data and recently completed projects, it appears the overall capital cost has increased by only 6% over the costs published in 2013. Analysis of the data indicates that the lack of a large number of FGD projects has resulted in competitive pressure to absorb any significant increase in the cost.

Units below 50 MW will typically not install an SDA FGD system. Sulfur reductions for small units would be accomplished by treating smaller units at a single site with one SDA FGD system, switching to a lower sulfur coal, repowering or converting to natural gas firing, using dry sorbent injection, and/or reducing operating hours. Capital costs of approximately $1,000/kW may be used for units below 50 MW under the premise that these units will be combined.

Based on the typical SDA FGD performance, the technology should not be applied to fuels with more than 3 lb SO_2/MMBtu, and the cost estimator should be limited to fuels with less than 3 lb SO_2/MMBtu. Typically, both SDA and circulating dry scrubber (CDS) technologies have been applied to low sulfur fuel (lower than 2 lb/MMBtu).

The alternate dry technology, CDS, can meet removals of 98% or greater over a large range of inlet sulfur concentrations. It should be noted that the lowest SO_2 emission guarantees for a CDS FGD system are 0.04 lb/MMBtu. Recent industry experience has shown that a CDS FGD system has a similar installed cost to a comparable SDA FGD system and has been the technology of choice in last four years.

SDA FGD Cost Development Methodology

Methodology

Inputs

Several input variables are required in order to predict future retrofit costs. The gross unit size in MW (equivalent acfm) and sulfur content of the fuel are the major variables for the capital estimation. A retrofit factor that equates to the difficulty of constructing the system must be defined. The costs herein could increase significantly for congested sites. The unit gross heat rate will factor into the amount of flue gas generated and ultimately the size of the absorber, reagent preparation, waste handling, and balance of plant costs. The SO_2 rate will have the greatest influence on the reagent handling and waste handling facilities. The type of fuel (Bituminous, PRB, or Lignite) will influence the flue gas quantities as a result of the different typical heating values.

The cost methodology is based on a unit located within 500 feet of sea level. The actual elevation of the site should be considered separately and factored into the cost due to the effects on the flue gas volume. The base absorber island and balance of plant costs are directly impacted by the site elevation. These two base cost modules should be increased based on the ratio of the atmospheric pressure at sea level and that at the unit location. As an example, a unit located 1 mile above sea level would have an approximate atmospheric pressure of 12.2 psia. Therefore, the base absorber island and balance of plant costs should be increased by:

14.7 psia/12.2 psia = 1.2 multiplier to the base absorber island and balance of plant costs

Outputs

Total Project Costs (TPC)

First, the installed costs are calculated for each required base module. The base module installed costs include:

- All equipment;
- Installation;
- Buildings;
- Foundations;
- Electrical; and
- Retrofit difficulty.

SDA FGD Cost Development Methodology

The base modules are:

BMR =	Base absorber island cost that includes an absorber and a baghouse
BMF =	Base reagent preparation and waste recycle/handling cost
BMB =	Base balance of plant costs including: ID or booster fans, piping, ductwork and reinforcement, electrical, etc…
BM =	BMR + BMF + BMB

The total base module installed cost (BM) is then increased by:

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

- Owner's home office costs (owner's engineering, management, and procurement) at 5% of the CECC; and
- Allowance for Funds Used During Construction (AFUDC) at 10% of the CECC and owner's costs. The AFUDC is based on a three-year engineering and construction cycle.

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

SDA FGD Cost Development Methodology

labor (FOMA) associated with the SDA FGD 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, 8 additional operators are required for an SDA FGD system. The FOMO was based on the number of additional operations staff required.
- The fixed maintenance materials and labor are a direct function of the process capital cost at 1.5% of the BM. Cost of bags and cages are included in the fixed O&M cost with the assumption that bag replacement is carried out once every 3 years and cage replacement is carried out once every 9 years.
- The administrative labor is a function of the FOMO and FOMM at 3% of the sum of (FOMO + 0.4 FOMM).

Variable O&M (VOM)

Variable O&M is a function of:

- Reagent use and unit costs;
- Waste production and unit disposal costs;
- Additional power required and unit power cost; and
- Makeup water required and unit water cost.

The following factors and assumptions underlie calculations of the VOM:

- All of the VOM costs were tabulated on a per megawatt-hour (MWh) basis.
- The reagent usage is a function of gross unit size, SO_2 feed rate, and removal efficiency. While the capital costs are based on a 95% sulfur removal design, the operating sulfur removal percentage can be adjusted to reflect actual variable operating costs.
- In addition to sulfur removal efficiency, the estimated reagent usage was based on a flue gas temperature into the SDA FGD of 300°F and an adiabatic approach to saturation of 30°F.
- The calcium-to-sulfur stoichiometric ratio varies based on inlet sulfur. The variation in stoichiometric ratio was accounted for in the estimation. The economic estimation is only valid up to 3 lb SO_2/MMBtu inlet.
- The basis for the lime purity was 90% CaO with the balance being inert material.
- The waste generation rate is a function of inlet sulfur and calcium to sulfur stoichiometry. Both variables are accounted for in the waste generation

SDA FGD Cost Development Methodology

estimation. The waste disposal rate is based on 10% moisture in the by-product.

- The additional power required includes increased fan power to account for the added SDA FGD pressure drop. This requirement is a function of gross unit size (actual gas flow rate) and sulfur rate.
- 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 makeup water rate is a function of gross unit size (actual gas flow rate) and sulfur feed rate.

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:

- Lime cost in $/ton. No escalation is observed in pebble lime cost. However, the cost could significantly vary with the location.
- Waste disposal costs in $/ton. The site-specific cost could be significantly different.
- Auxiliary power cost in $/kWh. No noticeable escalation has been observed for auxiliary power cost since 2013.
- Makeup water costs in $/1000 gallon.
- Operating labor rate (including all benefits) in $/hr.

The variables that contribute to the overall VOM are:

VOMR = Variable O&M costs for lime reagent

VOMW = Variable O&M costs for waste disposal

VOMP = Variable O&M costs for additional auxiliary power

VOMM = Variable O&M costs for makeup water

The total VOM is the sum of VOMR, VOMW, VOMP, and VOMM. Table 1 shows a complete capital and O&M cost estimate worksheet for an SDA FGD.

SDA FGD Cost Development Methodology

Table 1. Example of a Complete Cost Estimate for an SDA FGD

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	500	<--- User Input (Greater than 50 MW)
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9800	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input (SDA FGD Estimation only valid up to 3 lb/MMBtu SO2 Rate)
Type of Coal	E		PRB 1	<--- User Input
Coal Factor	F		1.05	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.98	C/10000
Heat Input	H	(Btu/hr)	4.90E+09	A*C*1000
Operating SO_2 Removal	J	(%)	95	<--- User Input (Used to adjust actual operating costs)
Design Lime Rate	K	(ton/hr)	7	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 removal)
Design Waste Rate	L	(ton/hr)	16	(0.8016*(D^2)+31.1917*D)*A*G/2000 (Based on 95% SO2 removal)
Aux Power **Include in VOM?** ☑	**M**	**(%)**	**1.35**	(0.000547*D^2+0.00649*D+1.3)*F*G
Makeup Water Rate	N	(1000 gph)	29	(0.04898*(D^2)+0.5925*D+55.11)*A*F*G/1000
Lime Cost	P	($/ton)	125	<--- User Input
Waste Disposal Cost	Q	($/ton)	30	<--- User Input
Aux Power Cost	R	($/kWh)	0.06	<--- User Input
Makeup Water Cost	S	($/kgal)	1	<--- User Input
Operating Labor Rate	T	($/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			
BMR ($) =	if (A>600 then (A*98000) else 637000*(A^0.716))*B*(F*G)^0.6*(D/4)^0.01	$ 55,086,000	Base module absorber island cost
BMF ($) =	if (A>600 then (A*52000) else 338000*(A^0.716))*B*(D*G)^0.2	$ 33,100,000	Base module reagent preparation and waste recycle/handling cost
BMB ($) =	if (A>600 then (A*138000) else 899000*(A^0.716))*B*(F*G)^0.4	$ 77,837,000	Base module balance of plant costs including: ID or booster fans, piping, ductwork modifications and strengthening, electrical, etc…
BM ($) =	BMR + BMF + BMW + BMB	$ 166,023,000	Total Base module cost including retrofit factor
BM ($/KW) =		332	Base module cost per kW

Total Project Cost	**Example**	**Comments**
A1 = 10% of BM	$ 16,602,000	Engineering and Construction Management costs
A2 = 10% of BM	$ 16,602,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 10% of BM	$ 16,602,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3	**$ 215,829,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) - Excludes Owner's Costs =	**432**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC	$ 10,791,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1	**$ 226,620,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =	**453**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)	$ 22,662,000	AFUDC (Based on a 3 year engineering and construction cycle)
C1 = 15% of (CECC + B1)	$ -	EPC fees of 15%
TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2	**$ 249,282,000**	Total project cost
TPC ($/kW) - Includes Owner's Costs and AFUDC =	**499**	Total project cost per kW

SDA FGD Cost Development Methodology

Table 1 Continued

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	500	<--- User Input (Greater than 50 MW)
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9800	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input (SDA FGD Estimation only valid up to 3 lb/MMBtu SO2 Rate)
Type of Coal	E		PRB 1	<--- User Input
Coal Factor	F		1.05	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.98	C/10000
Heat Input	H	(Btu/hr)	4.90E+09	A*C*1000
Operating SO_2 Removal	J	(%)	95	<--- User Input (Used to adjust actual operating costs)
Design Lime Rate	K	(ton/hr)	7	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 removal)
Design Waste Rate	L	(ton/hr)	16	(0.8016*(D^2)+31.1917*D)*A*G/2000 (Based on 95% SO2 removal)
Aux Power **Include in VOM?** ☑	**M**	**(%)**	**1.35**	(0.000547*D^2+0.00649*D+1.3)*F*G
Makeup Water Rate	N	(1000 gph)	29	(0.04898*(D^2)+0.5925*D+55.11)*A*F*G/1000
Lime Cost	P	($/ton)	125	<--- User Input
Waste Disposal Cost	Q	($/ton)	30	<--- User Input
Aux Power Cost	R	($/kWh)	0.06	<--- User Input
Makeup Water Cost	S	($/kgal)	1	<--- User Input
Operating Labor Rate	T	($/hr)	60	<--- User Input (Labor cost including all benefits)

Costs are all based on 2016 dollars

Fixed O&M Cost

FOMO ($/kW yr) = (8 additional operators)*2080*T/(A*1000)	$	2.00	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.015/(B*A*1000)	$	4.98	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.12	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**$**	**7.10**	Total Fixed O&M costs

Variable O&M Cost

VOMR ($/MWh) = K*P/A*J/95	$	1.81	Variable O&M costs for lime reagent
VOMW ($/MWh) = L*Q/A*J/95	$	0.96	Variable O&M costs for waste disposal
VOMP ($/MWh) =M*R*10	$	0.81	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM ($/MWh) = N*S/A	$	0.06	Variable O&M costs for makeup water
VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM	**$**	**3.64**	

AF&PA®

Emission Control Study – Technology Cost Estimates

American Forest & Paper Association
Washington, D.C.

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

Table of Contents

1. Results

See “AF&PA Emission Control Summary Sheet” Excel Spreadsheet

2. Capital Cost Estimate Basis

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

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

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

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

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

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

The capital cost estimate does not include the following:

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

3. Operating Cost Estimate Basis

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

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

4. NO_x Control Good Technology Limit

4.1. NDCE Kraft Recovery Furnace

4.1.1. Description

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

4.1.2. Major Equipment

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

4.1.3. Basis for Estimate

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

4.1.4. Capital Cost Estimate Assumptions

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

4.1.5. Operating Cost Estimate Assumptions

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

4.2. Lime Kiln – Route SOGs to new Thermal Oxidizer

4.2.1. Description

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

4.2.2. Major Equipment

- ✓ Thermal oxidizer
- ✓ Caustic scrubber

4.2.3. Basis for Estimate

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

4.2.4. Capital Cost Estimate Assumptions

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

4.2.5. Operating Cost Estimate Assumptions

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

4.3. Coal or Coal / Wood Boiler

4.3.1. Description

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

4.3.2. Major Equipment

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

4.3.3. Basis for Estimate

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

4.3.4. Capital Cost Estimate Assumptions

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

4.3.5. Operating Cost Estimate Assumptions

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

4.4. Gas Boiler

4.4.1. Description

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

4.4.2. Major Equipment

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

4.4.3. Basis for Estimate

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

4.4.4. Capital Cost Estimate Assumption

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

4.4.5. Operating Cost Estimate Assumptions

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

4.5. Gas Turbine – Water Injection

4.5.1. Description

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

4.5.2. Major Equipment

- ✓ High pressure water pump
- ✓ Water injection system

4.5.3. Basis for Estimate

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

4.5.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power.

4.5.5. Operating Cost Estimate Assumptions

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

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

4.6. Gas Turbine – Steam Injection

4.6.1. Description

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

4.6.2. Major Equipment

- ✓ High pressure water pump
- ✓ Water injection system

4.6.3. Basis for Estimate

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

4.6.4. Capital Cost Estimate Assumptions

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

4.6.5. Operating Cost Estimate Assumptions

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

4.7. Oil Boiler

4.7.1. Description

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

4.7.2. Major Equipment

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

4.7.3. Basis for Estimate

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

4.7.4. Capital Cost Estimate Assumption

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

4.7.5. Operating Cost Estimate Assumptions

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

4.8. Wood Boiler

4.8.1. Description

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

4.8.2. Major Equipment

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

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

4.8.3. Basis for Estimate

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

4.8.4. Capital Cost Estimate Assumptions

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

4.8.5. Operating Cost Estimate Assumptions

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

5. NO_x Control Best Technology Limit

5.1. Technical Feasibility of SNCR and SCR Technologies

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

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

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

5.2. NDCE Kraft Recovery - SNCR Technology

5.2.1. Description

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

5.2.2. Major Equipment

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

5.2.3. Basis for Estimate

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

5.2.4. Capital Cost Estimate Assumptions

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

5.2.5. Operating Cost Estimate Assumptions

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

5.3. NDCE Kraft Recovery – SCR Technology

5.3.1. Description

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

5.3.2. Major Equipment

- ✓ SCR reactor
- ✓ Duct burner
- ✓ CEM

5.3.3. Basis for Estimate

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

5.3.4. Capital Cost Estimate Assumptions

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

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

5.3.5. Operating Cost Estimate Assumptions

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

5.4. DCE Kraft Recovery – SNCR Technology

5.4.1. Description

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

5.4.2. Major Equipment

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

5.4.3. Basis for Estimate

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

5.4.4. Capital Cost Estimate Assumptions

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

5.4.5. Operating Cost Estimate Assumptions

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

5.5. DCE Kraft Recovery – SCR Technology

5.5.1. Description

Installation of a SCR NO_x control system in a DCE recovery furnace burning 1.7 x 10^6 (Mm) lb BLS per day. The target is 40 ppm @ 8% oxygen or 50% reduction) for a 30-day average.

5.5.2. Major Equipment

- ✓ SCR reactor
- ✓ Duct burner
- ✓ CEM

5.5.3. Basis for Estimate

Northern Kraft mill with a coal fired 120,000-lb/hr boiler. The project was estimated in 1999. The inlet NO_x is estimated to be 67 ppm and the outlet NO_x is estimated to be 13 ppm.

5.5.4. Capital Cost Estimate Assumptions

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

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

5.5.5. Operating Cost Estimate Assumptions

- ✓ Materials – catalyst: 697 ft^3 per yr.
- ✓ Chemicals – urea: 245 tons per year
- ✓ Maintenance: 2% of TIC
- ✓ Power: 355 kw
- ✓ Power usage factor: 70%
- ✓ Workhours: 28.6 hr per day
- ✓ Testing: $5,000 per year
- ✓ Water: 4 gpm
- ✓ Steam: 1,190 lb/hr
- ✓ Compressed air: 26 cfm

5.6. Lime Kiln – Low-NO_x burners, & SCR

5.6.1. Description

Install Low NO_x burners and SCR systems in lime kiln, which produces 240 tpd CaO. SCR can be applied at the limekiln provided the flue gas temperature is controlled and the dust is removed prior to application.

5.6.2. Major Equipment

- ✓ SCR reactor
- ✓ Low NO_x burners
- ✓ Upgrade to forced draft fan
- ✓ ID fan

5.6.3. Basis for Estimate

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

5.6.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the “0.6 power.”
- ✓ Costs were escalated to 2001 dollars
- ✓ R&D cost: 1.5% of total direct costs (i.e., labor, materials, subcontract, and equipment)

5.6.5. Operating Cost Estimate Assumptions

- ✓ Materials – catalyst: 323 ft^3 per yr.
- ✓ Chemicals – urea: 113.5 tons per year
- ✓ Maintenance: 2% of TIC
- ✓ Power: 165 kw
- ✓ Power usage factor: 70%
- ✓ Workhours: 28.6 hr per day
- ✓ Testing: $5,000 per year
- ✓ Water: 1.97 gpm
- ✓ Steam: 552 lb/hr
- ✓ Compressed air: 12 cfm

5.7. Coal or Coal / Wood Boiler – SCR

5.7.1. Description

Installation of a SCR system on a coal or coal/wood boiler producing 300,000 lb/hr of steam. The maximum NO_x emission rate is 0.17 lb/Mm Btu for a 30-day average.

5.7.2. Major Equipment

- ✓ SCR reactor
- ✓ Low NO_x burners
- ✓ Upgrade to forced draft fan
- ✓ ID fan

5.7.3. Basis for Estimate

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

5.7.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power."
- ✓ Costs were escalated to 2001 dollars
- ✓ R&D cost: 0.5% of total direct costs (i.e., labor, materials, subcontract, and equipment)

5.7.5. Operating Cost Estimate Assumptions

- ✓ Materials – catalyst: 1219 ft^3 per yr.
- ✓ Chemicals – urea: 428 tons per year
- ✓ Maintenance: 2% of TIC
- ✓ Power: 622 kw
- ✓ Power usage factor: 70%
- ✓ Workhours: 28.6 hr per day
- ✓ Testing: $5,000 per year
- ✓ Water: 7.43 gpm
- ✓ Steam: 2082 lb/hr
- ✓ Compressed air: 45 cfm

5.8. Coal or Coal / Wood Boiler – Switch to Natural Gas

5.8.1. Description

Switch from coal to natural gas for a coal or coal/wood boiler producing 300,000 lb/hr of steam.

5.8.2. Major Equipment

- ✓ New burners
- ✓ Natural gas reducing station

5.8.3. Basis for Estimate

Southeastern Kraft mill which switched from coal to natural gas for a boiler producing 420,000 lb/hr of steam. The project was estimated in 1999.

5.8.4. Capital Cost Estimate Assumptions

- ✓ Natural gas delivered at 700 psig to property line of plant.
- ✓ Costs were factored using the “0.6 power.”
- ✓ Costs were escalated to 2001 dollars

5.8.5. Operating Cost Estimate Assumptions

- ✓ Maintenance: 1% of TIC
- ✓ Power: N/A
- ✓ Workhours: 1.5 hr per day
- ✓ Testing: $5,000 per year

5.9. Gas Boiler

5.9.1. Description

Installation of SCR on natural gas-fired boiler producing 120,000 lb/hr of steam. The maximum NO_x emission rate is 0.015 lb/Mm Btu utilizing a 30-day average.

5.9.2. Major Equipment

- ✓ SCR reactor
- ✓ Low NO_x burners
- ✓ Upgrade to forced draft fan
- ✓ ID fan

5.9.3. Basis for Estimate

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

5.9.4. Capital Cost Estimate Assumptions

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

5.9.5. Operating Cost Estimate Assumptions

- ✓ Materials – catalyst: 464 ft^3 per yr. @ $350 per ft^3
- ✓ Chemicals – urea: 163 tons per year
- ✓ Maintenance: 2% of TIC
- ✓ Power: 237 kw
- ✓ Power usage factor: 70%
- ✓ Workhours: 28.6 hr per day
- ✓ Testing: $5,000 per year
- ✓ Water: 2.83 gpm
- ✓ Steam: 793 lb/hr
- ✓ Compressed air: 17 cfm

5.10. Gas Turbine

5.10.1. Description

Installation of SCR system for a 30-MW natural gas turbine yielding an emission level of 5 ppm @15% oxygen for a 30-day average representing a 95% NO_x reduction.

5.10.2. Major Equipment

- ✓ SCR reactor
- ✓ Low NO_x burners
- ✓ Upgrade to forced draft fan
- ✓ ID fan

5.10.3. Basis for Estimate

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

5.10.4. Capital Cost Estimate Assumptions

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

5.10.5. Operating Cost Estimate Assumptions

- ✓ Materials – catalyst: 298 ft^3 per yr. @ \$350 per ft^3
- ✓ Chemicals – urea: 105 tons per year
- ✓ Maintenance: 2% of TIC
- ✓ Power: 418 kw
- ✓ Power usage factor: 70%
- ✓ Workhours: 3 hr per day
- ✓ Testing: \$5,000 per year
- ✓ Water: 5 gpm
- ✓ Steam: 1400 lb/hr
- ✓ Compressed air: 30 cfm

5.11. Oil Boiler

5.11.1. Description

Installation of SCR system on oil-fired boiler producing 135,000 lb/hr of steam. The maximum NO_x emission rate is 0.04 lb/Mmbtu for a 30-day average or a 90% reduction.

5.11.2. Major Equipment

- ✓ SCR reactor
- ✓ Low NO_x burners
- ✓ Upgrade to forced draft fan
- ✓ ID fan

5.11.3. Basis for Estimate

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

5.11.4. Capital Cost Estimate Assumptions

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

- ✓ R&D cost: 0.5% of total direct costs (i.e., labor, materials, subcontract, and equipment)

5.11.5. Operating Cost Estimate Assumptions

- ✓ Materials – catalyst: 679 ft^3 per yr. @ \$350 per ft^3
- ✓ Chemicals – urea: 238 tons per year
- ✓ Maintenance: 2% of TIC
- ✓ Power: 346 kw
- ✓ Power usage factor: 70%
- ✓ Workhours: 28.6 hr per day
- ✓ Testing: \$5,000 per year
- ✓ Water: 4.14 gpm
- ✓ Steam: 1159 lb/hr
- ✓ Compressed air: 25 cfm

5.12. Wood Boiler - SNCR

5.12.1. Description

Installation of SNCR system on a wood boiler producing 300,000 lb/hr of steam. The maximum NO_x emission rate is 0.20 lb/ Mmbtu and represents a 40% reduction.

5.12.2. Major Equipment

- ✓ Urea storage and metering system
- ✓ Urea Injectors
- ✓ Boiler Modifications
- ✓ Control Enhancements

5.12.3. Basis for Estimate

An Atlantic states Kraft mill with a multi-fuel boiler producing 400,000 lb/hr of steam.

5.12.4. Capital Cost Estimate Assumptions

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

5.12.5. Operating Cost Estimate Assumptions

- ✓ Chemical – urea 165 tons per year
- ✓ Maintenance labor & materials: 3.5% of TIC
- ✓ Power: 13 kw
- ✓ Power usage factor: 80%
- ✓ Workhours: 3 hours per day
- ✓ Water: 3 gpm

5.13. Wood Boiler – SCR (technical feasibility)

5.13.1. Description

Installation of a SCR system on a wood-fired boiler capable of producing 300,000 lb/hr of steam. The maximum NO_x emission rate is 0.025 lb/Mmbtu with a 85% reduction anticipated. The SCR is feasible provided the temperature of the flue gas is controlled.

5.13.2. Major Equipment

- ✓ SCR reactor
- ✓ Low NO_x burners
- ✓ Upgrade to forced draft fan
- ✓ ID fan

5.13.3. Basis for Estimate

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

5.13.4. Capital Cost Estimate Assumptions

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

- ✓ R&D cost: 0.5% of total direct costs (i.e., labor, materials, subcontract, and equipment)

5.13.5. Operating Cost Estimate Assumptions

- ✓ Materials – catalyst: 821 ft^3 per yr. @ \$350 per ft^3
- ✓ Chemicals – urea: 287 tons per year
- ✓ Maintenance: 2% of TIC
- ✓ Power: 420 kw
- ✓ Power usage factor: 75%
- ✓ Workhours: 28.6 hr per day
- ✓ Testing: \$5,000 per year
- ✓ Water: 5 gpm
- ✓ Steam: 1403 lb/hr
- ✓ Compressed air: 30 cfm

6. SO_2 Reduction – Good Technology Limits

6.1. NDCE Recovery Boiler

6.1.1. Description

Installation of a chemical scrubber to achieve sulfur dioxide (SO_2) level in stack gas of 50 ppm @ 8% oxygen. The system is sized for a NDCE recovery furnace burning 3.7-Mm lb BLS per day.

6.1.2. Major Equipment

- ✓ Scrubber tower
- ✓ Booster fan
- ✓ Recirculation pump
- ✓ Caustic pump

6.1.3. Basis for Estimate

Southeast Kraft mill recovery furnace firing 2.5 x 10^6-lb black liquor solids per day. Project was estimated in 1998.

6.1.4. Capital Cost Estimate Assumptions

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

6.1.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3.5% of TIC
- ✓ Power: 1631 kw
- ✓ Power usage factor: 70%
- ✓ Chemical: 1.3 gpm 50% caustic soda
- ✓ Water: 148 gpm
- ✓ Wastewater: 15 gpm
- ✓ Workhours: 3 hours per day
- ✓ Testing: $5,000 per year

6.2. DCE Kraft Recovery Furnace

6.2.1. Description

Installation of a chemical scrubber to achieve sulfur dioxide (SO_2) level in stack gas of 50 ppm @ 8% oxygen. The system is sized for a DCE recovery furnace burning 1.7-Mm lb BLS per day.

6.2.2. Major Equipment

- ✓ Scrubber tower
- ✓ Booster fan
- ✓ Recirculation pump
- ✓ Oxidizer blower
- ✓ Caustic pump

6.2.3. Basis for Estimate

Southeast Kraft mill recovery furnace firing 2.5 x 10^6 lb black liquor solids per day. Project was estimated in 1998.

6.2.4. Capital Cost Estimate Assumptions

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

6.2.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3.5% of TIC
- ✓ Power: 1023 kw
- ✓ Power usage factor: 70%
- ✓ Chemical: 0.82 gpm 50% caustic soda
- ✓ Water: 68 gpm
- ✓ Wastewater: 6.8 gpm
- ✓ Workhours: 3 hours per day
- ✓ Testing: $5,000 per year

6.3. Coal or Coal / Wood Boiler

6.3.1. Description

Installation of a caustic scrubber for a coal or coal / wood boiler producing 300,000 lb/hour of steam. The SO_2 level would be reduced by 50% producing a maximum emission of 0.6 lb / Mm Btu.

6.3.2. Major Equipment

- ✓ Scrubber tower
- ✓ Recirculation pump
- ✓ Booster fan
- ✓ Caustic feed system

6.3.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler producing 600,000 lb/hour of steam. The project was estimated in 1992.

6.3.4. Capital Cost Estimate Assumptions

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

6.3.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3.5% of TIC
- ✓ Power: 1142 kw
- ✓ Power usage factor: 70%
- ✓ Chemical: 0.6 gpm 50% caustic soda
- ✓ Water: 143 gpm
- ✓ Wastewater: 14 gpm
- ✓ Workhours: 3 hours per day
- ✓ Testing: $5,000 per year

6.4. Oil Boiler

6.4.1. Description

Installation of caustic scrubber on a oil-fired boiler producing 135,000 lb/hr of steam. The SO_2 emission will be reduced by 50% with a maximum emission rate of 0.4 lb/Mm Btu for a 30-day average.

6.4.2. Major Equipment

- ✓ Scrubber tower
- ✓ Booster fan
- ✓ Caustic feed system

6.4.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler producing 600,000 lb/hour of steam. The project was estimated in 1992.

6.4.4. Capital Cost Estimate Assumptions

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

6.4.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3.0% of TIC
- ✓ Power: 555 kw
- ✓ Power usage factor: 70%
- ✓ Chemical: 0.26 gpm 50% caustic soda
- ✓ Water: 42.9 gpm
- ✓ Wastewater: 4.3 gpm
- ✓ Workhours: 3 hours per day
- ✓ Testing: $5,000 per year

7. SO_2 Reduction – Best Technology Limits

7.1. NDCE Recovery Boiler

7.1.1. Description

Installation of a caustic scrubber to achieve sulfur dioxide (SO_2) level in stack gas of 10 ppm @ 8% oxygen. The system is sized for a NDCE recovery furnace burning 3.7 Mm lb BLS per day.

7.1.2. Major Equipment

- ✓ Scrubber tower
- ✓ Booster fan
- ✓ Recirculation pump
- ✓ Caustic pump

7.1.3. Basis for Estimate

Southeast Kraft mill recovery furnace firing 2.5 x 10^6 lb black liquor solids per day. Project was estimated in 1998.

7.1.4. Capital Cost Estimate Assumptions

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

7.1.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3.5% of TIC
- ✓ Power: 1631 kw
- ✓ Power usage factor: 80%
- ✓ Chemical: 1.5 gpm 50% caustic soda
- ✓ Water: 148 gpm
- ✓ Wastewater: 15 gpm
- ✓ Work hours: 3 hours / day
- ✓ Testing: $5,000 per year

7.2. DCE Kraft Recovery Furnace

7.2.1. Description

Installation of a caustic scrubber to achieve sulfur dioxide (SO_2) level in stack gas of 10 ppm @ 8% oxygen. The system is sized for a DCE recovery furnace burning 1.7 Mm lb BLS per day.

7.2.2. Major Equipment

- ✓ Scrubber tower
- ✓ Booster fan
- ✓ Recirculation pump
- ✓ Oxidizer blower
- ✓ Caustic pump

7.2.3. Basis for Estimate

Southeast Kraft mill recovery furnace firing 2.5 x 10^6 lb black liquor solids per day. Project was estimated in 1998.

7.2.4. Capital Cost Estimate Assumptions

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

7.2.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3.5% of TIC
- ✓ Power: 1023 kw
- ✓ Power usage factor: 80%
- ✓ Chemical: 0.94 gpm 50% caustic soda
- ✓ Water: 68 gpm
- ✓ Wastewater: 6.8 gpm
- ✓ Work hours: 3 hours / day
- ✓ Testing: $5,000 per year

7.3. Coal or Coal / Wood Boiler

7.3.1. Description

Installation of a caustic scrubber for a coal or coal / wood boiler producing 300,000 lb/hour of steam. The SO_2 level would be reduced by 90% producing a maximum emission of 0.17 lb / Mm Btu for a 30-day average.

7.3.2. Major Equipment

- ✓ Scrubber tower
- ✓ Booster fan
- ✓ Caustic feed system

7.3.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler producing 600,000 lb/hour of steam. The project was estimated in 1992.

7.3.4. Capital Cost Estimate Assumptions

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

7.3.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3.5% of TIC
- ✓ Power: 1523 kw
- ✓ Power usage factor: 80%
- ✓ Chemical: 1.1 gpm 50% caustic soda
- ✓ Water: 143 gpm
- ✓ Wastewater: 14 gpm
- ✓ Workhours: 3 hours per day
- ✓ Testing: $5,000 per year

7.4. Oil Boiler

7.4.1. Description

Installation of caustic scrubber on a oil-fired boiler producing 135,000 lb/hr of steam. The SO_2 emission will be reduced by 90% with a maximum emission rate of 0.08 lb/Mm Btu for a 30-day average.

7.4.2. Major Equipment

- ✓ Scrubber tower
- ✓ Booster fan
- ✓ Caustic feed system

7.4.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler producing 600,000 lb/hour of steam. The project was estimated in 1992.

7.4.4. Capital Cost Estimate Assumptions

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

7.4.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3.0% of TIC
- ✓ Power: 740 kw
- ✓ Power usage factor: 80%
- ✓ Chemical: 0.34 gpm 50% caustic soda
- ✓ Water: 42.9 gpm
- ✓ Wastewater: 4.3 gpm
- ✓ Workhours: 3 hours per day
- ✓ Testing: $5,000 per year

8. Mercury Removal – Best Technology Limit

8.1. Coal or Coal / Wood Boiler

8.1.1. Description

Installation of a spray dryer absorber fabric filter dry scrubbing system with carbon injection for a coal or coal/wood-fired boiler producing 300,000 lb/hr of steam. The Hg emission level is anticipated to be lowered from 16 lb/10^{12} Btu to 8 lb/10^{12} Btu, representing a 50% reduction.

8.1.2. Major Equipment

- ✓ Fabric filter modules
- ✓ Lime storage and metering system
- ✓ Activated carbon storage and metering system
- ✓ Blower
- ✓ Atomizing air compressor
- ✓ Fabric filter scrubbing system

8.1.3. Basis for Estimate

A budget quotation from WAPC for a spray dryer absorber fabric filter dry scrubbing system with carbon injection for a coal-fired boiler.

8.1.4. Capital Cost Estimate Assumptions

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

8.1.5. Operating Cost Estimate Assumptions

- ✓ Chemicals – activated carbon: 0.08 tons per day
- ✓ Maintenance labor & materials: 5% of TIC
- ✓ Chemicals – pebble lime: 3750 lb/hr
- ✓ Power: 327 kw
- ✓ Power usage factor: 75%
- ✓ Workhours: 3 hours per day

- ✓ Testing: $5,000 per year
- ✓ Water: 64 gpm
- ✓ Wastewater: 20 gpm
- ✓ Incremental waste disposal: 15,780 tpy of carbon and lime

8.2. Wood Boiler

8.2.1. Description

Installation of a spray dryer absorber fabric filter dry scrubbing system with carbon injection for a wood-fired boiler producing 300,000 lb/hr of steam. The Hg emission level is anticipated to be lowered from 0.572 lb/10^{12} Btu to 0.286 lb/10^{12} Btu, representing a 50% reduction.

8.2.2. Major Equipment

- ✓ Fabric filter modules
- ✓ Lime storage and metering system
- ✓ Activated carbon storage and metering system
- ✓ Blower
- ✓ Atomizing air compressor
- ✓ Fabric filter scrubbing system

8.2.3. Basis for Estimate

A budget quotation from WAPC for a spray dryer absorber fabric filter dry scrubbing system with carbon injection for a wood fired boiler.

8.2.4. Capital Cost Estimate Assumptions

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

8.2.5. Operating Cost Estimate Assumptions

- ✓ Chemicals – activated carbon: 7.923 lb per day
- ✓ Maintenance labor & materials: 5% of TIC
- ✓ Chemicals – pebble lime: 375 lb/hr
- ✓ Power: 262 kw

- ✓ Power usage factor: 70%
- ✓ Workhours: 3 hours per day
- ✓ Testing: $5,000 per year
- ✓ Water: 90 gpm
- ✓ Wastewater: 28 gpm
- ✓ Incremental waste disposal: 1,576 tpy of carbon and lime

9. Particulate Matter – Good Technology Limits

9.1. NDCE Kraft Recovery Boiler – New Precipitator

9.1.1. Description

Installation of an electrostatic precipitator capable of achieving 0.044 gr/dscf @ 8% oxygen of particulate matter. The system is sized for a NDCE recovery furnace firing 3.7 Mm lb BLS per day

9.1.2. Major Equipment

- ✓ New electrostatic precipitator
- ✓ New concrete stack acid-brick lined
- ✓ Modification to existing ID fan
- ✓ Conveyors
- ✓ Dampers

9.1.3. Basis for Estimate

Southeast Kraft mill with a recovery boiler firing 2.15 x 10^6 lb black liquor solids per day. Project estimated in 2000.

9.1.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP at 3.7 x 10^6 lb black liquor solids per day.
- ✓ Costs escalated to 2001

9.1.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3.5% of TIC cost
- ✓ Power – 2023 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 3 hours per day
- ✓ Testing - $5,000 per year

9.2. NDCE Kraft Recovery Boiler – Rebuilt Precipitator

9.2.1. Description

ESP upgrade by addition of two parallel fields so that system is capable of achieving 0.044 gr/dscf @ 8% oxygen of particulate matter. The system is sized for a NDCE recovery furnace firing 3.7 Mm lb BLS per day

9.2.2. Major Equipment

- ✓ Modification to existing ESP
- ✓ Modifications to ash handling system

9.2.3. Basis for Estimate

Southeast Kraft mill with a recovery boiler firing 2.70 x 10^6 lb black liquor solids per day. Project estimated in 1999.

9.2.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP at 3.7 x 10^6 lb black liquor solids per day.
- ✓ Costs escalated to 2001

9.2.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 2% of TIC cost
- ✓ Power –377 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 1.5 hours per day
- ✓ Testing - $5,000 per year

9.3. DCE Kraft Recovery Boiler

9.3.1. Description

Installation of a electrostatic precipitator capable of achieving 0.044 gr/SDCF @ 8% oxygen of particulate matter. The system is sized for a DCE recovery furnace firing 1.7 Mm lb BLS per day.

9.3.2. Major Equipment

- ✓ New electrostatic precipitator
- ✓ New concrete stack acid-brick lined
- ✓ Modification to existing ID fan

- ✓ Conveyors
- ✓ Dampers

9.3.3. Basis for Estimate

Southeast Kraft mill with a recovery boiler firing 2.15 x 10^6 lb black liquor solids per day. Project estimated in 2000.

9.3.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP at 1.7 x 10^6 lb black liquor solids per day.
- ✓ Costs escalated to 2001

9.3.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3.5% of TIC cost
- ✓ Power – 1268 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 3 hours per day
- ✓ Testing - $5,000 per year

9.4. Smelt Dissolving Tank

9.4.1. Description

Installation of a scrubber on a smelt dissolving tank capable of achieving a particulate matter emission rate of 0.2 lb/ton BLS. The system is sized for a recovery furnace firing 3.7 Mm lb BLS per day.

9.4.2. Major Equipment

- ✓ New scrubber
- ✓ Fan
- ✓ Recirculation pump

9.4.3. Basis for Estimate

Atlantic states Kraft mill with a recovery furnace firing 2 Mm lb BLS per day. The project was estimated in 1997.

9.4.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for a smelt-dissolving tank scrubber at a recovery furnace firing rate of 3.7 x 10^6 lb black liquor solids per day. Costs escalated to 2001

9.4.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 2% of TIC cost
- ✓ Power – 287 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 1.5 hours per day
- ✓ Testing - $5,000 per year

9.5. Lime Kiln

9.5.1. Description

Installation of an electrostatic precipitator on a lime kiln processing 240 TPD of CaO. The emission rate for particulate matter is 0.064 gr/DSCF @ 10% oxygen.

9.5.2. Major Equipment

- ✓ New ESP
- ✓ Penthouse blower
- ✓ Hopper with screw conveyor
- ✓ Bucket elevator
- ✓ ID fan
- ✓ New stack

9.5.3. Basis for Estimate

Southeastern Kraft mill with a lime kiln capable of processing 540 TPD of CaO. The project was estimated in 2001.

9.5.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a lime kiln processing 240 tpd of CaO.

9.5.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3% of TIC cost

- ✓ Power 187 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 2.25 hours per day
- ✓ Testing - $5,000 per year

9.6. Coal Boiler

9.6.1. Description

Installation of electrostatic precipitator in a coal boiler producing 300,000 lb/hr of steam. The particulate emission rate is 0.065 lb / Mm Btu.

9.6.2. Major Equipment

- ✓ ID fan modification
- ✓ ESP
- ✓ Conveyors
- ✓ Penthouse blower

9.6.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler capable of producing 600,000 lb/hr of steam. The project was estimated in 1992.

9.6.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a boiler producing 300,000 lb/hr of steam.
- ✓ Costs escalated to 2001

9.6.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3% of TIC cost
- ✓ Power – 1331 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 3 hours per day
- ✓ Testing - $5,000 per year
- ✓ Incremental waste disposal: 39 tpy of ash

9.7. Coal / Wood Boiler

9.7.1. Description

Installation of electrostatic precipitator in a coal or coal / wood boiler producing 300,000 lb/hr of steam. The particulate emission rate is 0.065 lb / Mm Btu.

9.7.2. Major Equipment

- ✓ ID fan modification
- ✓ ESP
- ✓ Conveyors
- ✓ Penthouse blower

9.7.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler capable of producing 600,000 lb/hr of steam. The project was estimated in 1992.

9.7.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a boiler producing 300,000 lb/hr of steam.
- ✓ Costs escalated to 2001

9.7.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3% of TIC cost
- ✓ Power – 1331 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 3 hours per day
- ✓ Testing - $5,000 per year
- ✓ Incremental waste disposal: 94 tpy of ash

9.8. Oil Boiler

9.8.1. Description

The switch to low-sulfur fuel oil to achieve lower particulate matter emission rates from a oil-fired boiler capable of producing 135,000 lb/hr of steam.

9.8.2. Major Equipment

- ✓ Oil gun nozzles
- ✓ Flow meters

9.8.3. Basis for Estimate

Southeastern Kraft mill which switched from No. 6 to No. 2 fuel oil in a oil-fired boiler producing 135,000 lb/hour of steam. The project was estimated in 1999.

9.8.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a boiler producing 135,000 lb/hr of steam.
- ✓ Costs escalated to 2001

9.8.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3% of TIC cost
- ✓ Power – not applicable
- ✓ Workhours – not applicable
- ✓ Testing - $5,000 per year
- ✓ Fuel costs: $2.86 million per year

9.9. Wood Boiler

9.9.1. Description

Removal of existing scrubber and installation of electrostatic precipitator in a wood boiler producing 300,000 lb/hr of steam. The particulate emission rate is 0.065 lb / Mm Btu.

9.9.2. Major Equipment

- ✓ ID fan modification
- ✓ ESP
- ✓ Conveyors
- ✓ Penthouse blower

9.9.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler capable of producing 600,000 lb/hr of steam. The project was estimated in 1992.

9.9.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a boiler producing 300,000 lb/hr of steam.
- ✓ Costs escalated to 2001

9.9.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3.5% of TIC cost
- ✓ Power – 911 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 3 hours per day
- ✓ Testing - $5,000 per year
- ✓ Water – (200) gpm savings from elimination of scrubber
- ✓ Wastewater – (20) gpm savings from elimination of scrubber
- ✓ Incremental waste disposal: 551 tpy of ash

10. Particulate Matter – Best Technology Limit

10.1. NDCE Kraft Recovery Boiler – New Precipitator

10.1.1. Description

Installation of an electrostatic precipitator capable of achieving 0.015 gr/dscf @ 8% oxygen. The system would be installed in a recovery furnace burning 3.7 Mm lb BLS per day.

10.1.2. Major Equipment

- ✓ New electrostatic precipitator
- ✓ New concrete stack acid-brick lined
- ✓ Modification to existing ID fan
- ✓ Conveyors
- ✓ Dampers

10.1.3. Basis for Estimate

Southeast Kraft mill with a recovery boiler firing 2.15 x 10^6 lb black liquor solids per day. Project estimated in 2000.

10.1.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP at 3.7 x 10^6 lb black liquor solids per day.
- ✓ Costs escalated to 2001

10.1.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3.5% of TIC cost
- ✓ Power – 2528 kw
- ✓ Power usage factor: 80%
- ✓ Workhours – 3 hours per day
- ✓ Testing - $5,000 per year

10.2. NDCE Kraft Recovery Boiler – Rebuilt Precipitator

10.2.1. Description

ESP upgrade by addition of two parallel fields so that system is capable of achieving 0.015 gr/dscf @ 8% oxygen of particulate matter. The system is sized for a NDCE recovery furnace firing 3.7 Mm lb BLS per day

10.2.2. Major Equipment

- ✓ Modification to existing ESP
- ✓ Modifications to ash handling system

10.2.3. Basis for Estimate

Southeast Kraft mill with a recovery boiler firing 2.70 x 10^6 lb black liquor solids per day. Project estimated in 1999.

10.2.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP at 3.7 x 10^6 lb black liquor solids per day.
- ✓ Costs escalated to 2001

10.2.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 2% of TIC cost
- ✓ Power –411 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 1.5 hours per day
- ✓ Testing - $5,000 per year

10.3. DCE Kraft Recovery Boiler

10.3.1. Description

Installation of a electrostatic precipitator capable of achieving 0.015 gr/SDCF @ 8% oxygen of particulate matter. The system is sized for a DCE recovery furnace firing 1.7 Mm lb BLS per day.

10.3.2. Major Equipment

- ✓ New electrostatic precipitator
- ✓ New concrete stack acid-brick lined
- ✓ Modification to existing ID fan

- ✓ Conveyors
- ✓ Dampers

10.3.3. Basis for Estimate

Southeast Kraft mill with a recovery boiler firing 2.15 x 10^6 lb black liquor solids per day. Project estimated in 2000.

10.3.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP at 1.7 x 10^6 lb black liquor solids per day.
- ✓ Costs escalated to 2001

10.3.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3.5% of TIC cost
- ✓ Power – 1585 kw
- ✓ Power usage factor: 80%
- ✓ Workhours – 3 hours per day
- ✓ Testing - $5,000 per year

10.4. Smelt Dissolving Tank

10.4.1. Description

Installation of a scrubber on a smelt dissolving tank capable of achieving a particulate matter emission rate of 0.12 lb/ton BLS. The system is sized for a recovery furnace firing 3.7 Mm lb BLS per day.

10.4.2. Major Equipment

- ✓ New scrubber
- ✓ Fan
- ✓ Recirculation pump

10.4.3. Basis for Estimate

Atlantic states Kraft mill with a recovery furnace firing 2 Mm lb BLS per day. The project was estimated in 1997.

10.4.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for a smelt-dissolving tank scrubber at a recovery furnace firing rate of 3.7 x 10^6 lb black liquor solids per day.
- ✓ Costs escalated to 2001

10.4.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 2% of TIC cost
- ✓ Power – 315 kw
- ✓ Power usage factor: 80%
- ✓ Workhours – 1.5 hours per day
- ✓ Testing - $5,000 per year

10.5. Lime Kiln – New ESP

10.5.1. Description

Installation of an electrostatic precipitator on a lime kiln processing 240 TPD of CaO. The emission rate for particulate matter is 0.01 gr/DSCF @ 10% oxygen.

10.5.2. Major Equipment

- ✓ New ESP
- ✓ Penthouse blower
- ✓ Hopper with screw conveyor
- ✓ Bucket elevator
- ✓ ID fan
- ✓ New stack

10.5.3. Basis for Estimate

Southeastern Kraft mill with a lime kiln capable of processing 540 TPD of CaO. The project was estimated in 2001.

10.5.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a lime kiln processing 240 TPD of CaO.

10.5.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3% of TIC cost
- ✓ Power – 233 kw
- ✓ Power usage factor: 80%
- ✓ Workhours – 2.25 hours per day
- ✓ Testing - $5,000 per year

10.6. Lime Kiln – Upgraded ESP

10.6.1. Description

Addition of a single electric field to an existing electrostatic precipitator on a lime kiln processing 240 TPD of CaO. The emission rate for particulate matter is 0.01 gr/DSCF @ 10% oxygen.

10.6.2. Major Equipment

- ✓ Modifications to existing ESP
- ✓ Ductwork modifications

10.6.3. Basis for Estimate

Southeastern Kraft mill with a lime kiln capable of processing 540 TPD of CaO. The project was estimated in 2001.

10.6.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a lime kiln processing 240 TPD of CaO

10.6.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 1% of TIC cost
- ✓ Power – 100 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 1.5 hours per day
- ✓ Testing - $5,000 per year

10.7. Coal Boiler – New ESP

10.7.1. Description

Installation of electrostatic precipitator in a coal boiler producing 300,000 lb/hr of steam. The particulate emission rate is 0.04 lb / Mm Btu.

10.7.2. Major Equipment

- ✓ ID fan modification
- ✓ ESP
- ✓ Conveyors
- ✓ Penthouse blower

10.7.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler capable of producing 600,000 lb/hr of steam. The project was estimated in 1992.

10.7.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a boiler producing 300,000 lb/hr of steam.
- ✓ Costs escalated to 2001

10.7.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3% of TIC cost
- ✓ Power – 1664 kw
- ✓ Power usage factor: 80%
- ✓ Workhours – 3 hours per day
- ✓ Testing - $5,000 per year
- ✓ Incremental waste disposal: 77 tpy of ash

10.8. Coal Boiler – Rebuild Existing ESP

10.8.1. Description

Addition of a single electric field in two chambers to an electrostatic precipitator in a coal boiler producing 300,000 lb/hr of steam. The particulate emission rate is 0.04 lb / Mm Btu.

10.8.2. Major Equipment

- ✓ Modifications to existing ESP
- ✓ Ductwork modifications

10.8.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler capable of producing 600,000 lb/hr of steam. The project was estimated in 1992.

10.8.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a boiler producing 300,000 lb/hr of steam.
- ✓ Costs escalated to 2001

10.8.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 1% of TIC cost
- ✓ Power – 550 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 3 hours per day
- ✓ Testing - $5,000 per year
- ✓ Incremental waste disposal: 38 tpy of ash

10.9. Coal / Wood Boiler - New

10.9.1. Description

Installation of electrostatic precipitator in a coal or coal / wood boiler producing 300,000 lb/hr of steam. The particulate emission rate is 0.04 lb / Mm Btu.

10.9.2. Major Equipment

- ✓ ID fan modification
- ✓ ESP
- ✓ Conveyors
- ✓ Penthouse blower

10.9.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler capable of producing 600,000 lb/hr of steam. The project was estimated in 1992.

10.9.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a boiler producing 300,000 lb/hr of steam.
- ✓ Costs escalated to 2001

10.9.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3% of TIC cost
- ✓ Power 1331 kw
- ✓ Power usage factor: 80%
- ✓ Workhours – 3 hours per day
- ✓ Testing - $5,000 per year
- ✓ Incremental waste disposal: 137 tpy of ash

10.10. Coal / Wood Boiler – Rebuild Existing ESP

10.10.1. Description

Addition of single electric field in two chambers to an existing electrostatic precipitator in a coal or coal / wood boiler producing 300,000 lb/hr of steam. The particulate emission rate is 0.04 lb / Mm Btu.

10.10.2. Major Equipment

- ✓ Modifications to existing ESP
- ✓ Ductwork modifications

10.10.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler capable of producing 600,000 lb/hr of steam. The project was estimated in 1992.

10.10.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a boiler producing 300,000 lb/hr of steam.
- ✓ Costs escalated to 2001

10.10.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 1% of TIC cost
- ✓ Power 500 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 3 hours per day
- ✓ Testing - $5,000 per year
- ✓ Incremental waste disposal: 43 tpy of ash

10.11. Oil Boiler

10.11.1. Description

Installation of electrostatic precipitator in a oil-fired boiler producing 135,000 lb/hr of steam. The particulate emission rate is 0.02 lb / Mm Btu.

10.11.2. Major Equipment

- ✓ ID fan modification
- ✓ ESP
- ✓ Conveyors
- ✓ Penthouse blower

10.11.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler capable of producing 600,000 lb/hr of steam. The project was estimated in 1992.

10.11.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a boiler producing 135,000 lb/hr of steam.
- ✓ Costs escalated to 2001

10.11.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3% of TIC cost
- ✓ Power – 1098 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 3 hours per day

- ✓ Testing - $5,000 per year
- ✓ Incremental waste disposal: 99 tpy of ash

10.12. Wood Boiler

10.12.1. Description

Installation of an electrostatic precipitator in wood boiler producing 300,000 lb/hr of steam. The particulate emission rate is 0.04 lb / Mm Btu.

10.12.2. Major Equipment

- ✓ ID fan modification
- ✓ ESP
- ✓ Conveyors
- ✓ Penthouse blower

10.12.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler capable of producing 600,000 lb/hr of steam. The project was estimated in 1992.

10.12.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a boiler producing 300,000 lb/hr of steam.
- ✓ Costs escalated to 2001

10.12.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3.5% of TIC cost
- ✓ Power – 1978 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 3 hours per day
- ✓ Testing - $5,000 per year
- ✓ Incremental waste disposal: 599 tpy of ash

10.13. Wood Boiler – upgrade existing ESP

10.13.1. Description

Upgrade of existing electrostatic precipitator in a wood boiler producing 300,000 lb/hr of steam. The particulate emission rate is moved from 0.1 to 0.04 lb / Mm Btu.

10.13.2. Major Equipment

- ✓ ID fan modification
- ✓ ESP
- ✓ Conveyors
- ✓ Penthouse blower

10.13.3. Basis for Estimate

Southeastern Kraft mill boiler ESP rebuild for a boiler capable of producing 310,000 lb/hr of steam. The project was estimated in 1996.

10.13.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a boiler producing 300,000 lb/hr of steam.
- ✓ Costs escalated to 2001

10.13.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3.5% of TIC cost
- ✓ Power – 250 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 3 hours per day
- ✓ Testing - $5,000 per year
- ✓ Incremental waste disposal: 116 tpy of ash

11. Carbon Monoxide – Best Technology Limit

11.1. Coal or Coal / Wood Boiler

11.1.1. Description

Installation of combustion control modifications on a coal-fired boiler producing 300,000 lb/hr of steam. The carbon monoxide (CO) emission rate is anticipated to be 200 or less ppm for a 24-hour average.

11.1.2. Major Equipment

- ✓ Replace forced draft fan
- ✓ Repairs to windbox
- ✓ Replace combustion air dampers
- ✓ New set of tertiary air nozzles
- ✓ New furnace cameras
- ✓ New CEM
- ✓ DCS control upgrade

11.1.3. Basis for Estimate

Southeastern Kraft mill which installed combustion controls on a wood-fired boiler producing 350,000 lb/hr of steam. The project was estimated in 2000.

11.1.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a boiler producing 300,000 lb/hr of steam.
- ✓ Costs escalated to 2001

11.1.5. Operating Cost Estimate Assumptions

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

11.2. Wood Boiler

11.2.1. Description

Installation of combustion control modifications on a wood-fired boiler producing 300,000 lb/hr of steam. The carbon monoxide (CO) emission rate is anticipated to be 200 or less ppm for a 24-hour average.

11.2.2. Major Equipment

- ✓ Replace forced draft fan
- ✓ Repairs to windbox
- ✓ Replace combustion air dampers
- ✓ New set of tertiary air nozzles
- ✓ New furnace cameras
- ✓ New CEM
- ✓ DCS control upgrade

11.2.3. Basis for Estimate

Southeastern Kraft mill which installed combustion controls on a wood-fired boiler producing 350,000 lb/hr of steam. The project was estimated in 2000.

11.2.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a boiler producing 300,000 lb/hr of steam.
- ✓ Costs escalated to 2001

11.2.5. Operating Cost Estimate Assumptions

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

12. HCl – Good Technology Limit

12.1. Coal Boiler

12.1.1. Description

Installation of caustic scrubber to remove HCl to the level of 0.048 lb/Mm Btu from a coal-fired boiler producing 300,000 lb/hr of steam. Assumes inlet HCl concentration of 0.064 lb/Mm Btu.

12.1.2. Major Equipment

- ✓ Scrubber tower
- ✓ Recirculation pump
- ✓ Booster fan
- ✓ Caustic feed system

12.1.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler producing 600,000 lb/hour of steam. The project was estimated in 1992.

12.1.4. Capital Cost Estimate Assumptions

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

12.1.5. Operating Cost Estimate Assumptions

- ✓ Chloride content of coal is 800 ppm which equates to 23 lb/hr of HCl
- ✓ Maintenance labor & materials: 5% of TIC
- ✓ Power: 811 kw
- ✓ Power usage factor: 70%
- ✓ Chemical: 8 lb/hr caustic soda
- ✓ Testing: $5,000 per year
- ✓ Water: 64 gpm
- ✓ Wastewater: 20 gpm
- ✓ Workhours: 3 hours per day

13. HCl – Best Technology Limit

13.1. Coal Boiler

13.1.1. Description

Installation of caustic scrubber to remove HCl to the level of 0.015 lb/Mm Btu from a coal-fired boiler producing 300,000 lb/hr of steam. Assumes inlet HCl concentration of 0.064 lb/Mm Btu.

13.1.2. Major Equipment

- ✓ Scrubber tower
- ✓ Recirculation pump
- ✓ Booster fan
- ✓ Caustic feed system

13.1.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler producing 600,000 lb/hour of steam. The project was estimated in 1992.

13.1.4. Capital Cost Estimate Assumptions

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

13.1.5. Operating Cost Estimate Assumptions

- ✓ Chloride content of coal is 800 ppm which equates to 23 lb/hr of HCl
- ✓ Maintenance labor & materials: 5% of TIC
- ✓ Power: 811 kw
- ✓ Power usage factor: 80%
- ✓ Chemical: 25 lb/hr caustic soda
- ✓ Testing: $5,000 per year
- ✓ Water: 64 gpm
- ✓ Wastewater: 20 gpm
- ✓ Workhours: 3 hours per day

14. VOC – Good Technology Limit

14.1. DCE Kraft Recovery Furnace

14.1.1. Description

Collection of black liquor oxidation system vent gases from a DCE recovery furnace burning 1.7 Mm lb BLS per day. The vent gases would be incinerated in an existing multi-fuel boiler.

14.1.2. Major Equipment

- ✓ Vent fan
- ✓ Condensate pump

14.1.3. Basis for Estimate

Rust MACT Cost Analysis report for a DCE recovery furnace burning 1.5 Mm lb BLS per day. The work was done in October 1993.

14.1.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power."
- ✓ Costs were escalated to 2001 dollars
- ✓ Rust estimate was escalated and included as a TIC only.
- ✓ No additional indirect costs were applied to the Rust estimate.

14.1.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3% of TIC
- ✓ Power: 151 kw
- ✓ Power usage factor: 70%
- ✓ Testing: $5,000 per year
- ✓ Steam: 500 lb/hr
- ✓ Workhours: 3 hours per day

14.2. Paper Machines

14.2.1. Description

Based upon NCASI studies ("Volatile Organic Emissions from Pulp & Paper Sources Part VII - Pulp Dryers & Paper Machines at Integrated Chemical Pulp Mills. Tech Bulletin No.681 Oct 1994 NCASI) the paper machines utilizing unbleached pulps had the highest non-additive VOC emission rates. The machines utilizing bleached pulps had very low VOC emissions.

The source of the VOC was from the fluid contained in the unbleached pulp. If the consistency of the unbleached pulp is raised to 30+% (from a nominal 12%) prior to discharge to either the high density storage or to the paper machines, then the VOC contained in the fluid will be reduced by more than two-thirds.

To increase the consistency to 30+%, a screw press would be installed ahead of the high density storage for the unbleached Kraft, semi-chemical (or NSSC), and mechanical pulp mills. The re-dilution water to be used after the screw press would be paper machine whitewater. In the case of the unbleached Kraft mill and semi-chemical mill, the filtrate from the press would be sent to the spent pulping liquor system.

The system was sized for a 1000 ton per day paper machine.

14.2.2. Major Equipment

- ✓ Two screw presses
- ✓ Pressate (filtrate) tank
- ✓ Thick stock pump

14.2.3. Basis for Estimate

Estimate for 1000 tons per day screw press system based upon a quotation from Kvaerner Pulping. The estimate is in 2001 dollars.

14.2.4. Capital Cost Estimate Assumptions

- ✓ None

14.2.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3% of TIC
- ✓ Power: 861 kw
- ✓ Power usage factor: 70%
- ✓ Testing: $5,000 per year

- ✓ Workhours: 1.5 hours per day
- ✓ A COD reduction will result from utilizing the screw press, which can result in enhanced runnability, improved sheet quality, and reduced chemical costs. However, these potential savings are very paper machine specific and were deemed beyond the scope of this study.

14.3. Mechanical Pulping - TMP

14.3.1. Description

Installation of a heat recovery system on TMP systems which will produce clean steam, a NCG vent, and dirty condensates. The system is designed to condense the VOCs to <0.5 lb C / ODTP.

14.3.2. Major Equipment

- ✓ Reboiler
- ✓ Vent condenser / feed water heater
- ✓ Boiler feed water heater
- ✓ Atmospheric start-up scrubber with silencer

14.3.3. Basis for Estimate

Estimate for 500 tpd TMP heat recovery system based upon quotation from Andritz-Ahlstrom for a 500 ADTPD TMP heat recovery system. The quotation was in 2001 dollars.

14.3.4. Capital Cost Estimate Assumptions

- ✓ None

14.3.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3% of TIC
- ✓ Power: 165 kw
- ✓ Power usage factor: 70%
- ✓ Testing: $5,000
- ✓ Workhours: 1.5 hours per day
- ✓ Water: 192 gpm
- ✓ Wastewater: 194
- ✓ Steam: (94,255 lb/hr) (This is projected amount of steam to be recovered.)

14.4. Mechanical Pulping – Pressure Groundwood

14.4.1. Description

Installation of a heat recovery system on pressure groundwood systems which will produce clean steam, a NCG vent, and dirty condensates. The system is designed to condense the VOCs to <0.5 lb C / ODTP.

14.4.2. Major Equipment

- ✓ Reboiler
- ✓ Vent condenser / feed water heater
- ✓ Boiler feed water heater
- ✓ Atmospheric start-up scrubber with silencer

14.4.3. Basis for Estimate

Estimate for 500-tpd-pressure groundwood heat recovery system based upon quotation from Andritz-Ahlstrom for a 500 ADTPD TMP heat recovery system. The quotation was in 2001 dollars.

14.4.4. Capital Cost Estimate Assumptions

- ✓ None

14.4.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3% of TIC
- ✓ Power: 165 kw
- ✓ Power usage factor: 70%
- ✓ Testing: $5,000 per year
- ✓ Workhours: 1.5 hours per day
- ✓ Water: 192 gpm
- ✓ Wastewater: 39
- ✓ Steam: (18,851 lb/hr) (This is projected amount of steam to be recovered and assumes that the heat recovery would be 20% of that for a comparable TMP plant.)

15. VOC – Best Technology Limit

15.1. NDCE Kraft Recovery Furnace

15.1.1. Description

Conversion of wet bottom ESP to a dry bottom ESP for a NDCE recovery furnace burning 3.7 Mm lb BLS per day. 99.8% particulate collection efficiency was assumed.

15.1.2. Major Equipment

- ✓ New dry bottom hopper
- ✓ Ash mix tank
- ✓ Conveyors

15.1.3. Basis for Estimate

Rust MACT Cost Analysis report for a NDCE recovery furnace burning 1.5-Mm lb BLS per day. The work was done in October 1993.

15.1.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power."
- ✓ Costs were escalated to 2001 dollars
- ✓ Rust estimate was escalated and included as a TIC only.
- ✓ No additional indirect costs were applied to the Rust estimate.

15.1.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 2% of TIC
- ✓ Power: 15 kw
- ✓ Power usage factor: 70%
- ✓ Testing: $5,000 per year
- ✓ Workhours: 1.5 hours per day

15.2. DCE Kraft Recovery Furnace

15.2.1. Description

Conversion of DCE recovery furnace burning 1.7 Mm lb BLS per day to a NDCE type.

15.2.2. Major Equipment

- ✓ New economizer
- ✓ New spent pulping liquor concentrator
- ✓ Additional soot blowers
- ✓ Ash mix tank
- ✓ CEMS

15.2.3. Basis for Estimate

Rust MACT Cost Analysis report for a DCE recovery furnace burning 1.5-Mm lb BLS per day. The work was done in October 1993.

15.2.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power."
- ✓ Costs were escalated to 2001 dollars
- ✓ Rust estimate was escalated and included as a TIC only.
- ✓ No additional indirect costs were applied to the Rust estimate.
- ✓

15.2.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3% of TIC
- ✓ Power: 450 kw
- ✓ Power usage factor: 70%
- ✓ Testing: $5,000 per year
- ✓ Steam: (26,984 lb/hr) (steam savings)
- ✓ Workhours: 3 hours per day

15.3. Paper Machines – Wet End

15.3.1. Description

Collection of wet end exhaust gases from a 1000 TPD paper machine and incineration in a regenerative thermal oxidizer (RTO).

15.3.2. Major Equipment

- ✓ Combustion blower
- ✓ Seal fan
- ✓ Main fan
- ✓ Regenerative thermal oxidizer
- ✓ 100' stack with testing platform
- ✓ 316L stainless steel duct

15.3.3. Basis for Estimate

Northern pulp mill with dryer equipped with a collection system and RTO unit. The mill is designed to produce 415 ODTPD of deink pulp. The project was estimated in 2000.

15.3.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power."
- ✓ R&D costs: 1.5% of total direct costs (i.e., labor, materials, subcontract, and equipment)

15.3.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3% of TIC
- ✓ Power: 310 kw
- ✓ Power usage factor: 70%
- ✓ Testing: $5,000 per year
- ✓ Natural gas: 4.71 Mmbtu/hr
- ✓ Workhours: 1.5 hours per day

15.4. Paper Machines – Dry End

15.4.1. Description

Collection of dry-end exhaust gases from a 1000 TPD paper machine and incineration in a RTO.

15.4.2. Major Equipment

15.4.3. Major Equipment

- ✓ Combustion blower
- ✓ Seal fan
- ✓ Main fan
- ✓ Regenerative thermal oxidizer
- ✓ 100' stack with testing platform
- ✓ 316L stainless steel duct

15.4.4. Basis for Estimate

Northern pulp mill with dryer equipped with a collection system and RTO unit. The mill is designed to produce 415 ODTPD of deink pulp. The project was estimated in 2000.

15.4.5. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power."
- ✓ R&D costs: 1.5% of total direct costs (i.e., labor, materials, subcontract, and equipment)

15.4.6. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3% of TIC
- ✓ Power: 380 kw
- ✓ Power usage factor: 70%
- ✓ Testing: $5,000 per year
- ✓ Natural gas: 8.1 MmBtu/hr
- ✓ Workhours: 1.5 hours per day

15.5. Mechanical Pulping – TMP with Existing Heat Recovery System

15.5.1. Description

Collection and incineration of the NCGs from a TMP heat recovery system. The system was sized for a 500 ADTPD mechanical pulp mill.

15.5.2. Major Equipment

- ✓ Duct work
- ✓ Combustion blower
- ✓ Thermal oxidizer

15.5.3. Basis for Estimate

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

15.5.4. Capital Cost Estimate Assumptions

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

15.5.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3.5% of TIC
- ✓ Power: 22 kw
- ✓ Power usage factor: 70%
- ✓ Workhours: 2.25 hours per day
- ✓ Testing: $5,000 per year
- ✓ Water: 10gpm
- ✓ Wastewater: 10 gpm

15.6. Mechanical Pulping – TMP Without Existing Heat Recovery System

15.6.1. Description

Installation of a heat recovery system on mechanical pulping systems which will produce clean steam, a NCG vent, and dirty condensates. Then collection and incineration of the NCGs. The system was sized for a 500 ADTPD TMP mill.

15.6.2. Major Equipment

- ✓ Reboiler
- ✓ Vent condenser / feed water heater
- ✓ Boiler feed water heater
- ✓ Atmospheric start-up scrubber with silencer
- ✓ Duct work
- ✓ Combustion blower
- ✓ Thermal oxidizer

15.6.3. Basis for Estimate

Estimate for 500 tpd TMP heat recovery system based upon quotation from Andritz-Ahlstrom for a 500 ADTPD TMP heat recovery system. The quotation was in 2001 dollars.

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

15.6.4. Capital Cost Estimate Assumptions

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

15.6.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3.5% of TIC
- ✓ Power: 187 kw
- ✓ Power usage factor: 70%
- ✓ Workhours: 2.25 hours per day
- ✓ Testing: $5,000 per year
- ✓ Water: 202gpm
- ✓ Wastewater: 204 gpm
- ✓ Steam: (94,255 lb/hr) (This is projected amount of steam to be recovered)

15.7. Mechanical Pulping – Pressurized Groundwood Without Existing Heat Recovery System

15.7.1. Description

Installation of a heat recovery system on pressurized groundwood pulping systems which will produce clean steam, a NCG vent, and dirty condensates. Then collection and incineration of the NCGs. The system was sized for a 500 ADTPD pressurized groundwood mill.

15.7.2. Major Equipment

- ✓ Reboiler
- ✓ Vent condenser / feed water heater
- ✓ Boiler feed water heater
- ✓ Atmospheric start-up scrubber with silencer
- ✓ Duct work
- ✓ Combustion blower
- ✓ Thermal oxidizer

15.7.3. Basis for Estimate

Estimate for 500 tpd pressurized groundwood heat recovery system based upon quotation from Andritz-Ahlstrom for a 500 ADTPD TMP heat recovery system. The quotation was in 2001 dollars.

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

15.7.4. Capital Cost Estimate Assumptions

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

15.7.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3.5% of TIC
- ✓ Power: 198 kw
- ✓ Power usage factor: 70%

- ✓ Workhours: 2.25 hours per day
- ✓ Testing: $5,000 per year
- ✓ Water: 202gpm
- ✓ Wastewater: 49 gpm
- ✓ Steam: (18,851 lb/hr) (This is projected amount of steam to be recovered and assumes that the heat recovery would be 20% of that for a comparable TMP plant.)

15.8. Mechanical Pulping – Atmospheric Groundwood

15.8.1. Description

Collection and incineration of the NCGs from a atmospheric groundwood system. The system was sized for a 500 ADTPD mechanical pulp mill. The estimated emission was 20,000 ACFM.

15.8.2. Major Equipment

- ✓ Hoods
- ✓ Duct work
- ✓ Combustion blower
- ✓ Thermal oxidizer

15.8.3. Basis for Estimate

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

15.8.4. Capital Cost Estimate Assumptions

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

15.8.5. Operating Cost Estimate Assumptions

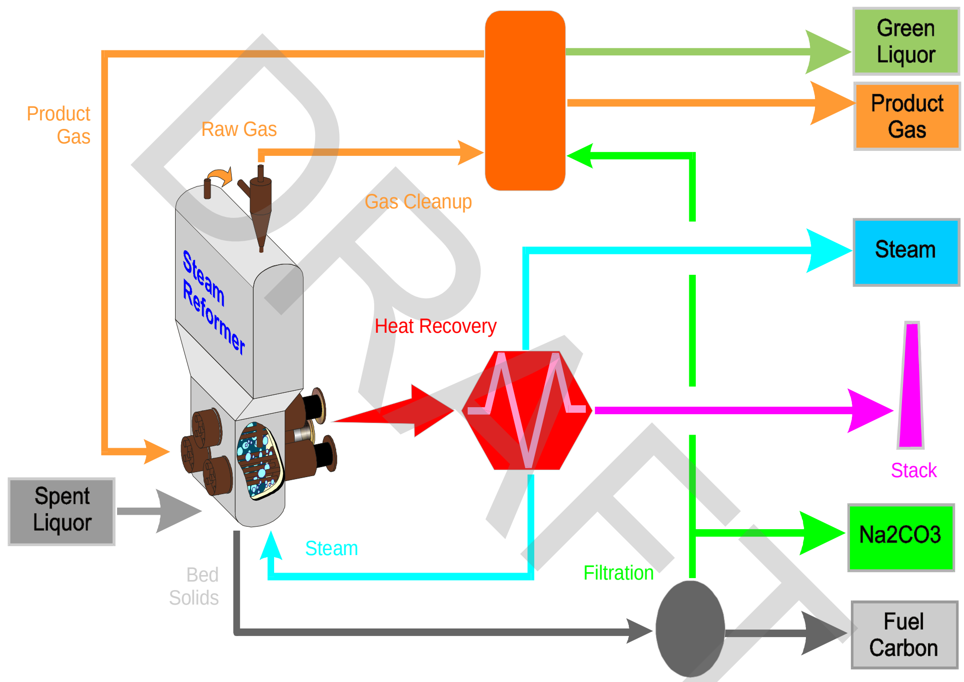
- ✓ Maintenance labor & materials: 3.5% of TIC
- ✓ Power: 22 kw
- ✓ Power usage factor: 70%
- ✓ Workhours: 2.25 hours per day

- ✓ Testing: $5,000 per year
- ✓ Water: 10gpm
- ✓ Wastewater: 10 gpm

16. Gasification

16.1. Description of Technology

For this study, chemical recovery via gasification is based on the PulseEnhanced™ Steam Reformation technology developed by MTCI/ThermoChem, which is designed to process spent liquor and recover its chemical and energy value. A simplified diagram of the technology is shown below.

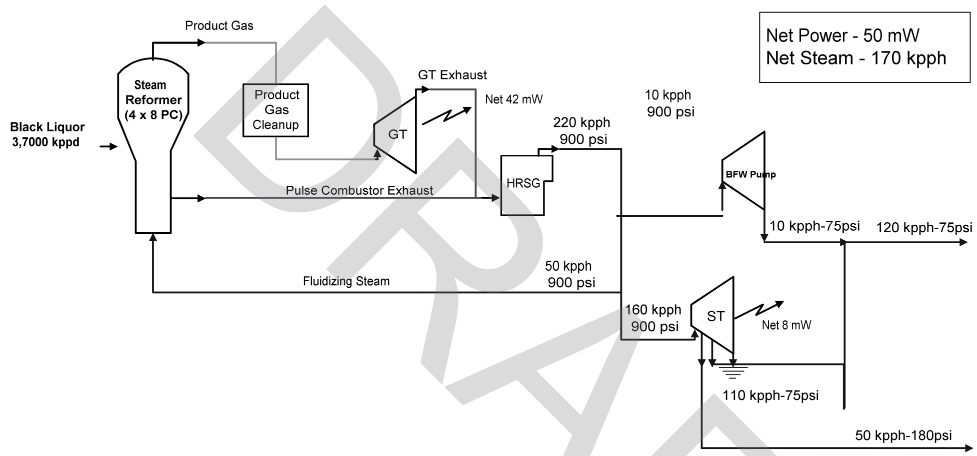


The recovery of chemicals and energy from spent liquor is effected by an indirectly heated steam-reforming process which results in the generation of a hydrogen-rich, medium-Btu product gas and bed solids, a dry alkali, which flow from the bottom of the reformer. Neither direct combustion nor alkali salt smelt formation occurs in this steam-reforming process.

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

The product gas is cleaned, compressed, and then sent to the pulse heaters to provide the indirect heat in the reformer and to a combustion turbine to produce electricity. The combustion turbine exhaust is combined with the pulse heater exhaust and then sent to a heat recovery steam generator. The resulting high-pressure steam is then sent to an extraction/condensing steam turbine where addition electricity is produced and lower pressure steam is made available to the mill. A process flow diagram showing the complete system is shown on the following page.

AF&PA/BE&K **Black Liquor Gasification Combined Cycle System Block Flow diagram** **Project 12104 23 June, 2001**



INDUSTRA Engineers & Consultants

The scope developed assumes that the mill can supply concentrated black liquor (80% solids). Since the costs for doing this can vary widely between mills and modern recovery boilers would require a similar concentration, these costs have been omitted from this study.

We recognize that the steam produced by this system is probably not sufficient for a typical Kraft mill. The additional steam requirements will either need to be provided by a biomass gasifier or boiler or a power boiler. These additional systems offer the opportunity for further power generation as well as steam production. This too is site specific and not included in this study.

16.2. Major Equipment

The major subsystems include liquor injection, steam reformer, gas cleanup, combustion turbine, heat recovery and steam generation, steam turbine, bed solids dissolution, sodium carbonate solution filter, and bed solids storage.

16.2.1. Black Liquor Supply and Steam Reformer

High solids black liquor is supplied to the reformer via a recirculation line feeding multiple steam jacketed injectors. Four reformers each containing 8-pulse heaters are required for this size plant. Each steam reformer is a carbon steel; fabricated vessel lined with refractory. The upper region of the vessel is expanded to reduce gas velocity, permitting entrained particles to disengage and fall back to the fluid bed. Internal stainless cyclones, mounted from the roof of the reformer, provide primary dust collection and a second set of external cyclones further captures fines. The reformer is fluidized with superheated steam using stainless fluidizer headers that are located just above the refractory floor. Bed drains penetrate the refractory floor for removal of bed solids via lock hoppers during normal operation.

Pulsed jet heater modules (fired heat exchangers) are used to indirectly heat the reformer. Pulsed heater modules are cantilever-mounted in the reformer utilizing a flange located on the front of the vessel. Each module extends through the reformer with it resonance tubes in contact with the fluid bed particles inside the vessel.

16.2.2. Product Gas Cleanup

Cyclone-cleaned product gas exits the reformer and enters a product gas heat recovery steam generator (HRSG) which cools the gas prior to entering a venturi separator, which further cools the gas and washes out any solids carryover. A packed gas cooler follows the venturi separator. Once the gas is cooled, it enters the H2S absorber (green liquor column). The absorber is a carbon steel cylinder with two packed stages.

16.2.3. Product Gas Combustion

The clean/cool product gas is sent to the pulse heaters and to a compressor, which then feeds a combustion turbine. The CT generates 50mW of net power.

16.2.4. Heat Recovery and Steam Generation

Steam is generated in both the product gas HRSG and the waste heat boiler. The product gas HRSG consists of a vertical shell and tube generating section and an external steam drum. The product gas HRSG also serves as a source of cooling water for the pulsed heaters.

The waste heat boiler is a two-drum, bottom-supported boiler. Hot flue gas from the pulse heaters and the combustion turbine flows into the HRSG to produce 220-pph 900psi/900F steam.

16.2.5. Steam Turbine

Steam from the waste heat boiler is sent to an extraction condensing steam turbine, which will extract the energy in the high-pressure steam to generate a net 8 mw of power. The resulting lower pressure steam is then piped to the mill steam distribution system.

16.2.6. Solids Dissolution

The solids from each reformer flows through refractory-lined lock hoppers into dissolving tanks. The dissolving tank is carbon steel, insulated tank outfitted with a side-entry agitator, and sized to provide additional retention time to effect dissolution of the soluble sodium carbonate.

16.2.7. Sodium Carbonate Filter

The function of the filter system is to filter the dissolving tank solution to produce a clear sodium carbonate liquor; free of suspended solids such as unreacted organic carbon and non-process elements.

16.2.8. Media Storage Bin

The media bin is an insulated carbon steel vessel (mass flow design) with a capacity sufficient to hold the inventory of several reformers during repair and maintenance.

16.3. Basis for Estimate

Our database of studies, extending over the last 5 years for systems ranging from 250,000 lb/day to 1,000,000 lb/day black liquor solids, was used to create a base for the capital cost estimate.

16.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the “0.6 power.”
- ✓ Costs were escalated to 2001 dollars
- ✓ Engineering was assumed to 8% vs. the standard 15% because of the high cost of the equipment and the fact that there is little integration to existing plant
- ✓ R&D expenses of 1.5% of the direct costs were assumed.
- ✓ Equipment foundations on spread footings
- ✓ No allowance for disposal of any potential contaminated soils

- ✓ Except for the purchase of one spare pulsed heater unit, no standalone spares are included. Installed spares are listed as equipment.
- ✓ No demolition costs
- ✓ Pricing was obtained for major equipment. Some prices were not competitively bid and no negotiations were undertaken to firm or clarify process scope.

16.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3% of TIC cost
- ✓ Utilities: 0.1% of TIC cost
- ✓ Power
  - ♦ New loads: 11,600 kw
  - ♦ Credit for shutdown of existing recovery boiler: (3700) kw
  - ♦ Revenue – sale of power: 50,000 kw
- ✓ Dregs disposal: 1.9 tons per hour
- ✓ Waste water treatment: 650 gpm
- ✓ Steam (revenue): (170,000) lb/hr

16.6. Impact on Emissions

Emissions estimates prepared in earlier studies were scaled up for the 3.7 million-lb/day gasifier and then compared to equivalent data for a similarly sized recovery boiler. The emissions are shown in the tables and chart below.

Black Liquor Gasification Emission Estimates

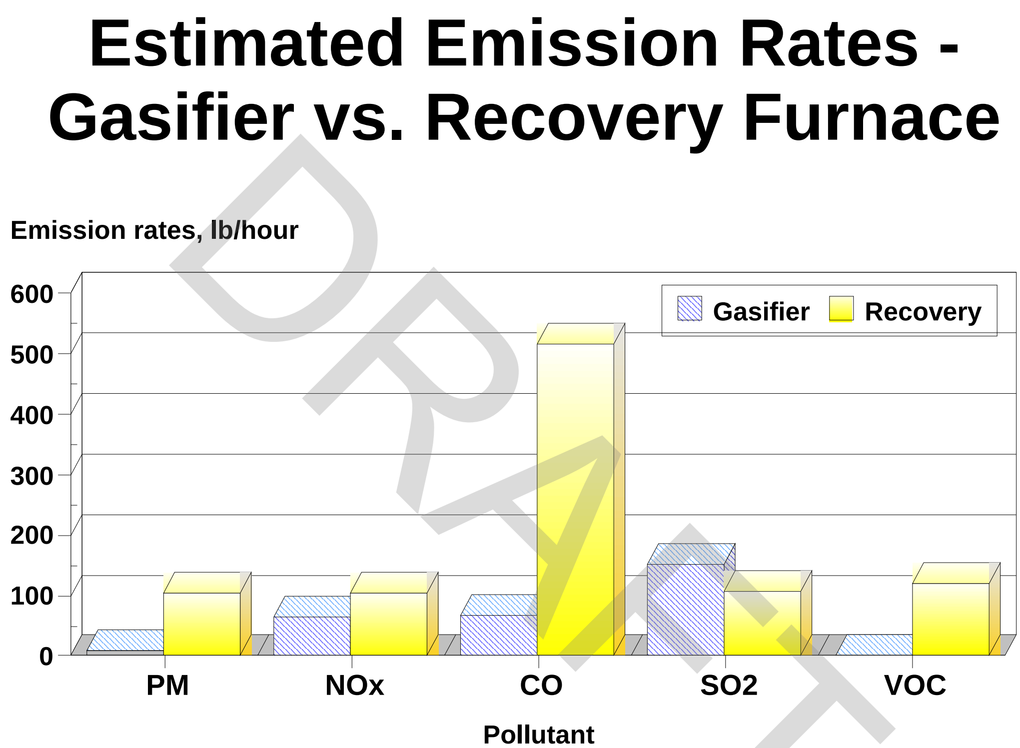
	Black Liquor Reformer Pulse Combustion Exhaust	Combustion Turbine Exhaust	Total
	(lb/hr)	(lb/hr)	(lb/hr)
Particulate matter	2.9	5.7	8.5
Nitrous oxides (NO_x)	18.7	46.1	64.7
Carbon monoxide (CO)	11.4	56.1	67.5
Sulfur dioxide (SO_2)	70.0	81.0	151.0
Volatile organic (as carbon)	0.4	0.0	0.4
as Methanol	2.8	0.0	2.8
TRS (as H_2S)	0.0	0.0	0.0

Recovery Boiler & Smelt Dissolver Emission Estimates

	Recovery Boiler Exhaust	Smelt Dissolving Exhaust	Total
	lb/hr	lb/hr	lb/hr
Particulate matter	93.9	9.4	103.3
Nitrous oxides (NO_x)	89.2	16.1	105.3
Carbon monoxide (CO)	516.5	0.3	516.8
Sulfur dioxide (SO_2)	98.7	9.4	108.1
Volatile organic (as carbon)	37.6	7.5	45.1
as Methanol	100.2	20.0	120.2
TRS (as H_2S)	4.7	2.5	7.2

Additionally for carbon dioxide the black liquor gasification emission rate is estimated to be 240,400 lb/hr for a 4 Mm lb BLS/day unit, while a comparable Tomilson unit would discharge 318,600 lb/hour.

The following illustrates the differences between a black liquor gasification unit and a Tomilson recovery system:



Emission estimates based on 3.7 Mmlb BLS/day firing rate.

17. Industry – Wide Control Cost Estimates

17.1. General Assumptions

The following are the general assumptions:

17.1.1. Capital Costs

- ✓ The individual mill cost estimates are based upon using the 0.6 power rule [Project A cost x (AF&PA firing rate / Project A firing rate)$^{0.6}$] to factor the control technology estimates
- ✓ The boiler emission rates are compared with pollutant limits to determine relative compliance. If the mill discharge level is less than 90% of the pollutant limit, then no control technology will be installed.
- ✓ The base labor is $58.62 per hour and was determined from:

Area	Rate, $/hour	Comment
Base rate	$17.50	
Benefits	$3.25	18.55% of base rate
Fringes	$2.01	11.50% of base rate
Workman's compensation insurance	$2.13	Varies by craft from 6 to 30% of base rate
Indirects	$27.00	Includes home office expenses, field supervision, temporary facilities, tools/ consumables, construction equipment, permits/miscellaneous, and contractor's fee
Premium mark-up	$2.07	
Per diem	$4.66	Includes direct and indirect
Total	**$58.62**	

- ✓ The labor costs portion of the TIC were adjusted for each mill utilizing the BE&K labor rates by region. See Appendix 18.1 for a listing of the factors by state.
- ✓ The material and subcontract costs were adjusted for each mill utilizing the MEANS database factors averaged for each state. See Appendix 18.1 for a listing of the factors by state.
- ✓ Research & Development expenses were assumed for the SCR-non-natural gas, mercury removal, and paper machine VOC removal – best technology applications. They ranged from 0.5 to 1.5% of the sum of the labor, material, subcontract, and equipment direct costs.
- ✓ The BE&K project costs were escalated according to the following:

Period	Escalation rate
1994 to 1995	2.50%
1995 to 1996	3.30%
1996 to 1997	1.70%
1997 to 1998	1.60%
1998 to 1999	2.70%
1999 to 2000	3.40%

17.1.2. Annual Operating and Maintenance Costs

- ✓ The maintenance labor and material annual costs were reported as a percentage of the TIC. The typical range was between 1% and 5% of the total TIC.
- ✓ The operating costs for the mills were proportionately factored for each of the areas (excluding testing and workhours) from the design case.
- ✓ 355 operating days per year were assumed for the equipment.
- ✓ The materials category such as fabric filter or SCR catalyst was reported in terms of 2001 dollars.
- ✓ The wastewater category reported the usage in gallons per year based upon the estimated flow; gpm/feed rate x feed rate x 1440 min/day x 365 dy/yr. The water usage used the same formula but with only 350 dy/yr.

- ✓ The steam and compressed air usage was calculated by multiplying the usage per feed rate x feed rate per day x 350 dy/yr.
- ✓ The estimated cost for process water was $0.58 per thousand gallons.
- ✓ The estimated cost for wastewater treatment was $0.41 per thousand gallons.
- ✓ The estimated cost for caustic soda was $0.17 per lb.
- ✓ The estimated cost for urea was $225 per ton
- ✓ The estimated cost for activated carbon is $0.58 per lb
- ✓ The estimated cost for pebble lime is $56.50 per ton
- ✓ The differential price between No. 2 and No. 6 fuel oil is $0.84 per Mmbtu (assumes a cost of $4.32 /Mmbtu for No. 6 fuel oil and $5.16 / MmBtu for No. 2 fuel oil)
- ✓ The energy usage was first calculated in kWh/year and is based upon the estimated connected kilowatts x 24/hr/day times 350 days times usage factor (typically 70 to 80%).
- ✓ The price of electricity was assumed to $0.05/kwhr and was multiplied by the kWh/year.
- ✓ The price of steam was assumed to be $0.00500 per lb of steam and was multiplied by the steam usage in lb/hr per year. For any recovered steam, a recovered steam factor times the price of steam was used to determine the value of the steam.
- ✓ The price of compressed air was assume to be $0.00010 per cfm and was multiplied by the compressed air usage in cfm/year.
- ✓ The utilities category totals the costs for compressed air, water, wastewater, steam, and solid waste disposal.
- ✓ The price of natural gas was assumed to be $4.00 per Mmbtu.
- ✓ The landfill cost for hauling and disposal was assumed to be $25 per ton of solid waste.
- ✓ An annual testing cost of $5,000 was assumed for each technology applied and was assumed constant independent of the size of the facility.
- ✓ The workhours were reported in $ /year based upon hours / day x 350 operating days/year x the hourly rate. The hourly rate was obtained from AF&PA Labor

Database with 91% of member contracts entered (missing about 20); the average hourly rate for year 2000 was $18.14. This data only includes hourly employees. An additional 40% was added to the figure to account for benefits to yield a rate of $25.40. The workhour dollars were not factored, but were assumed to be constant no matter what the size of the facility.

- ✓ The NCASI database for recovery furnaces, limekilns, and power boilers was used. This included equipment information, combustion firing rates and types, and pulping information.
- ✓ NCASI provided the mill code for the BE&K supplied paper machine and mechanical pulping information.

17.2. CO_2 Emission Assumptions

- ✓ The CO_2 emissions were calculated by multiplying the 1995 NCASI fossil fuel usage from the power boilers, recovery furnaces, and lime kilns times the CO_2 factors times 99% (assuming a 99% burn factor). This was the recommended calculation technique from the DOE Emission of Greenhouse Gases in the United States report.
- ✓ The CO_2 emission factors are:

Distillate Oil (No.2)	21.945	Tons / MmBtu
Residual Oil (No.6)	23.639	Tons / MmBtu
Coal Industrial (other)	28.193	Tons / MmBtu
Natural gas	15.917	Tons / MmBtu
Petroleum Coke*	30.635	Tons / MmBtu

* Petroleum Coke was assumed to have a heat content of 15,000 Btu/lb

17.3. Recovery Furnace Assumptions

The following are the assumptions:

17.3.1. General Assumptions

- ✓ NDCE recovery furnace firing 3.7 Mm lb BLS/day is assumed to have an air flow of 27,500 lb/min, NO_x Control Technology.
- ✓ For the cases where the design heat load (i.e., Mm Btu/hr) is not known, it was calculated from the design BLS firing rate, utilizing a heat content of 5900 Btu/lb.

17.3.2. NO_x Control Technology

- ✓ The limits were converted to a lb/Mm Btu basis that equates to.

NDCE at 80 ppm	0.1415 lb / Mm Btu
NDCE at 40 ppm	0.0726 lb / Mm Btu
DCE at 30 ppm	0.0544 lb / Mm Btu

- ✓ The annual NO_x emission rates from the NCASI database were converted to lb/Mm Btu and compared with 80% of the above limits. The NO_x limits are based upon 30-day averages and it was assumed that to comply with the 30-day average limits the annual average would be approximately 80% of the 30-day limits.
- ✓ For the case of the good technology, if a given furnace did not meet the adjusted limit, then its emission rate was assumed to average the adjusted limit (i.e., 80% of the 30-day average limits) after treatment. The adjustment of 80% represents a compliance safety margin.
- ✓ If no emission rates were indicated for 1995, then no treatment estimate was made for that furnace.
- ✓ For the case of the best technology, if a given furnace did not meet the adjusted limit, then its emission rate was assumed to be reduced by 50% after treatment

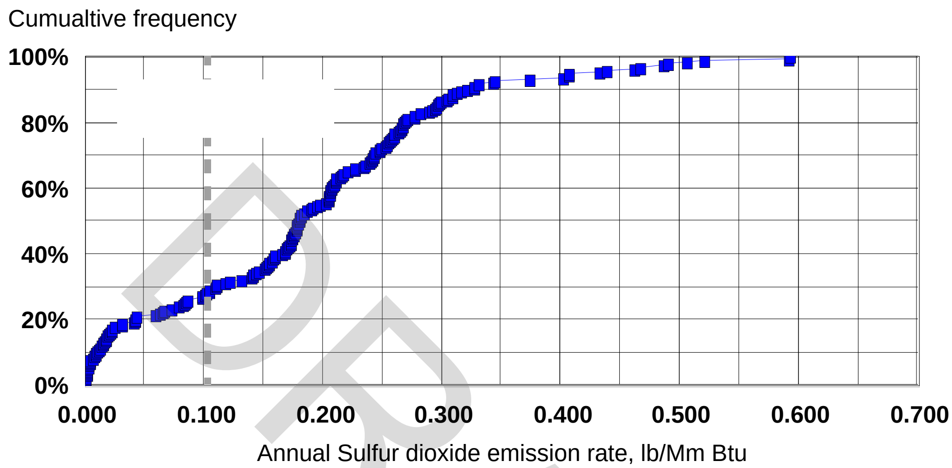
17.3.3. SO_2 Control Technology

- ✓ The limits were converted to a lb/Mm Btu basis that equates to.

NDCE at 50 ppm	0.12 Lb / MmBtu
NDCE at 10 ppm	0.0.024 Lb / MmBtu
DCE at 50 ppm	0.0.12 Lb / MmBtu
DCE at 10 ppm	0.0.024 Lb / MmBtu

- ✓ The annual SO_2 emission rates from the NCASI database were converted to lb/Mm Btu basis and compared with 80% of the above limits. The SO_2 limits are based upon 30-day averages and it was assumed that to comply with the 30-day average limits the annual average would be approximately 80% of the 30-day limits.
- ✓ The following illustrates the cumulative distribution for the recovery furnace SO_2 emission rates from the 1995 NCASI database:

Recovery Furnace SO2 Emission Distribution



Basis: 1995 NCASI emission data base
Good technology limit is based upon 30-day average time 0.8

- ✓ For recovery furnaces with up to four-times the adjusted SO_2 limit (i.e., 0.3628 lb/Mm Btu), combustion control modifications (**<u>these are the same as what was estimated for good controls for NO_x</u>**) would be implemented. For recovery furnaces with SO_2 limits greater than 0.3628 lb/Mm Btu, a new scrubber would be installed. In either case, the controlled emission rate would be equivalent to an annual average of 40 ppm (i.e., 50 ppm x 80%).
- ✓ If no emissions were indicated for 1995, then no treatment estimate was made for the furnace.
- ✓ For both technologies, if a given furnace did not meet the adjusted limit, then its emission rate was assumed to average the adjusted limit. The adjustment of 80% represents a compliance safety margin.

17.3.4. PM Control Technology

- ✓ Any recovery furnace ESP built or rebuilt after 1990 but before 1998 was assumed capable of meeting the good PM technology limit.

- ✓ Any recovery furnace ESP built after 1990 but before 1998 will be upgraded with additional fields for best PM technology limits.
- ✓ Any NDCE recovery furnace ESP built or rebuilt before 1980 will be upgraded with additional field for the good PM technology limit and be replaced for the best PM technology limit.
- ✓ Any NDCE recovery furnace ESP built or rebuilt after 1980 will meet the good technology limits.
- ✓ Any non-NDCE recovery furnace ESP or scrubber built before 1990 will be replaced with a new ESP for either good or best PM technology.
- ✓ Any recovery furnace ESP built or rebuilt after 1998 was assumed to comply with the best PM technology limit.

17.3.5. VOC Control Technology

- ✓ Good VOC technology limit consists of collecting and incinerating the BLO vent gas from any non-NDCE recovery furnace.
- ✓ Best VOC technology consists of converting any NDCE recovery furnace ESPs from wet to dry bottom and converting any non-NDCE to a NDCE recovery furnace

17.3.6. Smelt Dissolving Tank Scrubber - PM Technology

- ✓ Number of smelt dissolving tank was determined based upon the manufacturer. Combustion Engineering furnaces with greater than a 3.5 Mm lb BLS/ day firing rates are assumed to have two smelt dissolving tanks and the other manufacturer's have one smelt dissolving tank. For the case of the two smelt dissolving tank scrubbers, the initial scrubber was factored based on half the black liquor-firing rate and then multiplied by two.
- ✓ Any recovery furnace built before 1976 will require a new smelt dissolving tank scrubber.
- ✓ Any recovery furnace built or rebuilt after 1976 but before 1990 was assumed to meet the good PM technology limit
- ✓ Any recovery furnace built or rebuilt after 1990 was assumed to meet the best PM technology limit

17.4. Lime Kiln Assumptions

The following are the assumptions:

17.4.1. PM Control Technology

- ✓ Any lime kiln built after 1976 and equipped with a wet scrubber or those kiln equipped with an ESP installed prior to 1990 was assumed to meet the good PM technology limit.
- ✓ Any limekiln equipped with an ESP installed prior to 1990 was assumed upgradable to meet the best PM technology limit.
- ✓ Any lime kiln equipped with an ESP installed after 1990 was assumed to meet the best PM technology limit

17.4.2. NO_x Control Technology

- ✓ If the annual NCASI-estimated NO_x levels are less than 20 TPY, no controls will be added. This level represents approximately 10% of the limekilns from the NCASI database.
- ✓ If no emissions where indicated for 1995, then no treatment estimate was made for the kiln.
- ✓ If the mill burns the NCGs primarily in the limekiln, then it was assumed that if there is a stripper present the stripper off-gases (SOGs) are burned in the limekiln.
- ✓ The NO_x level in the limekiln if NCGs are being burned will decrease by 30% if the SOGs are burned in a thermal oxidizer. The thermal oxidizer would be equipped with staged combustion to control the NO_x levels.
- ✓ The NO_x level in the limekiln will decrease by 60% with the incorporation of SCR and low-NO_x burners. If a good technology fix was required, the best technology was additive: the 60% reduction was compounded on the 30% reduction for a total of a 72% reduction [(1-0.3) x (1-0.6)].

17.5. Boiler and Turbine Assumptions

- ✓ 350 operating days per year were assumed.
- ✓ If the Btu/hr capacity of the boiler was not provided, then the steam output was multiplied by the assumed heating value for the steam of 1200 Btu/lb.
- ✓ If only the fuel combusted in 1995 was known,

- ✓ The fuel usage for each boiler from the NCASI database was multiplied by the following heating values:

Coal	25,000	MmBtu/1000 ton
Residual Oil (No.6)	5,920	MmBtu/1000 bbl
Distillate Oil (No.2)	5,376	MmBtu/1000 bbl
Natural gas	950	MmBtu/MmCF
Wood	9,000	MmBtu/1000 ton
Sludge	10,000	MmBtu/1000 ton

- ✓ If the design information for the boiler – either steam or Btu were not provided, then the sizing was based upon the 1995 NCASI fuel usage (if given) and Btu estimate. The steam output was calculated from the Btu estimate and the boiler efficiency, which was assumed 85% for everything, except for wood-fired boilers, which was assumed to have a 65% efficiency.
- ✓ The boiler design figure was compared with the predicted steam (i.e., based upon 1995 reported fuel usages) and which ever was higher was used to compute the capital costs for the control technologies. The operating costs were based upon the predicted steam usage.
- ✓ The best estimate SO_2, and NO_x yearly emission rates were converted to pounds and divided by Btus to determine a lb/MmBtu emission rate.
- ✓ The SO_2 and NO_x emission rates were then multiplied by 80% and compared with the technology limits. The technology limits are based upon 30-day averages and it was assumed that to comply with the 30-day average limits the annual average would be approximately 80% of the 30-day limits.
- ✓ For the case of the good technology, if a given furnace did not meet the adjusted limit, then its emission rate was assumed to average the adjusted limit after treatment (i.e., 80% of the 30-day average limits).
- ✓ For the case of SO_2 control technology, no control costs were assumed for any boiler designated as a wood or gas boiler, regardless of the emission level.
- ✓ <u>NCASI has listed 1225 boilers or turbines, and had fuel consumption information on 1074 of them. Control technology estimates for boilers were only made if fuel consumption information was provided.</u>

17.6. Coal Boiler Assumptions

17.6.1. General

- ✓ If more than 80% of the gross Btu's originated from coal, then the boiler was assumed a coal boiler.

17.6.2. NO_x Limits

- ✓ Any coal boilers after 1990 are assumed to have low NO_x burners and are assumed to meet the 0.3 lb/10^6 Btu, 30-day average.
- ✓ If the coal boilers were converted to natural gas with low NO_x-burners, then the emission rates were assumed to be 0.0490 and 0.1373 lb / 10^6 Btu for boilers less than and greater than 100 million Btu/hr, respectively.

17.6.3. SO_2 Limits

- ✓ Application of scrubbers to coal boilers will yield 50% reduction at good technology and 90% reduction at best technology.

17.6.4. Hg limits

- ✓ The uncontrolled limits were obtained by multiplying the MmBtu/year for 1995 by 16 lb/10^{12} Btu that is the AP-42 emission factor.
- ✓ The removal rate for the carbon injection and fabric filter approach was assumed 50%.

17.6.5. PM limits

- ✓ Any coal boiler with an ESP built or rebuilt after 1980 is assumed able to meet the good technology limit. If the ESP was built or rebuilt before 1980, the ESP's would be upgraded by adding a single field. If the year the ESP was constructed or rebuilt was not in the NCASI database, then the ESP was assumed to have been built or rebuilt before 1980. Any coal boiler constructed after 1990 is assumed to meet the good technology limit.
- ✓ Any coal boiler with an ESP built or rebuilt after 1980 can be upgraded to by adding a single field in two chambers to meet the best technology limit. A new ESP will be priced out for an ESP built or rebuilt before 1980.
- ✓ Any coal boiler constructed or an ESP built or rebuilt after 1998 is assumed to meet the best technology limit.

17.6.6. CO limits

- ✓ Any coal boiler constructed after 1990 is assumed to be able to meet the best technology limit of 200 ppm (24-hour average).

17.6.7. HCl limits

- ✓ Use same criteria as for SO_2 limits – if a scrubber was required for SO2, then it was assumed a scrubber would be required for HCl control. This applied to both good and best control technologies.
- ✓ If SO_2 control is installed there will be no need to install HCl controls as well; the chemical addition rate for SO_2 is greater than what is required to remove the HCl present.

17.7. Coal / Wood Boiler Assumptions

17.7.1. General Assumptions

- ✓ At least 20% of the Btus had to come from coal or wood provided both were used within the boiler.

17.7.2. NO_x Limits

- ✓ Any coal boilers after 1990 were assumed to have low NO_x burners and were assumed to meet the 0.3 lb/10^6 Btu, 30-day average
- ✓ For the case of the good or best technology, if a given boiler did not meet the adjusted limit, then its emission rate was assumed to average the adjusted limit (i.e., 80% of the 30-day average limits) after treatment

17.7.3. SO_2 Limits

- ✓ Application of scrubbers to coal/wood boilers will yield 50% reduction at good technology and 90% reduction at best technology.

17.7.4. Hg limits

- ✓ The uncontrolled limits were obtained by multiplying the MmBtu/year for 1995 by 16 lb/10^{12} Btu for coal and by 0.572 lb/10^{12} Btu for wood. Both are based upon the AP-42 emission factor with the wood corrected for the difference in heavy metals between coal and wood.
- ✓ The removal rate for the carbon injection and fabric filter approach was assumed 50%.

17.7.5. PM limits

- ✓ Any coal/wood boiler with an ESP built or rebuilt after 1980 is assumed able to meet the good technology limit. If the ESP was built or rebuilt before 1980, the ESP's would be upgraded by adding a single field in two chambers. If the year the ESP was constructed or rebuilt was not in the NCASI database, then the ESP was assumed to have been built or rebuilt before 1980.

- ✓ Any coal/wood boiler constructed after 1990 is assumed to meet the good technology limit.
- ✓ Any coal /wood boiler with an ESP built or rebuilt after 1980 can be upgraded to by adding a single field in two chambers to meet the best technology limit. A new ESP will be priced out for an ESP built or rebuilt before 1980.
- ✓ Any coal/wood boiler constructed or an ESP built or rebuilt after 1998 is assumed to meet the best technology limit.

17.7.6. CO limits

- ✓ Any coal / wood boiler will require controls to meet the best technology limit of 200 ppm (24-hour average)

17.8. Gas Boiler Assumptions

17.8.1. General Assumptions

- ✓ A minimum of 90% of the Btu's had to come from natural gas, in order for the boiler to be considered a gas boiler.

17.8.2. NO_x Limits

- ✓ Any gas boilers after 1990 are assumed to have low-NO_x burners and are assumed to meet the 0.05 lb/10^6 Btu, 30-day average
- ✓ For the case of the good or best technology, if a given boiler did not meet the adjusted limit, then its emission rate was assumed to average the adjusted limit (i.e., 80% of the 30-day average limits) after treatment

17.9. Gas Turbine Assumptions

17.9.1. NO_x Limits

- ✓ Any gas turbines after 1995 are assumed to have water or steam injection to control to the good technology limit of 25 ppm @ 15% oxygen.
- ✓ For the case of the good or best technology, if a given turbine did not meet the adjusted limit, then its emission rate was assumed to average the adjusted limit (i.e., 80% of the 30-day average limits) after treatment

17.10. Oil Boiler Assumptions

17.10.1. General Assumptions

- ✓ If both oil and gas are burned, then if more than 15% of the Btu's originates from oil, the boiler was considered an oil boiler.

- ✓ If oil and wood or coal was burned, then at least 85% of the Btu had to originate from oil for the boiler to be considered an oil boiler.

17.10.2. NO_x Limits

- ✓ Any oil boilers after 1990 are assumed to have low-NO_x burners and are assumed to meet the 0.2 lb/10^6 Btu, 30-day average
- ✓ For the case of the good or best technology, if a given boiler did not meet the adjusted limit, then its emission rate was assumed to average the adjusted limit (i.e., 80% of the 30-day average limits) after treatment

17.10.3. SO_2 Limits

- ✓ Application of scrubbers to oil boilers will yield 50% reduction at good technology and 90% reduction at best technology.

17.10.4.PM limits

- ✓ Any oil boiler with an ESP is assumed able to meet the good technology limit.
- ✓ Any oil boiler constructed after 1990 is assumed to meet the good technology limit.
- ✓ Any oil boiler burning distillate oil is assumed to meet the good technology limit.
- ✓ Any oil boiler with an ESP can be upgraded to by adding a single field in two chambers to meet the best technology limit.
- ✓ Any oil boiler constructed after 1998 is assumed to meet the best technology limit.

17.11. Wood-Fired Boiler Assumptions

17.11.1. General Assumptions

- ✓ Any boiler where at least 80% of the Btu originate from wood, then the boiler is considered a wood-fired boiler.

17.11.2. NO_x Limits

- ✓ Any wood boiler after 1990 are assumed to have combustion controls and are assumed to meet the 0.25 lb/10^6 Btu, 30-day average
- ✓ For the case of the good or best technology, if a given boiler did not meet the adjusted limit, then its emission rate was assumed to average the adjusted limit after treatment (i.e., 80% of the 30-day average limits).

17.11.3. Hg limits

- ✓ The uncontrolled limits were obtained by multiplying the MmBtu/year for 1995 by 0.572 lb/10^{12} Btu for wood. This is based upon the AP-42 emission factor for coal corrected for the difference in heavy metals between coal and wood.
- ✓ The removal rate for the carbon injection and fabric filter approach was assumed 50%.

17.11.4. PM limits

- ✓ Any wood boiler with an ESP built or rebuilt after 1980 is assumed able to meet the good technology limit. If the ESP was built or rebuilt before 1980, the ESP's would be upgraded by adding a single field in two chambers. If the year the ESP was constructed or rebuilt was not in the NCASI database, then the ESP was assumed to have been built or rebuilt before 1980.
- ✓ Any wood boiler constructed after 1990 is assumed to meet the good technology limit.
- ✓ Any wood boiler with an ESP built or rebuilt after 1980 can be upgraded to by adding a single field in two chambers to meet the best technology limit. A new ESP will be priced out for an ESP built or rebuilt before 1980.
- ✓ Any wood boiler constructed or an ESP built or rebuilt after 1998 is assumed to meet the best technology limit.

17.11.5.CO limits

- ✓ Any wood boiler will require cotnrols to meet the best technology limit of 200 ppm (24-hour average)

17.12. Paper Machine Assumptions

- ✓ Fisher Database statistics were used.
- ✓ Minimum machine size capacity of 50 tons per day was used as the cut-off.
- ✓ Only paper machines with unbleached Kraft, semi-chemical, NSSC, and mechanical pulp furnishes were considered for the good technology limits. Unbleached recycle fiber furnishes were considered for the best technology limits.
- ✓ Each mechanical pulp line was treated separately for the good technology limit.
- ✓ The good technology was sized based upon the pulp mill production. A minimum of 200 tons per day was used as the cut-off for the pulp mill production for everything but mechanical pulping, which was set at 100 tons per day.

- ✓ The best technology was sized based upon the paper machine capacity. If only a portion of a paper machine's furnish was one of the above fiber furnishes, then the paper machine was treated.
- ✓ The untreated emission rate for the unbleached paper machines was assumed to be 0.47 lb C / ODTP. (Basis: NCASI Tech Bulletin No. 681)
- ✓ The emission reduction for the good technology was assumed 67%.
- ✓ The emission reduction for the best technology was assumed 99%.

17.13. Mechanical Pulping

- ✓ Fisher Database statistics were used
- ✓ Minimum production level of 18,000 tons per year was used as the cut-off.
- ✓ Any TMP line constructed after 1989 is assumed to meet the good technology limits. Heat recovery was applied to all pressure groundwood mills regardless of age.
- ✓ Heat recovery was not applied to any atmospheric groundwood pulping lines.
- ✓ Any TMP pulping line constructed after 1998 is assumed to meet the best technology limits.

18. Appendix

18.1. MEANS and BE&K Labor Rate Factors by State

The following presents the state factors for the RS Means Open Shop Building Construction Cost Data 17th edition location factors for materials and subcontracting (or total) and the BE&K construction labor factors:

	Materials Factor	Subcontracting Factor	BE&K Construction Labor Factor
Alabama	0.967	0.823	1.000
Alaska	1.354	1.254	0.959
Arizona	0.989	0.876	0.975
Arkansas	0.957	0.778	0.970
California	1.076	1.119	0.983
Colorado	1.019	0.937	0.974
Connecticut	1.028	1.054	0.979
Delaware	0.992	1.009	0.968
Florida	0.987	0.841	0.992
Georgia	0.967	0.840	0.979
Idaho	1.021	0.938	0.960
Illinois	0.970	1.041	0.997
Indiana	0.975	0.957	0.958
Iowa	0.996	0.918	0.995
Kansas	0.966	0.864	0.961
Kentucky	0.955	0.895	0.992
Louisiana	0.989	0.824	0.990
Maine	0.996	0.824	1.003
Massachusetts	0.997	1.043	0.975
Maryland	0.937	0.884	0.973

	Materials Factor	Subcontracting Factor	BE&K Construction Labor Factor
Michigan	0.970	0.948	0.973
Minnesota	0.984	1.073	0.983
Mississippi	0.985	0.739	0.977
Missouri	0.962	0.950	0.987
Montana	0.995	0.938	0.977
Nebraska	0.978	0.828	0.962
Nevada	1.020	0.993	0.967
New Hampshire	0.983	0.913	0.982
New Jersey	1.028	1.125	0.965
New Mexico	1.006	0.912	0.972
New York	0.968	0.945	0.977
North Carolina	0.959	0.734	0.982
North Dakota	1.008	0.849	0.939
Ohio	0.967	0.944	0.954
Oklahoma	0.971	0.789	0.990
Oregon	1.044	1.060	0.967
Pennsylvania	0.975	0.982	0.982
Rhode Island	1.001	1.040	0.980
South Carolina	0.954	0.726	0.970
South Dakota	0.989	0.778	0.970
Tennessee	0.968	0.803	0.998
Texas	0.965	0.807	0.991
Utah	1.018	0.899	0.951
Vermont	1.010	0.855	0.973
Virginia	0.972	0.838	0.966
Washington	1.062	1.016	0.964
West Virginia	0.970	0.937	1.005

	Materials Factor	Subcontracting Factor	BE&K Construction Labor Factor
Wisconsin	0.984	0.959	0.979
Wyoming	1.003	0.826	0.939

18.2. Net Downtime

Although mill or process downtime costs were not included in the analysis, an estimate was made of the net downtime. Since the work would be done during scheduled downtime, the net downtime is the additional time required above the typical scheduled downtime. The following is BE&K's estimate for net downtime:

Good / Best Technology	Pollutant	Equipment	Net Downtime, days
Good	PM	NDCE Kraft Recovery Furnace	3
Best	PM	NDCE Kraft Recovery Furnace	3
Good	SO2	NDCE Kraft Recovery Furnace	3
Best	SO2	NDCE Kraft Recovery Furnace	3
Good	NOx	NDCE Kraft Recovery Furnace	3
Best	NOx	NDCE Kraft Recovery Furnace	3
Best	VOC	NDCE Kraft Recovery Furnace	3
Good	PM	DCE Kraft Recovery Furnace	3
Best	PM	DCE Kraft Recovery Furnace	3
Good	SO2	DCE Kraft Recovery Furnace	3
Best	SO2	DCE Kraft Recovery Furnace	3
Best	NOx	DCE Kraft Recovery Furnace	3
Good	VOC	DCE Kraft Recovery Furnace	4
Best	VOC	DCE Kraft Recovery Furnace	20
Good	PM	Smelt Dissolving tank	3
Best	PM	Smelt Dissolving tank	3
Good	PM	Lime Kilns	3
Best	PM	Lime Kilns	3
Best	NOx	Lime Kilns	3
Best	NOx	Lime Kilns	5
Good	PM	Coal Boiler	3
Best	PM	Coal Boiler	3

Good / Best Technology	Pollutant	Equipment	Net Downtime, days
Good	HCl	Coal Boiler	3
Best	HCl	Coal Boiler	3
Good	PM	Coal/Wood Boiler (50/50)	3
Best	PM	Coal/Wood Boiler (50/50)	3
Good	SO2	Coal or Coal/Wood boiler (50/50)	3
Best	SO2	Coal or Coal/Wood boiler (50/50)	3
Good	NOx	Coal or Coal/Wood boiler (50/50)	3
Best	NOx	Coal or Coal/Wood boiler (50/50)	5
Best	NOx	Coal or Coal/Wood boiler (50/50)	3
Best	Hg	Coal or Coal/Wood boiler (50/50)	5
Best	CO	Coal or Coal/Wood boiler (50/50)	3
Good	NOx	Gas boiler	3
Best	NOx	Gas boiler	5
Good	NOx	Gas turbine	5
Good	NOx	Gas turbine	5
Best	NOx	Gas turbine	5
Good	PM	Oil boiler	3
Best	PM	Oil boiler	3
Good	SO2	Oil boiler	3
Best	SO2	Oil boiler	3
Good	NOx	Oil boiler	3
Best	NOx	Oil boiler	5
Good	PM	Wood boiler	5
Best	PM	Wood boiler	3
Best	PM	Wood boiler	5
Good	NOx	Wood boiler	3
Best	NOx	Wood boiler	3

Good / Best Technology	Pollutant	Equipment	Net Downtime, days
Best	NOx	Wood boiler	5
Best	Hg	Wood boiler	5
Best	CO	Wood boiler	3
Good	VOC	Paper machines	3
Best	VOC	Paper machines	3
Best	VOC	Paper machines	3
Good	VOC	Mechanical pulping	3
Best	VOC	Mechanical pulping	3
Best	Various	Recovery Furnace	NA
Best	PM	NDCE Kraft Recovery Furnace	3
Good	PM	NDCE Kraft Recovery Furnace	3
Best	PM	Lime Kilns	3
Best	PM	Coal Boiler	3
Best	PM	Coal/Wood Boiler (50/50)	3
Best	NOx	NDCE Kraft Recovery Furnace	5
Best	NOx	DCE Kraft Recovery Furnace	5
Best	VOC	Mechanical Pulp	3

															15%		20%	5%	5%		Annual Operating and Maintenance Costs and Assumptions						
No.	Good / Best	Pollutant	Equipment	Size	Technology limit	R&D % of Labor + Mat + Sub + equip	R&D	Labor hours	Labor $/hr	Labor	Materials	Subcontracts	Equipment	Total Directs Costs	Engineering	Subtotal	Contingency of direct costs + engineering	Owner's Cost % of direct costs	Construction Management % of direct costs	Total	Size of base unit	Feed rate	Materials Consumables (fabric filters, SCR media, etc.) at design	Chemical for design rate	Units	Type of chemical	Chemical (2) for design rate
1	Good	PM	NDCE Kraft Recovery Furnace	3.7x 106 lb BLS/day	ESP - 0.044 gr/dscf @ 8% Oxygen	0.0%	$ -	74,844	$ 58.62	$ 4,387,355	$ 1,834,000	$ 10,009,900	$ 1,054,500	$ 17,285,755	$ 2,592,863	$ 19,878,619	$ 3,975,724	$ 864,288	$ 864,288	$ 25,582,918	2.15	Mmlb BLS/day	$ -	-	NA	NA	-
2	Best	PM	NDCE Kraft Recovery Furnace	3.7x 106 lb BLS/day	ESP - 0.015 gr/dscf @ 8% Oxygen	0.0%	$ -	74,844	$ 58.62	$ 4,387,355	$ 1,834,000	$ 12,261,000	$ 1,319,600	$ 19,801,955	$ 2,970,293	$ 22,772,249	$ 4,554,450	$ 990,098	$ 990,098	$ 29,306,894	2.15	Mmlb BLS/day	$ -	-	NA	NA	-
3	Good	SO2	NDCE Kraft Recovery Furnace	3.7x 106 lb BLS/day	Scrubber - 50 ppm@ 8% Oxygen, 30-day average	0.0%	$ -	50,443	$ 58.62	$ 2,956,969	$ 861,100	$ 1,274,100	$ 3,586,000	$ 8,678,169	$ 1,301,725	$ 9,979,894	$ 1,995,979	$ 433,908	$ 433,908	$ 12,843,690	2.50	Mmlb BLS/day	$ -	1.33	gpm	50% NaOH	-
4	Best	SO2	NDCE Kraft Recovery Furnace	3.7x 106 lb BLS/day	Scrubber - 10 ppm @ 8% Oxygen, 30-day average	0.0%	$ -	50,443	$ 58.62	$ 2,956,969	$ 861,100	$ 1,274,100	$ 3,586,000	$ 8,678,169	$ 1,301,725	$ 9,979,894	$ 1,995,979	$ 433,908	$ 433,908	$ 12,843,690	2.50	Mmlb BLS/day	$ -	1.53	gpm	50% NaOH	-
5	Good	NOx	NDCE Kraft Recovery Furnace	3.7x 106 lb BLS/day	Combustion control - 80 ppm@ 8% Oxygen, 30-day average	0.0%	$ -	1,713	$ 58.62	$ 100,416	$ 28,800	$ 14,000	$ 278,500	$ 421,716	$ 63,257	$ 484,973	$ 96,995	$ 21,086	$ 21,086	$ 624,140	2.60	Mmlb BLS/day	$ -	-	NA	NA	-
6	Best	NOx	NDCE Kraft Recovery Furnace	3.7x 106 lb BLS/day	SNCR - 40 ppm@ 8% Oxygen (50% reduction, 30-day average)	1.0%	$ 34,210	-	$ 58.62	$ -	$ -	$ 3,421,000	$ -	$ 3,455,210	$ 518,282	$ 3,973,492	$ 794,698	$ 172,761	$ 172,761	$ 5,113,711	3.50	Mmlb BLS/day	$ -	256.00	tpy	urea	-
7	Best	VOC	NDCE Kraft Recovery Furnace	3.7x 106 lb BLS/day	Replace wet bottom with dry bottom, no limit	0.0%	$ -	-	$ 58.62	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,266,300	1.50	Mmlb BLS/day	$ -	-	NA	NA	-
8	Good	PM	DCE Kraft Recovery Furnace	1.7x 106 lb BLS/day	ESP - 0.044 gr/dscf @ 8% Oxygen	0.0%	$ -	46,755	$ 58.62	$ 2,740,778	$ 1,152,300	$ 6,273,200	$ 665,300	$ 10,831,578	$ 1,624,737	$ 12,456,315	$ 2,491,263	$ 541,579	$ 541,579	$ 16,030,736	2.15	Mmlb BLS/day	$ -	-	NA	NA	-
9	Best	PM	DCE Kraft Recovery Furnace	1.7x 106 lb BLS/day	ESP - 0.015 gr/dscf @ 8% Oxygen	0.0%	$ -	46,755	$ 58.62	$ 2,740,778	$ 1,152,300	$ 7,702,300	$ 829,000	$ 12,424,378	$ 1,863,657	$ 14,288,035	$ 2,857,607	$ 621,219	$ 621,219	$ 18,388,080	2.15	Mmlb BLS/day	$ -	-	NA	NA	-
10	Good	SO2	DCE Kraft Recovery Furnace	1.7x 106 lb BLS/day	Scrubber - 50 ppm @ 8% Oxygen, 30-day average	0.0%	$ -	31,777	$ 58.62	$ 1,862,768	$ 542,800	$ 802,900	$ 2,203,800	$ 5,412,268	$ 811,840	$ 6,224,108	$ 1,244,822	$ 270,613	$ 270,613	$ 8,010,156	2.50	Mmlb BLS/day	$ -	0.82	gpm	50% NaOH	-
11	Best	SO2	DCE Kraft Recovery Furnace	1.7x 106 lb BLS/day	Scrubber - 10 ppm @ 8% Oxygen, 30-day average	0.0%	$ -	31,777	$ 58.62	$ 1,862,768	$ 542,800	$ 802,900	$ 2,203,800	$ 5,412,268	$ 811,840	$ 6,224,108	$ 1,244,822	$ 270,613	$ 270,613	$ 8,010,156	2.50	Mmlb BLS/day	$ -	0.94	gpm	50% NaOH	-
12	Best	NOx	DCE Kraft Recovery Furnace	1.7x 106 lb BLS/day	SNCR - 50% reduction (30ppm @ 8% Oxygen)	1.0%	$ 16,020	-	$ 58.62	$ -	$ -	$ 1,602,000	$ -	$ 1,618,020	$ 242,703	$ 1,860,723	$ 372,145	$ 80,901	$ 80,901	$ 2,394,670	3.50	Mmlb BLS/day	$ -	117.69	tpy	urea	-
13	Good	VOC	DCE Kraft Recovery Furnace	1.7x 106 lb BLS/day	BLO vent gas collection & incineration	0.0%	$ -	-	$ 58.62	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,554,700	1.50	Mmlb BLS/day	$ -	-	NA	NA	-
14	Best	VOC	DCE Kraft Recovery Furnace	1.7x 106 lb BLS/day	Conversion to NDCE	0.0%	$ -	-	$ 58.62	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 19,664,100	1.50	Mmlb BLS/day	$ -	-	NA	NA	-
15	Good	PM	Smelt Dissolving tank	3.7x 106 lb BLS/day	0.2 lb/ton BLS	0.0%	$ -	16,177	$ 58.62	$ 948,296	$ 244,900	$ 13,500	$ 342,400	$ 1,549,096	$ 232,364	$ 1,781,460	$ 356,292	$ 77,455	$ 77,455	$ 2,292,662	2	Mmlb BLS/day	$ -	-	NA	NA	-
16	Best	PM	Smelt Dissolving tank	3.7x 106 lb BLS/day	0.12 lb/ton BLS	0.0%	$ -	16,177	$ 58.62	$ 948,296	$ 244,900	$ 13,500	$ 394,000	$ 1,600,696	$ 240,104	$ 1,840,800	$ 368,160	$ 80,035	$ 80,035	$ 2,369,030	2	Mmlb BLS/day	$ -	-	NA	NA	-
17	Good	PM	Lime Kilns	240 tons CaO/day	0.064 gr/dscf @ 10% oxy	0.0%	$ -	6,529	$ 58.62	$ 382,730	$ 70,700	$ 425,600	$ 1,022,900	$ 1,901,930	$ 285,289	$ 2,187,219	$ 437,444	$ 95,096	$ 95,096	$ 2,814,856	540	TPD CaO	$ -	-	NA	NA	-
18	Best	PM	Lime Kilns	240 tons CaO/day	0.01 gr/dscf @ 10%oxy	0.0%	$ -	6,633	$ 58.62	$ 388,826	$ 70,700	$ 526,600	$ 1,280,200	$ 2,266,326	$ 339,949	$ 2,606,275	$ 521,255	$ 113,316	$ 113,316	$ 3,354,163	540	TPD CaO	$ -	-	NA	NA	-
19	Best	NOx	Lime Kilns	240 tons CaO/day	Route stripper off-gas to new thermal oxidizer	0.0%	$ -	10,126	$ 58.62	$ 593,586	$ 272,500	$ 233,600	$ 870,100	$ 1,969,786	$ 295,468	$ 2,265,254	$ 453,051	$ 98,489	$ 98,489	$ 2,915,283	20,000	ACFM	$ -	-	gpm	Net reclaim for NaOH	-
20	Best	NOx	Lime Kilns	240 tons CaO/day	Low-NOx burners & SCR.	1.0%	$ 43,387	7,438	$ 58.62	$ 436,016	$ 367,600	$ 525,800	$ 3,009,300	$ 4,382,103	$ 657,315	$ 5,039,418	$ 1,007,884	$ 219,105	$ 219,105	$ 6,485,512	120,000	lb/hr stm	$ 113,113	113.51	tpy	urea	-
21	Good	PM	Coal Boiler	300,000 pph	ESP - 0.065 lb/106 Btu	0.0%	$ -	48,985	$ 58.62	$ 2,871,501	$ 1,207,300	$ 7,314,700	$ 694,900	$ 12,088,401	$ 1,813,260	$ 13,901,661	$ 2,780,332	$ 604,420	$ 604,420	$ 17,890,833	600,000	lb/hr stm	$ -	-	NA	NA	-
22	Best	PM	Coal Boiler	300,000 pph	ESP - 0.04 lb/106 Btu	0.0%	$ -	48,985	$ 58.62	$ 2,871,501	$ 1,207,300	$ 8,928,000	$ 867,000	$ 13,873,801	$ 2,081,070	$ 15,954,871	$ 3,190,974	$ 693,690	$ 693,690	$ 20,533,225	600,000	lb/hr stm	$ -	-	NA	NA	-
23	Good	HCl	Coal Boiler	300,000 pph	Wet scrubber - 0.048 lb/106 Btu	0.0%	$ -	26,215	$ 58.62	$ 1,536,723	$ 447,400	$ 715,100	$ 1,832,500	$ 4,531,723	$ 679,758	$ 5,211,482	$ 1,042,296	$ 226,586	$ 226,586	$ 6,706,950	300,000	lb/hr stm	$ -	8.47	lb/hr	caustic soda	-
24	Best	HCl	Coal Boiler	300,000 pph	Wet scrubber - 0.015 lb/106 Btu	0.0%	$ -	26,215	$ 58.62	$ 1,536,723	$ 447,400	$ 715,100	$ 1,832,500	$ 4,531,723	$ 679,758	$ 5,211,482	$ 1,042,296	$ 226,586	$ 226,586	$ 6,706,950	300,000	lb/hr stm	$ -	25	lb/hr	caustic soda	-
25	Good	PM	Coal/Wood Boiler (50/50)	300,000 pph	ESP - 0.065 lb/106 Btu	0.0%	$ -	48,985	$ 58.62	$ 2,871,501	$ 1,207,300	$ 7,314,700	$ 694,900	$ 12,088,401	$ 1,813,260	$ 13,901,661	$ 2,780,332	$ 604,420	$ 604,420	$ 17,890,833	600,000	lb/hr stm	$ -	-	NA	NA	-
26	Best	PM	Coal/Wood Boiler (50/50)	300,000 pph	ESP - 0.04 lb/106 Btu	0.0%	$ -	48,985	$ 58.62	$ 2,871,501	$ 1,207,300	$ 8,928,000	$ 867,000	$ 13,873,801	$ 2,081,070	$ 15,954,871	$ 3,190,974	$ 693,690	$ 693,690	$ 20,533,225	600,000	lb/hr stm	$ -	-	NA	NA	-
27	Good	SO2	Coal or Coal/Wood boiler (50/50)	300,000 pph	50% reduction, max. 0.6 lb/106 Btu	0.0%	$ -	26,215	$ 58.62	$ 1,536,723	$ 447,300	$ 715,100	$ 2,305,000	$ 5,004,123	$ 750,618	$ 5,754,742	$ 1,150,948	$ 250,206	$ 250,206	$ 7,406,102	600,000	lb/hr stm	$ -	0.57	gpm	50% NaOH	-
28	Best	SO2	Coal or Coal/Wood boiler (50/50)	300,000 pph	Scrubber - 90% reduction, max. 0.12 lb/106 Btu	0.0%	$ -	26,215	$ 58.62	$ 1,536,723	$ 447,300	$ 715,100	$ 2,305,000	$ 5,004,123	$ 750,618	$ 5,754,742	$ 1,150,948	$ 250,206	$ 250,206	$ 7,406,102	600,000	lb/hr stm	$ -	1.14	gpm	50% NaOH	-
29	Good	NOx	Coal or Coal/Wood boiler (50/50)	300,000 pph	Low-NOx burners max. 0.3 lb/10^6 Btu	0.0%	$ -	2,883	$ 58.62	$ 169,001	$ 151,400	$ 216,500	$ 1,428,400	$ 1,965,301	$ 294,795	$ 2,260,097	$ 452,019	$ 98,265	$ 98,265	$ 2,908,646	420,000	lb/hr stm	$ -	-	NA	NA	-
30	Best	NOx	Coal or Coal/Wood boiler (50/50)	300,000 pph	SCR - 0.17 lb/106 Btu, 30-day average	0.5%	$ 81,841	28,068	$ 58.62	$ 1,645,346	$ 1,386,500	$ 1,983,500	$ 11,352,800	$ 16,449,987	$ 2,467,498	$ 18,917,485	$ 3,783,497	$ 822,499	$ 822,499	$ 24,345,981	120,000	lb/hr stm	$ 426,728	428.21	tpy	urea	-
31	Best	NOx	Coal or Coal/Wood boiler (50/50)	300,000 pph	Switch from coal to gas	0.0%	$ -	7,262	$ 58.62	$ 425,698	$ 261,100	$ 541,400	$ 709,100	$ 1,937,298	$ 290,595	$ 2,227,893	$ 445,579	$ 96,865	$ 96,865	$ 2,867,202	420,000	lb/hr stm	$ -	-	NA	NA	-
32	Best	Hg	Coal or Coal/Wood boiler (50/50)	300,000 pph	Carbon injection and fabric filter	1.5%	$ 83,294	15,168	$ 58.62	$ 889,148	$ 274,900	$ 1,253,900	$ 3,135,000	$ 5,636,242	$ 845,436	$ 6,481,679	$ 1,296,336	$ 281,812	$ 281,812	$ 8,341,639	300,000	lb/hr stm	$ -	0.08	tpd	activated carbon	3,750
33	Best	CO	Coal or Coal/Wood boiler (50/50)	300,000 pph	Combustion controls to achieve a 200 ppm (24-hour average)	0.0%	$ -	402	$ 58.62	$ 23,565	$ 20,000	$ 1,852,000	$ 346,000	$ 2,241,565	$ 336,235	$ 2,577,800	$ 515,560	$ 112,078	$ 112,078	$ 3,317,517	300,000	lb/hr stm	$ -	-	NA	NA	-
34	Good	NOx	Gas boiler	120,000 pph	Combustion modification - low-Nox burners, FGR - 0.05 lb /106Btu, 30-day average	0.0%	$ -	1,928	$ 58.62	$ 113,019	$ 102,100	$ 126,100	$ 865,800	$ 1,207,019	$ 181,053	$ 1,388,072	$ 277,614	$ 60,351	$ 60,351	$ 1,786,389	420,000	lb/hr stm	$ -	-	NA	NA	-
35	Best	NOx	Gas boiler	120,000 pph	SCR- 0.015 lb/106 Btu, 30-day average	0.0%	$ -	10,682	$ 58.62	$ 626,179	$ 528,000	$ 755,200	$ 4,322,200	$ 6,231,579	$ 934,737	$ 7,166,316	$ 1,433,263	$ 311,579	$ 311,579	$ 9,222,737	120,000	lb/hr stm	$ 162,469	163.03	tpy	urea	-
36a	Good	NOx	Gas turbine	30 MW	Water injection - 25 ppm @15% Oxygen, 30-day average	0.0%	$ -	1,752	$ 58.62	$ 102,702	$ 17,100	$ 2,637,200	$ -	$ 2,757,002	$ 413,550	$ 3,170,553	$ 634,111	$ 137,850	$ 137,850	$ 4,080,363	30	MW	$ -	-	NA	NA	-
36b	Good	NOx	Gas turbine	30 MW	Steam injection - 25 ppm @15% Oxygen, 30-day average	0.0%	$ -	1,332	$ 58.62	$ 78,082	$ 14,700	$ 4,299,000	$ -	$ 4,391,782	$ 658,767	$ 5,050,549	$ 1,010,110	$ 219,589	$ 219,589	$ 6,499,837	30	MW	$ -	-	NA	NA	-
37	Best	NOx	Gas turbine	30 MW	SCR - 5 ppm @ 15% Oxygen, 30-day average	0.0%	$ -	-	$ 58.62	$ -	$ -	$ 2,182,900	$ 2,467,400	$ 4,650,300	$ 697,545	$ 5,347,845	$ 1,069,569	$ 232,515	$ 232,515	$ 6,882,444	30	MW	$ 104,393	104.76	tpy	urea	-
38	Good	PM	Oil boiler	135,000 pph	Switch to low-sulfur oil	0.0%	$ -	408	$ 58.62	$ 23,917	$ 2,000	$ 63,000	$ 9,400	$ 98,317	$ 14,748	$ 113,065	$ 22,613	$ 4,916	$ 4,916	$ 145,509	420,000	lb/hr stm	$ -	-	NA	NA	-
39	Best	PM	Oil boiler	135,000 pph	ESP - 0.02 lb/106 Btu	0.0%	$ -	32,240	$ 58.62	$ 1,889,909	$ 794,600	$ 4,763,900	$ 571,700	$ 8,020,109	$ 1,203,016	$ 9,223,125	$ 1,844,625	$ 401,005	$ 401,005	$ 11,869,761	600,000	lb/hr stm	$ -	-	NA	NA	-
40	Good	SO2	Oil boiler	135,000 pph	Scrubbing, 50% reduction, max 0.4 lb/106 Btu, 30-day average	0.0%	$ -	23,831	$ 58.62	$ 1,396,973	$ 406,700	$ 601,900	$ 1,670,600	$ 4,076,173	$ 611,426	$ 4,687,599	$ 937,520	$ 203,809	$ 203,809	$ 6,032,736	600,000	lb/hr stm	$ -	0.26	gpm	50% NaOH	-
41	Best	SO2	Oil boiler	135,000 pph	Scrubber - 90% reduction, max. 0.08 lb/106 Btu, 30-day average	0.0%	$ -	23,831	$ 58.62	$ 1,396,973	$ 406,700	$ 601,900	$ 1,670,600	$ 4,076,173	$ 611,426	$ 4,687,599	$ 937,520	$ 203,809	$ 203,809	$ 6,032,736	600,000	lb/hr stm	$ -	0.34	gpm	50% NaOH	-
42	Good	NOx	Oil boiler	135,000 pph	Combustion modification, 50% reduction, max 0.2 lb/106 Btu, 30-day average	0.0%	$ -	1,786	$ 58.62	$ 104,695	$ 94,000	$ 134,100	$ 884,700	$ 1,217,495	$ 182,624	$ 1,400,120	$ 280,024	$ 60,875	$ 60,875	$ 1,801,893	420,000	lb/hr stm	$ -	-	NA	NA	-
43	Best	NOx	Oil boiler	135,000 pph	SCR- 90% reduction, max 0.04 lb/106 Btu, 30-day average	0.5%	$ 45,560	15,620	$ 58.62	$ 915,644	$ 772,100	$ 1,104,200	$ 6,320,000	$ 9,157,504	$ 1,373,626	$ 10,531,130	$ 2,106,226	$ 457,875	$ 457,875	$ 13,553,106	120,000	lb/hr stm	$ 237,563	228.00	tpy	urea	-
44	Good	PM	Wood boiler	300,000 pph	Replace scrubber with ESP - 0.065 lb/10^6 Btu	0.0%	$ -	58,214	$ 58.62	$ 3,412,505	$ 1,434,700	$ 7,044,000	$ 763,000	$ 12,654,205	$ 1,898,131	$ 14,552,335	$ 2,910,467	$ 632,710	$ 632,710	$ 18,728,223	600,000	lb/hr stm	$ -	-	NA	NA	-
45	Best	PM	Wood boiler	300,000 pph	ESP - 0.04 lb/106 Btu	0.0%	$ -	58,214	$ 58.62	$ 3,412,505	$ 1,434,700	$ 8,589,300	$ 955,800	$ 14,392,305	$ 2,158,846	$ 16,551,150	$ 3,310,230	$ 719,615	$ 719,615	$ 21,300,611	600,000	lb/hr stm	$ -	-	NA	NA	-
46	Best	PM	Wood boiler	300,000 pph	Upgrade existing ESP from 0.1 to 0.04 lb/106 Btu	0.0%	$ -	3,074	$ 58.62	$ 180,198	$ 86,000	$ 1,305,000	$ 905,000	$ 2,476,198	$ 371,430	$ 2,847,628	$ 569,526	$ 123,810	$ 123,810	$ 3,664,773	310,000	lb/hr stm	$ -	-	NA	NA	-
47	Good	NOx	Wood boiler	300,000 pph	Combustion Controls - 0.25 lb/106 Btu	0.0%	$ -	402	$ 58.62	$ 23,565	$ 20,000	$ 1,776,500	$ 359,000	$ 2,179,065	$ 326,860	$ 2,505,925	$ 501,185	$ 108,953	$ 108,953	$ 3,225,017	120,000	lb/hr stm	$ -	-	NA	NA	-
48	Best	NOx	Wood boiler	300,000 pph	SNCR - 0.20 lb/106 Btu - 40% reduction	0.0%	$ -	2,618	$ 58.62	$ 153,467	$ 26,500	$ 477,600	$ 359,200	$ 1,016,767	$ 152,515	$ 1,169,282	$ 233,856	$ 50,838	$ 50,838	$ 1,504,815	400,000	lb/hr stm	$ -	165.16	tpy	urea	-
49	Best	NOx	Wood boiler	300,000 pph	SCR- 0.17 lb/106 Btu - 50% reduction	0.5%	$ 55,525	19,038	$ 58.62	$ 1,116,008	$ 940,900	$ 1,345,700	$ 7,702,400	$ 11,160,533	$ 1,674,080	$ 12,834,612	$ 2,566,922	$ 558,027	$ 558,027	$ 16,517,588	120,000	lb/hr stm	$ 287,197	287.09	tpy	urea	-
50	Best	Hg	Wood boiler	300,000 pph	Carbon injection and fabric filter	1.5%	$ 95,964	15,734	$ 58.62	$ 922,327	$ 305,100	$ 1,269,900	$ 3,900,300	$ 6,493,591	$ 974,039	$ 7,467,630	$ 1,493,526	$ 324,680	$ 324,680	$ 9,610,515	300,000	lb/hr stm	$ -	0.003962	tpd	activated carbon	375.00
51	Best	CO	Wood boiler	300,000 pph	Combustion controls to achieve a 200 ppm (24-hour average)	0.0%	$ -	402	$ 58.62	$ 23,565	$ 20,000	$ 1,776,500	$ 359,000	$ 2,179,065	$ 326,860	$ 2,505,925	$ 501,185	$ 108,953	$ 108,953	$ 3,225,017	350,000	lb/hr stm	$ -	-	NA	NA	-
52	Good	VOC	Paper machines	1000 tpd	Installation of screw press prior to high-density storage in pulp mill for unbleached Kraft and OCC recycle mills.	0.0%	$ -	25,575	$ 58.62	$ 1,499,207	$ 904,100	$ 235,000	$ 1,464,300	$ 4,102,607	$ 615,391	$ 4,717,997	$ 943,599	$ 205,130	$ 205,130	$ 6,071,858	1,000	ton/day	$ -	-	NA	NA	-
53	Best	VOC	Paper machines	1000 tpd	Collect & incinerate wet-end vent gases	1.5%	$ 35,750	5,719	$ 58.62	$ 335,248	$ 101,300	$ 940,800	$ 1,005,976	$ 2,419,074	$ 362,861	$ 2,781,935	$ 556,387	$ 120,954	$ 120,954	$ 3,580,229	1,000	ton/day	$ -	-	NA	NA	-
54	Best	VOC	Paper machines	1000 tpd	Collect & incinerate dry-end vent gases	1.5%	$ 51,303	5,700	$ 58.62	$ 334,134	$ 98,700	$ 1,410,400	$ 1,576,998	$ 3,471,535	$ 520,730	$ 3,992,265	$ 798,453	$ 173,577	$ 173,577	$ 5,137,872	1,000	ton/day	$ -	-	NA	NA	-
55	Good	VOC	Mechanical pulping	500 tpd	Better heat recovery from TMP mill to condense VOCs to < 0.5 lb C/ODTP	0.0%	$ -	11,908	$ 58.62	$ 698,047	$ 268,400	$ 197,800	$ 742,900	$ 1,907,147	$ 286,072	$ 2,193,219	$ 438,644	$ 95,357	$ 95,357	$ 2,822,578	500	ton/day	$ -	-	NA	NA	-
56	Best	VOC	Mechanical pulping	500 tpd	Collect & incinerate heat recovery vent gases from TMP mill	0.0%	$ -	5,473	$ 58.62	$ 320,827	$ 143,400	$ 122,900	$ 457,800	$ 1,044,927	$ 156,739	$ 1,201,666	$ 240,333	$ 52,246	$ 52,246	$ 1,546,492	500	ton/day	$ -	-	NA	NA	-
57	Best	Various	Recovery Furnace	3.7x 106 lb BLS/day	Black liquor gasifier utilizing Pulse Enhanced Steam reformation	1.5%	$1,645,212	105,780	$ 58.62	$ 6,200,824	$ 2,808,000	$ 23,712,000	$ 76,960,000	$ 111,326,036	$ 8,906,083	$ 120,232,119	$ 24,046,424	$ 5,566,302	$ 445,304	$ 150,290,149	3.7	Mmlb BLS/day	$ -	-	NA	NA	-
58	Best	PM	NDCE Kraft Recovery Furnace	3.7x 106 lb BLS/day	Add two parallel fields to upgrade ESP to Best technology	0.0%	$ -	-	$ 58.62	$ -	$ -	$ 3,630,000	$ -	$ 3,630,000	$ 544,500	$ 4,174,500	$ 834,900	$ 181,500	$ 181,500	$ 5,372,400	2.7	Mmlb BLS/day	$ -	-	NA	NA	-
59	Good	PM	NDCE Kraft Recovery Furnace	3.7x 106 lb BLS/day	Add two parallel fields to upgrade ESP to Good technology	0.0%	$ -	-	$ 58.62	$ -	$ -	$ 3,040,000	$ -	$ 3,040,000	$ 456,000	$ 3,496,000	$ 699,200	$ 152,000	$ 152,000	$ 4,499,200	2.7	Mmlb BLS/day	$ -	-	NA	NA	-
60	Best	PM	Lime Kilns	240 tons CaO/day	Add single field to upgrade ESP to Best technology	0.0%	$ -	-	$ 58.62	$ -	$ -	$ 536,000	$ 325,000	$ 861,000	$ 129,150	$ 990,150	$ 198,030	$ 43,050	$ 43,050	$ 1,274,280	540	TPD CaO	$ -	-	NA	NA	-
61	Best	PM	Coal Boiler	300,000 pph	Add single field in two chambers to upgrade ESP to Best technology	0.0%	$ -	-	$ 58.62	$ -	$ -	$ 1,992,000	$ 1,250,000	$ 3,242,000	$ 486,300	$ 3,728,300	$ 745,660	$ 162,100	$ 162,100	$ 4,798,160	600,000	lb/hr stm	$ -	-	NA	NA	-
62	Best	PM	Coal/Wood Boiler (50/50)	300,000 pph	Add single field in two chambers to upgrade ESP to Best technology	0.0%	$ -	-	$ 58.62	$ -	$ -	$ 2,153,000	$ 1,550,000	$ 3,703,000	$ 555,450	$ 4,258,450	$ 851,690	$ 185,150	$ 185,150	$ 5,480,440	600,000	lb/hr stm	$ -	-	NA	NA	-
63	Best	NOx	NDCE Kraft Recovery Furnace	3.7x 106 lb BLS/day	SCR - 80% reduction	1.5%	$ 196,955	-	$ 58.62	$ -	$ -	$ 13,130,300	$ -	$ 13,327,255	$ 1,999,088	$ 15,326,343	$ 3,065,269	$ 666,363	$ 666,363	$ 19,724,337	120,000	lb/hr stm- Coal boiler	$ 375,251	376.56	tpy	urea	-
64	Best	NOx	DCE Kraft Recovery Furnace	1.7x 106 lb BLS/day	SCR - 80% reduction	1.5%	$ 128,061	-	$ 58.62	$ -	$ -	$ 8,537,400	$ -	$ 8,665,461	$ 1,299,819	$ 9,965,280	$ 1,993,056	$ 433,273	$ 433,273	$ 12,824,882	120,000	lb/hr stm- Coal boiler	$ 243,990	244.84	tpy	urea	-
65	Best	VOC	Mechanical pulping	500 tpd	Heat recovery system from TMP mill to condense VOCs. Then collection and incineration of the NCGs.	0.0%	$ -	17,381	$ 58.62	$ 1,018,874	$ 411,800	$ 320,700	$ 1,200,700	$ 2,952,074	$ 442,811	$ 3,394,885	$ 678,977	$ 147,604	$ 147,604	$ 4,369,070	500	ton/day	$ -	-	NA	NA	-
66	Good	VOC	Mechanical pulping	500 tpd	Heat recovery system from pulping processes to condense VOCs from a pressurized groundwood	0.0%	$ -	11,908	$ 58.62	$ 698,047	$ 268,400	$ 197,800	$ 742,900	$ 1,907,147	$ 286,072	$ 2,193,219	$ 438,644	$ 95,357	$ 95,357	$ 2,822,578	500	ton/day	$ -	-	NA	NA	-
67	Best	VOC	Mechanical pulping	500 tpd	Heat recovery system from pulping processes to condense VOCs from a pressurized groundwood Then collection & incineration of the NCGs	0.0%	$ -	20,202	$ 58.62	$ 1,184,220	$ 487,600	$ 384,946	$ 1,436,877	$ 3,493,643	$ 524,046	$ 4,017,689	$ 803,538	$ 174,682	$ 174,682	$ 5,170,591	500	ton/day	$ -	-	NA	NA	-
68	Best	VOC	Mechanical pulping	500 tpd	Collection & incineration of NCGs from an atmospheric groundwood	0.0%	$ -	29,599	$ 58.62	$ 1,612,370	$ 782,300	$ 667,900	$ 2,476,719	$ 5,539,289	$ 830,893	$ 6,370,182	$ 1,274,036	$ 276,964	$ 276,964	$ 8,198,148	500	ton/day	$ -	-	NA	NA	-

No.	Good / Best	Pollutant	Equipment	Units	Type of chemical	Maintenance labor & materials, % of TIC	Energy, kw/feed rate at design rate	units	Usage Factor	Manpower hr/dy	Testing	Water, gpm at design rate	wastewater, gpm at design rate	Steam at steam rate	units	Compress air at design rate	units	Fuel cost	units	Natural gas usage	units	General Utilities	Units	Incremental Solid Waste Disposal	Units	Downtime Net downtime assumes that outage can be coordinated with scheduled equipment downtime: net downtime is additional downtime beyond the normal scheduled outage - days
1	Good	PM	NDCE Kraft Recovery Furnace	NA	NA	3.50%	546.63983	kw/Mmlb BLS	70%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
2	Best	PM	NDCE Kraft Recovery Furnace	NA	NA	3.50%	683.29978	kw/Mmlb BLS	80%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
3	Good	SO2	NDCE Kraft Recovery Furnace	NA	NA	3.50%	440.92377	kw/Mmlb BLS	70%	3.00	$ 5,000	148.00	14.80	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
4	Best	SO2	NDCE Kraft Recovery Furnace	NA	NA	3.50%	440.92377	kw/Mmlb BLS	80%	3.00	$ 5,000	148.00	14.80	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
5	Good	NOx	NDCE Kraft Recovery Furnace	NA	NA	1.00%	20.14061	kw/Mmlb BLS	70%	0.75	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
6	Best	NOx	NDCE Kraft Recovery Furnace	NA	NA	3.50%	4.26257	kw/Mmlb BLS	70%	3.00	$ 5,000	3.00	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
7	Best	VOC	NDCE Kraft Recovery Furnace	NA	NA	2.00%	4.03243	kw/Mmlb BLS	70%	1.50	$ 5,000	-	-	$ -	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
8	Good	PM	DCE Kraft Recovery Furnace	NA	NA	3.50%	746.10919	kw/Mmlb BLS	70%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
9	Best	PM	DCE Kraft Recovery Furnace	NA	NA	3.50%	932.63649	kw/Mmlb BLS	80%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
10	Good	SO2	DCE Kraft Recovery Furnace	NA	NA	3.50%	601.81726	kw/Mmlb BLS	70%	3.00	$ 5,000	68.00	6.80	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
11	Best	SO2	DCE Kraft Recovery Furnace	NA	NA	3.50%	601.81726	kw/Mmlb BLS	80%	3.00	$ 5,000	68.00	6.80	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
12	Best	NOx	DCE Kraft Recovery Furnace	NA	NA	3.50%	9.27736	kw/Mmlb BLS	70%	3.00	$ 5,000	3.00	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
13	Good	VOC	DCE Kraft Recovery Furnace	NA	NA	3.00%	88.64235	kw/Mmlb BLS	70%	3.00	$ 5,000	-	-	294.12	lb/hr/Mmlb BLS/day	-	NA	$ -	NA	-	NA	-	NA	-	NA	4
14	Best	VOC	DCE Kraft Recovery Furnace	NA	NA	3.00%	264.96165	kw/Mmlb BLS	70%	3.00	$ 5,000	-	-	(15,873)	lb/hr/Mmlb BLS/day	-	NA	$ -	NA	-	NA	-	NA	-	NA	20
15	Good	PM	Smelt Dissolving tank	NA	NA	2.00%	77.47584	kw/Mmlb BLS	70%	1.50	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
16	Best	PM	Smelt Dissolving tank	NA	NA	2.00%	85.22343	kw/Mmlb BLS	80%	1.50	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
17	Good	PM	Lime Kilns	NA	NA	3.00%	0.77961	kw/tpd CaO	70%	2.25	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
18	Best	PM	Lime Kilns	NA	NA	3.00%	0.97451	kw/tpd CaO	80%	2.25	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
19	Best	NOx	Lime Kilns	NA	NA	3.50%	0.31083	kw/tpd CaO	70%	3.00	$ 5,000	35.00	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
20	Best	NOx	Lime Kilns	NA	NA	2.00%	0.68643	kw/tpd CaO	70%	28.57	$ 5,000	1.97	-	2.30	lb/hr/tpd CaO	0.05	cfm/tpd CaO	$ -	NA	-	NA	-	NA	-	NA	5
21	Good	PM	Coal Boiler	NA	NA	3.00%	0.00444	hp/lb/hr stm	70%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	39.00	tpy of ash	3
22	Best	PM	Coal Boiler	NA	NA	3.00%	0.00555	kw/lb/hr/stm	80%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	77.00	tpy of ash	3
23	Good	HCl	Coal Boiler	NA	NA	5.00%	0.00270	kw/lb/hr/stm	70%	3.00	$ 5,000	64.00	20.00	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
24	Best	HCl	Coal Boiler	NA	NA	5.00%	0.00270	kw/lb/hr/stm	80%	3.00	$ 5,000	64.00	20.00	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
25	Good	PM	Coal/Wood Boiler (50/50)	NA	NA	3.00%	0.00444	kw/lb/hr/stm	70%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	94.00	tpy of ash	3
26	Best	PM	Coal/Wood Boiler (50/50)	NA	NA	3.00%	0.00555	kw/lb/hr/stm	80%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	137.00	tpy of ash	3
27	Good	SO2	Coal or Coal/Wood boiler (50/50)	NA	NA	3.50%	0.00381	kw/lb/hr/stm	70%	3.00	$ 5,000	142.86	14.29	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
28	Best	SO2	Coal or Coal/Wood boiler (50/50)	NA	NA	3.50%	0.00508	kw/lb/hr/stm	80%	3.00	$ 5,000	142.86	14.29	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
29	Good	NOx	Coal or Coal/Wood boiler (50/50)	NA	NA	2.00%	0.00081	kw/lb/hr/stm	70%	1.50	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
30	Best	NOx	Coal or Coal/Wood boiler (50/50)	NA	NA	2.00%	0.00207	kw/lb/hr/stm	70%	28.57	$ 5,000	7.43	-	0.006939	lb/hr/lb/hr stm	0.00015	cfm/lb/hr stm	$ -	NA	-	NA	-	NA	-	NA	5
31	Best	NOx	Coal or Coal/Wood boiler (50/50)	NA	NA	1.00%	-	NA	0%	1.50	$ 5,000	-	-	-	-	-	-	$ -	NA	0.00120	Mmbtu/hr /Mlb/hr steam	-	NA	-	NA	3
32	Best	Hg	Coal or Coal/Wood boiler (50/50)	lb/hr	lime	5.00%	0.00109	kw/lb/hr/stm	70%	3.00	$ 5,000	64.00	20.00	-	-	-	-	$ -	NA	-	NA	-	NA	15,779.65	tpy of lime & carbon	5
33	Best	CO	Coal or Coal/Wood boiler (50/50)	NA	NA	3.00%	0.00099	kw/lb/hr/stm	70%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
34	Good	NOx	Gas boiler	NA	NA	3.00%	0.00147	kw/lb/hr/stm	70%	1.50	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
35	Best	NOx	Gas boiler	NA	NA	2.00%	0.00197	kw/lb/hr/stm	70%	28.57	$ 5,000	2.83	-	0.00660	lb/hr/lb/hr stm	0.000142	cfm/lb/hr stm	$ -	NA	-	NA	-	NA	-	NA	5
36a	Good	NOx	Gas turbine	NA	NA	2.00%	0.06667	kw/MW	70%	1.50	$ 5,000	10.00	-	-	-	-	-	$ -	NA	-	NA	-	NA	-	NA	5
36b	Good	NOx	Gas turbine	NA	NA	2.00%	0.06667	kw/MW	70%	1.50	$ 5,000	4.76	-	79.3800	lb/hr/MW	-	-	$ -	NA	-	NA	-	NA	-	NA	5
37	Best	NOx	Gas turbine	NA	NA	2.00%	13.93333	kw/MW	70%	3.00	$ 5,000	5.00	-	46.67	lb/hr/MW	1.00	cfm/MW	$ -	NA	-	NA	-	NA	-	NA	5
38	Good	PM	Oil boiler	NA	NA	3.00%	-	NA	0%	-	$ 5,000	-	-	-	-	-	-	$ 21.21	$/yr/lb/hr st	-	NA	-	NA	-	NA	3
39	Best	PM	Oil boiler	NA	NA	3.00%	0.00813	kw/lb/hr/stm	70%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	99.00	tpy of ash	3
40	Good	SO2	Oil boiler	NA	NA	3.00%	0.00411	kw/lb/hr/stm	70%	3.00	$ 5,000	42.86	4.29	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
41	Best	SO2	Oil boiler	NA	NA	3.00%	0.00548	kw/lb/hr/stm	80%	3.00	$ 5,000	42.86	4.29	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
42	Good	NOx	Oil boiler	NA	NA	3.00%	0.00112	kw/lb/hr/stm	70%	1.50	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
43	Best	NOx	Oil boiler	NA	NA	2.00%	0.00256	kw/lb/hr/stm	70%	28.57	$ 5,000	4.14	-	0.00858	lb/hr/lb/hr stm	0.00018	cfm/lb/hr stm	$ -	NA	-	NA	-	NA	-	NA	5
44	Good	PM	Wood boiler	NA	NA	3.50%	0.00304	kw/lb/hr/stm	70%	3.00	$ 5,000	(200.00)	(20.00)	-	NA	-	NA	$ -	NA	-	NA	-	NA	551.00	tpy of ash	5
45	Best	PM	Wood boiler	NA	NA	3.50%	0.00659	kw/lb/hr/stm	70%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	599.00	tpy of ash	3
46	Best	PM	Wood boiler	NA	NA	2.00%	0.00083	kw/lb/hr/stm	70%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	116.00	tpy of ash	5
47	Good	NOx	Wood boiler	NA	NA	3.00%	0.00099	kw/lb/hr/stm	70%	1.50	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
48	Best	NOx	Wood boiler	NA	NA	3.50%	0.00004	kw/lb/hr/stm	80%	3.00	$ 5,000	3.00	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
49	Best	NOx	Wood boiler	NA	NA	2.00%	0.00140	kw/lb/hr/stm	75%	28.57	$ 5,000	5.00	-	0.004676	lb/hr/lb/hr stm	0.00010	cfm/lb/hr stm	$ -	NA	-	NA	-	NA	-	NA	5
50	Best	Hg	Wood boiler	lb/hr	pebble lime	5.00%	0.00087	kw/lb/hr/stm	70%	3.00	$ 5,000	89.60	28.00	-	NA	-	NA	$ -	NA	-	NA	-	NA	1,576.39	tpy of lime & carbon	5
51	Best	CO	Wood boiler	NA	NA	3.00%	0.00099	kw/lb/hr/stm	70%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
52	Good	VOC	Paper machines	NA	NA	3.00%	0.86089	kw/tpd	70%	1.50	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	5
53	Best	VOC	Paper machines	NA	NA	3.00%	0.31160	kw/tpd	70%	1.50	$ 5,000	-	-	-	NA	-	NA	$ -	NA	0.00471	Mmbtu/hr/tpd	-	NA	-	NA	5
54	Best	VOC	Paper machines	NA	NA	3.00%	0.37975	kw/tpd	70%	1.50	$ 5,000	-	-	-	NA	-	NA	$ -	NA	0.00810	Mmbtu/hr/tpd	-	NA	-	NA	5
55	Good	VOC	Mechanical pulping	NA	NA	3.00%	0.32912	kw/tpd	70%	1.50	$ 5,000	192.00	194.00	(188.51)	lb/hr/tpd pulp	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
56	Best	VOC	Mechanical pulping	NA	NA	3.50%	0.04476	kw/tpd	70%	2.25	$ 5,000	10.00	10.00	-	NA	-	NA	$ -	NA	0.00371	Mmbtu/hr/tpd	-	NA	-	NA	3
57	Best	Various	Recovery Furnace	NA	NA	3.00%	###################	kW/Mmlb BLS	70%	-	$ 5,000	-	650.00	########	lb/hr/Mmlb BLS/day	-	NA	$ -	NA	-	NA	0.10%	Of TIC	12.32	tons/day/Mm lb BLS	NA
58	Best	PM	NDCE Kraft Recovery Furnace	NA	NA	2.00%	81.08108	kw/Mmlb BLS	70%	1.50	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
59	Good	PM	NDCE Kraft Recovery Furnace	NA	NA	2.00%	74.32432	kw/Mmlb BLS	70%	1.50	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
60	Best	PM	Lime Kilns	NA	NA	1.00%	0.41667	kw/tpd CaO	70%	2.25	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
61	Best	PM	Coal Boiler	NA	NA	1.00%	0.00183	kw/lb/hr/stm	70%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	38.00	NA	3
62	Best	PM	Coal/Wood Boiler (50/50)	NA	NA	1.00%	0.00167	kw/lb/hr/stm	70%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	43.00	NA	3
63	Best	NOx	NDCE Kraft Recovery Furnace	NA	NA	2.00%	147.71161	kw/Mmlb BLS	70%	28.57	$ 5,000	6.54	-	494.73	lb/hr/Mmlb BLS/day	10.60	cfm/Mmlb BLS/day	$ -	NA	-	NA	-	NA	-	NA	5
64	Best	NOx	DCE Kraft Recovery Furnace	NA	NA	2.00%	209.03447	kw/Mmlb BLS	70%	28.57	$ 5,000	4.25	-	700.12	lb/hr/Mmlb BLS/day	25.50	cfm/Mmlb BLS/day	$ -	NA	-	NA	-	NA	-	NA	5
65	Best	VOC	Mechanical pulping	NA	NA	3.50%	0.37388	kw/tpd	70%	2.25	$ 5,000	202.00	204.00	(188.51)	lb/hr/tpd pulp	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
66	Good	VOC	Mechanical pulping	NA	NA	3.00%	0.32912	kw/tpd	70%	1.50	$ 5,000	192.00	38.80	(37.70)	lb/hr/tpd pulp	-	NA	$ -	NA	-	NA	-	NA	-	NA	
67	Best	VOC	Mechanical pulping	NA	NA	3.50%	0.39696	kw/tpd	70%	2.25	$ 5,000	202.00	48.80	(37.70)	lb/hr/tpd/pulp	-	NA	$ -	NA	0.00742	Mmbtu/hr/tpd	-	NA	-	NA	
68	Best	VOC	Mechanical pulping	NA	NA	3.50%	0.34847	kw/tpd	70%	2.25	$ 5,000	10.00	20.00	-	NA	-	NA	$ -	NA	0.03021	Mmbtu/hr/tpd	-	NA	-	NA	

Appendix G-2k WestRock Panama City Response.

Regional Haze Rule Four-Factor Analysis for the WestRock Panama City Mill

October 2020

Submitted by:

WestRock

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TABLE OF CONTENTS

Section Name **Page Number**

TABLE OF CONTENTS

Section Name **Page Number**

LIST OF TABLES

LIST OF APPENDICES

1. INTRODUCTION

The Florida Department of Environmental Protection (FDEP) Division of Air Resource Management is in the process of developing a State Implementation Plan (SIP) revision for the second implementation 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 manmade emissions of visibility impairing pollutants. The U.S. EPA developed the RHR to meet the Clean Air Act (CAA) requirements for the protection of visibility in 156 scenic areas, called Mandatory Class I Federal areas, across the United States. The RHR requires states to submit periodic SIPs demonstrating how they have and will continue to make progress towards achieving the national visibility goal by 2064. The first Regional Haze SIPs were due in 2007 and were required to include a long-term strategy and reasonable progress goals. Regional Haze SIPs must be updated in 2021, 2028, and every 10 years thereafter.

FDEP is required to submit its Regional Haze SIP for the second implementation period by July 31, 2021. The long-term strategy in the SIP submittal must include enforceable emissions limitations, compliance schedules and other measures necessary to make reasonable progress toward the national visibility goal. In determining the emissions reduction measures necessary to make reasonable progress, the RHR requires states to consider four factors, i.e., to conduct a four-factor analysis (FFA). Using the results of a screening analysis and source apportionment modeling, FDEP has identified the facilities in the state for which an FFA of emission controls is required and requested their cooperation in conducting the FFA for their facilities. FDEP will use the FFAs to determine the emission controls necessary for making reasonable further progress under the RH program and include those emission controls in its RH SIP.

FDEP has requested that WestRock provide an FFA of SO_2 emission control measures for the emission units at the Panama City Mill (the Mill) that are projected to emit more than 5 tons per year of SO_2 in 2028, specifically, the following emission units:

- No. 3 Combination Boiler
- No. 4 Combination Boiler
- No. 1 Recovery Boiler
- No. 2 Recovery Boiler

This report provides the requested FFA in Sections 2 through 5. Appendix A presents the control cost calculations and Appendix B presents supporting information.

1.1 FOUR-FACTOR ANALYSIS METHODOLOGY

FDEP has requested that the Mill address the following four factors specified in the Clean Air Act at Section 169A(g)(1) for technically feasible SO_2 emission control measures identified for the two power boilers and two recovery boilers at the Mill:

- Cost of compliance;
- Time necessary for compliance;
- Energy and non-air quality environmental impacts of compliance;
- Remaining useful life.

FDEP asked that WestRock also provide the control effectiveness and expected emission reductions that would be achieved by implementation of each technically feasible emission control measure, and that if a control measure is not technically feasible, WestRock should provide justification for that determination. FDEP further specified that WestRock should consult the August 2019 U.S. EPA Regional Haze Guidance in determining which emission control measures to consider and in developing the FFA of those control measures.

WestRock has addressed the four statutory factors in the FFA for each of the included emission units. WestRock has performed the cost analysis for the FFA using available site-specific data, capital costs of controls from vendor estimates, 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 Mill has not performed a significant degree of site-specific engineering analyses for this study due to the time constraints for this process but has used readily available information and sound engineering judgement 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 expected actual emissions in 2028.

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 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 utility costs are based on Mill-specific values.

1.2 SUMMARY OF SOURCES EVALUATED AND EXISTING REGULATORY REQUIREMENTS

Table 1-1 lists the SO_2 emissions units included in the FFA with their installation dates, fuels, existing emissions control technology, expected 2028 SO_2 emissions, and applicable major air regulations. 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). Power boilers and recovery 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 criteria pollutant emissions and promote good combustion practices. Actual emissions are based on 2017 values.

Table 1-1
Summary of Emissions Sources Evaluated

Emissions Unit Description	Year Installed	Fuels Fired[1]	Air Pollution Control Device	Actual SO_2 Emissions, tpy	Major Regulatory Programs
No. 3 Combination Boiler (EU015)	1954	Carbonaceous fuel (bark, wood, sawdust, wastewater wood fiber residuals, and bark ash), Natural gas[2], No. 2 fuel oil, No. 6 fuel oil	Fly ash arrestor, Variable throat venturi wet scrubber	190	MACT DDDDD
No. 4 Combination Boiler (EU016)	1965	Carbonaceous fuel (bark, wood, sawdust, wastewater wood fiber residuals, and bark ash), Coal, Natural gas[3], No. 2 fuel oil, No. 6 fuel oil	Fly ash arrestor, Wet scrubber	570	MACT DDDDD
No. 1 Recovery Boiler (EU001)	1970	Black liquor solids (BLS) with Natural gas, No. 2 fuel oil, No. 6 fuel oil (max 2.4% sulfur by wt.) as backup	Electrostatic precipitator (ESP), Two-stage heavy black liquor oxidation (BLOX)	166	MACT MM
No. 2 Recovery Boiler (EU019)	1971	BLS with Natural gas, No. 2 fuel oil, No. 6 fuel oil (max 2.4% sulfur by wt.) as backup	ESP, Two-stage BLOX	74	MACT MM

1. The Mill does not currently burn No. 2 fuel oil due to cost.
2. No. 3 Combination Boiler cannot burn natural gas at full load.
3. No. 4 Combination Boiler is permitted to burn natural gas but is only equipped with natural gas ignitors for burning coal.

1.3 SUMMARY OF RECENT EMISSIONS REDUCTIONS

Since 2010, the Mill has made emissions reductions for a variety of reasons. As shown in Table 1-1, the Mill 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. Emissions standards for HCl also serve to limit emissions of SO_2.

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 No. 3 Combination Boiler:** provides the FFA for the No. 3 Combination Boiler.
- **Section 3 – Four-Factor Analysis for No. 4 Combination Boiler:** provides the FFA for the No. 4 Combination Boiler.
- **Section 4 – Four-Factor Analysis for No. 1 Recovery Boiler:** provides the FFA for the No. 1 Recovery Boiler.
- **Section 5 – Four-Factor Analysis for No. 2 Recovery Boiler:** provides the FFA for the No. 2 Recovery Boiler.
- **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 NO. 3 COMBINATION BOILER

This section of the report presents the FFA for SO_2 control alternatives for the No. 3 Combination Boiler at the WestRock Panama City Mill. Using the four factors specified in the Clean Air Act and FDEP's instructions, the analysis consists of the following steps:

- Identification of available control measures
- Elimination of technically infeasible options
- Selection of control measures for analysis
- Assessment of the cost of compliance for the selected control measures (statutory factor 1)
- Assessment of the time necessary for compliance (statutory factor 2)
- Assessment of the energy and non-air quality environmental impacts of compliance (statutory factor 3)
- Assessment of the remaining useful life of the emission unit (statutory factor 4)

2.1 AVAILABLE CONTROL MEASURES

Air pollution control measures (including lower-emitting processes and practices) that have the potential for practical application to the emissions unit and pollutant under evaluation were considered. The scope of possible control options for the No. 3 Combination Boiler was determined based on a review of the RBLC database[1] and knowledge of typical controls used on boilers. RBLC entries that were not representative of the type of emissions unit or fuel being fired were excluded from further consideration. Table 2-1 summarizes the available SO_2 control technologies for industrial boilers.

[1] 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
SO_2	Low-sulfur fuels Wet scrubbers Dry scrubbing systems

The available control measures for reducing emissions of SO_2 from industrial boilers are discussed in detail below.

Low-sulfur Fuels

Uncontrolled emissions of SO_2 are proportional to the amount of sulfur in the fuel being fired. Combustion of natural gas, clean biomass, and ULSD all produce negligible SO_2 emissions. The No. 3 Combination Boiler is permitted to fire these low-sulfur fuels but also burns No. 6 fuel oil.

Acid Gas Scrubbers

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 (physical or chemical). Wet scrubbing involves a mass transfer operation in which one or more soluble components of an acid gas are dissolved in a liquid that has low volatility under process conditions. For SO_2 control, the absorption process is chemical-based and uses an alkali solution (*i.e.*, sodium hydroxide, sodium carbonate, sodium bicarbonate, calcium hydroxide, etc.) as a sorbent or reagent in combination with water. Removal efficiencies are affected by the chemistry of the absorbing solution as it reacts with the pollutant and the design of the wet scrubber. Most wet scrubbers have SO_2 removal efficiencies of at least 90 percent. Wet scrubbers may take the form of a variety of different configurations, including packed columns, plate or tray columns, spray chambers, and venturi scrubbers. The No. 3 Combination Boiler is equipped with a venturi scrubber.

Dry Scrubbing Systems

Types of dry scrubbing systems include spray dryer absorbers (SDA), circulating dry scrubbers (CDS), and dry sorbent injection systems (DSI). SDA systems are gas absorption systems that inject hydrated sorbent, typically lime (CaO) or hydrated lime ($Ca(OH)_2$), into the flue gas after a boiler's air heater. The hydrated sorbent chemically reacts with acid gas compounds and the fly ash in the gas stream to form calcium based salts while absorbing a portion of the residual heat in the flue gas to dry the resultant particles that are later removed in the downstream particulate control device. The July 2020 draft Section 5, Chapter 1, Section 1.2.2 of the U.S. EPA's OAQPS Air Pollution Control Cost Manual indicates that removal efficiencies for SO_2 of up to 95% are achievable for coal-fired power plants. However, the highest removal efficiencies are likely achievable only where a fabric filter is utilized for the particulate control device as is common in the utility industry (it is noted in July 2020 draft Cost Manual Section 5 that the filter cake of a fabric filter removes SO_2 from the gases, and reference 14 indicates that the removal across the filter can be significant).

Unlike an SDA system, a CDS operates like a circulating fluidized bed that the combustion gases pass through following a boiler's air heater section. In this type of system, the flue gas leaving the air heater section is wetted as it passes through a venturi section and enters upwards into the absorber body. Inside the absorber, water is added to reduce the flue gas temperature which aids in the chemical reaction with the hydrated lime and fly ash to form calcium salts. Particulates from the absorber are captured in the downstream control device. Flue gas flow rate is controlled to maintain the fluidized effect inside the absorber. The July 2020 draft Section 5, Chapter 1, Section 1.2.2 of the U.S. EPA's OAQPS Air Pollution Control Cost Manual indicates that removal efficiencies for SO_2 of up to 98% are achievable for coal-fired power plants. However, as with the SDA technology described above, some of the removal occurs in the filter cake of the fabric filter control devices employed by many coal-fired power plants for particulate removal and the highest removal efficiencies are likely achievable only where a fabric filter is used.

A DSI system controls acid gases by injecting a dry reagent (*i.e.*, lime or trona) into the flue gas stream prior to PM air pollution control equipment. A reaction takes place in the flue gas between the reagent and the acid gases, producing neutral salts that must be removed by the PM air pollution control equipment located downstream. The process is totally "dry," meaning it produces a dry disposal product and introduces the reagent as a dry powder. The benefits of this type of system include the elimination of liquid handling equipment requiring routine maintenance such as pumps, agitators, and atomizers. The drawbacks to using this type of system are the costs associated with the installation of a dry PM control device to collect the dry by-product, as well as ongoing operating costs to procure the sorbent material and dispose of additional dry waste. Dry sorbents can also prove challenging to maintain a very low moisture content and keep flowing. DSI systems are typically used to control SO_2 and other acid gases on coal-fired boilers. The July 2020 draft Section 5, Chapter 1, Section 1.2.1.3 of the U.S. EPA's Air Pollution Control Cost Manual for SO_2 Control indicates that DSI systems can be expected to achieve control efficiencies ranging from 50-70%.

2.2 ELIMINATION OF TECHNICALLY INFEASIBLE OPTIONS

An available control measure could be technically infeasible for a particular emission unit based on physical, chemical, or engineering principles that preclude its successful use for that emission unit. A technology is generally considered technically feasible if it has been demonstrated and operated successfully on the same or similar type of emission unit under review or is available and applicable to the emission unit type under review.

<u>Low-Sulfur Fuels</u>

The No. 3 Combination Boiler is a 505 MMBtu/hr unit that typically burns biomass, wastewater treatment plant (WWTP) residuals, and No. 6 fuel oil. It is capable of burning ULSD and some natural gas, but is not capable of burning natural gas at full load. The permitted capacity of natural gas is greater than the actual capacity of the installed burners and the actual gas burning capacity is lower than the total oil burning capacity. Replacement of No. 6 fuel oil with a lower-sulfur fuel is an available control measure for the No. 3 Combination Boiler but would require a detailed engineering evaluation.

Replacement with ULSD: Replacement of No. 6 fuel oil with ULSD would be technically feasible, but it is not cost effective as shown in Table 2-3.

Replacement with natural gas: Replacement of No. 6 fuel oil with natural gas is not technically feasible because there is a capacity constraint on the utility's pipeline supplying the Mill (*i.e.,* it is technically feasible to burn some natural gas in No. 3 Combination Boiler, but it is not technically feasible to obtain enough natural gas to replace No. 6 fuel oil usage). A preliminary evaluation has also determined that the existing natural gas infrastructure not only leading up to but within the Mill is inadequate to support the replacement of the total oil burner heat input capacity with a sufficient gas supply (flow and pressure). New, larger natural gas burners would be needed to replace the current fuel oil burning capacity of the boiler. Given the age of the existing burner management system (BMS), a new BMS may also be required. Finally, if the utility increased the pipeline capacity to make more gas available, a new natural gas contract would need to be negotiated to assure the Mill has an adequate, dependable supply of gas at adequate pressure to accommodate fuel oil replacement. Even if an engineering study were performed, the cost effectiveness and feasibility of this option would depend heavily on the capital cost for installing additional load burners, a new BMS, and the necessary gas supply infrastructure; the cost for firm natural gas at a higher supply rate; and the availability of adequate natural gas for Mill consumption requirements.

<u>Wet Scrubber</u>

The No. 3 Combination Boiler is controlled with a wet venturi scrubber. The wet scrubber currently achieves roughly 80% SO_2 removal efficiency on an annual average.[2] WestRock conducted a short term trial to determine if it would be technically feasible to increase caustic addition to the existing wet scrubber to increase the SO_2 control efficiency to at least 98%. In order to limit SO_2 emissions to less than 5 pounds per hour (lb/hr), 3 gallons per minute (gpm) of

[2] Control efficiency was calculated using emission factors for the amount of sulfur contained in pulp Mill NCGs and SOGs, fuel sulfur content, fuel usage, and actual (controlled) SO_2 emissions based on CEMS data. Calculations are included in Appendix A.

50% caustic (sodium hydroxide) had to be added to the wet scrubber, and the scrubber effluent pH increased to 10.5. This is not a sustainable operating scenario because the existing materials of construction would likely experience accelerated corrosion and scaling rates, and the Mill would need to increase acid addition to the wastewater treatment plant to counteract such a caustic stream. During the short-term scrubber trial (approximately 6 hours), the mill had to use an additional 600 gallons of sulfuric acid to neutralize the pH of the wastewater entering the primary wastewater treatment system. Even with the additional acid feed, the pH of the wastewater entering the primary wastewater treatment system had significant swings between basic and acidic. Such swings would present a risk to the long-term operation of the treatment system. Additionally, if this control option was implemented and a low short-term SO_2 emission limit (3-hour average or less) was established, it would have far-reaching implications on Mill operations. If transient scrubber operating problems occurred or the scrubber needed to be taken offline for necessary maintenance (such as for descaling), the boiler would not be able to meet the short-term SO_2 limit as currently configured and the Mill would have to shut down the boiler to avoid non-compliance. Because the Mill does not have spare boiler capacity, shutting down a boiler requires shutting down other parts of the pulp and papermaking process, which would have an adverse impact on mill production and profitability.

<u>Dry Scrubbing</u>
WestRock expects that it would be technically feasible to replace the wet scrubber with an SDA and fabric filter.

2.3 SELECTION OF CONTROL MEASURES FOR ANALYSIS

FDEP's request for an FFA states that WestRock should utilize the U.S. EPA's August 2019 Regional Haze Guidance in determining which emission control measures to consider. With respect to determining which emission control measures to consider in the FFA, that guidance states the following on page 29: "A state must reasonably pick and justify the measures that it will consider, recognizing that there is no statutory or regulatory requirement to consider all technically feasible measures or any particular measures. A range of technically feasible measures available to reduce emissions would be one way to justify a reasonable set."

WestRock selected at least one specific control measure from each of the control measure categories that were identified as available and technically feasible for application to the No. 3 Combination Boiler.

<u>Low-Sulfur Fuel</u>

Replacement of the No. 6 fuel oil fired in the No. 3 Combination Boiler with a lower-sulfur fuel was identified as a technically feasible alternative. WestRock selected the following replacement alternative for the FFA.

- Replace all No. 6 fuel oil with ULSD.

As described above, it is not currently feasible to replace all fuel oil with natural gas.

<u>Wet Scrubbing</u>

Although venturi scrubbers are designed primarily for PM control, additional caustic could be added to the existing scrubber to achieve improved SO_2 control. WestRock selected the following alternative for inclusion in the FFA:

- Wet scrubber improvement: increase the caustic addition rate to increase the SO_2 control efficiency to 98%.

<u>Dry Scrubbing System</u>

Dry scrubbing systems were identified as available and are expected to be technically feasible for application to the No. 3 Combination Boiler. Dry scrubbing systems typically utilize a dry PM control device such as a fabric filter, which increases the SO_2 reduction associated with the dry scrubber because SO_2 is removed across the filter cake in the fabric filter. The No. 3 Combination

Boiler is equipped with a venturi scrubber for particulate removal, so an SDA system would be designed with a fabric filer to replace the existing venturi scrubber.

WestRock selected the following dry scrubbing alternative for inclusion in the FFA:

- Spray dryer absorber (SDA): install and operate an SDA (including fabric filter) designed for 95% SO_2 removal and utilizing hydrated lime as the sorbent.

WestRock chose an SDA rather than CDS for analysis because we have some experience operating an SDA system at another WestRock mill and we have a recent vendor quotation for the cost of replacing most of the SDA system at that mill to increase control efficiency to 95% and could use that estimate to benchmark the cost of adding an SDA for the No. 3 Combination Boiler. Additionally, WestRock did not select a DSI system for further analysis because it would likely achieve no more than 50% SO_2 reduction and would require an upgrade or replacement of the existing wet scrubber in order to address the additional particulate loading.

2.4 COST OF COMPLIANCE

Cost analyses were developed for the selected control alternatives. 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, vendor estimates, previously developed company project costs, and/or EPA costing methodologies. The cost effectiveness for each selected 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. Actual emissions were used as the basis for emissions reductions. The actual 2017 emissions are a reasonable estimate of 2028 actual emissions.

Table 2-2 summarizes the control technologies for which costs were estimated for the No. 3 Combination Boiler.

Table 2-2
Control Technologies Evaluated for No. 3 Combination Boiler

Permitted Fuels	Existing SO_2 Control Technology	Additional SO_2 Control Technology Costed
Carbonaceous fuel (bark, wood, sawdust, wastewater wood fiber residuals, and bark ash), Natural gas, No. 2 fuel oil, No. 6 fuel oil	Variable throat venturi scrubber	Replace No. 6 fuel oil with ULSD Increase caustic addition to the wet scrubber SDA and fabric filter

Capital, operating, and total annual cost estimates and the assumed control efficiency and estimated emissions reduction for each control alternative are presented in Appendix A and summarized in Table 2-3. It should be noted that these are screening level cost estimates and are not based on detailed site-specific engineering studies. Site-specific factors such as space constraints, utility limitations (need for utility upgrades), or the ability to achieve the estimated emission reductions with a retrofitted control device could significantly impact the actual cost of implementing controls.

Table 2-3
No. 3 Combination Boiler Additional Control Measures Cost Summary

Control Measure	Capital Cost ($)	Annual Cost ($/yr)	SO_2 Control Efficiency Assumed	Annual SO_2 Emissions Reduction (tpy)	Cost Effectiveness of Controls ($/Ton SO_2)
Replace No. 6 fuel oil with ULSD	$2.3 Million	$457,458	2.85% incremental	5.4	$84,520
Increase caustic to the wet scrubber	TBD	$2.8 Million	98%	169	$16,364
Install an SDA and FF	$37.5 Million	$14.3 Million	95%	1,005 total 137 incremental	$14,267 total $104,601 incremental

<u>Low-Sulfur Fuel</u>

The cost to replace No. 6 fuel oil firing in No. 3 Combination Boiler with ULSD was evaluated using Mill-specific fuel costs and representative costs incurred at other mills to switch fuels. The estimated annual cost and cost effectiveness of implementing the selected No. 6 fuel oil replacement option for the No. 3 Combination Boiler is based on the current fuel costs and projected 2028 actual fuel use and emissions. The cost effectiveness depends heavily on the cost of fuel, which changes from year to year.

<u>Increase Caustic to the Wet Scrubber</u>

The Mill uses spent water treatment plant caustic in the wet scrubber, which achieves about 80% SO_2 reduction on an annual average and does not have a significant associated operating cost. We calculated the increased operating cost based on the amount of caustic that would be required to increase the current control efficiency to 98% using purchased 50% sodium hydroxide solution and the current cost of that caustic. Based on a recent short trial conducted at the Mill, the amount of caustic required to be added to the venturi scrubber to achieve 98% control is an order of magnitude higher than the stoichiometric amount. To be able to manage the volume of extra caustic required, a capital project would be required to install the equipment needed to receive the chemical and supply it to the scrubber. Because the need for this capital was just identified, we were unable to develop a capital cost estimate for inclusion in the FFA and it is shown as TBD (to be determined) in Table 2-3 above.

<u>SDA</u>

The capital and operating costs for an SDA system, including a fabric filter, were estimated using a January 2017 Sargent and Lundy report prepared under a U.S. EPA contract[3] and Mill specific cost data. These equations are also included in the draft update to the OAQPS Control Cost Manual, Section 5, SO_2 and Acid Gas Controls. The true cost effectiveness is likely between the

[3] Sargent & Lundy LLC. 2017. *SDA FGD Cost Development Methodology.* Project 13527-001, Eastern Research Group, Inc. Chicago, IL.

total and incremental cost per ton shown in Table 2-3 since the SDA system would replace the wet scrubber.

2.5 ENERGY AND NON-AIR RELATED IMPACTS

Low-Sulfur Fuel

Discontinuing No. 6 fuel oil firing would result in a one-time increase in waste generation, due to cleanout of the existing fuel oil storage and delivery systems.

Increase Caustic Addition to the Wet Scrubber

There are no significant energy impacts for this approach. It would however require a significant increase in purchased chemical and cause a significant increase in the pH of the scrubber blowdown to the wastewater treatment plant. This, in turn, would result in the need to add acid to the incoming wastewater to neutralize the caustic scrubber blowdown. During a short-term trial, significant swings in the incoming wastewater pH occurred, which would present a risk to the long-term operation of the treatment system.

Install an SDA System

Installation of an SDA system would increase solid waste and electricity usage.

2.6 TIME NECESSARY FOR COMPLIANCE

If fuel switching or a new add-on control system is ultimately required to meet RHR requirements, the Mill would need a minimum of four years to implement them after final EPA approval of the RHR SIP. At least four years would be required because the process to undertake a retrofitting project is complex, involving design, engineering, permitting, procurement, and installation to name only some of the necessary work streams. Also, since the start of the COVID pandemic, the time necessary to implement construction projects has increased considerably. Lead times for obtaining critical parts and equipment are much longer and the ability to bring outside skilled labor on site has become more difficult than in pre-COVID times. To implement one of the control alternatives, the Mill would need time to obtain corporate approvals for capital funding. Once funding was secured, the design, permitting, procurement, installation, and shakedown of a retrofit emissions control project could consume four years. The Mill would need to engage engineering consultants, equipment vendors, construction contractors, financial institutions, and other critical suppliers. 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. The Mill would need to continue to operate as much as possible while retrofitting to meet any new requirements.

2.7 REMAINING USEFUL LIFE OF NO. 3 COMBINATION BOILER

The No. 3 Combination Boiler is assumed to have a remaining useful life of twenty years or more.

3. FOUR-FACTOR ANALYSIS FOR NO. 4 COMBINATION BOILER

This section of the report presents the FFA for SO_2 control alternatives for the No. 4 Combination Boiler at the WestRock Panama City Mill. Using the four factors specified in the Clean Air Act and FDEP's instructions, the analysis consists of the following steps:

- Identification of available control measures
- Elimination of technically infeasible options
- Selection of control measures for analysis
- Assessment of the cost of compliance for the selected control measures (statutory factor 1)
- Assessment of the time necessary for compliance (statutory factor 2)
- Assessment of the energy and non-air quality environmental impacts of compliance (statutory factor 3)
- Assessment of the remaining useful life of the emission unit (statutory factor 4)

3.1 AVAILABLE CONTROL MEASURES

Air pollution control measures (including lower-emitting processes and practices) that have the potential for practical application to the emissions unit and pollutant under evaluation were considered. The scope of possible control options for the No. 4 Combination Boiler was determined based on a review of the RBLC database and knowledge of typical controls used on boilers. RBLC entries that were not representative of the type of emissions unit or fuel being fired were excluded from further consideration. Table 3-1 summarizes the available SO_2 control technologies for industrial boilers.

Table 3-1
Control Technology Summary

Pollutant	Controls on Industrial Boilers
SO_2	Low-sulfur fuels Wet scrubbers Dry scrubbing systems

The available control measures for reducing emissions of SO_2 from industrial boilers are discussed in detail below.

Low-sulfur Fuels

Uncontrolled emissions of SO_2 are proportional to the amount of sulfur in the fuel being fired. Combustion of natural gas, clean biomass, and ULSD all produce negligible SO_2 emissions. The No. 4 Combination Boiler is permitted to fire these low-sulfur fuels but also burns No. 6 fuel oil and coal.

Acid Gas Scrubbers

<u>Wet Scrubbers</u>

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 (physical or chemical). Wet scrubbing involves a mass transfer operation in which one or more soluble components of an acid gas are dissolved in a liquid that has low volatility under process conditions. For SO_2 control, the absorption process is chemical-based and uses an alkali solution (*i.e.*, sodium hydroxide, sodium carbonate, sodium bicarbonate, calcium hydroxide, etc.) as a sorbent or reagent in combination with water. Removal efficiencies are affected by the chemistry of the absorbing solution as it reacts with the pollutant and the design of the wet scrubber. Most wet scrubbers have SO_2 removal efficiencies of at least 90 percent. Wet scrubbers may take the form of a variety of different configurations, including packed columns, plate or tray columns, spray chambers, and venturi scrubbers. The No. 4 Combination Boiler is equipped with a venturi scrubber.

<u>Dry Scrubbing Systems</u>

Types of dry scrubbing systems include SDA, CDS, and DSI. SDA systems are gas absorption systems that inject hydrated sorbent, typically lime (CaO) or hydrated lime ($Ca(OH)_2$), into the flue gas after a boiler's air heater. The hydrated sorbent chemically reacts with acid gas compounds and the fly ash in the gas stream to form calcium based salts while absorbing a portion of the residual heat in the flue gas to dry the resultant particles that are later removed in the downstream particulate control device. The July 2020 draft Section 5, Chapter 1, Section 1.2.2 of the U.S. EPA's OAQPS Air Pollution Control Cost Manual indicates that removal efficiencies for SO_2 of up to 95% are achievable for coal-fired power plants. However, the highest removal efficiencies are likely achievable only where a fabric filter is utilized for the particulate control device as is common in the utility industry (it is noted in July 2020 draft Cost Manual Section 5 that the filter cake of a fabric filter removes SO_2 from the gases, and reference 14 indicates that the removal across the filter can be significant).

Unlike an SDA system, a CDS operates like a circulating fluidized bed that the combustion gases pass through following a boiler's air heater section. In this type of system, the flue gas leaving the air heater section is wetted as it passes through a venturi section and enters upwards into the absorber body. Inside the absorber, water is added to reduce the flue gas temperature which aids in the chemical reaction with the hydrated lime and fly ash to form calcium salts. Particulates from the absorber are captured in the downstream control device. Flue gas flow rate is controlled to maintain the fluidized effect inside the absorber. The July 2020 draft Section 5, Chapter 1, Section 1.2.2 of the U.S. EPA's OAQPS Air Pollution Control Cost Manual indicates that removal efficiencies for SO_2 of up to 98% are achievable for coal-fired power plants. However, as with the SDA technology described above, some of the removal occurs in the filter cake of the fabric filter control devices employed by many coal-fired power plants for particulate removal and the highest removal efficiencies are likely achievable only where a fabric filter is used.

A DSI system controls acid gases by injecting a dry reagent (*i.e.*, lime or trona) into the flue gas stream prior to PM air pollution control equipment. A reaction takes place in the flue gas between the reagent and the acid gases, producing neutral salts that must be removed by the PM air pollution control equipment located downstream. The process is totally "dry," meaning it produces a dry disposal product and introduces the reagent as a dry powder. The benefits of this type of system include the elimination of liquid handling equipment requiring routine maintenance such as pumps, agitators, and atomizers. The drawbacks to using this type of system are the costs associated with the installation of a dry PM control device to collect the dry by-product, as well as ongoing operating costs to procure the sorbent material and dispose of additional dry waste. Dry sorbents can also prove challenging to maintain a very low moisture content and keep flowing. DSI systems are typically used to control SO_2 and other acid gases on coal-fired boilers. The July 2020 draft Section 5, Chapter 1, Section 1.2.1.3 of the U.S. EPA's Air Pollution Control Cost Manual for SO_2 Control indicates that DSI systems can be expected to achieve control efficiencies ranging from 50-70%.

3.2 ELIMINATION OF TECHNICALLY INFEASIBLE OPTIONS

An available control measure could be technically infeasible for a particular emission unit based on physical, chemical, or engineering principles that preclude its successful use for that emission unit. A technology is generally considered technically feasible if it has been demonstrated and operated successfully on the same or similar type of emission unit under review or is available and applicable to the emission unit type under review.

<u>Low-Sulfur Fuel</u>

The No. 4 Combination Boiler is a 545 MMBtu/hr unit that typically burns biomass, wastewater treatment plant residuals, pulverized coal, and No. 6 fuel oil. It is capable of burning ULSD but does not have natural gas load-bearing burners (only gas ignitors for the coal burners). Replacement of No. 6 fuel oil and coal with a lower sulfur fuel (*e.g.,* natural gas or ULSD) is an available control measure for the No. 4 Combination Boiler.

Replacement with ULSD: Replacement of No. 6 fuel oil and coal with ULSD would be technically feasible, but it is not cost effective as shown in Table 3-3.

Replacement with natural gas: Replacement of No. 6 fuel oil and coal with natural gas is not technically feasible because there is a capacity constraint on the utility's pipeline supplying the Mill (*i.e.,* it is technically feasible to burn some natural gas in No. 4 Combination Boiler, but it is not technically feasible to obtain enough natural gas to replace No. 6 fuel oil and coal usage). A preliminary evaluation has also determined that the existing natural gas infrastructure not only leading up to but within the Mill is inadequate to support the replacement of the total oil and coal burner heat input capacity with a sufficient gas supply (flow and pressure). New load-bearing natural gas burners would be needed to replace the current fuel oil and coal burning capacity of the boiler. Given the age of the existing BMS, a new BMS may also be required. Finally, if the utility increased the pipeline capacity to make more gas available, a new natural gas contract would need to be negotiated to assure the Mill has an adequate, dependable supply of gas at adequate pressure to accommodate fuel oil and coal replacement. Even if an engineering study were performed, the cost effectiveness and feasibility of this option would depend heavily on the capital cost for installing new load burners, a new BMS, and the necessary gas supply infrastructure; the cost for firm natural gas at a higher supply rate; and the availability of adequate natural gas for Mill consumption requirements

<u>Wet Scrubbers</u>

The No. 4 Combination Boiler is controlled with a wet venturi scrubber. The wet scrubber currently achieves roughly 60% SO_2 removal efficiency based on an annual average.[4] WestRock expects that it would be technically feasible to increase caustic addition to the existing wet scrubber to increase the SO_2 control efficiency. WestRock conducted a short term trial to determine if it would be technically feasible to increase caustic addition to the existing wet scrubber to increase the SO_2 control efficiency to at least 98%. In order to limit SO_2 emissions to less than 5 lb/hr, 4 gpm of 50% caustic (sodium hydroxide) had to be added to the wet scrubber, and the scrubber

[4] Control efficiency was calculated using emission factors for the amount of sulfur contained in pulp Mill NCGs and SOGs, fuel sulfur content, fuel usage, and actual (controlled) SO_2 emissions based on CEMS data. Calculations are included in Appendix A.

effluent pH increased to 10.5. This is not a sustainable operating scenario because the existing materials of construction would likely experience accelerated corrosion and scaling rates and the Mill would need to increase acid addition to the wastewater treatment plant to counteract such a caustic stream. During the short-term scrubber trial (approximately 6 hours), the mill had to use an additional 600 gallons of sulfuric acid to neutralize the pH of the wastewater entering the primary wastewater treatment system. Even with the additional acid, the pH of the wastewater entering the primary wastewater treatment system had significant swings between basic and acidic. Such swings would present a risk to the long-term operation of the treatment system. Additionally, if this control option was implemented and a short-term SO_2 emission limit (3-hour average or less) was established, it would have far-reaching implications on Mill operations. If transient scrubber operating problems occurred or the scrubber needed to be taken offline for necessary maintenance (such as for descaling), the boiler would not be able to meet the short-term SO_2 limit in its current configuration and the Mill would have to shut down the boiler to avoid non-compliance. Because the Mill does not have spare boiler capacity, shutting down a boiler requires shutting down other parts of the pulp and papermaking process.

<u>Dry Scrubbing</u>

WestRock expects that it would be technically feasible to replace the wet scrubber with an SDA and fabric filter. While it may be technically feasible to install a DSI system, WestRock expects that an upgrade or replacement of the existing wet scrubber would be required to handle the additional particulate loading from the dry sorbent.

3.3 SELECTION OF CONTROL MEASURES FOR ANALYSIS

FDEP's request for an FFA states that WestRock should utilize the U.S. EPA's August 2019 Regional Haze Guidance in determining which emission control measures to consider. With respect to determining which emission control measures to consider in the FFA, that guidance states the following on page 29: "A state must reasonably pick and justify the measures that it will consider, recognizing that there is no statutory or regulatory requirement to consider all technically feasible measures or any particular measures. A range of technically feasible measures available to reduce emissions would be one way to justify a reasonable set."

WestRock selected at least one specific control measure from each of the control measure categories that were identified as available and technically feasible for application to the No. 4 Combination Boiler.

Low-Sulfur Fuel

Replacement of the coal and No. 6 fuel oil fired in the No. 4 Combination Boiler with a lower sulfur fuel was identified as a technically feasible alternative. WestRock selected the following replacement alternative for the FFA:

- Replace all No. 6 fuel oil and coal with ULSD.

As discussed above, it is not currently feasible to replace fuel oil and coal with natural gas.

Wet Scrubbing

Although venturi scrubbers are designed primarily for PM control, additional caustic could be added to the existing scrubber to achieve improved SO_2 control. WestRock selected the following alternative for inclusion in the FFA:

- Wet scrubber improvement: increase the caustic addition rate to increase the SO_2 control efficiency to 98%.

Dry Scrubbing System

Dry scrubbing systems were identified as available and are expected to be technically feasible for application to the No. 4 Combination Boiler. Dry scrubbing systems typically utilize a dry PM control device such as a fabric filter, which increases the SO_2 reduction associated with the dry scrubber because SO_2 is removed across the filter cake in the fabric filter. The No. 4 Combination

Boiler is equipped with a venturi scrubber for particulate removal, so an SDA system would be designed with a fabric filer to replace the existing venturi scrubber.

WestRock selected the following dry scrubbing alternative for inclusion in the FFA:

- Spray dryer absorber (SDA): install and operate an SDA (including fabric filter) designed for 95% SO_2 removal and utilizing hydrated lime as the sorbent.

WestRock chose an SDA rather than CDS for analysis because we have some experience operating an SDA system at another WestRock Mill and we have a recent vendor quotation for the cost of replacing most of the SDA system at that Mill to increase control efficiency to 95% and could use that estimate to benchmark the cost of adding an SDA for the No. 4 Combination Boiler. Additionally, WestRock did not select a DSI system for further analysis because it would likely achieve no more than 50% SO_2 reduction and would require an upgrade or replacement of the existing wet scrubber in order to address the additional particulate loading.

3.4 COST OF COMPLIANCE

Cost analyses were developed for the selected control alternatives. 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, vendor estimates, previously developed company project costs, and/or EPA costing methodologies. The cost effectiveness for each selected 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. Actual emissions were used as the basis for emissions reductions. The actual 2017 emissions are a reasonable estimate of 2028 actual emissions.

Table 3-2 summarizes the control technologies for which costs were estimated for the No. 4 Combination Boiler.

Table 3-2
Control Technologies Evaluated for No. 4 Combination Boiler

Permitted Fuels	Existing SO_2 Control Technology	Additional SO_2 Control Technology Costed
Carbonaceous fuel (bark, wood, sawdust, wastewater wood fiber residuals, and bark ash), Natural gas, No. 2 fuel oil, No. 6 fuel oil	Variable throat venturi scrubber	Replace coal and No. 6 fuel oil with ULSD Increase caustic addition to the wet scrubber SDA and fabric filter

Capital, operating, and total annual cost estimates and the assumed control efficiency and estimated emissions reduction for each control alternative are presented in Appendix A and summarized in Table 3-3. It should be noted that these are screening level cost estimates and are not based on detailed site-specific engineering studies. Site-specific factors such as space constraints, utility limitations (need for utility upgrades) or the ability to achieve the estimated emission reductions with a retrofitted control device could significantly impact the actual cost of implementing controls.

Table 3-3
No. 4 Combination Boiler Additional Control Measures Cost Summary

Control Measure	Capital Cost ($)	Annual Cost ($/yr)	SO_2 Control Efficiency Assumed	Annual SO_2 Emissions Reduction (tpy)	Cost Effectiveness of Controls ($/Ton SO_2)
Replace coal and No. 6 fuel oil with ULSD	$2.3 Million	$9.2 Million	32%	183	$50,097/ton
Increase caustic to the wet scrubber	TBD	$3.7 Million	98%	540	$6,816/ton
Install an SDA	$46.9 Million	$18.6 Million	95%	1,436 (total) 495 (incremental)	$12,966/ton (total) $37,610 (incremental)

Low-Sulfur Fuel

The costs to eliminate coal and No. 6 fuel oil firing in No. 4 Combination Boiler with ULSD were evaluated using Mill-specific fuel costs and representative costs incurred at other mills to switch fuels. The estimated annual cost and cost effectiveness of implementing the selected fuel replacement option for the No. 4 Combination Boiler are based on the current fuel costs and projected 2028 actual fuel use and emissions. The cost effectiveness depends heavily on the costs of coal and fuel oil, which change from year to year.

Increase Caustic to the Wet Scrubber

The Mill uses spent water treatment plant caustic in the wet scrubber, which achieves about 60% SO_2 reduction on an annual average and does not have any significant operating cost associated with it. We calculated the increased operating cost based on the amount of caustic that would be required to increase the current control efficiency to 98% using purchased 50% sodium hydroxide solution and the current cost of caustic. Based on a short trial conducted at the Mill, the amount of caustic required to be added to the venturi scrubber to achieve 98% control is an order of magnitude higher than the stoichiometric amount. To be able to manage the extra volume of caustic required, a capital project would be required to install the equipment needed to receive the chemical and supply it to the scrubber. Because the need for this capital was just identified, we were unable to develop a capital cost estimate for inclusion in the FFA and it is shown as TBD (to be determined) in Table 3-3 above.

SDA

The capital and operating costs for an SDA system, including a fabric filter, were estimated using a January 2017 Sargent and Lundy report prepared under a U.S. EPA contract[5] and Mill specific cost data. These equations are also included in the draft update to the OAQPS Control Cost Manual, Section 5, SO_2 and Acid Gas Controls. The true cost effectiveness is likely between the

[5] Sargent & Lundy LLC. 2017. *SDA FGD Cost Development Methodology.* Project 13527-001, Eastern Research Group, Inc. Chicago, IL.

total and incremental cost per ton shown in Table 3-3 since the SDA system would replace the wet scrubber.

3.5 ENERGY AND NON-AIR RELATED IMPACTS

Low-Sulfur Fuel

Discontinuing No. 6 fuel oil firing would result in a one-time increase in waste generation, due to cleanout of the fuel oil storage and delivery systems. Discontinuing coal usage would decrease energy use by the coal handling system and reduce the amount of boiler ash generated.

Increase Caustic Addition to the Wet Scrubber

There are no significant energy impacts for this approach. It would however require a significant increase in purchased chemical and cause a significant increase in the pH of the scrubber blowdown to the wastewater treatment plant. This in turn would result in the need to add acid to the incoming wastewater to neutralize the caustic scrubber blowdown. During a short-term trial, significant swings in the incoming wastewater pH occurred, which would present a risk to the long-term operation of the treatment system.

Install an SDA System

Installation of an SDA system would increase solid waste and electricity usage.

3.6 TIME NECESSARY FOR COMPLIANCE

If fuel switching or installation of a new control system is ultimately required to meet RHR requirements, the Mill would need a minimum of four years to implement them after final EPA approval of the RHR SIP. At least four years would be required because the process to undertake a retrofitting project is complex, involving design, engineering, permitting, procurement, and installation to name only some of the necessary work streams. Also, since the start of the COVID pandemic, the time necessary to implement construction projects has increased considerably. Lead times for obtaining critical parts and equipment are much longer and the ability to bring outside skilled labor on site has become more difficult than in pre-COVID times. To implement one of the control alternatives, the Mill would need time to obtain corporate approvals for capital funding. Once funding was secured, the design, permitting, procurement, installation, and shakedown of a retrofit emissions control project could consume four years. The Mill would need to engage engineering consultants, equipment vendors, construction contractors, financial institutions, and other critical suppliers. 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. The Mill would need to continue to operate as much as possible while retrofitting to meet any new requirements.

3.7 REMAINING USEFUL LIFE OF NO. 4 COMBINATION BOILER

The No. 4 Combination Boiler is assumed to have a remaining useful life of twenty years or more.

4. FOUR-FACTOR ANALYSIS FOR NO. 1 RECOVERY BOILER

This section of the report presents the FFA for SO_2 control alternatives for the No. 1 Recovery Boiler at the WestRock Panama City Mill. Using the four factors specified in the Clean Air Act and FDEP's instructions, the analysis consists of the following steps:

- Identification of available control measures
- Elimination of technically infeasible options
- Selection of control measures for analysis
- Assessment of the cost of compliance for the selected control measures (statutory factor 1)
- Assessment of the time necessary for compliance (statutory factor 2)
- Assessment of the energy and non-air quality environmental impacts of compliance (statutory factor 3)
- Assessment of the remaining useful life of the emission unit (statutory factor 4)

4.1 AVAILABLE CONTROL TECHNOLOGIES

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 were evaluated. The scope of possible control options for recovery boilers was determined based on a review of the RBLC database and knowledge of typical controls used on recovery 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 4-1 summarizes the available SO_2 control technologies for recovery boilers.

Table 4-1
Control Technology Summary

Pollutant	Controls on Recovery Boilers
SO_2	Good operating practices Low-sulfur fuel for startup Wet scrubber

The available control measures for reducing emissions of SO_2 emissions from recovery boilers are discussed in detail below.

Good Operating Practices

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

Low-Sulfur Startup Fuel

Fossil fuel is used to start up a recovery boiler prior to introducing black liquor. Emissions of SO_2 during a cold startup are proportional to the amount of sulfur in the fossil fuel being fired. Natural gas and ULSD are considered low sulfur fossil fuels and produce negligible SO_2 emissions when combusted. No. 1 Recovery Boiler has gas startup burners but only has oil-fired load bearing burners. Startup begins on natural gas but No. 6 fuel oil is used to complete the startup process.

Wet Scrubbers

In wet scrubbing processes for gaseous control, a liquid is used to remove pollutants from an exhaust stream. The removal of pollutants in the gaseous stream is done by absorption. Wet scrubbers used for this type of pollutant control are often referred to as absorbers. Wet scrubbing involves a mass transfer operation in which one or more soluble components of an acid gas are dissolved in a liquid that has low volatility under process conditions. For SO_2 control, the absorption process is chemical-based and uses an alkali solution (*i.e.*, sodium hydroxide, sodium carbonate, sodium bicarbonate, calcium hydroxide, etc.) as a sorbent or reagent in combination with water. Removal efficiencies are affected by the chemistry of the absorbing solution as it reacts with the pollutant. Most wet scrubbers have SO_2 removal efficiencies of at least 90 percent. Wet scrubbers may take the form of a variety of different configurations, including plate or tray columns, spray chambers, and venturi scrubbers.

4.2 ELIMINATION OF TECHNICALLY INFEASIBLE OPTIONS

An available control measure could be technically infeasible for a specific emission unit based on physical, chemical, or engineering principles that would preclude its successful use for that emission unit. A technology is generally 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.

The No. 1 Recovery Boiler is not equipped with add-on SO_2 control technology. Good combustion practices and initial startup on natural gas are already utilized to minimize SO_2 emissions. Although SO_2 emissions from recovery boilers can be inherently low, the Mill may be able to replace No. 6 fuel oil burners with gas/ULSD burners. A study of whether additional sufficient natural gas could be reliably provided to the No. 1 Recovery Boiler would be needed to confirm No. 6 fuel oil could be completely replaced with gas. The addition of a wet scrubber to further reduce SO_2 emissions is also likely technically feasible. Note that only three currently operating recovery boilers in the U.S. have wet scrubbers installed after their ESPs. A detailed engineering study would need to be conducted in order to confirm with certainty that a wet scrubber could be successfully sited and installed for the No. 1 Recovery Boiler.

4.3 SELECTION OF CONTROL MEASURES FOR ANALYSIS

Three control measures were identified as available for reducing SO_2 emissions from recovery boilers. Good combustion practices are already used at the No. 1 Recovery Boiler. Although initial startup is conducted using natural gas, it is completed using No. 6 fuel oil and the load bearing burners are not capable of burning natural gas at this time. Converting No. 1 Recovery Boiler's load-bearing burners to fire either natural gas or ULSD and addition of a wet scrubber system were selected for inclusion in the FFA. The following specific control measures were evaluated:

- Low-sulfur startup fuels: replace load bearing burners with burners designed to fire natural gas and ULSD.
- Wet scrubber: install and operate a wet scrubber designed for 98% SO_2 removal using sodium hydroxide as the scrubbing liquid.

4.4 COST OF COMPLIANCE

Cost analyses were developed for the selected control alternatives. Budgetary estimates of capital and operating costs were determined and used to estimate the annualized costs considering existing equipment design and exhaust characteristics. The capital cost was based on company-specific data, vendor estimates, previously developed company project costs, and/or EPA costing methodologies. The cost effectiveness 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. Actual emissions were used as the basis for emissions reductions. The actual 2017 emissions are a reasonable estimate of 2028 actual emissions.

The control measures evaluated for cost effectiveness for No. 1 Recovery Boiler are summarized in Table 4-2.

Table 4-2
Control Technologies Evaluated for No. 1 Recovery Boiler

Emissions Unit	Existing SO_2 Control Technology	Additional SO_2 Control Technology Costed
No. 1 Recovery Boiler (EU007)	Gas startup burners Proper operation	Gas/ULSD load-bearing burners Wet scrubber

The capital, operating, and total annual cost estimates are presented in Appendix A and summarized in the table below. These are screening level cost estimates and are not based on detailed site-specific engineering studies.

Table 4-3
No. 1 Recovery Boiler Additional Control Measures Cost Summary

Control Measure	Capital Cost ($)	Annual Cost ($/yr)	SO_2 Control Efficiency Assumed	Annual SO_2 Emissions Reduction (tpy)	Cost Effectiveness of Controls ($/Ton SO_2)
Replace No. 6 fuel oil with gas	$18.8 Million	$1.0 Million	40%	30.0	$34,323/ton
Replace No. 6 fuel oil with ULSD	$2.3 Million	$4.6 Million	40%	29.7	$154,848/ton
Wet scrubber	$30.8 Million	$6.5 Million	98%	162.7	$39,961/ton

Low-Sulfur Startup Fuel

The costs to eliminate No. 6 fuel oil firing in No. 1 Recovery Boiler were evaluated using Mill-specific fuel costs and representative costs incurred at other Mills to switch fuels. The estimated annual cost and cost effectiveness of implementing the selected No. 6 fuel oil replacement options for the No. 1 Recovery Boiler are based on the current fuel costs and projected 2028 actual fuel use and emissions. The natural gas option also assumes that enough natural gas would be available to replace No. 6 fuel oil during recovery boiler startups. The cost effectiveness depends heavily on the cost and availability of natural gas and fuel oil, which change from year to year.

Wet Scrubber

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. Sections 7.1 and 7.2 present the costs associated with installing a wet scrubber for SO_2 control on an NDCE recovery boiler 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 the recovery boiler's throughput to the throughput of the boiler evaluated in the BE&K report. Operating costs were estimated using the factors in the OAQPS Cost Manual, Section 5, Chapter 1.

4.5 ENERGY AND NON-AIR RELATED IMPACTS

Low-Sulfur Startup Fuel

A conversion from No. 6 fuel oil to ULSD would generate waste from cleaning the residual No. 6 fuel oil out of the storage and delivery system prior to startup on ULSD.

Wet Scrubber

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

4.6 TIME NECESSARY FOR COMPLIANCE

If controls are ultimately required to meet RHR requirements, the Mill would need a minimum of four years to implement them after final EPA approval of the RHR SIP. At least four years would be required because the process to undertake a retrofitting project is complex, involving design, engineering, permitting, procurement, and installation to name only some of the necessary work streams. Also, since the start of the COVID pandemic, the time necessary to implement construction projects has increased considerably. Lead times for obtaining critical parts and equipment are much longer and the ability to bring outside skilled labor on site has become more difficult than in pre-COVID times. To implement he control alternative, the Mill would need time to obtain corporate approvals for capital funding. Once funding was secured, the design, permitting, procurement, installation, and shakedown of a retrofit emissions control project could consume four years. The Mill would need to engage engineering consultants, equipment vendors, construction contractors, financial institutions, and other critical suppliers. 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. The Mill would need to continue to operate as much as possible while retrofitting to meet any new requirements.

4.7 REMAINING USEFUL LIFE OF NO. 1 RECOVERY BOILER

The No. 1 Recovery Boiler is assumed to have a remaining useful life of twenty years or more.

5. FOUR-FACTOR ANALYSIS FOR NO. 2 RECOVERY BOILER

This section of the report presents the FFA for SO_2 control alternatives for the No. 2 Recovery Boiler at the WestRock Panama City Mill. Using the four factors specified in the Clean Air Act and FDEP's instructions, the analysis consists of the following steps:

- Identification of available control measures
- Elimination of technically infeasible options
- Selection of control measures for analysis
- Assessment of the cost of compliance for the selected control measures (statutory factor 1)
- Assessment of the time necessary for compliance (statutory factor 2)
- Assessment of the energy and non-air quality environmental impacts of compliance (statutory factor 3)
- Assessment of the remaining useful life of the emission unit (statutory factor 4)

5.1 AVAILABLE CONTROL TECHNOLOGIES

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 were evaluated. The scope of possible control options for recovery boilers was determined based on a review of the RBLC database and knowledge of typical controls used on recovery 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 5-1 summarizes the available SO_2 control technologies for recovery boilers.

Table 5-1
Control Technology Summary

Pollutant	Controls on Recovery Boilers
SO_2	Good operating practices Low-sulfur fuel for startup Wet scrubber

The available control measures for reducing emissions of SO_2 emissions from recovery boilers are discussed in detail below.

Good Operating Practices

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

Low-Sulfur Startup Fuel

Fossil fuel is used to start up a recovery boiler prior to introducing black liquor. Emissions of SO_2 during a cold startup are proportional to the amount of sulfur in the fossil fuel being fired. Natural gas and ULSD are considered low sulfur fossil fuels and produce negligible SO_2 emissions when combusted. No. 2 Recovery Boiler's startup burners burn No. 6 fuel oil and four of its load-bearing burners can burn natural gas, while the other four only burn No. 6 fuel oil.

Wet Scrubbers

In wet scrubbing processes for gaseous control, a liquid is used to remove pollutants from an exhaust stream. The removal of pollutants in the gaseous stream is done by absorption. Wet scrubbers used for this type of pollutant control are often referred to as absorbers. Wet scrubbing involves a mass transfer operation in which one or more soluble components of an acid gas are dissolved in a liquid that has low volatility under process conditions. For SO_2 control, the absorption process is chemical-based and uses an alkali solution (*i.e.*, sodium hydroxide, sodium carbonate, sodium bicarbonate, calcium hydroxide, etc.) as a sorbent or reagent in combination with water. Removal efficiencies are affected by the chemistry of the absorbing solution as it reacts with the pollutant. Most wet scrubbers have SO_2 removal efficiencies of at least 90 percent. Wet scrubbers may take the form of a variety of different configurations, including plate or tray columns, spray chambers, and venturi scrubbers.

5.2 ELIMINATION OF TECHNICALLY INFEASIBLE OPTIONS

An available control measure could be technically infeasible for a specific emission unit based on physical, chemical, or engineering principles that would preclude its successful use for that emission unit. A technology is generally 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.

The No. 2 Recovery Boiler is not equipped with add-on SO_2 control technology. Good combustion practices and low-sulfur startup fuels (ULSD and natural gas) are already utilized to minimize SO_2 emissions. Although SO_2 emissions from recovery boilers can be inherently low, the Mill may be able to replace No. 6 fuel oil burners with gas/ULSD burners. A study of whether additional sufficient natural gas could be reliably provided to the No. 2 Recovery Boiler would be needed to confirm No. 6 fuel oil could be completely replaced with gas. The addition of a wet scrubber to further reduce SO_2 emissions is also likely technically feasible. Note that only three currently operating recovery boilers in the U.S. have wet scrubbers installed after their ESPs. A detailed engineering study would need to be conducted in order to confirm with certainty that a wet scrubber could be successfully sited and installed for the No. 2 Recovery Boiler.

5.3 SELECTION OF CONTROL MEASURES FOR ANALYSIS

Three control measures were identified as available for reducing SO_2 emissions from recovery boilers. Good combustion practices are already used at the No. 1 Recovery Boiler. Converting No. 2 Recovery Boiler's startup burners and half of the load-bearing burners to fire either natural gas or ULSD and addition of a wet scrubber system were selected for inclusion in the FFA. The following specific control measures were evaluated:

- Low-sulfur startup fuels: replace the four startup burners and four of the load-bearing burners with burners designed to fire natural gas and ULSD.
- Wet scrubber: install and operate a wet scrubber designed for 98% SO_2 removal using sodium hydroxide as the scrubbing liquid.

5.4 COST OF COMPLIANCE

Cost analyses were developed for the selected control alternatives. Budgetary estimates of capital and operating costs were determined and used to estimate the annualized costs considering existing equipment design and exhaust characteristics. The capital cost was based on company-specific data, vendor estimates, previously developed company project costs, and/or EPA costing methodologies. The cost effectiveness 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. Actual emissions were used as the basis for emissions reductions. The actual 2017 emissions are a reasonable estimate of 2028 actual emissions.

The control measures evaluated for cost effectiveness for No. 2 Recovery Boiler are summarized in Table 5-2.

Table 5-2
Control Technologies Evaluated for No. 2 Recovery Boiler

Emissions Unit	Existing SO_2 Control Technology	Additional SO_2 Control Technology Costed
No. 2 Recovery Boiler (EU011)	Some gas load burners Proper operation	Low-sulfur startup fuel Wet scrubber

The capital, operating, and total annual cost estimates are presented in Appendix A and summarized in the table below. These are screening level cost estimates and are not based on detailed site-specific engineering studies.

Table 5-3
No. 2 Recovery Boiler Additional Control Measures Cost Summary

Control Measure	Capital Cost ($)	Annual Cost ($/yr)	SO_2 Control Efficiency Assumed	Annual SO_2 Emissions Reduction (tpy)	Cost Effectiveness of Controls ($/Ton SO_2)
Replace No. 6 Fuel oil with natural gas	$15 Million	$1.5 Million	73%	121	$12,217/ton
Replace No. 6 Fuel oil with ULSD	$2.3 Million	$5.2 Million	73%	121	$43,143/ton
Wet scrubber	$30.8 Million	$6.5 Million	98%	72.9	$89,221/ton

Low-Sulfur Startup Fuel

The costs to eliminate No. 6 fuel oil firing in No. 2 Recovery Boiler were evaluated using Mill-specific fuel costs and representative costs incurred at other Mills to switch fuels. The estimated annual cost and cost effectiveness of implementing the selected No. 6 fuel oil replacement options for the No. 2 Recovery Boiler are based on the current fuel costs and projected 2028 actual fuel use and emissions. The natural gas option also assumes that enough natural gas would be available to replace No. 6 fuel oil during recovery boiler startups. The cost effectiveness depends heavily on the cost of natural gas and fuel oil, which change from year to year.

Wet Scrubber

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. Sections 7.1 and 7.2 present the costs associated with installing a wet scrubber for SO_2 control on an NDCE recovery boiler 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 the recovery boiler's throughput to the throughput of the boiler evaluated in the BE&K report. Operating costs were estimated using the factors in the OAQPS Cost Manual, Section 5, Chapter 1.

5.5 ENERGY AND NON-AIR RELATED IMPACTS

Low-Sulfur Startup Fuel

A conversion from No. 6 fuel oil to ULSD would generate waste from cleaning the residual No. 6 fuel oil out of the storage and delivery system prior to startup on ULSD.

Wet Scrubber

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

5.6 TIME NECESSARY FOR COMPLIANCE

If controls are ultimately required to meet RHR requirements, the Mill would need a minimum of four years to implement them after final EPA approval of the RHR SIP. At least four years would be required because the process to undertake a retrofitting project is complex, involving design, engineering, permitting, procurement, and installation to name only some of the necessary work streams. Also, since the start of the COVID pandemic, the time necessary to implement construction projects has increased considerably. Lead times for obtaining critical parts and equipment are much longer and the ability to bring outside skilled labor on site has become more difficult than in pre-COVID times. To implement he control alternative, the Mill would need time to obtain corporate approvals for capital funding. Once funding was secured, the design, permitting, procurement, installation, and shakedown of a retrofit emissions control project could consume four years. The Mill would need to engage engineering consultants, equipment vendors, construction contractors, financial institutions, and other critical suppliers. 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. The Mill would need to continue to operate as much as possible while retrofitting to meet any new requirements.

5.7 REMAINING USEFUL LIFE OF NO. 2 RECOVERY BOILER

The No. 2 Recovery Boiler is assumed to have a remaining useful life of twenty years or more.

6. SUMMARY OF FINDINGS AND PROPOSED DETERMINATION

In response to a request from FDEP, WestRock conducted an FFA to evaluate whether additional emissions controls for SO_2 are feasible for the Panama City Mill's power boilers and recovery boilers. 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.

FDEP's request for the FFA states that WestRock should provide a proposed determination of whether it is reasonable to require any control measure(s) for each unit. FDEP did not provide any specific guidance on the criteria to be used for determining what would be reasonable, including what FDEP would consider cost effective for purposes of making reasonable progress under the Regional Haze Rule. We believe that the cost effectiveness threshold for reasonable progress under the RHR second implementation period should be less than the threshold for BACT, and therefore less than $5,000/ton.

Our analysis shows that it would not be cost effective to implement additional SO_2 control measures for the No. 1 Recovery Boiler or No. 2 Recovery Boiler. As such, we believe it would not be reasonable to require SO_2 controls during the second implementation period for these emissions units and are proposing a no control determination. Although we believe it can be concluded that no control measures are reasonable based solely on cost effectiveness, we also considered the other three statutory factors—energy and non-air impacts, time necessary for compliance, and remaining useful life of the emission units—and do not find that they provide any compelling case for determining additional controls are reasonable. The energy and non-air impacts analyses show that implementing additional control measures would increase chemical usage, energy usage, water usage, wastewater generation, and/or solid waste generation. All of the emission units are presumed to have a remaining useful life exceeding 20 years and the time necessary to implement any of the control measures would be at least four years. Given the four factors, we are proposing that adding SO_2 control measures to the No. 1 Recovery Boiler or the No. 2 Recovery Boiler would not be reasonable for purposes of making further progress in reducing regional haze.

For the No. 3 Combination Boiler and No. 4 Combination Boiler, our analysis shows that it would not be cost effective to replace higher sulfur fuels (No. 6 fuel oil for both boilers and coal for No. 4 Combination Boiler) with ULSD or to install a dry scrubbing system. It is not currently feasible to replace fuel oil and coal burned in these boilers with natural gas due to current limitations of the natural gas infrastructure up to and within the Mill. Our analysis shows that it is not cost-effective to increase the amount of caustic fed to the Combination Boilers' wet scrubbers to achieve a significant increase in control efficiency because the chemical addition required is an order of magnitude above the stoichiometric requirement based on a short trial at the Mill. We did not identify any significant energy or non-air environmental impacts that would provide a case for the controls being reasonable. Given the four factors, we are proposing that adding SO_2 control measures to the No. 3 Combination Boiler or the No. 4 Combination Boiler would not be reasonable for purposes of making further progress in reducing regional haze.

APPENDIX A -
CONTROL COST ESTIMATES

NO. 3 COMBINATION BOILER CONTROL COST ESTIMATES

Table A-1a
New Burner System and Fuel Switching Cost (ULSD) - WestRock Panama City No. 3 Combination Boiler

CAPITAL COSTS			
New gas igniters, new oil burner tips and fuel oil system conversion to ULSD	(a)	*TCI*	*$2,276,500*

ANNUALIZED COSTS				
	COST ITEM	COST FACTOR	UNIT COST	COST ($)
Annual Operating Costs - Direct Annual Costs				
(b)	Maintenance Costs	no incremental increase		*$0*
Fuel				
(c)	ULSD cost	[redacted]	[redacted]	*$605,072*
	No. 6 fuel oil cost savings	[redacted]	[redacted]	*-$417,494*
	Total Direct Annual Costs:		*DAC*	*$187,578*
Annual Operating Costs - Indirect Annual Costs				
(b)	Overhead	no increase		*$0*
(b)	Administrative Charges	2% of TCI		*$45,530*
(b)	Property Taxes	1% of TCI		*$22,765*
(b)	Insurance	1% of TCI		*$22,765*
	Total Indirect Annual Costs:		*IDAC*	*$91,060*
	Total Annual Costs:		*TAC*	*$278,638*
Cost Effectiveness				
(d)	Expected lifetime of equipment, years	20		
(d)	Interest rate, %/yr	4.75%		
(d)	Capital recovery factor	0.079		
(d)	Total Capital Investment Cost	$2,276,500		
	Annualized Capital Investment Cost:			*$178,820*
	Total Annualized Cost:			*$457,458*
(e)	SO_2 Reduction	2.85%		
	Pre-retrofit SO_2	190 tons SO_2/yr		
	Post-retrofit SO_2 Using Burner System	185 tons SO_2/yr		
	SO_2 Removed	5.4 tons SO_2/yr		
	Annual Cost/Ton Removed:			*$84,520*

(a) Based on WestRock's experience at other mills, represents the capital cost of converting a recovery furnace to startup on ULSD instead of No. 6 fuel oil and includes addition of natural gas igniters for safety.
(b) No additional maintenance costs estimated.
(c) Current WestRock Panama City fuel costs.
(d) U.S. EPA Air Pollution Control Cost Manual, Section 1, Chapter 2.
(e) Pre-retrofit SO_2 emissions estimated based on projected 2028 actual throughput/fuel usage. Post-retrofit SO_2 emissions estimated based on equivalent heat input of pre-retrofit SO_2 emissions and AP-42 Sections 1.3 and 1.4.

Table A-1b
Caustic Addition - WestRock Panama City No. 3 Combination Boiler

ANNUALIZED COSTS				
	COST ITEM	COST FACTOR	UNIT COST	COST ($)
Caustic				
(a)	Estimated Caustic Rate to Reach 98% Removal	[redacted]	[redacted]	***$2,761,608***
	Total Annualized Costs:		***DAC***	***$2,761,608***
(b)	Current uncontrolled SO_2	1,058 tons SO_2/yr		
	Current SO_2 emissions (controlled SO_2)	190 tons SO_2/yr		
	Current SO_2 removal efficiency	82%		
	Current SO_2 removed	868 tons SO_2/yr		
	Future uncontrolled SO_2	1,058 tons SO_2/yr		
	Future SO_2 emissions (controlled SO_2)	21 tons SO_2/yr		
	Future SO_2 removal efficiency	98%		
	Future SO_2 removed	1,037 tons SO_2/yr		
	SO_2 Removed by Caustic Addition Control Measure	169 tons SO_2/yr		
	Annual Cost/Ton Removed:			***$16,364***

(a) Current mill caustic cost and 3 gpm 50% NaOH rate necessary during trial to achieve at least 98% control.

(b) Current SO_2 emissions estimated based on projected 2028 actual throughput/fuel usage. Future SO_2 emissions estimated based on 98% target SO_2 control efficiency for purchased caustic rate and 2028 actual emissions rate (1,059 tpy).

Table A-1c

SO_2 Fuel Switching Emissions Calculations - WestRock Panama City No. 3 Combination Boiler

Projected 2028 Actual Throughput/Fuel Usage			Projected 2028 Actual SO_2 Emissions - Before Controls		Projected 2028 Actual SO_2 Emissions - After Controls	
Current SO_2						
Biomass (bark and primary WWTP residuals), as received basis	179,549	tons/yr	42.0	tpy	190	tpy
	2.15E+06	MMBtu/yr				
No. 6 Fuel Oil	295,795	gpy	30.2	tpy		
	4.37E+04	MMBtu/yr				
LVHC NCG / SOG	6.54E+05	ADTP	986	tpy		
Total			1,058	tpy		
Post-change SO_2 (ULSD)						
Biomass (bark and primary WWTP residuals), as received basis	179,549	tons/yr	42.0	tpy	185	tpy
	2.15E+06	MMBtu/yr				
ULSD	311,893	gpy	3.32E-02	tpy		
	4.37E+04	MMBtu/yr				
LVHC NCG / SOG	6.54E+05	ADTP	986	tpy		
Total			1,028	tpy		
SO_2 Removed					5.4	tpy

Control Efficiency	82%

LVHC NCG / SOG Emissions Factors		
SOG Only[1]	5.66	lb/ADTP
LVHC NCG Only[1]	1.46	lb/ADTP
SOG and LVHC NCG[1]	7.12	lb/ADTP

Heat Content		
Biomass (bark and WWTP residuals mix)[2]	12	MMBtu/ton (wet basis)
Natural Gas[1]	1,060	Btu/scf
No. 6 Fuel Oil[1]	148	MMBtu/Mgal
ULSD[2]	140	MMBtu/Mgal

Biomass Emissions Factor		
Biomass Emissions Factor[5] (uncontrolled emissions)	0.039	lb/MMBtu

No. 6 Fuel Oil Emissions Factor		
No. 6 Fuel Oil Sulfur Content[2]	1.3	%
No. 6 Fuel Oil Emissions Factor[3]	204.1	lb/Mgal

ULSD Emissions Factor		
ULSD Sulfur Content[3]	15	ppm
ULSD Emissions Factor[3]	0.213	lb/Mgal

Natural Gas Emissions Factor		
Natural Gas Emissions Factor[4]	0.6	lb/MMscf

1 - NCASI TB 1050, Table 15, median value, full conversion of TRS as S to SO_2
2 - Mill Specific Information
3 - AP-42 Section 1.3
4 - AP-42 Section 1.4
5- 0.025 lb/MMBtu for for bark and wet wood fired boilers from AP-42 Section 1.6 Table 1.6-2 ; 0.37% sulfur content for WWTP residuals

Table A-2
WestRock Panama City No. 3 Combination Boiler
Capital and Annual Costs Associated with SDA System

Variable	Designation	Units	Value	Calculation
Unit Size	A	MW	44	505 MMBtu/hr heat input, assumes 30% efficiency to convert to equivalent MW output
Retrofit Factor	B	-	1	Average retrofit
Gross Heat Rate	C	Btu/kWh	11,383	Assumes 30% efficiency
SO_2 Rate (uncontrolled)	D	lb/MMBtu	0.96	Actual SO_2 emissions divided by actual fuel use.
Coal Factor	F	-	1	
Heat Rate Factor	G	-	1.13832	C/10000
Heat Input	H	Btu/hr	5.05E+08	A*C*1000
Operating SO_2 Removal	J	-	95	Default value in Sargent and Lundy document.
Design Lime Rate	K	ton/hr	0.34	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 removal)
Design Waste Rate	L	ton/hr	0.78	(0.8016*(D^2)+31.1971*D)*A*G/2000 (Based on 95% SO_2 removal)
Aux Power	M	%	1.488	(0.000547*D^2+0.00649*D+1.3)*F*G
Makeup Water Rate	N	kgph	2.81	(0.04898*(D^2)+0.5925*D+55.11)*A*F*G/1000
Lime Cost	P	$/ton	[redacted]	[redacted]
Waste Disposal Cost	Q	$/ton	[redacted]	[redacted]
Aux Power Cost	R	$/kWh	[redacted]	[redacted]
Makeup Water Cost	S	$/kgal	[redacted]	[redacted]
Operating Labor Rate	T	$/hr	[redacted]	[redacted]

SO_2 Control Efficiency:	95%
Uncontrolled Actual Emissions, tpy	1,058
Post Control SO2:	53
Removed SO_2 Emissions:	1,005

Capital Costs [(a)]					
Direct Costs					
Base module absorber island cost (includes baghouse)	BMR		$	10,256,126	637000*(A^0.716))*B*(F*G)^0.6*(D/4)^0.01
Base module reagent prep/waste handling cost	BMF		$	5,201,544	338000*(A^0.716))*B*(D*G)^0.2
Base module balance of plant costs	BMB		$	14,306,611	899000*(A^0.716))*B*(F*G)^0.4
	BM		$	29,764,281	
Indirect Costs					
Engineering & Construction Management	A1	$	$	2,976,428	10% BM
Labor adjustment	A2	$	$	1,488,214	10% BM
Contractor profit and fees	A3	$	$	1,488,214	10% BM
Capital, engineering and construction cost subtotal	CECC	$	$	35,717,138	BM+A1+A2+A3
Owner costs including all "home office" costs	B1	$	$	1,785,857	5% CEC
Total project cost w/out AFUDC	TPC	$	$	37,502,994	B1+CEC
AFUDC (0 for <1 year engineering and construction cycle)	B2	$		0	0% of (CECC+B1)
Total Project Cost	**TCI**	**$**	**$**	**37,502,994**	

Annualized Costs [a]					
Fixed O&M Cost					
Additional operating labor costs	FOMO	$	$	476,736	(8 additional operators)*2080*T
Additional maintenance material and labor costs	FOMM	$	$	375,030	BM*0.015/B
Additional administrative labor costs	FOMA	$	$	18,802	0.03*(FOMO+0.4*FOMM)
Total Fixed O&M Costs	**FOM**	**$**	**$**	**870,568**	FOMO+FOMM+FOMA
Variable O&M Cost					
Costs for lime reagent	VOMR	$	$	566,016	K*P
Costs for waste disposal	VOMW	$	$	908,581	L*Q
Additional auxiliary power required	VOMP	$	$	6,941,706	M*R*10*ton SO_2
Costs for makeup water	WOMM	$	$	1,294	N*S
Total Variable O&M Cost	**VOM**	**$**	**$**	**8,417,597**	VOMR+VOMW+VOMP
Indirect Annual Costs					
General and Administrative	2%	of TCI	$	750,060	
Property Tax	1%	of TCI	$	375,030	
Insurance	1%	of TCI	$	375,030	
Capital Recovery	9.47%	x TCI	$	3,552,326	
Total Indirect Annual Costs			**$**	**5,052,446**	
Life of the Control:	15	years		4.75%	interest
Total Annual Costs			**$**	**14,340,612**	
Total Annual Costs/SO_2 Emissions			**$**	**14,267**	

[a] Cost information based on the January 2017 "SDA FGD Cost Development Methodology" study by Sargent & Lundy.

NO. 4 COMBINATION BOILER
CONTROL COST ESTIMATES

Table A-3a
New Burner System and Fuel Switching Cost (ULSD) - WestRock Panama City No. 4 Combination Boiler

CAPITAL COSTS			
New gas igniters, new oil burner tips and fuel oil system conversion to ULSD	(a)	*TCI*	*$2,276,500*

ANNUALIZED COSTS				
	COST ITEM	COST FACTOR	UNIT COST	COST ($)
Annual Operating Costs - Direct Annual Costs				
(b)	Maintenance Costs	no incremental increase		*$0*
Fuel				
(c)	ULSD cost	[redacted]	[redacted]	*$13,266,431*
	Coal cost savings			*-$3,961,516*
	No. 6 fuel oil cost savings			*-$382,439*
	Total Direct Annual Costs:		*DAC*	*$8,922,476*
Annual Operating Costs - Indirect Annual Costs				
(b)	Overhead	no increase		*$0*
(b)	Administrative Charges	2% of TCI		*$45,530*
(b)	Property Taxes	1% of TCI		*$22,765*
(b)	Insurance	1% of TCI		*$22,765*
	Total Indirect Annual Costs:		*IDAC*	*$91,060*
	Total Annual Costs:		*TAC*	*$9,013,536*
Cost Effectiveness				
(e)	Expected lifetime of equipment, years	20		
(e)	Interest rate, %/yr	4.75%		
(e)	Capital recovery factor	0.079		
(e)	Total Capital Investment Cost	$2,276,500		
	Annualized Capital Investment Cost:			*$178,820*
	Total Annualized Cost:			*$9,192,356*
(f)	SO_2 Reduction	32%		
	Pre-retrofit SO_2	570 tons SO_2/yr		
	Post-retrofit SO_2 Using Burner System	387 tons SO_2/yr		
	SO_2 Removed	183 tons SO_2/yr		
	Annual Cost/Ton Removed:			*$50,097*

(a) Based on WestRock's experience at other mills, represents the capital cost of converting a recovery furnace to startup on ULSD instead of No. 6 fuel oil and includes addition of natural gas igniters for safety.
(b) No additional burner system maintenance costs estimated.
(c) Current WestRock Panama City fuel costs.
(d) No charge taken here due to operational cost savings from removing coal.
(e) U.S. EPA Air Pollution Control Cost Manual, Section 1, Chapter 2.
(f) Pre-retrofilt SO_2 emissions estimated based on projected 2028 actual throughput/fuel usage. Post-retrofit SO_2 emissions estimated based on equivalent heat input of pre-retrofit SO_2 emissions and AP-42 Sections 1.1, 1.3, and 1.4.

Table A-3b
Caustic Addition - WestRock Panama City No. 4 Combination Boiler

ANNUALIZED COSTS					
	COST ITEM	COST FACTOR		UNIT COST	COST ($)
Caustic					
(a)	Estimated Caustic Rate Increase to Reach 98% Removal	[redacted]		[redacted]	***$3,682,143***
	Total Annualized Costs:			***DAC***	***$3,682,143***
(b)	Current uncontrolled SO_2	1,511	tons SO_2/yr		
	Current SO_2 emissions (controlled SO_2)	570			
	Current SO_2 removal efficiency	62%			
	Current SO_2 removed	941	tons SO_2/yr		
	Future uncontrolled SO_2	1,511	tons SO_2/yr		
	Future SO_2 emissions (controlled SO_2)	30			
	Future SO_2 removal efficiency	98%			
	Future SO_2 removed	1,481	tons SO_2/yr		
	SO_2 Removed	540	tons SO_2/yr		
	Annual Cost/Ton Removed:				***$6,816***

(a) Current mill caustic cost and 4 gpm 50% NaOH rate necessary during trial to achieve at least 98% control.
(b) Current SO_2 emissions estimated based on projected 2028 actual throughput/fuel usage. Future SO_2 emissions estimated based on 98% target SO_2 control efficiency for purchased caustic rate and 2028 actual emissions rate (1,481 tpy).

Table A-3c

SO_2 Fuel Switching Emissions Calculations - WestRock Panama City No. 4 Combination Boiler

Projected 2028 Actual Throughput/Fuel Usage			Projected 2028 Actual SO_2 Emissions - Before Controls		Projected 2028 Actual SO_2 Emissions - After Controls	
Current SO_2						
Biomass (bark and primary WWTP residuals), as received basis	152,540	tons/yr	38.4	tpy	570	tpy
	1.83E+06	MMBtu/yr				
Coal	32,944	tpy	507	tpy		
	8.89E+05	MMBtu/yr				
No. 6 Fuel Oil	270,959	gpy	27.7	tpy		
	4.00E+04	MMBtu/yr				
LVHC NCG / SOG	6.54E+05	ADTP	938	tpy		
Total			1,511	tpy		
Post-change SO_2 (ULSD)						
Biomass (bark and primary WWTP residuals), as received basis	152,540	tons/yr	38.4	tpy	387	tpy
	1.83E+06	MMBtu/yr				
ULSD	6,838,367	gpy	7.28E-01	tpy		
	9.57E+05	MMBtu/yr				
LVHC NCG / SOG	6.54E+05	ADTP	986	tpy		
Total			1,025	tpy		
SO_2 Removed					183	tpy

Control Efficiency	62%

LVCH NCG / SOG Emissions Factors		
SOG Only[1]	5.66	lb/ADTP
LVHC NCG Only[1]	1.46	lb/ADTP
SOG and LVHC NCG[1]	7.12	lb/ADTP
Heat Content		
Biomass (bark and WWTP residuals mix)[2]	12	MMBtu/ton (wet basis)
Coal Heat Content[2]	27	MMBtu/ton
Natural Gas[2]	1,060	Btu/scf
No. 6 Fuel Oil[2]	148	MMBtu/Mgal
ULSD[4]	140	MMBtu/Mgal

Biomass Emissions Factor		
Biomass Emissions Factor[6] (uncontrolled emissions)	0.042	lb/MMBtu

Coal Emissions Factor		
Coal Sulfur Content[3]	0.81	% weight
Coal Emissions Factor[3]	30.8	lb/ton

No. 6 Fuel Oil Emissions Factor		
No. 6 Fuel Oil Sulfur Content[2]	1.3	%
No. 6 Fuel Oil Emissions Factor[4]	204.1	lb/Mgal

ULSD Emissions Factor		
ULSD Sulfur Content[4]	15	ppm
ULSD Emissions Factor[4]	0.213	lb/Mgal

Natural Gas Emissions Factor		
Natural Gas Emissions Factor[5]	0.6	lb/MMscf

1 - NCASI TB 1050, Table 15, median value, full conversion of TRS as S to SO_2
2 - Mill Specific Information
3 - AP-42 Section 1.1
4 - AP-42 Section 1.3
5 - AP-42 Section 1.4
6- 0.025 lb/MMBtu for for bark and wet wood fired boilers from AP-42 Section 1.6 Table 1.6-2 ; 0.37% sulfur content for WWTP residuals

Table A-4
WestRock Panama City No. 4 Combination Boiler
Capital and Annual Costs Associated with SDA System

Variable	Designation	Units	Value	Calculation
Unit Size	A	MW	48	545 MMBtu/hr heat input, assumes 30% efficiency to convert to equivalent MW output
Retrofit Factor	B	-	1	Average retrofit
Gross Heat Rate	C	Btu/kWh	11,383	Assumes 30% efficiency
SO_2 Rate (uncontrolled)	D	lb/MMBtu	1.09	Actual SO_2 emissions divided by actual fuel use.
Type of Coal	E	-	Bituminous	
Coal Factor	F	-	1	
Heat Rate Factor	G	-	1.13832	C/10000
Heat Input	H	Btu/hr	5.45E+08	A*C*1000
Operating SO_2 Removal	J	-	95	Default value in Sargent and Lundy document.
Design Lime Rate	K	ton/hr	0.42	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 removal)
Design Waste Rate	L	ton/hr	0.96	(0.8016*(D^2)+31.1971*D)*A*G/2000 (Based on 95% SO_2 removal)
Aux Power	M	%	1.489	(0.000547*D^2+0.00649*D+1.3)*F*G
Makeup Water Rate	N	kgph	3.04	(0.04898*(D^2)+0.5925*D+55.11)*A*F*G/1000
Lime Cost	P	$/ton	[redacted]	[redacted]
Waste Disposal Cost	Q	$/ton	[redacted]	[redacted]
Aux Power Cost	R	$/kWh	[redacted]	[redacted]
Makeup Water Cost	S	$/kgal	[redacted]	[redacted]
Operating Labor Rate	T	$/hr	[redacted]	[redacted]

SO_2 Control Efficiency:	95%
Uncontrolled Actual Emissions, tpy	1,511
Controlled SO2 Emission Rate:	76
Removed SO_2 Emissions:	1,436

Capital Costs [(a)]					
Direct Costs					
Base module absorber island cost (includes baghouse)	BMR		$	10,845,414	637000*(A^0.716))*B*(F*G)^0.6*(D/4)^0.01
Base module reagent prep/waste handling cost	BMF		$	5,636,710	338000*(A^0.716))*B*(D*G)^0.2
Base module balance of plant costs	BMB		$	15,109,151	899000*(A^0.716))*B*(F*G)^0.4
	BM		$	31,591,274	
Indirect Costs					
Engineering & Construction Management	A1	$	$	3,159,127	10% BM
Labor adjustment	A2	$	$	3,159,127	10% BM
Contractor profit and fees	A3	$	$	3,159,127	10% BM
Capital, engineering and construction cost subtotal	CECC	$	$	41,068,657	BM+A1+A2+A3
Owner costs including all "home office" costs	B1	$	$	2,053,433	5% CECC
Total project cost w/out AFUDC	TPC	$	$	43,122,089	B1+CECC
AFUDC (Based on 3 year engineering and construction cycle)					
EPC Fees of 15%	B2	$	$	6,468,313	15% of (CECC+B1)
Total Project Cost	**TCI**	**$**	**$**	**49,590,403**	

Annualized Costs [(a)]					
Fixed O&M Cost					
Additional operating labor costs	FOMO	$	$	476,736	(8 additional operators)*2080*T
Additional maintenance material and labor costs	FOMM	$	$	495,904	BM*0.015/B
Additional administrative labor costs	FOMA	$	$	20,253	0.03*(FOMO+0.4*FOMM)
Total Fixed O&M Costs	**FOM**	**$**	**$**	**992,893**	FOMO+FOMM+FOMA
Variable O&M Cost					
Costs for lime reagent	VOMR	$	$	699,221	K*P
Costs for waste disposal	VOMW	$	$	1,119,074	L*Q
Additional auxiliary power required	VOMP	$	$	9,921,516	M*R*10*ton SO_2
Costs for makeup water	WOMM	$	$	1,399	N*S
Total Variable O&M Cost	**VOM**	**$**	**$**	**11,741,210**	VOMR+VOMW+VOMP
Indirect Annual Costs					
General and Administrative	2%	of TCI	$	991,808	
Property Tax	1%	of TCI	$	495,904	
Insurance	1%	of TCI	$	495,904	
Capital Recovery	7.86%	x TCI	$	3,895,349	
Total Indirect Annual Costs			**$**	**5,878,965**	
Life of the Control:	20	years		4.75%	interest
Total Annual Costs			**$**	**18,613,068**	
Total Annual Costs/SO_2 Emissions			**$**	**12,966**	

[(a)]Cost information based on the January 2017 "SDA FGD Cost Development Methodology" study by Sargent & Lundy.

NO. 1 RECOVERY BOILER
CONTROL COST ESTIMATES

Table A-5a
Fuel Switching Cost (Natural Gas) - WestRock Panama City No. 1 Recovery Boiler

CAPITAL COSTS			
Total Capital Investment for 8 New Load Burners and Required Infrastructure:	(a)	*TCI*	*$18,750,000*

ANNUALIZED COSTS					
	COST ITEM	COST FACTOR		UNIT COST	COST ($)
Annual Operating Costs - Direct Annual Costs					
(b)	Maintenance Costs	no incremental increase			*$0*
Fuel					
(c)	Increased natural gas cost	[redacted]		[redacted]	*$450,846*
	No. 6 fuel oil cost savings	[redacted]		[redacted]	*-$1,645,295*
	Total Direct Annual Costs:			*DAC*	*-$1,194,449*
Annual Operating Costs - Indirect Annual Costs					
(b)	Overhead		no increase		*$0*
(b)	Administrative Charges	2%	of TCI		*$375,000*
(b)	Property Taxes	1%	of TCI		*$187,500*
(b)	Insurance	1%	of TCI		*$187,500*
	Total Indirect Annual Costs:			*IDAC*	*$750,000*
	Total Annual Costs:			*TAC*	*-$444,449*
Cost Effectiveness					
(d)	Expected lifetime of equipment, years	20			
(d)	Interest rate, %/yr	4.75%			
(d)	Capital recovery factor	0.079			
(d)	Total Capital Investment Cost	$18,750,000			
	Annualized Capital Investment Cost:				*$1,472,821*
	Total Annualized Cost:				*$1,028,372*
(e)	SO_2 Reduction	40%			
	Pre-retrofit SO_2	74.4	tons SO_2/yr		
	Post-retrofit SO_2 Using Burner System	44.4	tons SO_2/yr		
	SO_2 Removed	30	tons SO_2/yr		
	Annual Cost/Ton Removed:				*$34,323*

(a) Based on project estimate performed by WestRock Fernandina Beach for burner system with similar heat input.
(b) No increase in maintenance costs estimated.
(c) WestRock Panama City fuel costs.
(d) U.S. EPA Air Pollution Control Cost Manual, Section 1, Chapter 2.
(e) Pre-retrofilt SO_2 emissions estimated based on projected 2028 actual throughput/fuel usage. Post-retrofit SO_2 emissions estimated based on equivalent heat input of pre-retrofit SO_2 emissions and AP-42 Sections 1.3 and 1.4.

Table A-5b
Fuel Switching Cost (ULSD) - WestRock Panama City No. 1 Recovery Boiler

CAPITAL COSTS			
New gas igniters, new oil burner tips and fuel oil system conversion to ULSD	(a)	*TCI*	*$2,276,500*

	ANNUALIZED COSTS COST ITEM	COST FACTOR		UNIT COST	COST ($)
Annual Operating Costs - Direct Annual Costs					
(b)	Maintenance Costs	no incremental increase			*$0*
Fuel					
(c)	ULSD cost	[redacted]		[redacted]	*$6,904,932*
	Natural gas fuel cost savings				*-$925,733*
	No. 6 fuel oil cost savings				*-$1,645,295*
	Total Direct Annual Costs:			*DAC*	*$4,333,904*
Annual Operating Costs - Indirect Annual Costs					
(b)	Overhead	60%	of sum of operating & maintenance costs		*$0*
(b)	Administrative Charges	2%	of TCI		*$45,530*
(b)	Property Taxes	1%	of TCI		*$22,765*
(b)	Insurance	1%	of TCI		*$22,765*
	Total Indirect Annual Costs:			*IDAC*	*$91,060*
	Total Annual Costs:			*TAC*	*$4,424,964*
Cost Effectiveness					
(d)	Expected lifetime of equipment, years	20			
(d)	Interest rate, %/yr	4.75%			
(d)	Capital recovery factor	0.079			
(d)	Total Capital Investment Cost	$2,276,500			
	Annualized Capital Investment Cost:				*$178,820*
	Total Annualized Cost:				*$4,603,784*
(e)	SO_2 Reduction	40%			
	Pre-retrofit SO_2	74.4	tons SO_2/yr		
	Post-retrofit SO_2 Using ULSD	44.6	tons SO_2/yr		
	SO_2 Removed	29.7	tons SO_2/yr		
	Annual Cost/Ton Removed:				*$154,848*

(a) Based on WestRock's experience at other mills, represents the capital cost of converting a recovery furnace to startup on ULSD instead of No. 6 fuel oil and includes addition of natural gas igniters for safety.
(b) No increase in maintenance costs estimated.
(c) WestRock Panama City No. 6 fuel oil cost, Fernandina Beach Mill ULSD cost.
(d) U.S. EPA Air Pollution Control Cost Manual, Section 1, Chapter 2.
(e) Pre-retrofilt SO_2 emissions estimated based on projected 2028 actual throughput/fuel usage. Post-retrofit SO_2 emissions estimated based on equivalent heat input of pre-retrofit SO_2 emissions and AP-42 Sections 1.3 and 1.4.

Table A-5c

SO_2 Fuel Switching Emissions Calculations - WestRock Panama City No. 1 Recovery Boiler

Projected 2028 Actual Throughput/Fuel Usage			Projected 2028 Actual SO_2 Emissions	
Current SO_2				
Black Liquor Solids	541,806	tpy	74	tpy
	3,159	MMBtu/yr		
No. 6 Fuel Oil	1,165,695	gpy		
	1.72E+05	MMBtu/yr		
Natural Gas	333	MMscf/yr		
	3.53E+05	MMBtu/yr		
Post-change SO_2 (Natural Gas)				
Black Liquor Solids	541,806	tpy	44.4	tpy
	3,159	MMBtu/yr		
Natural Gas	4.96E+02	MMscf/yr		
	5.25E+05	MMBtu/yr		
SO_2 Removed			30	tpy
Post-change SO_2 (ULSD)				
Black Liquor Solids	541,806	tpy	44.6	tpy
	3,159	MMBtu/yr		
ULSD	3.56E+06	gpy		
	5.25E+05	MMBtu/yr		
SO_2 Removed			30	tpy

Heat Content		
Black Liquor Solids[1]	5,830	Btu/lb
Natural Gas[1]	1,060	Btu/scf
No. 6 Fuel Oil[1]	148	MMBtu/Mgal
ULSD[2]	140	MMBtu/Mgal

No. 6 Fuel Oil Emissions Factor		
No. 6 Fuel Oil Sulfur Content[1]	1.3	%
No. 6 Fuel Oil Emissions Factor[2]	204.1	lb/Mgal

ULSD Emissions Factor		
ULSD Sulfur Content[2]	15	ppm
ULSD Emissions Factor[2]	0.213	lb/Mgal

Natural Gas Emissions Factor		
Natural Gas Emissions Factor[3]	0.6	lb/MMscf

1 - Mill Specific Information

2 - AP-42 Section 1.3

3 - AP-42 Section 1.4

Table A-6
Wet Scrubber Cost - WestRock Panama City No. 1 Recovery Boiler

CAPITAL COSTS[a]

		COST ITEM	COST FACTOR	COST ($)
		Direct Costs		
		Purchased Equipment Costs		
(a)	***A***	Equipment Costs		***$11,876,323***
(b)		Instrumentation	0.10 A	$1,187,632
(b)		Sales Tax	0.03 A	$356,290
(b)		Freight	0.05 A	$593,816
	B	***Total Purchased Equipment Cost***		***$14,014,061***
		Direct Installation Costs		
(b)		Foundations and Supports	0.12 B	$1,681,687
(b)		Handling and erection	0.40 B	$5,605,625
(b)		Electrical	0.01 B	$140,141
(b)		Piping	0.30 B	$4,204,218
(b)		Insulation for ductwork	0.01 B	$140,141
(b)		Painting	0.01 B	$140,141
		Direct Installation Cost		***$11,911,952***
		Total Direct Costs		***$25,926,013***
		Indirect Costs		
(b)		Engineering	0.10 B	$1,401,406
(b)		Construction Management	0.10 B	$1,401,406
(b)		Contractor fees	0.10 B	$1,401,406
(b)		Start-up	0.01 B	$140,141
(b)		Performance test	0.01 B	$140,141
(b)		Contingencies	0.03 B	$420,422
		Total Indirect Costs		***$4,904,921***
		Total Capital Investment (TCI)		***$30,830,935***

ANNUALIZED COSTS

	COST ITEM	COST FACTOR	RATE	COST ($)
	Direct Annual Costs			
	Operating Labor			
(b)	Operator[c]	[redacted]	[redacted] [redacted] [redacted] [d]	$15,686
(b)	Supervisor	15% of operator labor		$2,353
	Maintenance			
(b)	Maintenance labor[c]	[redacted]	[redacted] [redacted] [redacted] [d]	$18,971
(b)	Maintenance materials	100% of maintenance labor		$18,971
	Utilities			
	Electricity	[redacted]	[redacted] [redacted] [d]	$866,263
	Chemicals	[redacted]	[redacted] [redacted] [redacted] [d]	$1,362,332
	Fresh water usage	[redacted]	[redacted] [redacted] [redacted]	$28,888
	Wastewater disposal	[redacted]	[redacted] [redacted] [redacted] [d]	$2,928
	Total Direct Annual Costs			***$2,316,391***
	Indirect Annual Costs			
(b)	Overhead	60% Labor and Material Costs		$33,588
(b)	General and administrative	2% of TCI		$616,619
(b)	Property taxes	1% of TCI		$308,309
(b)	Insurance	1% of TCI		$308,309
(b)	Capital recovery	0.095 x TCI		$2,920,341
	Life of the control:	15 years at	4.75% interest	
	Total Indirect Annual Costs			***$4,187,167***
	Total Annual Costs			***$6,503,558***
	Cost Effectiveness ($/ton)			
	SO_2 Control Efficiency[e]:	98%		
	SO_2 Emissions[f]:	166 tpy	Total Annual Costs/Controlled SO_2 Emissions:	
	Controlled SO_2 Emissions:	162.7 tons of SO_2 removed annually		***$39,961***

[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 Boiler was scaled based on furnace BLS throughput capacity. 2001 dollars were scaled to 2019 dollars based on the 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 WestRock Charleston rates.

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

[f] Projected actual SO_2 emissions.

NO. 2 RECOVERY BOILER
CONTROL COST ESTIMATES

Table A-7a
Fuel Switching Cost (Natural Gas) - WestRock Panama City No. 2 Recovery Boiler

CAPITAL COSTS			
Total Capital Investment for 8 New Burners and Required Infrastructure:	(a)	*TCI*	*$15,003,082*

ANNUALIZED COSTS

	COST ITEM	COST FACTOR	UNIT COST	COST ($)
Annual Operating Costs - Direct Annual Costs				
(b)	Maintenance Costs	no incremental increase		*$0*
Fuel				
(c)	Increased natural gas cost	[redacted]	[redacted]	*$104,116*
	No. 6 fuel oil cost savings	[redacted]	[redacted]	*-$400,634*
	Total Direct Annual Costs:		*DAC*	*-$296,518*
Annual Operating Costs - Indirect Annual Costs				
(b)	Overhead	no increase		*$0*
(b)	Administrative Charges	2% of TCI		*$300,062*
(b)	Property Taxes	1% of TCI		*$150,031*
(b)	Insurance	1% of TCI		*$150,031*
	Total Indirect Annual Costs:		*IDAC*	*$600,123*
	Total Annual Costs:		*TAC*	*$303,605*
Cost Effectiveness				
(d)	Expected lifetime of equipment, years	20		
(d)	Interest rate, %/yr	4.75%		
(d)	Capital recovery factor	0.079		
(d)	Total Capital Investment Cost	$15,003,082		
	Annualized Capital Investment Cost:			*$1,178,499*
	Total Annualized Cost:			*$1,482,105*
(e)	SO_2 Reduction	73%		
	Pre-retrofit SO_2	166 tons SO_2/yr		
	Post-retrofit SO_2 Using Burner System	44.8 tons SO_2/yr		
	SO_2 Removed	121 tons SO_2/yr		
	Annual Cost/Ton Removed:			*$12,217*

(a) Based on project estimate performed by WestRock Fernandina Beach, scaled using total burner heat input that would need to be replaced.
(b) No increase in maintenance costs estimated.
(c) WestRock Panama City fuel costs.
(d) U.S. EPA Air Pollution Control Cost Manual, Section 1, Chapter 2.
(e) Pre-retrofilt SO_2 emissions estimated based on projected 2028 actual throughput/fuel usage. Post-retrofit SO_2 emissions estimated based on equivalent heat input of pre-retrofit SO_2 emissions and AP-42 Sections 1.3 and 1.4.

Table A-7b
Fuel Switching Cost (ULSD) - WestRock Panama City No. 2 Recovery Boiler

CAPITAL COSTS			
New gas igniters, new oil burner tips and fuel oil system conversion to ULSD	(a)	*TCI*	*$2,276,500*

ANNUALIZED COSTS				
	COST ITEM	**COST FACTOR**	**UNIT COST**	**COST ($)**
Annual Operating Costs - Direct Annual Costs				
(b)	Maintenance Costs	no incremental increase		*$0*
Fuel				
(d)	ULSD cost	[redacted]	[redacted]	*$6,558,776*
	Natural gas cost savings	[redacted]	[redacted]	*-$1,203,453*
	No. 6 fuel oil cost savings	[redacted]	[redacted]	*-$400,634*
	Total Direct Annual Costs:		***DAC***	***$4,954,689***
Annual Operating Costs - Indirect Annual Costs				
(e)	Overhead	no increase		*$0*
(f)	Administrative Charges	2% of TCI		*$45,530*
(f)	Property Taxes	1% of TCI		*$22,765*
(f)	Insurance	1% of TCI		*$22,765*
	Total Indirect Annual Costs:		***IDAC***	***$91,060***
	Total Annual Costs:		***TAC***	***$5,045,749***
Cost Effectiveness				
(f)	Expected lifetime of equipment, years	20		
(f)	Interest rate, %/yr	4.75%		
(f)	Capital recovery factor	0.079		
(f)	Total Capital Investment Cost	$2,276,500		
	Annualized Capital Investment Cost:			***$178,820***
	Total Annualized Cost:			***$5,224,569***
(g)	SO_2 Reduction	73%		
	Pre-retrofit SO_2	166 tons SO_2/yr		
	Post-retrofit SO_2 Using ULSD	45.0 tons SO_2/yr		
	SO_2 Removed	121 tons SO_2/yr		
	Annual Cost/Ton Removed:			***$43,143***

(a) Based on WestRock's experience at other mills, represents the capital cost of converting a recovery furnace to startup on ULSD instead of No. 6 fuel oil and includes addition of natural gas igniters for safety.
(b) No increase in maintenance costs estimated.
(c) WestRock Panama City No. 6 fuel oil cost, Fernandina Beach Mill ULSD cost.
(d) U.S. EPA Air Pollution Control Cost Manual, Section 1, Chapter 2.
(e) Pre-retrofilt SO_2 emissions estimated based on projected 2028 actual throughput/fuel usage. Post-retrofit SO_2 emissions estimated based on equivalent heat input of pre-retrofit SO_2 emissions and AP-42 Sections 1.3 and 1.4.

Table A-7c

SO_2 Fuel Switching Emissions Calculations - WestRock Fernandina Beach No. 2 Recovery Boiler

Projected 2028 Actual Throughput/Fuel Usage			**Projected 2028 Actual SO_2 Emissions**	
Current SO_2				
Black Liquor Solids	541,806	tpy	166	tpy
	3,159	MMBtu/yr		
No. 6 Fuel Oil	283,850	gpy		
	3.97E+04	MMBtu/yr		
Natural Gas	433	MMscf/yr		
	4.59E+05	MMBtu/yr		
Post-change SO_2 (Natural Gas)				
Black Liquor Solids	541,806	tpy	44.8	tpy
	3,159	MMBtu/yr		
Natural Gas	471	MMscf/yr		
	4.99E+05	MMBtu/yr		
SO_2 Removed			121	tpy
Post-change SO_2 (ULSD)				
Black Liquor Solids	541,806	tpy	45.0	tpy
	3,159	MMBtu/yr		
ULSD	3.38E+06	gpy		
	4.99E+05	MMBtu/yr		
SO_2 Removed			121	tpy

Heat Content		
Black Liquor Solids	5,830	Btu/lb
Natural Gas[1]	1,060	Btu/scf
No. 6 Fuel Oil[1]	148	MMBtu/Mgal
ULSD[2]	140	MMBtu/Mgal

No. 6 Fuel Oil Emissions Factor		
No. 6 Fuel Oil Sulfur Content[1]	1.3	%
No. 6 Fuel Oil Emissions Factor[2]	204.1	lb/Mgal

ULSD Emissions Factor		
ULSD Sulfur Content[2]	15	ppm
ULSD Emissions Factor[2]	0.213	lb/Mgal

Natural Gas Emissions Factor		
Natural Gas Emissions Factor[3]	0.6	lb/MMscf

1 - Mill Specific Information

2 - AP-42 Section 1.3

3 - AP-42 Section 1.4

Table A-8

Wet Scrubber Cost - WestRock Panama City No. 2 Recovery Boiler

CAPITAL COSTS[a]

	COST ITEM	COST FACTOR	COST ($)
	Direct Costs		
	Purchased Equipment Costs		
(a)	***A*** Equipment Costs		***$11,876,323***
(b)	Instrumentation	0.10 A	$1,187,632
(b)	Sales Tax	0.03 A	$356,290
(b)	Freight	0.05 A	$593,816
	B Total Purchased Equipment Cost		***$14,014,061***
	Direct Installation Costs		
(b)	Foundations and Supports	0.12 B	$1,681,687
(b)	Handling and erection	0.40 B	$5,605,625
(b)	Electrical	0.01 B	$140,141
(b)	Piping	0.30 B	$4,204,218
(b)	Insulation for ductwork	0.01 B	$140,141
(b)	Painting	0.01 B	$140,141
	Direct Installation Cost		***$11,911,952***
	Total Direct Costs		***$25,926,013***
	Indirect Costs		
(b)	Engineering	0.10 B	$1,401,406
(b)	Construction Management	0.10 B	$1,401,406
(b)	Contractor fees	0.10 B	$1,401,406
(b)	Start-up	0.01 B	$140,141
(b)	Performance test	0.01 B	$140,141
(b)	Contingencies	0.03 B	$420,422
	Total Indirect Costs		***$4,904,921***
	Total Capital Investment (TCI)		***$30,830,935***

ANNUALIZED COSTS

	COST ITEM	COST FACTOR	RATE	COST ($)
	Direct Annual Costs			
	Operating Labor			
(b)	Operator[c]	[redacted]	[redacted] [redacted] [redacted] [d]	$15,686
(b)	Supervisor	15% of operator labor		$2,353
	Maintenance			
(b)	Maintenance labor[c]	[redacted]	[redacted] [redacted] [redacted] [d]	$18,971
(b)	Maintenance materials	100% of maintenance labor		$18,971
	Utilities			
	Electricity	1,648 kW	$0.060 per kWh[d]	$866,263
	Chemicals	1.52 gpm NaOH	$1.71 per gal NaOH[d]	$1,362,332
	Fresh water usage	150 gpm	$0.37 per 1000 gallon[d]	$28,888
	Wastewater disposal	15.2 gpm	$0.37 per 1000 gallon[d]	$2,928
	Total Direct Annual Costs			***$2,316,391***
	Indirect Annual Costs			
(b)	Overhead	60% Labor and Material Costs		$33,588
(b)	General and administrative	2% of TCI		$616,619
(b)	Property taxes	1% of TCI		$308,309
(b)	Insurance	1% of TCI		$308,309
(b)	Capital recovery	0.095 x TCI		$2,920,341
	Life of the control:	15 years at	4.75% interest	
	Total Indirect Annual Costs			***$4,187,167***
	Total Annual Costs			***$6,503,558***
	Cost Effectiveness ($/ton)			
	SO_2 Control Efficiency[e]:	98%		
	SO_2 Emissions[f]:	74.4 tpy	Total Annual Costs/Controlled SO_2 Emissions:	
	Controlled SO_2 Emissions:	72.9 tons of SO_2 removed annually		***$89,221***

[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 Boiler was scaled based on furnace BLS throughput capacity. 2001 dollars were scaled to 2019 dollars based on the 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 WestRock Charleston rates.

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

[f] Projected actual SO_2 emissions.

APPENDIX B -
SUPPORTING INFORMATION

IPM Model – Updates to Cost and Performance for APC Technologies

SDA FGD Cost Development Methodology

Final

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Project 13527-001

Eastern Research Group, Inc.

Prepared by

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SDA FGD Cost Development 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 impact costs, such as flue gas volume or 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 a facility would incur to install a retrofit control such as project contingency.

Establishment of the Cost Basis

Cost data for the SDA FGD systems based on actual installations were more limited than those for the wet FGD systems until 2012. However, since 2012 the market trend has shifted toward the installation of dry FGD/CDS technology. Even with the new data, a similar trend of capital cost with generating capacity (MW size) is generally seen between the wet and SDA system. The same least-square curve fit power relationship for capital costs as a function of generating capacity, up to 600 MW, was used for the wet and SDA cost estimation with the constant multiplier adjusted to ensure that the curve represented the data available.

The curve fit was set to represent proprietary in-house cost data of a "typical" SDA FGD retrofit for removal of 95% of the inlet sulfur. It should be noted that the lowest available SO_2 emission guarantees, from the original equipment manufactures of SDA FGD systems, are 0.06 lb/MMBtu. The typical SDA FGD retrofit was based on:

- Retrofit Difficulty = 1 (Average retrofit difficulty);
- Gross Heat Rate = 9800 Btu/kWh;
- SO_2 Rate = 2.0 lb/MMBtu;
- Type of Coal = PRB;

SDA FGD Cost Development Methodology

- Project Execution = Multiple lump-sum contracts; and
- Recommended SO_2 emission floor = 0.08 lb/MMBtu.

A dry FGD system designed to treat 100% of the flue gas is capable of meeting Mercury Air Toxics Standards (MATS) limits for HCl of 0.002 lb/MBtu. Dry FGDs can remove up to 99% HCl in the flue gas.

Based on the recently acquired data and recently completed projects, it appears the overall capital cost has increased by only 6% over the costs published in 2013. Analysis of the data indicates that the lack of a large number of FGD projects has resulted in competitive pressure to absorb any significant increase in the cost.

Units below 50 MW will typically not install an SDA FGD system. Sulfur reductions for small units would be accomplished by treating smaller units at a single site with one SDA FGD system, switching to a lower sulfur coal, repowering or converting to natural gas firing, using dry sorbent injection, and/or reducing operating hours. Capital costs of approximately $1,000/kW may be used for units below 50 MW under the premise that these units will be combined.

Based on the typical SDA FGD performance, the technology should not be applied to fuels with more than 3 lb SO_2/MMBtu, and the cost estimator should be limited to fuels with less than 3 lb SO_2/MMBtu. Typically, both SDA and circulating dry scrubber (CDS) technologies have been applied to low sulfur fuel (lower than 2 lb/MMBtu).

The alternate dry technology, CDS, can meet removals of 98% or greater over a large range of inlet sulfur concentrations. It should be noted that the lowest SO_2 emission guarantees for a CDS FGD system are 0.04 lb/MMBtu. Recent industry experience has shown that a CDS FGD system has a similar installed cost to a comparable SDA FGD system and has been the technology of choice in last four years.

SDA FGD Cost Development Methodology

Methodology

Inputs

Several input variables are required in order to predict future retrofit costs. The gross unit size in MW (equivalent acfm) and sulfur content of the fuel are the major variables for the capital estimation. A retrofit factor that equates to the difficulty of constructing the system must be defined. The costs herein could increase significantly for congested sites. The unit gross heat rate will factor into the amount of flue gas generated and ultimately the size of the absorber, reagent preparation, waste handling, and balance of plant costs. The SO_2 rate will have the greatest influence on the reagent handling and waste handling facilities. The type of fuel (Bituminous, PRB, or Lignite) will influence the flue gas quantities as a result of the different typical heating values.

The cost methodology is based on a unit located within 500 feet of sea level. The actual elevation of the site should be considered separately and factored into the cost due to the effects on the flue gas volume. The base absorber island and balance of plant costs are directly impacted by the site elevation. These two base cost modules should be increased based on the ratio of the atmospheric pressure at sea level and that at the unit location. As an example, a unit located 1 mile above sea level would have an approximate atmospheric pressure of 12.2 psia. Therefore, the base absorber island and balance of plant costs should be increased by:

14.7 psia/12.2 psia = 1.2 multiplier to the base absorber island and balance of plant costs

Outputs

Total Project Costs (TPC)

First, the installed costs are calculated for each required base module. The base module installed costs include:

- All equipment;
- Installation;
- Buildings;
- Foundations;
- Electrical; and
- Retrofit difficulty.

SDA FGD Cost Development Methodology

The base modules are:

BMR =	Base absorber island cost that includes an absorber and a baghouse
BMF =	Base reagent preparation and waste recycle/handling cost
BMB =	Base balance of plant costs including: ID or booster fans, piping, ductwork and reinforcement, electrical, etc…
BM =	BMR + BMF + BMB

The total base module installed cost (BM) is then increased by:

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

- Owner's home office costs (owner's engineering, management, and procurement) at 5% of the CECC; and
- Allowance for Funds Used During Construction (AFUDC) at 10% of the CECC and owner's costs. The AFUDC is based on a three-year engineering and construction cycle.

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 SDA FGD 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, 8 additional operators are required for an SDA FGD system. The FOMO was based on the number of additional operations staff required.
- The fixed maintenance materials and labor are a direct function of the process capital cost at 1.5% of the BM. Cost of bags and cages are included in the fixed O&M cost with the assumption that bag replacement is carried out once every 3 years and cage replacement is carried out once every 9 years.
- The administrative labor is a function of the FOMO and FOMM at 3% of the sum of (FOMO + 0.4 FOMM).

Variable O&M (VOM)

Variable O&M is a function of:

- Reagent use and unit costs;
- Waste production and unit disposal costs;
- Additional power required and unit power cost; and
- Makeup water required and unit water cost.

The following factors and assumptions underlie calculations of the VOM:

- All of the VOM costs were tabulated on a per megawatt-hour (MWh) basis.
- The reagent usage is a function of gross unit size, SO_2 feed rate, and removal efficiency. While the capital costs are based on a 95% sulfur removal design, the operating sulfur removal percentage can be adjusted to reflect actual variable operating costs.
- In addition to sulfur removal efficiency, the estimated reagent usage was based on a flue gas temperature into the SDA FGD of 300°F and an adiabatic approach to saturation of 30°F.
- The calcium-to-sulfur stoichiometric ratio varies based on inlet sulfur. The variation in stoichiometric ratio was accounted for in the estimation. The economic estimation is only valid up to 3 lb SO_2/MMBtu inlet.
- The basis for the lime purity was 90% CaO with the balance being inert material.
- The waste generation rate is a function of inlet sulfur and calcium to sulfur stoichiometry. Both variables are accounted for in the waste generation

SDA FGD Cost Development Methodology

estimation. The waste disposal rate is based on 10% moisture in the by-product.

- The additional power required includes increased fan power to account for the added SDA FGD pressure drop. This requirement is a function of gross unit size (actual gas flow rate) and sulfur rate.
- 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 makeup water rate is a function of gross unit size (actual gas flow rate) and sulfur feed rate.

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:

- Lime cost in $/ton. No escalation is observed in pebble lime cost. However, the cost could significantly vary with the location.
- Waste disposal costs in $/ton. The site-specific cost could be significantly different.
- Auxiliary power cost in $/kWh. No noticeable escalation has been observed for auxiliary power cost since 2013.
- Makeup water costs in $/1000 gallon.
- Operating labor rate (including all benefits) in $/hr.

The variables that contribute to the overall VOM are:

VOMR = Variable O&M costs for lime reagent

VOMW = Variable O&M costs for waste disposal

VOMP = Variable O&M costs for additional auxiliary power

VOMM = Variable O&M costs for makeup water

The total VOM is the sum of VOMR, VOMW, VOMP, and VOMM. Table 1 shows a complete capital and O&M cost estimate worksheet for an SDA FGD.

SDA FGD Cost Development Methodology

Table 1. Example of a Complete Cost Estimate for an SDA FGD

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	500	<--- User Input (Greater than 50 MW)
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9800	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input (SDA FGD Estimation only valid up to 3 lb/MMBtu SO2 Rate)
Type of Coal	E		PRB 1	<--- User Input
Coal Factor	F		1.05	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.98	C/10000
Heat Input	H	(Btu/hr)	4.90E+09	A*C*1000
Operating SO_2 Removal	J	(%)	95	<--- User Input (Used to adjust actual operating costs)
Design Lime Rate	K	(ton/hr)	7	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 removal)
Design Waste Rate	L	(ton/hr)	16	(0.8016*(D^2)+31.1917*D)*A*G/2000 (Based on 95% SO2 removal)
Aux Power **Include in VOM?** ☑	**M**	**(%)**	**1.35**	(0.000547*D^2+0.00649*D+1.3)*F*G
Makeup Water Rate	N	(1000 gph)	29	(0.04898*(D^2)+0.5925*D+55.11)*A*F*G/1000
Lime Cost	P	($/ton)	125	<--- User Input
Waste Disposal Cost	Q	($/ton)	30	<--- User Input
Aux Power Cost	R	($/kWh)	0.06	<--- User Input
Makeup Water Cost	S	($/kgal)	1	<--- User Input
Operating Labor Rate	T	($/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			
BMR ($) =	if (A>600 then (A*98000) else 637000*(A^0.716))*B*(F*G)^0.6*(D/4)^0.01	$ 55,086,000	Base module absorber island cost
BMF ($) =	if (A>600 then (A*52000) else 338000*(A^0.716))*B*(D*G)^0.2	$ 33,100,000	Base module reagent preparation and waste recycle/handling cost
BMB ($) =	if (A>600 then (A*138000) else 899000*(A^0.716))*B*(F*G)^0.4	$ 77,837,000	Base module balance of plant costs including: ID or booster fans, piping, ductwork modifications and strengthening, electrical, etc…
BM ($) =	BMR + BMF + BMW + BMB	$ 166,023,000	Total Base module cost including retrofit factor
BM ($/KW) =		332	Base module cost per kW

Total Project Cost	Example	Comments
A1 = 10% of BM	$ 16,602,000	Engineering and Construction Management costs
A2 = 10% of BM	$ 16,602,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 10% of BM	$ 16,602,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3	**$ 215,829,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) - Excludes Owner's Costs =	**432**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC	$ 10,791,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1	**$ 226,620,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =	**453**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)	$ 22,662,000	AFUDC (Based on a 3 year engineering and construction cycle)
C1 = 15% of (CECC + B1)	$ -	EPC fees of 15%
TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2	**$ 249,282,000**	Total project cost
TPC ($/kW) - Includes Owner's Costs and AFUDC =	**499**	Total project cost per kW

SDA FGD Cost Development Methodology

Table 1 Continued

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	500	<--- User Input (Greater than 50 MW)
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9800	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input (SDA FGD Estimation only valid up to 3 lb/MMBtu SO2 Rate)
Type of Coal	E		PRB 1	<--- User Input
Coal Factor	F		1.05	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.98	C/10000
Heat Input	H	(Btu/hr)	4.90E+09	A*C*1000
Operating SO_2 Removal	J	(%)	95	<--- User Input (Used to adjust actual operating costs)
Design Lime Rate	K	(ton/hr)	7	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 removal)
Design Waste Rate	L	(ton/hr)	16	(0.8016*(D^2)+31.1917*D)*A*G/2000 (Based on 95% SO2 removal)
Aux Power **Include in VOM?** ☑	**M**	**(%)**	**1.35**	(0.000547*D^2+0.00649*D+1.3)*F*G
Makeup Water Rate	N	(1000 gph)	29	(0.04898*(D^2)+0.5925*D+55.11)*A*F*G/1000
Lime Cost	P	($/ton)	125	<--- User Input
Waste Disposal Cost	Q	($/ton)	30	<--- User Input
Aux Power Cost	R	($/kWh)	0.06	<--- User Input
Makeup Water Cost	S	($/kgal)	1	<--- User Input
Operating Labor Rate	T	($/hr)	60	<--- User Input (Labor cost including all benefits)

Costs are all based on 2016 dollars

Fixed O&M Cost

FOMO ($/kW yr) = (8 additional operators)*2080*T/(A*1000)	$	2.00	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.015/(B*A*1000)	$	4.98	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.12	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**$**	**7.10**	Total Fixed O&M costs

Variable O&M Cost

VOMR ($/MWh) = K*P/A*J/95	$	1.81	Variable O&M costs for lime reagent
VOMW ($/MWh) = L*Q/A*J/95	$	0.96	Variable O&M costs for waste disposal
VOMP ($/MWh) =M*R*10	$	0.81	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM ($/MWh) = N*S/A	$	0.06	Variable O&M costs for makeup water
VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM	**$**	**3.64**	

AF&P A®

Emission Control Study – Technology Cost Estimates

American Forest & Paper Association
Washington, D.C.

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

Table of Contents

1. Results

See “AF&PA Emission Control Summary Sheet” Excel Spreadsheet

2. Capital Cost Estimate Basis

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

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

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

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

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

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

The capital cost estimate does not include the following:

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

3. Operating Cost Estimate Basis

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

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

4. NO_x Control Good Technology Limit

4.1. NDCE Kraft Recovery Furnace

4.1.1. Description

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

4.1.2. Major Equipment

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

4.1.3. Basis for Estimate

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

4.1.4. Capital Cost Estimate Assumptions

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

4.1.5. Operating Cost Estimate Assumptions

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

4.2. Lime Kiln – Route SOGs to new Thermal Oxidizer

4.2.1. Description

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

4.2.2. Major Equipment

- ✓ Thermal oxidizer
- ✓ Caustic scrubber

4.2.3. Basis for Estimate

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

4.2.4. Capital Cost Estimate Assumptions

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

4.2.5. Operating Cost Estimate Assumptions

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

4.3. Coal or Coal / Wood Boiler

4.3.1. Description

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

4.3.2. Major Equipment

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

4.3.3. Basis for Estimate

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

4.3.4. Capital Cost Estimate Assumptions

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

4.3.5. Operating Cost Estimate Assumptions

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

4.4. Gas Boiler

4.4.1. Description

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

4.4.2. Major Equipment

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

4.4.3. Basis for Estimate

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

4.4.4. Capital Cost Estimate Assumption

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

4.4.5. Operating Cost Estimate Assumptions

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

4.5. Gas Turbine – Water Injection

4.5.1. Description

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

4.5.2. Major Equipment

- ✓ High pressure water pump
- ✓ Water injection system

4.5.3. Basis for Estimate

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

4.5.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power.

4.5.5. Operating Cost Estimate Assumptions

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

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

4.6. Gas Turbine – Steam Injection

4.6.1. Description

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

4.6.2. Major Equipment

- ✓ High pressure water pump
- ✓ Water injection system

4.6.3. Basis for Estimate

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

4.6.4. Capital Cost Estimate Assumptions

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

4.6.5. Operating Cost Estimate Assumptions

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

4.7. Oil Boiler

4.7.1. Description

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

4.7.2. Major Equipment

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

4.7.3. Basis for Estimate

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

4.7.4. Capital Cost Estimate Assumption

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

4.7.5. Operating Cost Estimate Assumptions

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

4.8. Wood Boiler

4.8.1. Description

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

4.8.2. Major Equipment

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

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

4.8.3. Basis for Estimate

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

4.8.4. Capital Cost Estimate Assumptions

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

4.8.5. Operating Cost Estimate Assumptions

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

5. NO_x Control Best Technology Limit

5.1. Technical Feasibility of SNCR and SCR Technologies

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

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

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

5.2. NDCE Kraft Recovery - SNCR Technology

5.2.1. Description

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

5.2.2. Major Equipment

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

5.2.3. Basis for Estimate

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

5.2.4. Capital Cost Estimate Assumptions

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

5.2.5. Operating Cost Estimate Assumptions

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

5.3. NDCE Kraft Recovery – SCR Technology

5.3.1. Description

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

5.3.2. Major Equipment

- ✓ SCR reactor
- ✓ Duct burner
- ✓ CEM

5.3.3. Basis for Estimate

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

5.3.4. Capital Cost Estimate Assumptions

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

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

5.3.5. Operating Cost Estimate Assumptions

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

5.4. DCE Kraft Recovery – SNCR Technology

5.4.1. Description

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

5.4.2. Major Equipment

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

5.4.3. Basis for Estimate

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

5.4.4. Capital Cost Estimate Assumptions

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

5.4.5. Operating Cost Estimate Assumptions

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

5.5. DCE Kraft Recovery – SCR Technology

5.5.1. Description

Installation of a SCR NO_x control system in a DCE recovery furnace burning 1.7 x 10^6 (Mm) lb BLS per day. The target is 40 ppm @ 8% oxygen or 50% reduction) for a 30-day average.

5.5.2. Major Equipment

- ✓ SCR reactor
- ✓ Duct burner
- ✓ CEM

5.5.3. Basis for Estimate

Northern Kraft mill with a coal fired 120,000-lb/hr boiler. The project was estimated in 1999. The inlet NO_x is estimated to be 67 ppm and the outlet NO_x is estimated to be 13 ppm.

5.5.4. Capital Cost Estimate Assumptions

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

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

5.5.5. Operating Cost Estimate Assumptions

- ✓ Materials – catalyst: 697 ft^3 per yr.
- ✓ Chemicals – urea: 245 tons per year
- ✓ Maintenance: 2% of TIC
- ✓ Power: 355 kw
- ✓ Power usage factor: 70%
- ✓ Workhours: 28.6 hr per day
- ✓ Testing: $5,000 per year
- ✓ Water: 4 gpm
- ✓ Steam: 1,190 lb/hr
- ✓ Compressed air: 26 cfm

5.6. Lime Kiln – Low-NO_x burners, & SCR

5.6.1. Description

Install Low NO_x burners and SCR systems in lime kiln, which produces 240 tpd CaO. SCR can be applied at the limekiln provided the flue gas temperature is controlled and the dust is removed prior to application.

5.6.2. Major Equipment

- ✓ SCR reactor
- ✓ Low NO_x burners
- ✓ Upgrade to forced draft fan
- ✓ ID fan

5.6.3. Basis for Estimate

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

5.6.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power."
- ✓ Costs were escalated to 2001 dollars
- ✓ R&D cost: 1.5% of total direct costs (i.e., labor, materials, subcontract, and equipment)

5.6.5. Operating Cost Estimate Assumptions

- ✓ Materials – catalyst: 323 ft^3 per yr.
- ✓ Chemicals – urea: 113.5 tons per year
- ✓ Maintenance: 2% of TIC
- ✓ Power: 165 kw
- ✓ Power usage factor: 70%
- ✓ Workhours: 28.6 hr per day
- ✓ Testing: $5,000 per year
- ✓ Water: 1.97 gpm
- ✓ Steam: 552 lb/hr
- ✓ Compressed air: 12 cfm

5.7. Coal or Coal / Wood Boiler – SCR

5.7.1. Description

Installation of a SCR system on a coal or coal/wood boiler producing 300,000 lb/hr of steam. The maximum NO_x emission rate is 0.17 lb/Mm Btu for a 30-day average.

5.7.2. Major Equipment

- ✓ SCR reactor
- ✓ Low NO_x burners
- ✓ Upgrade to forced draft fan
- ✓ ID fan

5.7.3. Basis for Estimate

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

5.7.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the “0.6 power.”
- ✓ Costs were escalated to 2001 dollars
- ✓ R&D cost: 0.5% of total direct costs (i.e., labor, materials, subcontract, and equipment)

5.7.5. Operating Cost Estimate Assumptions

- ✓ Materials – catalyst: 1219 ft^3 per yr.
- ✓ Chemicals – urea: 428 tons per year
- ✓ Maintenance: 2% of TIC
- ✓ Power: 622 kw
- ✓ Power usage factor: 70%
- ✓ Workhours: 28.6 hr per day
- ✓ Testing: $5,000 per year
- ✓ Water: 7.43 gpm
- ✓ Steam: 2082 lb/hr
- ✓ Compressed air: 45 cfm

5.8. Coal or Coal / Wood Boiler – Switch to Natural Gas

5.8.1. Description

Switch from coal to natural gas for a coal or coal/wood boiler producing 300,000 lb/hr of steam.

5.8.2. Major Equipment

- ✓ New burners
- ✓ Natural gas reducing station

5.8.3. Basis for Estimate

Southeastern Kraft mill which switched from coal to natural gas for a boiler producing 420,000 lb/hr of steam. The project was estimated in 1999.

5.8.4. Capital Cost Estimate Assumptions

- ✓ Natural gas delivered at 700 psig to property line of plant.
- ✓ Costs were factored using the "0.6 power."
- ✓ Costs were escalated to 2001 dollars

5.8.5. Operating Cost Estimate Assumptions

- ✓ Maintenance: 1% of TIC
- ✓ Power: N/A
- ✓ Workhours: 1.5 hr per day
- ✓ Testing: $5,000 per year

5.9. Gas Boiler

5.9.1. Description

Installation of SCR on natural gas-fired boiler producing 120,000 lb/hr of steam. The maximum NO_x emission rate is 0.015 lb/Mm Btu utilizing a 30-day average.

5.9.2. Major Equipment

- ✓ SCR reactor
- ✓ Low NO_x burners
- ✓ Upgrade to forced draft fan
- ✓ ID fan

5.9.3. Basis for Estimate

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

5.9.4. Capital Cost Estimate Assumptions

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

5.9.5. Operating Cost Estimate Assumptions

- ✓ Materials – catalyst: 464 ft^3 per yr. @ \$350 per ft^3
- ✓ Chemicals – urea: 163 tons per year
- ✓ Maintenance: 2% of TIC
- ✓ Power: 237 kw
- ✓ Power usage factor: 70%
- ✓ Workhours: 28.6 hr per day
- ✓ Testing: \$5,000 per year
- ✓ Water: 2.83 gpm
- ✓ Steam: 793 lb/hr
- ✓ Compressed air: 17 cfm

5.10. Gas Turbine

5.10.1. Description

Installation of SCR system for a 30-MW natural gas turbine yielding an emission level of 5 ppm @15% oxygen for a 30-day average representing a 95% NO_x reduction.

5.10.2. Major Equipment

- ✓ SCR reactor
- ✓ Low NO_x burners
- ✓ Upgrade to forced draft fan
- ✓ ID fan

5.10.3. Basis for Estimate

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

5.10.4. Capital Cost Estimate Assumptions

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

5.10.5. Operating Cost Estimate Assumptions

- ✓ Materials – catalyst: 298 ft^3 per yr. @ $350 per ft^3
- ✓ Chemicals – urea: 105 tons per year
- ✓ Maintenance: 2% of TIC
- ✓ Power: 418 kw
- ✓ Power usage factor: 70%
- ✓ Workhours: 3 hr per day
- ✓ Testing: $5,000 per year
- ✓ Water: 5 gpm
- ✓ Steam: 1400 lb/hr
- ✓ Compressed air: 30 cfm

5.11. Oil Boiler

5.11.1. Description

Installation of SCR system on oil-fired boiler producing 135,000 lb/hr of steam. The maximum NO_x emission rate is 0.04 lb/Mmbtu for a 30-day average or a 90% reduction.

5.11.2. Major Equipment

- ✓ SCR reactor
- ✓ Low NO_x burners
- ✓ Upgrade to forced draft fan
- ✓ ID fan

5.11.3. Basis for Estimate

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

5.11.4. Capital Cost Estimate Assumptions

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

- ✓ R&D cost: 0.5% of total direct costs (i.e., labor, materials, subcontract, and equipment)

5.11.5. Operating Cost Estimate Assumptions

- ✓ Materials – catalyst: 679 ft^3 per yr. @ $350 per ft^3
- ✓ Chemicals – urea: 238 tons per year
- ✓ Maintenance: 2% of TIC
- ✓ Power: 346 kw
- ✓ Power usage factor: 70%
- ✓ Workhours: 28.6 hr per day
- ✓ Testing: $5,000 per year
- ✓ Water: 4.14 gpm
- ✓ Steam: 1159 lb/hr
- ✓ Compressed air: 25 cfm

5.12. Wood Boiler - SNCR

5.12.1. Description

Installation of SNCR system on a wood boiler producing 300,000 lb/hr of steam. The maximum NO_x emission rate is 0.20 lb/ Mmbtu and represents a 40% reduction.

5.12.2. Major Equipment

- ✓ Urea storage and metering system
- ✓ Urea Injectors
- ✓ Boiler Modifications
- ✓ Control Enhancements

5.12.3. Basis for Estimate

An Atlantic states Kraft mill with a multi-fuel boiler producing 400,000 lb/hr of steam.

5.12.4. Capital Cost Estimate Assumptions

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

5.12.5. Operating Cost Estimate Assumptions

- ✓ Chemical – urea 165 tons per year
- ✓ Maintenance labor & materials: 3.5% of TIC
- ✓ Power: 13 kw
- ✓ Power usage factor: 80%
- ✓ Workhours: 3 hours per day
- ✓ Water: 3 gpm

5.13. Wood Boiler – SCR (technical feasibility)

5.13.1. Description

Installation of a SCR system on a wood-fired boiler capable of producing 300,000 lb/hr of steam. The maximum NO_x emission rate is 0.025 lb/Mmbtu with a 85% reduction anticipated. The SCR is feasible provided the temperature of the flue gas is controlled.

5.13.2. Major Equipment

- ✓ SCR reactor
- ✓ Low NO_x burners
- ✓ Upgrade to forced draft fan
- ✓ ID fan

5.13.3. Basis for Estimate

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

5.13.4. Capital Cost Estimate Assumptions

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

- ✓ R&D cost: 0.5% of total direct costs (i.e., labor, materials, subcontract, and equipment)

5.13.5. Operating Cost Estimate Assumptions

- ✓ Materials – catalyst: 821 ft^3 per yr. @ $350 per ft^3
- ✓ Chemicals – urea: 287 tons per year
- ✓ Maintenance: 2% of TIC
- ✓ Power: 420 kw
- ✓ Power usage factor: 75%
- ✓ Workhours: 28.6 hr per day
- ✓ Testing: $5,000 per year
- ✓ Water: 5 gpm
- ✓ Steam: 1403 lb/hr
- ✓ Compressed air: 30 cfm

6. SO_2 Reduction – Good Technology Limits

6.1. NDCE Recovery Boiler

6.1.1. Description

Installation of a chemical scrubber to achieve sulfur dioxide (SO_2) level in stack gas of 50 ppm @ 8% oxygen. The system is sized for a NDCE recovery furnace burning 3.7-Mm lb BLS per day.

6.1.2. Major Equipment

- ✓ Scrubber tower
- ✓ Booster fan
- ✓ Recirculation pump
- ✓ Caustic pump

6.1.3. Basis for Estimate

Southeast Kraft mill recovery furnace firing 2.5 x 10^6-lb black liquor solids per day. Project was estimated in 1998.

6.1.4. Capital Cost Estimate Assumptions

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

6.1.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3.5% of TIC
- ✓ Power: 1631 kw
- ✓ Power usage factor: 70%
- ✓ Chemical: 1.3 gpm 50% caustic soda
- ✓ Water: 148 gpm
- ✓ Wastewater: 15 gpm
- ✓ Workhours: 3 hours per day
- ✓ Testing: $5,000 per year

6.2. DCE Kraft Recovery Furnace

6.2.1. Description

Installation of a chemical scrubber to achieve sulfur dioxide (SO_2) level in stack gas of 50 ppm @ 8% oxygen. The system is sized for a DCE recovery furnace burning 1.7-Mm lb BLS per day.

6.2.2. Major Equipment

- ✓ Scrubber tower
- ✓ Booster fan
- ✓ Recirculation pump
- ✓ Oxidizer blower
- ✓ Caustic pump

6.2.3. Basis for Estimate

Southeast Kraft mill recovery furnace firing 2.5 x 10^6 lb black liquor solids per day. Project was estimated in 1998.

6.2.4. Capital Cost Estimate Assumptions

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

6.2.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3.5% of TIC
- ✓ Power: 1023 kw
- ✓ Power usage factor: 70%
- ✓ Chemical: 0.82 gpm 50% caustic soda
- ✓ Water: 68 gpm
- ✓ Wastewater: 6.8 gpm
- ✓ Workhours: 3 hours per day
- ✓ Testing: $5,000 per year

6.3. Coal or Coal / Wood Boiler

6.3.1. Description

Installation of a caustic scrubber for a coal or coal / wood boiler producing 300,000 lb/hour of steam. The SO_2 level would be reduced by 50% producing a maximum emission of 0.6 lb / Mm Btu.

6.3.2. Major Equipment

- ✓ Scrubber tower
- ✓ Recirculation pump
- ✓ Booster fan
- ✓ Caustic feed system

6.3.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler producing 600,000 lb/hour of steam. The project was estimated in 1992.

6.3.4. Capital Cost Estimate Assumptions

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

6.3.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3.5% of TIC
- ✓ Power: 1142 kw
- ✓ Power usage factor: 70%
- ✓ Chemical: 0.6 gpm 50% caustic soda
- ✓ Water: 143 gpm
- ✓ Wastewater: 14 gpm
- ✓ Workhours: 3 hours per day
- ✓ Testing: $5,000 per year

6.4. Oil Boiler

6.4.1. Description

Installation of caustic scrubber on a oil-fired boiler producing 135,000 lb/hr of steam. The SO_2 emission will be reduced by 50% with a maximum emission rate of 0.4 lb/Mm Btu for a 30-day average.

6.4.2. Major Equipment

- ✓ Scrubber tower
- ✓ Booster fan
- ✓ Caustic feed system

6.4.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler producing 600,000 lb/hour of steam. The project was estimated in 1992.

6.4.4. Capital Cost Estimate Assumptions

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

6.4.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3.0% of TIC
- ✓ Power: 555 kw
- ✓ Power usage factor: 70%
- ✓ Chemical: 0.26 gpm 50% caustic soda
- ✓ Water: 42.9 gpm
- ✓ Wastewater: 4.3 gpm
- ✓ Workhours: 3 hours per day
- ✓ Testing: $5,000 per year

7. SO_2 Reduction – Best Technology Limits

7.1. NDCE Recovery Boiler

7.1.1. Description

Installation of a caustic scrubber to achieve sulfur dioxide (SO_2) level in stack gas of 10 ppm @ 8% oxygen. The system is sized for a NDCE recovery furnace burning 3.7 Mm lb BLS per day.

7.1.2. Major Equipment

- ✓ Scrubber tower
- ✓ Booster fan
- ✓ Recirculation pump
- ✓ Caustic pump

7.1.3. Basis for Estimate

Southeast Kraft mill recovery furnace firing 2.5 x 10^6 lb black liquor solids per day. Project was estimated in 1998.

7.1.4. Capital Cost Estimate Assumptions

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

7.1.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3.5% of TIC
- ✓ Power: 1631 kw
- ✓ Power usage factor: 80%
- ✓ Chemical: 1.5 gpm 50% caustic soda
- ✓ Water: 148 gpm
- ✓ Wastewater: 15 gpm
- ✓ Work hours: 3 hours / day
- ✓ Testing: $5,000 per year

7.2. DCE Kraft Recovery Furnace

7.2.1. Description

Installation of a caustic scrubber to achieve sulfur dioxide (SO_2) level in stack gas of 10 ppm @ 8% oxygen. The system is sized for a DCE recovery furnace burning 1.7 Mm lb BLS per day.

7.2.2. Major Equipment

- ✓ Scrubber tower
- ✓ Booster fan
- ✓ Recirculation pump
- ✓ Oxidizer blower
- ✓ Caustic pump

7.2.3. Basis for Estimate

Southeast Kraft mill recovery furnace firing 2.5 x 10^6 lb black liquor solids per day. Project was estimated in 1998.

7.2.4. Capital Cost Estimate Assumptions

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

7.2.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3.5% of TIC
- ✓ Power: 1023 kw
- ✓ Power usage factor: 80%
- ✓ Chemical: 0.94 gpm 50% caustic soda
- ✓ Water: 68 gpm
- ✓ Wastewater: 6.8 gpm
- ✓ Work hours: 3 hours / day
- ✓ Testing: $5,000 per year

7.3. Coal or Coal / Wood Boiler

7.3.1. Description

Installation of a caustic scrubber for a coal or coal / wood boiler producing 300,000 lb/hour of steam. The SO_2 level would be reduced by 90% producing a maximum emission of 0.17 lb / Mm Btu for a 30-day average.

7.3.2. Major Equipment

- ✓ Scrubber tower
- ✓ Booster fan
- ✓ Caustic feed system

7.3.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler producing 600,000 lb/hour of steam. The project was estimated in 1992.

7.3.4. Capital Cost Estimate Assumptions

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

7.3.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3.5% of TIC
- ✓ Power: 1523 kw
- ✓ Power usage factor: 80%
- ✓ Chemical: 1.1 gpm 50% caustic soda
- ✓ Water: 143 gpm
- ✓ Wastewater: 14 gpm
- ✓ Workhours: 3 hours per day
- ✓ Testing: $5,000 per year

7.4. Oil Boiler

7.4.1. Description

Installation of caustic scrubber on a oil-fired boiler producing 135,000 lb/hr of steam. The SO_2 emission will be reduced by 90% with a maximum emission rate of 0.08 lb/Mm Btu for a 30-day average.

7.4.2. Major Equipment

- ✓ Scrubber tower
- ✓ Booster fan
- ✓ Caustic feed system

7.4.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler producing 600,000 lb/hour of steam. The project was estimated in 1992.

7.4.4. Capital Cost Estimate Assumptions

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

7.4.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3.0% of TIC
- ✓ Power: 740 kw
- ✓ Power usage factor: 80%
- ✓ Chemical: 0.34 gpm 50% caustic soda
- ✓ Water: 42.9 gpm
- ✓ Wastewater: 4.3 gpm
- ✓ Workhours: 3 hours per day
- ✓ Testing: $5,000 per year

8. Mercury Removal – Best Technology Limit

8.1. Coal or Coal / Wood Boiler

8.1.1. Description

Installation of a spray dryer absorber fabric filter dry scrubbing system with carbon injection for a coal or coal/wood-fired boiler producing 300,000 lb/hr of steam. The Hg emission level is anticipated to be lowered from 16 lb/10^{12} Btu to 8 lb/10^{12} Btu, representing a 50% reduction.

8.1.2. Major Equipment

- ✓ Fabric filter modules
- ✓ Lime storage and metering system
- ✓ Activated carbon storage and metering system
- ✓ Blower
- ✓ Atomizing air compressor
- ✓ Fabric filter scrubbing system

8.1.3. Basis for Estimate

A budget quotation from WAPC for a spray dryer absorber fabric filter dry scrubbing system with carbon injection for a coal-fired boiler.

8.1.4. Capital Cost Estimate Assumptions

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

8.1.5. Operating Cost Estimate Assumptions

- ✓ Chemicals – activated carbon: 0.08 tons per day
- ✓ Maintenance labor & materials: 5% of TIC
- ✓ Chemicals – pebble lime: 3750 lb/hr
- ✓ Power: 327 kw
- ✓ Power usage factor: 75%
- ✓ Workhours: 3 hours per day

- ✓ Testing: $5,000 per year
- ✓ Water: 64 gpm
- ✓ Wastewater: 20 gpm
- ✓ Incremental waste disposal: 15,780 tpy of carbon and lime

8.2. Wood Boiler

8.2.1. Description

Installation of a spray dryer absorber fabric filter dry scrubbing system with carbon injection for a wood-fired boiler producing 300,000 lb/hr of steam. The Hg emission level is anticipated to be lowered from 0.572 lb/10^{12} Btu to 0.286 lb/10^{12} Btu, representing a 50% reduction.

8.2.2. Major Equipment

- ✓ Fabric filter modules
- ✓ Lime storage and metering system
- ✓ Activated carbon storage and metering system
- ✓ Blower
- ✓ Atomizing air compressor
- ✓ Fabric filter scrubbing system

8.2.3. Basis for Estimate

A budget quotation from WAPC for a spray dryer absorber fabric filter dry scrubbing system with carbon injection for a wood fired boiler.

8.2.4. Capital Cost Estimate Assumptions

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

8.2.5. Operating Cost Estimate Assumptions

- ✓ Chemicals – activated carbon: 7.923 lb per day
- ✓ Maintenance labor & materials: 5% of TIC
- ✓ Chemicals – pebble lime: 375 lb/hr
- ✓ Power: 262 kw

- ✓ Power usage factor: 70%
- ✓ Workhours: 3 hours per day
- ✓ Testing: $5,000 per year
- ✓ Water: 90 gpm
- ✓ Wastewater: 28 gpm
- ✓ Incremental waste disposal: 1,576 tpy of carbon and lime

9. Particulate Matter – Good Technology Limits

9.1. NDCE Kraft Recovery Boiler – New Precipitator

9.1.1. Description

Installation of an electrostatic precipitator capable of achieving 0.044 gr/dscf @ 8% oxygen of particulate matter. The system is sized for a NDCE recovery furnace firing 3.7 Mm lb BLS per day

9.1.2. Major Equipment

- ✓ New electrostatic precipitator
- ✓ New concrete stack acid-brick lined
- ✓ Modification to existing ID fan
- ✓ Conveyors
- ✓ Dampers

9.1.3. Basis for Estimate

Southeast Kraft mill with a recovery boiler firing 2.15 x 10^6 lb black liquor solids per day. Project estimated in 2000.

9.1.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP at 3.7 x 10^6 lb black liquor solids per day.
- ✓ Costs escalated to 2001

9.1.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3.5% of TIC cost
- ✓ Power – 2023 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 3 hours per day
- ✓ Testing - $5,000 per year

9.2. NDCE Kraft Recovery Boiler – Rebuilt Precipitator

9.2.1. Description

ESP upgrade by addition of two parallel fields so that system is capable of achieving 0.044 gr/dscf @ 8% oxygen of particulate matter. The system is sized for a NDCE recovery furnace firing 3.7 Mm lb BLS per day

9.2.2. Major Equipment

- ✓ Modification to existing ESP
- ✓ Modifications to ash handling system

9.2.3. Basis for Estimate

Southeast Kraft mill with a recovery boiler firing 2.70 x 10^6 lb black liquor solids per day. Project estimated in 1999.

9.2.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP at 3.7 x 10^6 lb black liquor solids per day.
- ✓ Costs escalated to 2001

9.2.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 2% of TIC cost
- ✓ Power –377 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 1.5 hours per day
- ✓ Testing - $5,000 per year

9.3. DCE Kraft Recovery Boiler

9.3.1. Description

Installation of a electrostatic precipitator capable of achieving 0.044 gr/SDCF @ 8% oxygen of particulate matter. The system is sized for a DCE recovery furnace firing 1.7 Mm lb BLS per day.

9.3.2. Major Equipment

- ✓ New electrostatic precipitator
- ✓ New concrete stack acid-brick lined
- ✓ Modification to existing ID fan

- ✓ Conveyors
- ✓ Dampers

9.3.3. Basis for Estimate

Southeast Kraft mill with a recovery boiler firing 2.15 x 10^6 lb black liquor solids per day. Project estimated in 2000.

9.3.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP at 1.7 x 10^6 lb black liquor solids per day.
- ✓ Costs escalated to 2001

9.3.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3.5% of TIC cost
- ✓ Power – 1268 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 3 hours per day
- ✓ Testing - $5,000 per year

9.4. Smelt Dissolving Tank

9.4.1. Description

Installation of a scrubber on a smelt dissolving tank capable of achieving a particulate matter emission rate of 0.2 lb/ton BLS. The system is sized for a recovery furnace firing 3.7 Mm lb BLS per day.

9.4.2. Major Equipment

- ✓ New scrubber
- ✓ Fan
- ✓ Recirculation pump

9.4.3. Basis for Estimate

Atlantic states Kraft mill with a recovery furnace firing 2 Mm lb BLS per day. The project was estimated in 1997.

9.4.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for a smelt-dissolving tank scrubber at a recovery furnace firing rate of 3.7 x 10^6 lb black liquor solids per day. Costs escalated to 2001

9.4.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 2% of TIC cost
- ✓ Power – 287 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 1.5 hours per day
- ✓ Testing - $5,000 per year

9.5. Lime Kiln

9.5.1. Description

Installation of an electrostatic precipitator on a lime kiln processing 240 TPD of CaO. The emission rate for particulate matter is 0.064 gr/DSCF @ 10% oxygen.

9.5.2. Major Equipment

- ✓ New ESP
- ✓ Penthouse blower
- ✓ Hopper with screw conveyor
- ✓ Bucket elevator
- ✓ ID fan
- ✓ New stack

9.5.3. Basis for Estimate

Southeastern Kraft mill with a lime kiln capable of processing 540 TPD of CaO. The project was estimated in 2001.

9.5.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a lime kiln processing 240 tpd of CaO.

9.5.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3% of TIC cost

- ✓ Power 187 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 2.25 hours per day
- ✓ Testing - $5,000 per year

9.6. Coal Boiler

9.6.1. Description

Installation of electrostatic precipitator in a coal boiler producing 300,000 lb/hr of steam. The particulate emission rate is 0.065 lb / Mm Btu.

9.6.2. Major Equipment

- ✓ ID fan modification
- ✓ ESP
- ✓ Conveyors
- ✓ Penthouse blower

9.6.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler capable of producing 600,000 lb/hr of steam. The project was estimated in 1992.

9.6.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a boiler producing 300,000 lb/hr of steam.
- ✓ Costs escalated to 2001

9.6.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3% of TIC cost
- ✓ Power – 1331 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 3 hours per day
- ✓ Testing - $5,000 per year
- ✓ Incremental waste disposal: 39 tpy of ash

9.7. Coal / Wood Boiler

9.7.1. Description

Installation of electrostatic precipitator in a coal or coal / wood boiler producing 300,000 lb/hr of steam. The particulate emission rate is 0.065 lb / Mm Btu.

9.7.2. Major Equipment

- ✓ ID fan modification
- ✓ ESP
- ✓ Conveyors
- ✓ Penthouse blower

9.7.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler capable of producing 600,000 lb/hr of steam. The project was estimated in 1992.

9.7.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a boiler producing 300,000 lb/hr of steam.
- ✓ Costs escalated to 2001

9.7.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3% of TIC cost
- ✓ Power – 1331 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 3 hours per day
- ✓ Testing - $5,000 per year
- ✓ Incremental waste disposal: 94 tpy of ash

9.8. Oil Boiler

9.8.1. Description

The switch to low-sulfur fuel oil to achieve lower particulate matter emission rates from a oil-fired boiler capable of producing 135,000 lb/hr of steam.

9.8.2. Major Equipment

- ✓ Oil gun nozzles
- ✓ Flow meters

9.8.3. Basis for Estimate

Southeastern Kraft mill which switched from No. 6 to No. 2 fuel oil in a oil-fired boiler producing 135,000 lb/hour of steam. The project was estimated in 1999.

9.8.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a boiler producing 135,000 lb/hr of steam.
- ✓ Costs escalated to 2001

9.8.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3% of TIC cost
- ✓ Power – not applicable
- ✓ Workhours – not applicable
- ✓ Testing - $5,000 per year
- ✓ Fuel costs: $2.86 million per year

9.9. Wood Boiler

9.9.1. Description

Removal of existing scrubber and installation of electrostatic precipitator in a wood boiler producing 300,000 lb/hr of steam. The particulate emission rate is 0.065 lb / Mm Btu.

9.9.2. Major Equipment

- ✓ ID fan modification
- ✓ ESP
- ✓ Conveyors
- ✓ Penthouse blower

9.9.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler capable of producing 600,000 lb/hr of steam. The project was estimated in 1992.

9.9.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a boiler producing 300,000 lb/hr of steam.
- ✓ Costs escalated to 2001

9.9.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3.5% of TIC cost
- ✓ Power – 911 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 3 hours per day
- ✓ Testing - $5,000 per year
- ✓ Water – (200) gpm savings from elimination of scrubber
- ✓ Wastewater – (20) gpm savings from elimination of scrubber
- ✓ Incremental waste disposal: 551 tpy of ash

10. Particulate Matter – Best Technology Limit

10.1. NDCE Kraft Recovery Boiler – New Precipitator

10.1.1. Description

Installation of an electrostatic precipitator capable of achieving 0.015 gr/dscf @ 8% oxygen. The system would be installed in a recovery furnace burning 3.7 Mm lb BLS per day.

10.1.2. Major Equipment

- ✓ New electrostatic precipitator
- ✓ New concrete stack acid-brick lined
- ✓ Modification to existing ID fan
- ✓ Conveyors
- ✓ Dampers

10.1.3. Basis for Estimate

Southeast Kraft mill with a recovery boiler firing 2.15 x 10^6 lb black liquor solids per day. Project estimated in 2000.

10.1.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP at 3.7 x 10^6 lb black liquor solids per day.
- ✓ Costs escalated to 2001

10.1.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3.5% of TIC cost
- ✓ Power – 2528 kw
- ✓ Power usage factor: 80%
- ✓ Workhours – 3 hours per day
- ✓ Testing - $5,000 per year

10.2. NDCE Kraft Recovery Boiler – Rebuilt Precipitator

10.2.1. Description

ESP upgrade by addition of two parallel fields so that system is capable of achieving 0.015 gr/dscf @ 8% oxygen of particulate matter. The system is sized for a NDCE recovery furnace firing 3.7 Mm lb BLS per day

10.2.2. Major Equipment

- ✓ Modification to existing ESP
- ✓ Modifications to ash handling system

10.2.3. Basis for Estimate

Southeast Kraft mill with a recovery boiler firing 2.70 x 10^6 lb black liquor solids per day. Project estimated in 1999.

10.2.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP at 3.7 x 10^6 lb black liquor solids per day.
- ✓ Costs escalated to 2001

10.2.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 2% of TIC cost
- ✓ Power –411 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 1.5 hours per day
- ✓ Testing - $5,000 per year

10.3. DCE Kraft Recovery Boiler

10.3.1. Description

Installation of a electrostatic precipitator capable of achieving 0.015 gr/SDCF @ 8% oxygen of particulate matter. The system is sized for a DCE recovery furnace firing 1.7 Mm lb BLS per day.

10.3.2. Major Equipment

- ✓ New electrostatic precipitator
- ✓ New concrete stack acid-brick lined
- ✓ Modification to existing ID fan

- ✓ Conveyors
- ✓ Dampers

10.3.3. Basis for Estimate

Southeast Kraft mill with a recovery boiler firing 2.15 x 10^6 lb black liquor solids per day. Project estimated in 2000.

10.3.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP at 1.7 x 10^6 lb black liquor solids per day.
- ✓ Costs escalated to 2001

10.3.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3.5% of TIC cost
- ✓ Power – 1585 kw
- ✓ Power usage factor: 80%
- ✓ Workhours – 3 hours per day
- ✓ Testing - $5,000 per year

10.4. Smelt Dissolving Tank

10.4.1. Description

Installation of a scrubber on a smelt dissolving tank capable of achieving a particulate matter emission rate of 0.12 lb/ton BLS. The system is sized for a recovery furnace firing 3.7 Mm lb BLS per day.

10.4.2. Major Equipment

- ✓ New scrubber
- ✓ Fan
- ✓ Recirculation pump

10.4.3. Basis for Estimate

Atlantic states Kraft mill with a recovery furnace firing 2 Mm lb BLS per day. The project was estimated in 1997.

10.4.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for a smelt-dissolving tank scrubber at a recovery furnace firing rate of 3.7 x 10^6 lb black liquor solids per day.
- ✓ Costs escalated to 2001

10.4.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 2% of TIC cost
- ✓ Power – 315 kw
- ✓ Power usage factor: 80%
- ✓ Workhours – 1.5 hours per day
- ✓ Testing - $5,000 per year

10.5. Lime Kiln – New ESP

10.5.1. Description

Installation of an electrostatic precipitator on a lime kiln processing 240 TPD of CaO. The emission rate for particulate matter is 0.01 gr/DSCF @ 10% oxygen.

10.5.2. Major Equipment

- ✓ New ESP
- ✓ Penthouse blower
- ✓ Hopper with screw conveyor
- ✓ Bucket elevator
- ✓ ID fan
- ✓ New stack

10.5.3. Basis for Estimate

Southeastern Kraft mill with a lime kiln capable of processing 540 TPD of CaO. The project was estimated in 2001.

10.5.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a lime kiln processing 240 TPD of CaO.

10.5.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3% of TIC cost
- ✓ Power – 233 kw
- ✓ Power usage factor: 80%
- ✓ Workhours – 2.25 hours per day
- ✓ Testing - $5,000 per year

10.6. Lime Kiln – Upgraded ESP

10.6.1. Description

Addition of a single electric field to an existing electrostatic precipitator on a lime kiln processing 240 TPD of CaO. The emission rate for particulate matter is 0.01 gr/DSCF @ 10% oxygen.

10.6.2. Major Equipment

- ✓ Modifications to existing ESP
- ✓ Ductwork modifications

10.6.3. Basis for Estimate

Southeastern Kraft mill with a lime kiln capable of processing 540 TPD of CaO. The project was estimated in 2001.

10.6.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a lime kiln processing 240 TPD of CaO

10.6.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 1% of TIC cost
- ✓ Power – 100 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 1.5 hours per day
- ✓ Testing - $5,000 per year

10.7. Coal Boiler – New ESP

10.7.1. Description

Installation of electrostatic precipitator in a coal boiler producing 300,000 lb/hr of steam. The particulate emission rate is 0.04 lb / Mm Btu.

10.7.2. Major Equipment

- ✓ ID fan modification
- ✓ ESP
- ✓ Conveyors
- ✓ Penthouse blower

10.7.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler capable of producing 600,000 lb/hr of steam. The project was estimated in 1992.

10.7.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a boiler producing 300,000 lb/hr of steam.
- ✓ Costs escalated to 2001

10.7.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3% of TIC cost
- ✓ Power – 1664 kw
- ✓ Power usage factor: 80%
- ✓ Workhours – 3 hours per day
- ✓ Testing - $5,000 per year
- ✓ Incremental waste disposal: 77 tpy of ash

10.8. Coal Boiler – Rebuild Existing ESP

10.8.1. Description

Addition of a single electric field in two chambers to an electrostatic precipitator in a coal boiler producing 300,000 lb/hr of steam. The particulate emission rate is 0.04 lb / Mm Btu.

10.8.2. Major Equipment

- ✓ Modifications to existing ESP
- ✓ Ductwork modifications

10.8.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler capable of producing 600,000 lb/hr of steam. The project was estimated in 1992.

10.8.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a boiler producing 300,000 lb/hr of steam.
- ✓ Costs escalated to 2001

10.8.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 1% of TIC cost
- ✓ Power – 550 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 3 hours per day
- ✓ Testing - $5,000 per year
- ✓ Incremental waste disposal: 38 tpy of ash

10.9. Coal / Wood Boiler - New

10.9.1. Description

Installation of electrostatic precipitator in a coal or coal / wood boiler producing 300,000 lb/hr of steam. The particulate emission rate is 0.04 lb / Mm Btu.

10.9.2. Major Equipment

- ✓ ID fan modification
- ✓ ESP
- ✓ Conveyors
- ✓ Penthouse blower

10.9.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler capable of producing 600,000 lb/hr of steam. The project was estimated in 1992.

10.9.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a boiler producing 300,000 lb/hr of steam.
- ✓ Costs escalated to 2001

10.9.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3% of TIC cost
- ✓ Power 1331 kw
- ✓ Power usage factor: 80%
- ✓ Workhours – 3 hours per day
- ✓ Testing - $5,000 per year
- ✓ Incremental waste disposal: 137 tpy of ash

10.10. Coal / Wood Boiler – Rebuild Existing ESP

10.10.1. Description

Addition of single electric field in two chambers to an existing electrostatic precipitator in a coal or coal / wood boiler producing 300,000 lb/hr of steam. The particulate emission rate is 0.04 lb / Mm Btu.

10.10.2. Major Equipment

- ✓ Modifications to existing ESP
- ✓ Ductwork modifications

10.10.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler capable of producing 600,000 lb/hr of steam. The project was estimated in 1992.

10.10.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a boiler producing 300,000 lb/hr of steam.
- ✓ Costs escalated to 2001

10.10.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 1% of TIC cost
- ✓ Power 500 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 3 hours per day
- ✓ Testing - $5,000 per year
- ✓ Incremental waste disposal: 43 tpy of ash

10.11. Oil Boiler

10.11.1. Description

Installation of electrostatic precipitator in a oil-fired boiler producing 135,000 lb/hr of steam. The particulate emission rate is 0.02 lb / Mm Btu.

10.11.2. Major Equipment

- ✓ ID fan modification
- ✓ ESP
- ✓ Conveyors
- ✓ Penthouse blower

10.11.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler capable of producing 600,000 lb/hr of steam. The project was estimated in 1992.

10.11.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a boiler producing 135,000 lb/hr of steam.
- ✓ Costs escalated to 2001

10.11.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3% of TIC cost
- ✓ Power – 1098 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 3 hours per day

- ✓ Testing - $5,000 per year
- ✓ Incremental waste disposal: 99 tpy of ash

10.12. Wood Boiler

10.12.1. Description

Installation of an electrostatic precipitator in wood boiler producing 300,000 lb/hr of steam. The particulate emission rate is 0.04 lb / Mm Btu.

10.12.2. Major Equipment

- ✓ ID fan modification
- ✓ ESP
- ✓ Conveyors
- ✓ Penthouse blower

10.12.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler capable of producing 600,000 lb/hr of steam. The project was estimated in 1992.

10.12.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a boiler producing 300,000 lb/hr of steam.
- ✓ Costs escalated to 2001

10.12.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3.5% of TIC cost
- ✓ Power – 1978 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 3 hours per day
- ✓ Testing - $5,000 per year
- ✓ Incremental waste disposal: 599 tpy of ash

10.13. Wood Boiler – upgrade existing ESP

10.13.1. Description

Upgrade of existing electrostatic precipitator in a wood boiler producing 300,000 lb/hr of steam. The particulate emission rate is moved from 0.1 to 0.04 lb / Mm Btu.

10.13.2. Major Equipment

- ✓ ID fan modification
- ✓ ESP
- ✓ Conveyors
- ✓ Penthouse blower

10.13.3. Basis for Estimate

Southeastern Kraft mill boiler ESP rebuild for a boiler capable of producing 310,000 lb/hr of steam. The project was estimated in 1996.

10.13.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a boiler producing 300,000 lb/hr of steam.
- ✓ Costs escalated to 2001

10.13.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor and materials – 3.5% of TIC cost
- ✓ Power – 250 kw
- ✓ Power usage factor: 70%
- ✓ Workhours – 3 hours per day
- ✓ Testing - $5,000 per year
- ✓ Incremental waste disposal: 116 tpy of ash

11. Carbon Monoxide – Best Technology Limit

11.1. Coal or Coal / Wood Boiler

11.1.1. Description

Installation of combustion control modifications on a coal-fired boiler producing 300,000 lb/hr of steam. The carbon monoxide (CO) emission rate is anticipated to be 200 or less ppm for a 24-hour average.

11.1.2. Major Equipment

- ✓ Replace forced draft fan
- ✓ Repairs to windbox
- ✓ Replace combustion air dampers
- ✓ New set of tertiary air nozzles
- ✓ New furnace cameras
- ✓ New CEM
- ✓ DCS control upgrade

11.1.3. Basis for Estimate

Southeastern Kraft mill which installed combustion controls on a wood-fired boiler producing 350,000 lb/hr of steam. The project was estimated in 2000.

11.1.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a boiler producing 300,000 lb/hr of steam.
- ✓ Costs escalated to 2001

11.1.5. Operating Cost Estimate Assumptions

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

11.2. Wood Boiler

11.2.1. Description

Installation of combustion control modifications on a wood-fired boiler producing 300,000 lb/hr of steam. The carbon monoxide (CO) emission rate is anticipated to be 200 or less ppm for a 24-hour average.

11.2.2. Major Equipment

- ✓ Replace forced draft fan
- ✓ Repairs to windbox
- ✓ Replace combustion air dampers
- ✓ New set of tertiary air nozzles
- ✓ New furnace cameras
- ✓ New CEM
- ✓ DCS control upgrade

11.2.3. Basis for Estimate

Southeastern Kraft mill which installed combustion controls on a wood-fired boiler producing 350,000 lb/hr of steam. The project was estimated in 2000.

11.2.4. Capital Cost Estimate Assumptions

- ✓ Costs were adjusted utilizing the 0.6 rule to obtain the cost for an ESP for a boiler producing 300,000 lb/hr of steam.
- ✓ Costs escalated to 2001

11.2.5. Operating Cost Estimate Assumptions

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

12. HCl – Good Technology Limit

12.1. Coal Boiler

12.1.1. Description

Installation of caustic scrubber to remove HCl to the level of 0.048 lb/Mm Btu from a coal-fired boiler producing 300,000 lb/hr of steam. Assumes inlet HCl concentration of 0.064 lb/Mm Btu.

12.1.2. Major Equipment

- ✓ Scrubber tower
- ✓ Recirculation pump
- ✓ Booster fan
- ✓ Caustic feed system

12.1.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler producing 600,000 lb/hour of steam. The project was estimated in 1992.

12.1.4. Capital Cost Estimate Assumptions

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

12.1.5. Operating Cost Estimate Assumptions

- ✓ Chloride content of coal is 800 ppm which equates to 23 lb/hr of HCl
- ✓ Maintenance labor & materials: 5% of TIC
- ✓ Power: 811 kw
- ✓ Power usage factor: 70%
- ✓ Chemical: 8 lb/hr caustic soda
- ✓ Testing: $5,000 per year
- ✓ Water: 64 gpm
- ✓ Wastewater: 20 gpm
- ✓ Workhours: 3 hours per day

13. HCl – Best Technology Limit

13.1. Coal Boiler

13.1.1. Description

Installation of caustic scrubber to remove HCl to the level of 0.015 lb/Mm Btu from a coal-fired boiler producing 300,000 lb/hr of steam. Assumes inlet HCl concentration of 0.064 lb/Mm Btu.

13.1.2. Major Equipment

- ✓ Scrubber tower
- ✓ Recirculation pump
- ✓ Booster fan
- ✓ Caustic feed system

13.1.3. Basis for Estimate

Southeastern Kraft mill multi-fuel boiler producing 600,000 lb/hour of steam. The project was estimated in 1992.

13.1.4. Capital Cost Estimate Assumptions

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

13.1.5. Operating Cost Estimate Assumptions

- ✓ Chloride content of coal is 800 ppm which equates to 23 lb/hr of HCl
- ✓ Maintenance labor & materials: 5% of TIC
- ✓ Power: 811 kw
- ✓ Power usage factor: 80%
- ✓ Chemical: 25 lb/hr caustic soda
- ✓ Testing: $5,000 per year
- ✓ Water: 64 gpm
- ✓ Wastewater: 20 gpm
- ✓ Workhours: 3 hours per day

14. VOC – Good Technology Limit

14.1. DCE Kraft Recovery Furnace

14.1.1. Description

Collection of black liquor oxidation system vent gases from a DCE recovery furnace burning 1.7 Mm lb BLS per day. The vent gases would be incinerated in an existing multi-fuel boiler.

14.1.2. Major Equipment

- ✓ Vent fan
- ✓ Condensate pump

14.1.3. Basis for Estimate

Rust MACT Cost Analysis report for a DCE recovery furnace burning 1.5 Mm lb BLS per day. The work was done in October 1993.

14.1.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the “0.6 power.”
- ✓ Costs were escalated to 2001 dollars
- ✓ Rust estimate was escalated and included as a TIC only.
- ✓ No additional indirect costs were applied to the Rust estimate.

14.1.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3% of TIC
- ✓ Power: 151 kw
- ✓ Power usage factor: 70%
- ✓ Testing: $5,000 per year
- ✓ Steam: 500 lb/hr
- ✓ Workhours: 3 hours per day

14.2. Paper Machines

14.2.1. Description

Based upon NCASI studies ("Volatile Organic Emissions from Pulp & Paper Sources Part VII - Pulp Dryers & Paper Machines at Integrated Chemical Pulp Mills. Tech Bulletin No.681 Oct 1994 NCASI) the paper machines utilizing unbleached pulps had the highest non-additive VOC emission rates. The machines utilizing bleached pulps had very low VOC emissions.

The source of the VOC was from the fluid contained in the unbleached pulp. If the consistency of the unbleached pulp is raised to 30+% (from a nominal 12%) prior to discharge to either the high density storage or to the paper machines, then the VOC contained in the fluid will be reduced by more than two-thirds.

To increase the consistency to 30+%, a screw press would be installed ahead of the high density storage for the unbleached Kraft, semi-chemical (or NSSC), and mechanical pulp mills. The re-dilution water to be used after the screw press would be paper machine whitewater. In the case of the unbleached Kraft mill and semi-chemical mill, the filtrate from the press would be sent to the spent pulping liquor system.

The system was sized for a 1000 ton per day paper machine.

14.2.2. Major Equipment

- ✓ Two screw presses
- ✓ Pressate (filtrate) tank
- ✓ Thick stock pump

14.2.3. Basis for Estimate

Estimate for 1000 tons per day screw press system based upon a quotation from Kvaerner Pulping. The estimate is in 2001 dollars.

14.2.4. Capital Cost Estimate Assumptions

- ✓ None

14.2.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3% of TIC
- ✓ Power: 861 kw
- ✓ Power usage factor: 70%
- ✓ Testing: $5,000 per year

- ✓ Workhours: 1.5 hours per day
- ✓ A COD reduction will result from utilizing the screw press, which can result in enhanced runnability, improved sheet quality, and reduced chemical costs. However, these potential savings are very paper machine specific and were deemed beyond the scope of this study.

14.3. Mechanical Pulping - TMP

14.3.1. Description

Installation of a heat recovery system on TMP systems which will produce clean steam, a NCG vent, and dirty condensates. The system is designed to condense the VOCs to <0.5 lb C / ODTP.

14.3.2. Major Equipment

- ✓ Reboiler
- ✓ Vent condenser / feed water heater
- ✓ Boiler feed water heater
- ✓ Atmospheric start-up scrubber with silencer

14.3.3. Basis for Estimate

Estimate for 500 tpd TMP heat recovery system based upon quotation from Andritz-Ahlstrom for a 500 ADTPD TMP heat recovery system. The quotation was in 2001 dollars.

14.3.4. Capital Cost Estimate Assumptions

- ✓ None

14.3.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3% of TIC
- ✓ Power: 165 kw
- ✓ Power usage factor: 70%
- ✓ Testing: $5,000
- ✓ Workhours: 1.5 hours per day
- ✓ Water: 192 gpm
- ✓ Wastewater: 194
- ✓ Steam: (94,255 lb/hr) (This is projected amount of steam to be recovered.)

14.4. Mechanical Pulping – Pressure Groundwood

14.4.1. Description

Installation of a heat recovery system on pressure groundwood systems which will produce clean steam, a NCG vent, and dirty condensates. The system is designed to condense the VOCs to <0.5 lb C / ODTP.

14.4.2. Major Equipment

- ✓ Reboiler
- ✓ Vent condenser / feed water heater
- ✓ Boiler feed water heater
- ✓ Atmospheric start-up scrubber with silencer

14.4.3. Basis for Estimate

Estimate for 500-tpd-pressure groundwood heat recovery system based upon quotation from Andritz-Ahlstrom for a 500 ADTPD TMP heat recovery system. The quotation was in 2001 dollars.

14.4.4. Capital Cost Estimate Assumptions

- ✓ None

14.4.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3% of TIC
- ✓ Power: 165 kw
- ✓ Power usage factor: 70%
- ✓ Testing: $5,000 per year
- ✓ Workhours: 1.5 hours per day
- ✓ Water: 192 gpm
- ✓ Wastewater: 39
- ✓ Steam: (18,851 lb/hr) (This is projected amount of steam to be recovered and assumes that the heat recovery would be 20% of that for a comparable TMP plant.)

15. VOC – Best Technology Limit

15.1. NDCE Kraft Recovery Furnace

15.1.1. Description

Conversion of wet bottom ESP to a dry bottom ESP for a NDCE recovery furnace burning 3.7 Mm lb BLS per day. 99.8% particulate collection efficiency was assumed.

15.1.2. Major Equipment

- ✓ New dry bottom hopper
- ✓ Ash mix tank
- ✓ Conveyors

15.1.3. Basis for Estimate

Rust MACT Cost Analysis report for a NDCE recovery furnace burning 1.5-Mm lb BLS per day. The work was done in October 1993.

15.1.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power."
- ✓ Costs were escalated to 2001 dollars
- ✓ Rust estimate was escalated and included as a TIC only.
- ✓ No additional indirect costs were applied to the Rust estimate.

15.1.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 2% of TIC
- ✓ Power: 15 kw
- ✓ Power usage factor: 70%
- ✓ Testing: $5,000 per year
- ✓ Workhours: 1.5 hours per day

15.2. DCE Kraft Recovery Furnace

15.2.1. Description

Conversion of DCE recovery furnace burning 1.7 Mm lb BLS per day to a NDCE type.

15.2.2. Major Equipment

- ✓ New economizer
- ✓ New spent pulping liquor concentrator
- ✓ Additional soot blowers
- ✓ Ash mix tank
- ✓ CEMS

15.2.3. Basis for Estimate

Rust MACT Cost Analysis report for a DCE recovery furnace burning 1.5-Mm lb BLS per day. The work was done in October 1993.

15.2.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power."
- ✓ Costs were escalated to 2001 dollars
- ✓ Rust estimate was escalated and included as a TIC only.
- ✓ No additional indirect costs were applied to the Rust estimate.
- ✓

15.2.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3% of TIC
- ✓ Power: 450 kw
- ✓ Power usage factor: 70%
- ✓ Testing: $5,000 per year
- ✓ Steam: (26,984 lb/hr) (steam savings)
- ✓ Workhours: 3 hours per day

15.3. Paper Machines – Wet End

15.3.1. Description

Collection of wet end exhaust gases from a 1000 TPD paper machine and incineration in a regenerative thermal oxidizer (RTO).

15.3.2. Major Equipment

- ✓ Combustion blower
- ✓ Seal fan
- ✓ Main fan
- ✓ Regenerative thermal oxidizer
- ✓ 100' stack with testing platform
- ✓ 316L stainless steel duct

15.3.3. Basis for Estimate

Northern pulp mill with dryer equipped with a collection system and RTO unit. The mill is designed to produce 415 ODTPD of deink pulp. The project was estimated in 2000.

15.3.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power."
- ✓ R&D costs: 1.5% of total direct costs (i.e., labor, materials, subcontract, and equipment)

15.3.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3% of TIC
- ✓ Power: 310 kw
- ✓ Power usage factor: 70%
- ✓ Testing: $5,000 per year
- ✓ Natural gas: 4.71 Mmbtu/hr
- ✓ Workhours: 1.5 hours per day

15.4. Paper Machines – Dry End

15.4.1. Description

Collection of dry-end exhaust gases from a 1000 TPD paper machine and incineration in a RTO.

15.4.2. Major Equipment

15.4.3. Major Equipment

- ✓ Combustion blower
- ✓ Seal fan
- ✓ Main fan
- ✓ Regenerative thermal oxidizer
- ✓ 100' stack with testing platform
- ✓ 316L stainless steel duct

15.4.4. Basis for Estimate

Northern pulp mill with dryer equipped with a collection system and RTO unit. The mill is designed to produce 415 ODTPD of deink pulp. The project was estimated in 2000.

15.4.5. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the "0.6 power."
- ✓ R&D costs: 1.5% of total direct costs (i.e., labor, materials, subcontract, and equipment)

15.4.6. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3% of TIC
- ✓ Power: 380 kw
- ✓ Power usage factor: 70%
- ✓ Testing: $5,000 per year
- ✓ Natural gas: 8.1 MmBtu/hr
- ✓ Workhours: 1.5 hours per day

15.5. Mechanical Pulping – TMP with Existing Heat Recovery System

15.5.1. Description

Collection and incineration of the NCGs from a TMP heat recovery system. The system was sized for a 500 ADTPD mechanical pulp mill.

15.5.2. Major Equipment

- ✓ Duct work
- ✓ Combustion blower
- ✓ Thermal oxidizer

15.5.3. Basis for Estimate

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

15.5.4. Capital Cost Estimate Assumptions

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

15.5.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3.5% of TIC
- ✓ Power: 22 kw
- ✓ Power usage factor: 70%
- ✓ Workhours: 2.25 hours per day
- ✓ Testing: $5,000 per year
- ✓ Water: 10gpm
- ✓ Wastewater: 10 gpm

15.6. Mechanical Pulping – TMP Without Existing Heat Recovery System

15.6.1. Description

Installation of a heat recovery system on mechanical pulping systems which will produce clean steam, a NCG vent, and dirty condensates. Then collection and incineration of the NCGs. The system was sized for a 500 ADTPD TMP mill.

15.6.2. Major Equipment

- ✓ Reboiler
- ✓ Vent condenser / feed water heater
- ✓ Boiler feed water heater
- ✓ Atmospheric start-up scrubber with silencer
- ✓ Duct work
- ✓ Combustion blower
- ✓ Thermal oxidizer

15.6.3. Basis for Estimate

Estimate for 500 tpd TMP heat recovery system based upon quotation from Andritz-Ahlstrom for a 500 ADTPD TMP heat recovery system. The quotation was in 2001 dollars.

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

15.6.4. Capital Cost Estimate Assumptions

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

15.6.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3.5% of TIC
- ✓ Power: 187 kw
- ✓ Power usage factor: 70%
- ✓ Workhours: 2.25 hours per day
- ✓ Testing: $5,000 per year
- ✓ Water: 202gpm
- ✓ Wastewater: 204 gpm
- ✓ Steam: (94,255 lb/hr) (This is projected amount of steam to be recovered)

15.7. Mechanical Pulping – Pressurized Groundwood Without Existing Heat Recovery System

15.7.1. Description

Installation of a heat recovery system on pressurized groundwood pulping systems which will produce clean steam, a NCG vent, and dirty condensates. Then collection and incineration of the NCGs. The system was sized for a 500 ADTPD pressurized groundwood mill.

15.7.2. Major Equipment

- ✓ Reboiler
- ✓ Vent condenser / feed water heater
- ✓ Boiler feed water heater
- ✓ Atmospheric start-up scrubber with silencer
- ✓ Duct work
- ✓ Combustion blower
- ✓ Thermal oxidizer

15.7.3. Basis for Estimate

Estimate for 500 tpd pressurized groundwood heat recovery system based upon quotation from Andritz-Ahlstrom for a 500 ADTPD TMP heat recovery system. The quotation was in 2001 dollars.

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

15.7.4. Capital Cost Estimate Assumptions

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

15.7.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3.5% of TIC
- ✓ Power: 198 kw
- ✓ Power usage factor: 70%

- ✓ Workhours: 2.25 hours per day
- ✓ Testing: $5,000 per year
- ✓ Water: 202gpm
- ✓ Wastewater: 49 gpm
- ✓ Steam: (18,851 lb/hr) (This is projected amount of steam to be recovered and assumes that the heat recovery would be 20% of that for a comparable TMP plant.)

15.8. Mechanical Pulping – Atmospheric Groundwood

15.8.1. Description

Collection and incineration of the NCGs from a atmospheric groundwood system. The system was sized for a 500 ADTPD mechanical pulp mill. The estimated emission was 20,000 ACFM.

15.8.2. Major Equipment

- ✓ Hoods
- ✓ Duct work
- ✓ Combustion blower
- ✓ Thermal oxidizer

15.8.3. Basis for Estimate

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

15.8.4. Capital Cost Estimate Assumptions

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

15.8.5. Operating Cost Estimate Assumptions

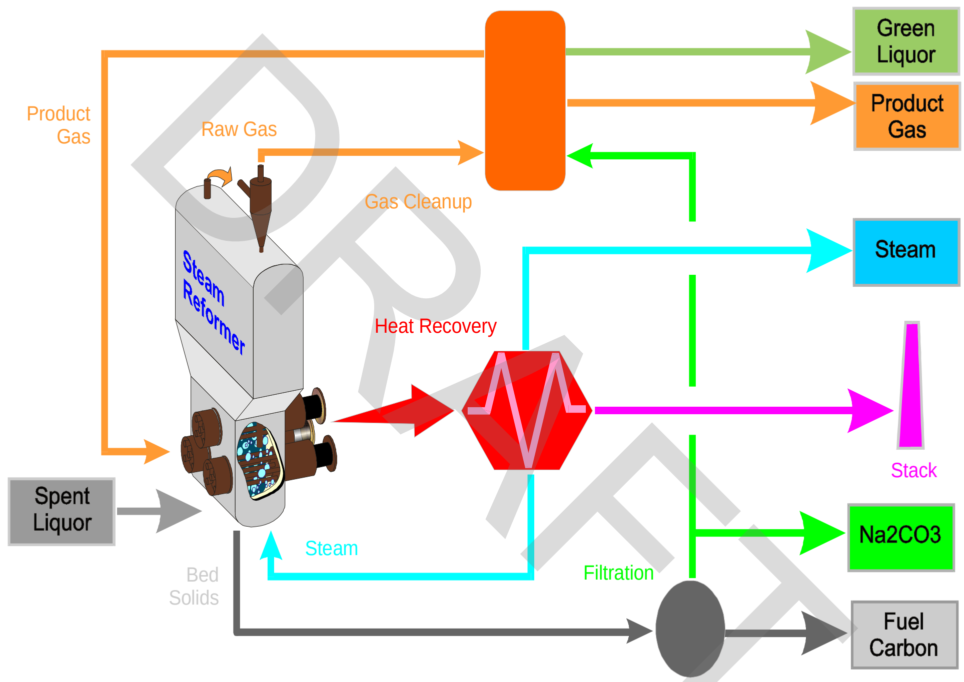
- ✓ Maintenance labor & materials: 3.5% of TIC
- ✓ Power: 22 kw
- ✓ Power usage factor: 70%
- ✓ Workhours: 2.25 hours per day

- ✓ Testing: $5,000 per year
- ✓ Water: 10gpm
- ✓ Wastewater: 10 gpm

16. Gasification

16.1. Description of Technology

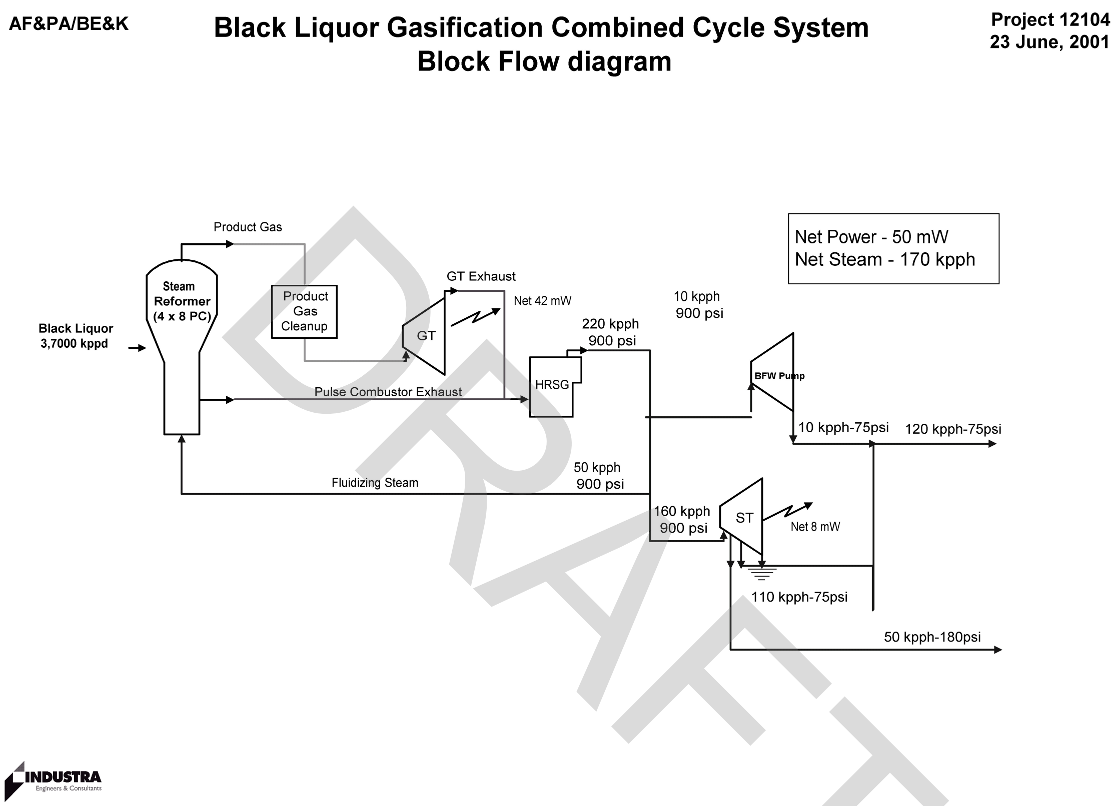
For this study, chemical recovery via gasification is based on the PulseEnhanced™ Steam Reformation technology developed by MTCI/ThermoChem, which is designed to process spent liquor and recover its chemical and energy value. A simplified diagram of the technology is shown below.



The recovery of chemicals and energy from spent liquor is effected by an indirectly heated steam-reforming process which results in the generation of a hydrogen-rich, medium-Btu product gas and bed solids, a dry alkali, which flow from the bottom of the reformer. Neither direct combustion nor alkali salt smelt formation occurs in this steam-reforming process.

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

The product gas is cleaned, compressed, and then sent to the pulse heaters to provide the indirect heat in the reformer and to a combustion turbine to produce electricity. The combustion turbine exhaust is combined with the pulse heater exhaust and then sent to a heat recovery steam generator. The resulting high-pressure steam is then sent to an extraction/condensing steam turbine where addition electricity is produced and lower pressure steam is made available to the mill. A process flow diagram showing the complete system is shown on the following page.



The scope developed assumes that the mill can supply concentrated black liquor (80% solids). Since the costs for doing this can vary widely between mills and modern recovery boilers would require a similar concentration, these costs have been omitted from this study.

We recognize that the steam produced by this system is probably not sufficient for a typical Kraft mill. The additional steam requirements will either need to be provided by a biomass gasifier or boiler or a power boiler. These additional systems offer the opportunity for further power generation as well as steam production. This too is site specific and not included in this study.

16.2. Major Equipment

The major subsystems include liquor injection, steam reformer, gas cleanup, combustion turbine, heat recovery and steam generation, steam turbine, bed solids dissolution, sodium carbonate solution filter, and bed solids storage.

16.2.1. Black Liquor Supply and Steam Reformer

High solids black liquor is supplied to the reformer via a recirculation line feeding multiple steam jacketed injectors. Four reformers each containing 8-pulse heaters are required for this size plant. Each steam reformer is a carbon steel; fabricated vessel lined with refractory. The upper region of the vessel is expanded to reduce gas velocity, permitting entrained particles to disengage and fall back to the fluid bed. Internal stainless cyclones, mounted from the roof of the reformer, provide primary dust collection and a second set of external cyclones further captures fines. The reformer is fluidized with superheated steam using stainless fluidizer headers that are located just above the refractory floor. Bed drains penetrate the refractory floor for removal of bed solids via lock hoppers during normal operation.

Pulsed jet heater modules (fired heat exchangers) are used to indirectly heat the reformer. Pulsed heater modules are cantilever-mounted in the reformer utilizing a flange located on the front of the vessel. Each module extends through the reformer with it resonance tubes in contact with the fluid bed particles inside the vessel.

16.2.2. Product Gas Cleanup

Cyclone-cleaned product gas exits the reformer and enters a product gas heat recovery steam generator (HRSG) which cools the gas prior to entering a venturi separator, which further cools the gas and washes out any solids carryover. A packed gas cooler follows the venturi separator. Once the gas is cooled, it enters the H2S absorber (green liquor column). The absorber is a carbon steel cylinder with two packed stages.

16.2.3. Product Gas Combustion

The clean/cool product gas is sent to the pulse heaters and to a compressor, which then feeds a combustion turbine. The CT generates 50mW of net power.

16.2.4. Heat Recovery and Steam Generation

Steam is generated in both the product gas HRSG and the waste heat boiler. The product gas HRSG consists of a vertical shell and tube generating section and an external steam drum. The product gas HRSG also serves as a source of cooling water for the pulsed heaters.

The waste heat boiler is a two-drum, bottom-supported boiler. Hot flue gas from the pulse heaters and the combustion turbine flows into the HRSG to produce 220-pph 900psi/900F steam.

16.2.5. Steam Turbine

Steam from the waste heat boiler is sent to an extraction condensing steam turbine, which will extract the energy in the high-pressure steam to generate a net 8 mw of power. The resulting lower pressure steam is then piped to the mill steam distribution system.

16.2.6. Solids Dissolution

The solids from each reformer flows through refractory-lined lock hoppers into dissolving tanks. The dissolving tank is carbon steel, insulated tank outfitted with a side-entry agitator, and sized to provide additional retention time to effect dissolution of the soluble sodium carbonate.

16.2.7. Sodium Carbonate Filter

The function of the filter system is to filter the dissolving tank solution to produce a clear sodium carbonate liquor; free of suspended solids such as unreacted organic carbon and non-process elements.

16.2.8. Media Storage Bin

The media bin is an insulated carbon steel vessel (mass flow design) with a capacity sufficient to hold the inventory of several reformers during repair and maintenance.

16.3. Basis for Estimate

Our database of studies, extending over the last 5 years for systems ranging from 250,000 lb/day to 1,000,000 lb/day black liquor solids, was used to create a base for the capital cost estimate.

16.4. Capital Cost Estimate Assumptions

- ✓ Costs were factored using the “0.6 power.”
- ✓ Costs were escalated to 2001 dollars
- ✓ Engineering was assumed to 8% vs. the standard 15% because of the high cost of the equipment and the fact that there is little integration to existing plant
- ✓ R&D expenses of 1.5% of the direct costs were assumed.
- ✓ Equipment foundations on spread footings
- ✓ No allowance for disposal of any potential contaminated soils

- ✓ Except for the purchase of one spare pulsed heater unit, no standalone spares are included. Installed spares are listed as equipment.
- ✓ No demolition costs
- ✓ Pricing was obtained for major equipment. Some prices were not competitively bid and no negotiations were undertaken to firm or clarify process scope.

16.5. Operating Cost Estimate Assumptions

- ✓ Maintenance labor & materials: 3% of TIC cost
- ✓ Utilities: 0.1% of TIC cost
- ✓ Power
  - ♦ New loads: 11,600 kw
  - ♦ Credit for shutdown of existing recovery boiler: (3700) kw
  - ♦ Revenue – sale of power: 50,000 kw
- ✓ Dregs disposal: 1.9 tons per hour
- ✓ Waste water treatment: 650 gpm
- ✓ Steam (revenue): (170,000) lb/hr

16.6. Impact on Emissions

Emissions estimates prepared in earlier studies were scaled up for the 3.7 million-lb/day gasifier and then compared to equivalent data for a similarly sized recovery boiler. The emissions are shown in the tables and chart below.

Black Liquor Gasification Emission Estimates

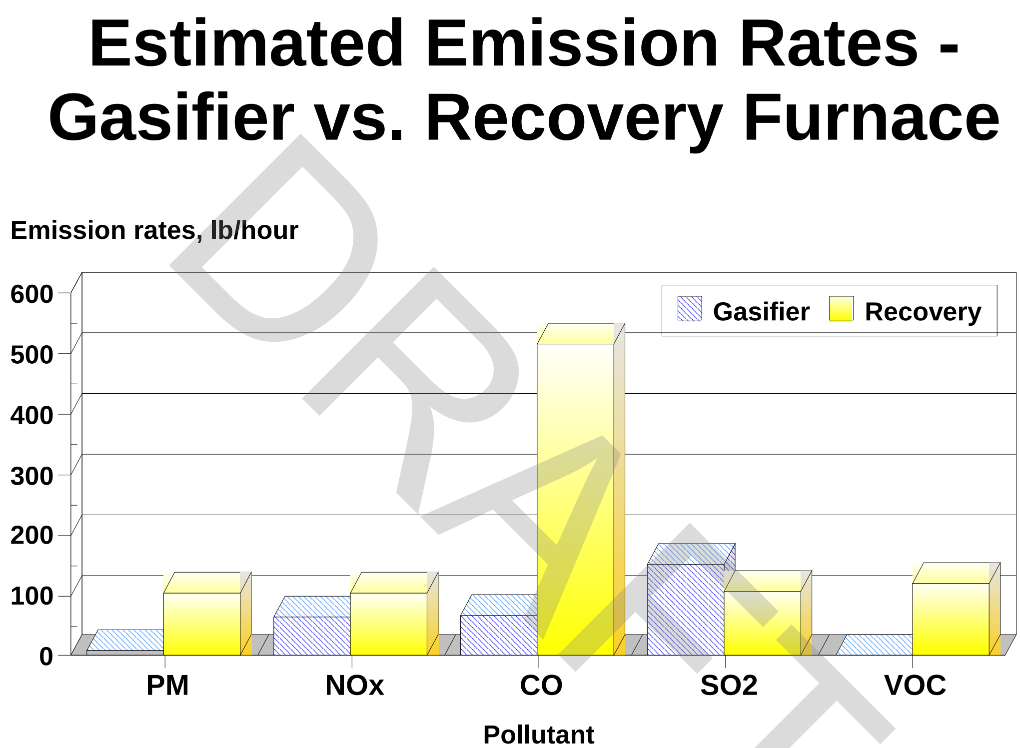
	Black Liquor Reformer Pulse Combustion Exhaust	Combustion Turbine Exhaust	Total
	(lb/hr)	(lb/hr)	(lb/hr)
Particulate matter	2.9	5.7	8.5
Nitrous oxides (NO_x)	18.7	46.1	64.7
Carbon monoxide (CO)	11.4	56.1	67.5
Sulfur dioxide (SO_2)	70.0	81.0	151.0
Volatile organic (as carbon)	0.4	0.0	0.4
as Methanol	2.8	0.0	2.8
TRS (as H_2S)	0.0	0.0	0.0

Recovery Boiler & Smelt Dissolver Emission Estimates

	Recovery Boiler Exhaust	Smelt Dissolving Exhaust	Total
	lb/hr	lb/hr	lb/hr
Particulate matter	93.9	9.4	103.3
Nitrous oxides (NO_x)	89.2	16.1	105.3
Carbon monoxide (CO)	516.5	0.3	516.8
Sulfur dioxide (SO_2)	98.7	9.4	108.1
Volatile organic (as carbon)	37.6	7.5	45.1
as Methanol	100.2	20.0	120.2
TRS (as H_2S)	4.7	2.5	7.2

Additionally for carbon dioxide the black liquor gasification emission rate is estimated to be 240,400 lb/hr for a 4 Mm lb BLS/day unit, while a comparable Tomilson unit would discharge 318,600 lb/hour.

The following illustrates the differences between a black liquor gasification unit and a Tomilson recovery system:



Emission estimates based on 3.7 Mmlb BLS/day firing rate.

17. Industry – Wide Control Cost Estimates

17.1. General Assumptions

The following are the general assumptions:

17.1.1. Capital Costs

- ✓ The individual mill cost estimates are based upon using the 0.6 power rule [Project A cost x (AF&PA firing rate / Project A firing rate)$^{0.6}$] to factor the control technology estimates
- ✓ The boiler emission rates are compared with pollutant limits to determine relative compliance. If the mill discharge level is less than 90% of the pollutant limit, then no control technology will be installed.
- ✓ The base labor is $58.62 per hour and was determined from:

Area	Rate, $/hour	Comment
Base rate	$17.50	
Benefits	$3.25	18.55% of base rate
Fringes	$2.01	11.50% of base rate
Workman's compensation insurance	$2.13	Varies by craft from 6 to 30% of base rate
Indirects	$27.00	Includes home office expenses, field supervision, temporary facilities, tools/ consumables, construction equipment, permits/miscellaneous, and contractor's fee
Premium mark-up	$2.07	
Per diem	$4.66	Includes direct and indirect
Total	**$58.62**	

- ✓ The labor costs portion of the TIC were adjusted for each mill utilizing the BE&K labor rates by region. See Appendix 18.1 for a listing of the factors by state.
- ✓ The material and subcontract costs were adjusted for each mill utilizing the MEANS database factors averaged for each state. See Appendix 18.1 for a listing of the factors by state.
- ✓ Research & Development expenses were assumed for the SCR-non-natural gas, mercury removal, and paper machine VOC removal – best technology applications. They ranged from 0.5 to 1.5% of the sum of the labor, material, subcontract, and equipment direct costs.
- ✓ The BE&K project costs were escalated according to the following:

Period	Escalation rate
1994 to 1995	2.50%
1995 to 1996	3.30%
1996 to 1997	1.70%
1997 to 1998	1.60%
1998 to 1999	2.70%
1999 to 2000	3.40%

17.1.2. Annual Operating and Maintenance Costs

- ✓ The maintenance labor and material annual costs were reported as a percentage of the TIC. The typical range was between 1% and 5% of the total TIC.
- ✓ The operating costs for the mills were proportionately factored for each of the areas (excluding testing and workhours) from the design case.
- ✓ 355 operating days per year were assumed for the equipment.
- ✓ The materials category such as fabric filter or SCR catalyst was reported in terms of 2001 dollars.
- ✓ The wastewater category reported the usage in gallons per year based upon the estimated flow; gpm/feed rate x feed rate x 1440 min/day x 365 dy/yr. The water usage used the same formula but with only 350 dy/yr.

- The steam and compressed air usage was calculated by multiplying the usage per feed rate x feed rate per day x 350 dy/yr.
- The estimated cost for process water was $0.58 per thousand gallons.
- The estimated cost for wastewater treatment was $0.41 per thousand gallons.
- The estimated cost for caustic soda was $0.17 per lb.
- The estimated cost for urea was $225 per ton
- The estimated cost for activated carbon is $0.58 per lb
- The estimated cost for pebble lime is $56.50 per ton
- The differential price between No. 2 and No. 6 fuel oil is $0.84 per Mmbtu (assumes a cost of $4.32 /Mmbtu for No. 6 fuel oil and $5.16 / MmBtu for No. 2 fuel oil)
- The energy usage was first calculated in kWh/year and is based upon the estimated connected kilowatts x 24/hr/day times 350 days times usage factor (typically 70 to 80%).
- The price of electricity was assumed to $0.05/kwhr and was multiplied by the kWh/year.
- The price of steam was assumed to be $0.00500 per lb of steam and was multiplied by the steam usage in lb/hr per year. For any recovered steam, a recovered steam factor times the price of steam was used to determine the value of the steam.
- The price of compressed air was assume to be $0.00010 per cfm and was multiplied by the compressed air usage in cfm/year.
- The utilities category totals the costs for compressed air, water, wastewater, steam, and solid waste disposal.
- The price of natural gas was assumed to be $4.00 per Mmbtu.
- The landfill cost for hauling and disposal was assumed to be $25 per ton of solid waste.
- An annual testing cost of $5,000 was assumed for each technology applied and was assumed constant independent of the size of the facility.
- The workhours were reported in $ /year based upon hours / day x 350 operating days/year x the hourly rate. The hourly rate was obtained from AF&PA Labor

Database with 91% of member contracts entered (missing about 20); the average hourly rate for year 2000 was $18.14. This data only includes hourly employees. An additional 40% was added to the figure to account for benefits to yield a rate of $25.40. The workhour dollars were not factored, but were assumed to be constant no matter what the size of the facility.

- ✓ The NCASI database for recovery furnaces, limekilns, and power boilers was used. This included equipment information, combustion firing rates and types, and pulping information.
- ✓ NCASI provided the mill code for the BE&K supplied paper machine and mechanical pulping information.

17.2. CO_2 Emission Assumptions

- ✓ The CO_2 emissions were calculated by multiplying the 1995 NCASI fossil fuel usage from the power boilers, recovery furnaces, and lime kilns times the CO_2 factors times 99% (assuming a 99% burn factor). This was the recommended calculation technique from the DOE Emission of Greenhouse Gases in the United States report.
- ✓ The CO_2 emission factors are:

Distillate Oil (No.2)	21.945	Tons / MmBtu
Residual Oil (No.6)	23.639	Tons / MmBtu
Coal Industrial (other)	28.193	Tons / MmBtu
Natural gas	15.917	Tons / MmBtu
Petroleum Coke*	30.635	Tons / MmBtu

* Petroleum Coke was assumed to have a heat content of 15,000 Btu/lb

17.3. Recovery Furnace Assumptions

The following are the assumptions:

17.3.1. General Assumptions

- ✓ NDCE recovery furnace firing 3.7 Mm lb BLS/day is assumed to have an air flow of 27,500 lb/min, NO_x Control Technology.
- ✓ For the cases where the design heat load (i.e., Mm Btu/hr) is not known, it was calculated from the design BLS firing rate, utilizing a heat content of 5900 Btu/lb.

17.3.2. NO_x Control Technology

- ✓ The limits were converted to a lb/Mm Btu basis that equates to.

NDCE at 80 ppm	0.1415 lb / Mm Btu
NDCE at 40 ppm	0.0726 lb / Mm Btu
DCE at 30 ppm	0.0544 lb / Mm Btu

- ✓ The annual NO_x emission rates from the NCASI database were converted to lb/Mm Btu and compared with 80% of the above limits. The NO_x limits are based upon 30-day averages and it was assumed that to comply with the 30-day average limits the annual average would be approximately 80% of the 30-day limits.
- ✓ For the case of the good technology, if a given furnace did not meet the adjusted limit, then its emission rate was assumed to average the adjusted limit (i.e., 80% of the 30-day average limits) after treatment. The adjustment of 80% represents a compliance safety margin.
- ✓ If no emission rates were indicated for 1995, then no treatment estimate was made for that furnace.
- ✓ For the case of the best technology, if a given furnace did not meet the adjusted limit, then its emission rate was assumed to be reduced by 50% after treatment

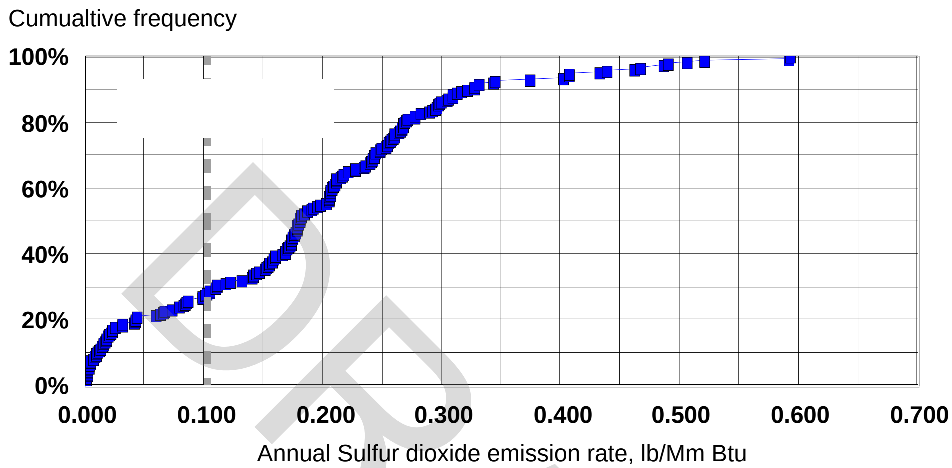
17.3.3. SO_2 Control Technology

- ✓ The limits were converted to a lb/Mm Btu basis that equates to.

NDCE at 50 ppm	0.12 Lb / MmBtu
NDCE at 10 ppm	0.0.024 Lb / MmBtu
DCE at 50 ppm	0.0.12 Lb / MmBtu
DCE at 10 ppm	0.0.024 Lb / MmBtu

- ✓ The annual SO_2 emission rates from the NCASI database were converted to lb/Mm Btu basis and compared with 80% of the above limits. The SO_2 limits are based upon 30-day averages and it was assumed that to comply with the 30-day average limits the annual average would be approximately 80% of the 30-day limits.
- ✓ The following illustrates the cumulative distribution for the recovery furnace SO_2 emission rates from the 1995 NCASI database:

Recovery Furnace SO2 Emission Distribution



Basis: 1995 NCASI emission data base
Good technology limit is based upon 30-day average time 0.8

- ✓ For recovery furnaces with up to four-times the adjusted SO_2 limit (i.e., 0.3628 lb/Mm Btu), combustion control modifications (**<u>these are the same as what was estimated for good controls for NO_x</u>**) would be implemented. For recovery furnaces with SO_2 limits greater than 0.3628 lb/Mm Btu, a new scrubber would be installed. In either case, the controlled emission rate would be equivalent to an annual average of 40 ppm (i.e., 50 ppm x 80%).
- ✓ If no emissions were indicated for 1995, then no treatment estimate was made for the furnace.
- ✓ For both technologies, if a given furnace did not meet the adjusted limit, then its emission rate was assumed to average the adjusted limit. The adjustment of 80% represents a compliance safety margin.

17.3.4. PM Control Technology

- ✓ Any recovery furnace ESP built or rebuilt after 1990 but before 1998 was assumed capable of meeting the good PM technology limit.

- ✓ Any recovery furnace ESP built after 1990 but before 1998 will be upgraded with additional fields for best PM technology limits.
- ✓ Any NDCE recovery furnace ESP built or rebuilt before 1980 will be upgraded with additional field for the good PM technology limit and be replaced for the best PM technology limit.
- ✓ Any NDCE recovery furnace ESP built or rebuilt after 1980 will meet the good technology limits.
- ✓ Any non-NDCE recovery furnace ESP or scrubber built before 1990 will be replaced with a new ESP for either good or best PM technology.
- ✓ Any recovery furnace ESP built or rebuilt after 1998 was assumed to comply with the best PM technology limit.

17.3.5. VOC Control Technology

- ✓ Good VOC technology limit consists of collecting and incinerating the BLO vent gas from any non-NDCE recovery furnace.
- ✓ Best VOC technology consists of converting any NDCE recovery furnace ESPs from wet to dry bottom and converting any non-NDCE to a NDCE recovery furnace

17.3.6.Smelt Dissolving Tank Scrubber - PM Technology

- ✓ Number of smelt dissolving tank was determined based upon the manufacturer. Combustion Engineering furnaces with greater than a 3.5 Mm lb BLS/ day firing rates are assumed to have two smelt dissolving tanks and the other manufacturer's have one smelt dissolving tank. For the case of the two smelt dissolving tank scrubbers, the initial scrubber was factored based on half the black liquor-firing rate and then multiplied by two.
- ✓ Any recovery furnace built before 1976 will require a new smelt dissolving tank scrubber.
- ✓ Any recovery furnace built or rebuilt after 1976 but before 1990 was assumed to meet the good PM technology limit
- ✓ Any recovery furnace built or rebuilt after 1990 was assumed to meet the best PM technology limit

17.4. Lime Kiln Assumptions

The following are the assumptions:

17.4.1. PM Control Technology

- ✓ Any lime kiln built after 1976 and equipped with a wet scrubber or those kiln equipped with an ESP installed prior to 1990 was assumed to meet the good PM technology limit.
- ✓ Any limekiln equipped with an ESP installed prior to 1990 was assumed upgradable to meet the best PM technology limit.
- ✓ Any lime kiln equipped with an ESP installed after 1990 was assumed to meet the best PM technology limit

17.4.2. NO_x Control Technology

- ✓ If the annual NCASI-estimated NO_x levels are less than 20 TPY, no controls will be added. This level represents approximately 10% of the limekilns from the NCASI database.
- ✓ If no emissions where indicated for 1995, then no treatment estimate was made for the kiln.
- ✓ If the mill burns the NCGs primarily in the limekiln, then it was assumed that if there is a stripper present the stripper off-gases (SOGs) are burned in the limekiln.
- ✓ The NO_x level in the limekiln if NCGs are being burned will decrease by 30% if the SOGs are burned in a thermal oxidizer. The thermal oxidizer would be equipped with staged combustion to control the NO_x levels.
- ✓ The NO_x level in the limekiln will decrease by 60% with the incorporation of SCR and low-NO_x burners. If a good technology fix was required, the best technology was additive: the 60% reduction was compounded on the 30% reduction for a total of a 72% reduction [(1-0.3) x (1-0.6)].

17.5. Boiler and Turbine Assumptions

- ✓ 350 operating days per year were assumed.
- ✓ If the Btu/hr capacity of the boiler was not provided, then the steam output was multiplied by the assumed heating value for the steam of 1200 Btu/lb.
- ✓ If only the fuel combusted in 1995 was known,

- ✓ The fuel usage for each boiler from the NCASI database was multiplied by the following heating values:

Coal	25,000	MmBtu/1000 ton
Residual Oil (No.6)	5,920	MmBtu/1000 bbl
Distillate Oil (No.2)	5,376	MmBtu/1000 bbl
Natural gas	950	MmBtu/MmCF
Wood	9,000	MmBtu/1000 ton
Sludge	10,000	MmBtu/1000 ton

- ✓ If the design information for the boiler – either steam or Btu were not provided, then the sizing was based upon the 1995 NCASI fuel usage (if given) and Btu estimate. The steam output was calculated from the Btu estimate and the boiler efficiency, which was assumed 85% for everything, except for wood-fired boilers, which was assumed to have a 65% efficiency.
- ✓ The boiler design figure was compared with the predicted steam (i.e., based upon 1995 reported fuel usages) and which ever was higher was used to compute the capital costs for the control technologies. The operating costs were based upon the predicted steam usage.
- ✓ The best estimate SO_2, and NO_x yearly emission rates were converted to pounds and divided by Btus to determine a lb/MmBtu emission rate.
- ✓ The SO_2 and NO_x emission rates were then multiplied by 80% and compared with the technology limits. The technology limits are based upon 30-day averages and it was assumed that to comply with the 30-day average limits the annual average would be approximately 80% of the 30-day limits.
- ✓ For the case of the good technology, if a given furnace did not meet the adjusted limit, then its emission rate was assumed to average the adjusted limit after treatment (i.e., 80% of the 30-day average limits).
- ✓ For the case of SO_2 control technology, no control costs were assumed for any boiler designated as a wood or gas boiler, regardless of the emission level.
- ✓ <u>NCASI has listed 1225 boilers or turbines, and had fuel consumption information on 1074 of them. Control technology estimates for boilers were only made if fuel consumption information was provided.</u>

17.6. Coal Boiler Assumptions

17.6.1. General

- ✓ If more than 80% of the gross Btu's originated from coal, then the boiler was assumed a coal boiler.

17.6.2. NO_x Limits

- ✓ Any coal boilers after 1990 are assumed to have low NO_x burners and are assumed to meet the 0.3 lb/10^6 Btu, 30-day average.
- ✓ If the coal boilers were converted to natural gas with low NO_x-burners, then the emission rates were assumed to be 0.0490 and 0.1373 lb / 10^6 Btu for boilers less than and greater than 100 million Btu/hr, respectively.

17.6.3. SO_2 Limits

- ✓ Application of scrubbers to coal boilers will yield 50% reduction at good technology and 90% reduction at best technology.

17.6.4. Hg limits

- ✓ The uncontrolled limits were obtained by multiplying the MmBtu/year for 1995 by 16 lb/10^{12} Btu that is the AP-42 emission factor.
- ✓ The removal rate for the carbon injection and fabric filter approach was assumed 50%.

17.6.5. PM limits

- ✓ Any coal boiler with an ESP built or rebuilt after 1980 is assumed able to meet the good technology limit. If the ESP was built or rebuilt before 1980, the ESP's would be upgraded by adding a single field. If the year the ESP was constructed or rebuilt was not in the NCASI database, then the ESP was assumed to have been built or rebuilt before 1980. Any coal boiler constructed after 1990 is assumed to meet the good technology limit.
- ✓ Any coal boiler with an ESP built or rebuilt after 1980 can be upgraded to by adding a single field in two chambers to meet the best technology limit. A new ESP will be priced out for an ESP built or rebuilt before 1980.
- ✓ Any coal boiler constructed or an ESP built or rebuilt after 1998 is assumed to meet the best technology limit.

17.6.6. CO limits

- ✓ Any coal boiler constructed after 1990 is assumed to be able to meet the best technology limit of 200 ppm (24-hour average).

17.6.7. HCl limits

- ✓ Use same criteria as for SO_2 limits – if a scrubber was required for SO2, then it was assumed a scrubber would be required for HCl control. This applied to both good and best control technologies.
- ✓ If SO_2 control is installed there will be no need to install HCl controls as well; the chemical addition rate for SO_2 is greater than what is required to remove the HCl present.

17.7. Coal / Wood Boiler Assumptions

17.7.1. General Assumptions

- ✓ At least 20% of the Btus had to come from coal or wood provided both were used within the boiler.

17.7.2. NO_x Limits

- ✓ Any coal boilers after 1990 were assumed to have low NO_x burners and were assumed to meet the 0.3 lb/10^6 Btu, 30-day average
- ✓ For the case of the good or best technology, if a given boiler did not meet the adjusted limit, then its emission rate was assumed to average the adjusted limit (i.e., 80% of the 30-day average limits) after treatment

17.7.3. SO_2 Limits

- ✓ Application of scrubbers to coal/wood boilers will yield 50% reduction at good technology and 90% reduction at best technology.

17.7.4. Hg limits

- ✓ The uncontrolled limits were obtained by multiplying the MmBtu/year for 1995 by 16 lb/10^{12} Btu for coal and by 0.572 lb/10^{12} Btu for wood. Both are based upon the AP-42 emission factor with the wood corrected for the difference in heavy metals between coal and wood.
- ✓ The removal rate for the carbon injection and fabric filter approach was assumed 50%.

17.7.5. PM limits

- ✓ Any coal/wood boiler with an ESP built or rebuilt after 1980 is assumed able to meet the good technology limit. If the ESP was built or rebuilt before 1980, the ESP's would be upgraded by adding a single field in two chambers. If the year the ESP was constructed or rebuilt was not in the NCASI database, then the ESP was assumed to have been built or rebuilt before 1980.

- ✓ Any coal/wood boiler constructed after 1990 is assumed to meet the good technology limit.
- ✓ Any coal /wood boiler with an ESP built or rebuilt after 1980 can be upgraded to by adding a single field in two chambers to meet the best technology limit. A new ESP will be priced out for an ESP built or rebuilt before 1980.
- ✓ Any coal/wood boiler constructed or an ESP built or rebuilt after 1998 is assumed to meet the best technology limit.

17.7.6. CO limits

- ✓ Any coal / wood boiler will require controls to meet the best technology limit of 200 ppm (24-hour average)

17.8. Gas Boiler Assumptions

17.8.1. General Assumptions

- ✓ A minimum of 90% of the Btu's had to come from natural gas, in order for the boiler to be considered a gas boiler.

17.8.2. NO_x Limits

- ✓ Any gas boilers after 1990 are assumed to have low-NO_x burners and are assumed to meet the 0.05 lb/10^6 Btu, 30-day average
- ✓ For the case of the good or best technology, if a given boiler did not meet the adjusted limit, then its emission rate was assumed to average the adjusted limit (i.e., 80% of the 30-day average limits) after treatment

17.9. Gas Turbine Assumptions

17.9.1. NO_x Limits

- ✓ Any gas turbines after 1995 are assumed to have water or steam injection to control to the good technology limit of 25 ppm @ 15% oxygen.
- ✓ For the case of the good or best technology, if a given turbine did not meet the adjusted limit, then its emission rate was assumed to average the adjusted limit (i.e., 80% of the 30-day average limits) after treatment

17.10. Oil Boiler Assumptions

17.10.1. General Assumptions

- ✓ If both oil and gas are burned, then if more than 15% of the Btu's originates from oil, the boiler was considered an oil boiler.

- ✓ If oil and wood or coal was burned, then at least 85% of the Btu had to originate from oil for the boiler to be considered an oil boiler.

17.10.2. NO_x Limits

- ✓ Any oil boilers after 1990 are assumed to have low-NO_x burners and are assumed to meet the 0.2 lb/10^6 Btu, 30-day average
- ✓ For the case of the good or best technology, if a given boiler did not meet the adjusted limit, then its emission rate was assumed to average the adjusted limit (i.e., 80% of the 30-day average limits) after treatment

17.10.3. SO_2 Limits

- ✓ Application of scrubbers to oil boilers will yield 50% reduction at good technology and 90% reduction at best technology.

17.10.4.PM limits

- ✓ Any oil boiler with an ESP is assumed able to meet the good technology limit.
- ✓ Any oil boiler constructed after 1990 is assumed to meet the good technology limit.
- ✓ Any oil boiler burning distillate oil is assumed to meet the good technology limit.
- ✓ Any oil boiler with an ESP can be upgraded to by adding a single field in two chambers to meet the best technology limit.
- ✓ Any oil boiler constructed after 1998 is assumed to meet the best technology limit.

17.11. Wood-Fired Boiler Assumptions

17.11.1. General Assumptions

- ✓ Any boiler where at least 80% of the Btu originate from wood, then the boiler is considered a wood-fired boiler.

17.11.2. NO_x Limits

- ✓ Any wood boiler after 1990 are assumed to have combustion controls and are assumed to meet the 0.25 lb/10^6 Btu, 30-day average
- ✓ For the case of the good or best technology, if a given boiler did not meet the adjusted limit, then its emission rate was assumed to average the adjusted limit after treatment (i.e., 80% of the 30-day average limits).

17.11.3. Hg limits

- ✓ The uncontrolled limits were obtained by multiplying the MmBtu/year for 1995 by 0.572 lb/10^{12} Btu for wood. This is based upon the AP-42 emission factor for coal corrected for the difference in heavy metals between coal and wood.
- ✓ The removal rate for the carbon injection and fabric filter approach was assumed 50%.

17.11.4. PM limits

- ✓ Any wood boiler with an ESP built or rebuilt after 1980 is assumed able to meet the good technology limit. If the ESP was built or rebuilt before 1980, the ESP's would be upgraded by adding a single field in two chambers. If the year the ESP was constructed or rebuilt was not in the NCASI database, then the ESP was assumed to have been built or rebuilt before 1980.
- ✓ Any wood boiler constructed after 1990 is assumed to meet the good technology limit.
- ✓ Any wood boiler with an ESP built or rebuilt after 1980 can be upgraded to by adding a single field in two chambers to meet the best technology limit. A new ESP will be priced out for an ESP built or rebuilt before 1980.
- ✓ Any wood boiler constructed or an ESP built or rebuilt after 1998 is assumed to meet the best technology limit.

17.11.5.CO limits

- ✓ Any wood boiler will require cotnrols to meet the best technology limit of 200 ppm (24-hour average)

17.12. Paper Machine Assumptions

- ✓ Fisher Database statistics were used.
- ✓ Minimum machine size capacity of 50 tons per day was used as the cut-off.
- ✓ Only paper machines with unbleached Kraft, semi-chemical, NSSC, and mechanical pulp furnishes were considered for the good technology limits. Unbleached recycle fiber furnishes were considered for the best technology limits.
- ✓ Each mechanical pulp line was treated separately for the good technology limit.
- ✓ The good technology was sized based upon the pulp mill production. A minimum of 200 tons per day was used as the cut-off for the pulp mill production for everything but mechanical pulping, which was set at 100 tons per day.

- ✓ The best technology was sized based upon the paper machine capacity. If only a portion of a paper machine's furnish was one of the above fiber furnishes, then the paper machine was treated.
- ✓ The untreated emission rate for the unbleached paper machines was assumed to be 0.47 lb C / ODTP. (Basis: NCASI Tech Bulletin No. 681)
- ✓ The emission reduction for the good technology was assumed 67%.
- ✓ The emission reduction for the best technology was assumed 99%.

17.13. Mechanical Pulping

- ✓ Fisher Database statistics were used
- ✓ Minimum production level of 18,000 tons per year was used as the cut-off.
- ✓ Any TMP line constructed after 1989 is assumed to meet the good technology limits. Heat recovery was applied to all pressure groundwood mills regardless of age.
- ✓ Heat recovery was not applied to any atmospheric groundwood pulping lines.
- ✓ Any TMP pulping line constructed after 1998 is assumed to meet the best technology limits.

18. Appendix

18.1. MEANS and BE&K Labor Rate Factors by State

The following presents the state factors for the RS Means Open Shop Building Construction Cost Data 17th edition location factors for materials and subcontracting (or total) and the BE&K construction labor factors:

	Materials Factor	Subcontracting Factor	BE&K Construction Labor Factor
Alabama	0.967	0.823	1.000
Alaska	1.354	1.254	0.959
Arizona	0.989	0.876	0.975
Arkansas	0.957	0.778	0.970
California	1.076	1.119	0.983
Colorado	1.019	0.937	0.974
Connecticut	1.028	1.054	0.979
Delaware	0.992	1.009	0.968
Florida	0.987	0.841	0.992
Georgia	0.967	0.840	0.979
Idaho	1.021	0.938	0.960
Illinois	0.970	1.041	0.997
Indiana	0.975	0.957	0.958
Iowa	0.996	0.918	0.995
Kansas	0.966	0.864	0.961
Kentucky	0.955	0.895	0.992
Louisiana	0.989	0.824	0.990
Maine	0.996	0.824	1.003
Massachusetts	0.997	1.043	0.975
Maryland	0.937	0.884	0.973

	Materials Factor	Subcontracting Factor	BE&K Construction Labor Factor
Michigan	0.970	0.948	0.973
Minnesota	0.984	1.073	0.983
Mississippi	0.985	0.739	0.977
Missouri	0.962	0.950	0.987
Montana	0.995	0.938	0.977
Nebraska	0.978	0.828	0.962
Nevada	1.020	0.993	0.967
New Hampshire	0.983	0.913	0.982
New Jersey	1.028	1.125	0.965
New Mexico	1.006	0.912	0.972
New York	0.968	0.945	0.977
North Carolina	0.959	0.734	0.982
North Dakota	1.008	0.849	0.939
Ohio	0.967	0.944	0.954
Oklahoma	0.971	0.789	0.990
Oregon	1.044	1.060	0.967
Pennsylvania	0.975	0.982	0.982
Rhode Island	1.001	1.040	0.980
South Carolina	0.954	0.726	0.970
South Dakota	0.989	0.778	0.970
Tennessee	0.968	0.803	0.998
Texas	0.965	0.807	0.991
Utah	1.018	0.899	0.951
Vermont	1.010	0.855	0.973
Virginia	0.972	0.838	0.966
Washington	1.062	1.016	0.964
West Virginia	0.970	0.937	1.005

	Materials Factor	Subcontracting Factor	BE&K Construction Labor Factor
Wisconsin	0.984	0.959	0.979
Wyoming	1.003	0.826	0.939

18.2. Net Downtime

Although mill or process downtime costs were not included in the analysis, an estimate was made of the net downtime. Since the work would be done during scheduled downtime, the net downtime is the additional time required above the typical scheduled downtime. The following is BE&K's estimate for net downtime:

Good / Best Technology	Pollutant	Equipment	Net Downtime, days
Good	PM	NDCE Kraft Recovery Furnace	3
Best	PM	NDCE Kraft Recovery Furnace	3
Good	SO2	NDCE Kraft Recovery Furnace	3
Best	SO2	NDCE Kraft Recovery Furnace	3
Good	NOx	NDCE Kraft Recovery Furnace	3
Best	NOx	NDCE Kraft Recovery Furnace	3
Best	VOC	NDCE Kraft Recovery Furnace	3
Good	PM	DCE Kraft Recovery Furnace	3
Best	PM	DCE Kraft Recovery Furnace	3
Good	SO2	DCE Kraft Recovery Furnace	3
Best	SO2	DCE Kraft Recovery Furnace	3
Best	NOx	DCE Kraft Recovery Furnace	3
Good	VOC	DCE Kraft Recovery Furnace	4
Best	VOC	DCE Kraft Recovery Furnace	20
Good	PM	Smelt Dissolving tank	3
Best	PM	Smelt Dissolving tank	3
Good	PM	Lime Kilns	3
Best	PM	Lime Kilns	3
Best	NOx	Lime Kilns	3
Best	NOx	Lime Kilns	5
Good	PM	Coal Boiler	3
Best	PM	Coal Boiler	3

Good / Best Technology	Pollutant	Equipment	Net Downtime, days
Good	HCl	Coal Boiler	3
Best	HCl	Coal Boiler	3
Good	PM	Coal/Wood Boiler (50/50)	3
Best	PM	Coal/Wood Boiler (50/50)	3
Good	SO2	Coal or Coal/Wood boiler (50/50)	3
Best	SO2	Coal or Coal/Wood boiler (50/50)	3
Good	NOx	Coal or Coal/Wood boiler (50/50)	3
Best	NOx	Coal or Coal/Wood boiler (50/50)	5
Best	NOx	Coal or Coal/Wood boiler (50/50)	3
Best	Hg	Coal or Coal/Wood boiler (50/50)	5
Best	CO	Coal or Coal/Wood boiler (50/50)	3
Good	NOx	Gas boiler	3
Best	NOx	Gas boiler	5
Good	NOx	Gas turbine	5
Good	NOx	Gas turbine	5
Best	NOx	Gas turbine	5
Good	PM	Oil boiler	3
Best	PM	Oil boiler	3
Good	SO2	Oil boiler	3
Best	SO2	Oil boiler	3
Good	NOx	Oil boiler	3
Best	NOx	Oil boiler	5
Good	PM	Wood boiler	5
Best	PM	Wood boiler	3
Best	PM	Wood boiler	5
Good	NOx	Wood boiler	3
Best	NOx	Wood boiler	3

Good / Best Technology	Pollutant	Equipment	Net Downtime, days
Best	NOx	Wood boiler	5
Best	Hg	Wood boiler	5
Best	CO	Wood boiler	3
Good	VOC	Paper machines	3
Best	VOC	Paper machines	3
Best	VOC	Paper machines	3
Good	VOC	Mechanical pulping	3
Best	VOC	Mechanical pulping	3
Best	Various	Recovery Furnace	NA
Best	PM	NDCE Kraft Recovery Furnace	3
Good	PM	NDCE Kraft Recovery Furnace	3
Best	PM	Lime Kilns	3
Best	PM	Coal Boiler	3
Best	PM	Coal/Wood Boiler (50/50)	3
Best	NOx	NDCE Kraft Recovery Furnace	5
Best	NOx	DCE Kraft Recovery Furnace	5
Best	VOC	Mechanical Pulp	3

															15%		20%	5%	5%		Annual Operating and Maintenance Costs and Assumptions						
No.	Good / Best	Pollutant	Equipment	Size	Technology limit	R&D % of Labor + Mat + Sub + equip	R&D	Labor hours	Labor $/hr	Labor	Materials	Subcontracts	Equipment	Total Directs Costs	Engineering	Subtotal	Contingency of direct costs + engineering	Owner's Cost % of direct costs	Construction Management % of direct costs	Total	Size of base unit	Feed rate	Materials Consumables (fabric filters, SCR media, etc.) at design	Chemical for design rate	Units	Type of chemical	Chemical (2) for design rate
1	Good	PM	NDCE Kraft Recovery Furnace	3.7x 106 lb BLS/day	ESP - 0.044 gr/dscf @ 8% Oxygen	0.0%	$ -	74,844	$ 58.62	$ 4,387,355	$ 1,834,000	$ 10,009,900	$ 1,054,500	$ 17,285,755	$ 2,592,863	$ 19,878,619	$ 3,975,724	$ 864,288	$ 864,288	$ 25,582,918	2.15	Mmlb BLS/day	$ -	-	NA	NA	-
2	Best	PM	NDCE Kraft Recovery Furnace	3.7x 106 lb BLS/day	ESP - 0.015 gr/dscf @ 8% Oxygen	0.0%	$ -	74,844	$ 58.62	$ 4,387,355	$ 1,834,000	$ 12,261,000	$ 1,319,600	$ 19,801,955	$ 2,970,293	$ 22,772,249	$ 4,554,450	$ 990,098	$ 990,098	$ 29,306,894	2.15	Mmlb BLS/day	$ -	-	NA	NA	-
3	Good	SO2	NDCE Kraft Recovery Furnace	3.7x 106 lb BLS/day	Scrubber - 50 ppm@ 8% Oxygen, 30-day average	0.0%	$ -	50,443	$ 58.62	$ 2,956,969	$ 861,100	$ 1,274,100	$ 3,586,000	$ 8,678,169	$ 1,301,725	$ 9,979,894	$ 1,995,979	$ 433,908	$ 433,908	$ 12,843,690	2.50	Mmlb BLS/day	$ -	1.33	gpm	50% NaOH	-
4	Best	SO2	NDCE Kraft Recovery Furnace	3.7x 106 lb BLS/day	Scrubber - 10 ppm @ 8% Oxygen, 30-day average	0.0%	$ -	50,443	$ 58.62	$ 2,956,969	$ 861,100	$ 1,274,100	$ 3,586,000	$ 8,678,169	$ 1,301,725	$ 9,979,894	$ 1,995,979	$ 433,908	$ 433,908	$ 12,843,690	2.50	Mmlb BLS/day	$ -	1.53	gpm	50% NaOH	-
5	Good	NOx	NDCE Kraft Recovery Furnace	3.7x 106 lb BLS/day	Combustion control - 80 ppm@ 8% Oxygen, 30-day average	0.0%	$ -	1,713	$ 58.62	$ 100,416	$ 28,800	$ 14,000	$ 278,500	$ 421,716	$ 63,257	$ 484,973	$ 96,995	$ 21,086	$ 21,086	$ 624,140	2.60	Mmlb BLS/day	$ -	-	NA	NA	-
6	Best	NOx	NDCE Kraft Recovery Furnace	3.7x 106 lb BLS/day	SNCR - 40 ppm@ 8% Oxygen (50% reduction, 30-day average)	1.0%	$ 34,210	-	$ 58.62	$ -	$ -	$ 3,421,000	$ -	$ 3,455,210	$ 518,282	$ 3,973,492	$ 794,698	$ 172,761	$ 172,761	$ 5,113,711	3.50	Mmlb BLS/day	$ -	256.00	tpy	urea	-
7	Best	VOC	NDCE Kraft Recovery Furnace	3.7x 106 lb BLS/day	Replace wet bottom with dry bottom, no limit	0.0%	$ -	-	$ 58.62	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,266,300	1.50	Mmlb BLS/day	$ -	-	NA	NA	-
8	Good	PM	DCE Kraft Recovery Furnace	1.7x 106 lb BLS/day	ESP - 0.044 gr/dscf @ 8% Oxygen	0.0%	$ -	46,755	$ 58.62	$ 2,740,778	$ 1,152,300	$ 6,273,200	$ 665,300	$ 10,831,578	$ 1,624,737	$ 12,456,315	$ 2,491,263	$ 541,579	$ 541,579	$ 16,030,736	2.15	Mmlb BLS/day	$ -	-	NA	NA	-
9	Best	PM	DCE Kraft Recovery Furnace	1.7x 106 lb BLS/day	ESP - 0.015 gr/dscf @ 8% Oxygen	0.0%	$ -	46,755	$ 58.62	$ 2,740,778	$ 1,152,300	$ 7,702,300	$ 829,000	$ 12,424,378	$ 1,863,657	$ 14,288,035	$ 2,857,607	$ 621,219	$ 621,219	$ 18,388,080	2.15	Mmlb BLS/day	$ -	-	NA	NA	-
10	Good	SO2	DCE Kraft Recovery Furnace	1.7x 106 lb BLS/day	Scrubber - 50 ppm @ 8% Oxygen, 30-day average	0.0%	$ -	31,777	$ 58.62	$ 1,862,768	$ 542,800	$ 802,900	$ 2,203,800	$ 5,412,268	$ 811,840	$ 6,224,108	$ 1,244,822	$ 270,613	$ 270,613	$ 8,010,156	2.50	Mmlb BLS/day	$ -	0.82	gpm	50% NaOH	-
11	Best	SO2	DCE Kraft Recovery Furnace	1.7x 106 lb BLS/day	Scrubber - 10 ppm @ 8% Oxygen, 30-day average	0.0%	$ -	31,777	$ 58.62	$ 1,862,768	$ 542,800	$ 802,900	$ 2,203,800	$ 5,412,268	$ 811,840	$ 6,224,108	$ 1,244,822	$ 270,613	$ 270,613	$ 8,010,156	2.50	Mmlb BLS/day	$ -	0.94	gpm	50% NaOH	-
12	Best	NOx	DCE Kraft Recovery Furnace	1.7x 106 lb BLS/day	SNCR - 50% reduction (30ppm @ 8% Oxygen)	1.0%	$ 16,020	-	$ 58.62	$ -	$ -	$ 1,602,000	$ -	$ 1,618,020	$ 242,703	$ 1,860,723	$ 372,145	$ 80,901	$ 80,901	$ 2,394,670	3.50	Mmlb BLS/day	$ -	117.69	tpy	urea	-
13	Good	VOC	DCE Kraft Recovery Furnace	1.7x 106 lb BLS/day	BLO vent gas collection & incineration	0.0%	$ -	-	$ 58.62	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,554,700	1.50	Mmlb BLS/day	$ -	-	NA	NA	-
14	Best	VOC	DCE Kraft Recovery Furnace	1.7x 106 lb BLS/day	Conversion to NDCE	0.0%	$ -	-	$ 58.62	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 19,664,100	1.50	Mmlb BLS/day	$ -	-	NA	NA	-
15	Good	PM	Smelt Dissolving tank	3.7x 106 lb BLS/day	0.2 lb/ton BLS	0.0%	$ -	16,177	$ 58.62	$ 948,296	$ 244,900	$ 13,500	$ 342,400	$ 1,549,096	$ 232,364	$ 1,781,460	$ 356,292	$ 77,455	$ 77,455	$ 2,292,662	2	Mmlb BLS/day	$ -	-	NA	NA	-
16	Best	PM	Smelt Dissolving tank	3.7x 106 lb BLS/day	0.12 lb/ton BLS	0.0%	$ -	16,177	$ 58.62	$ 948,296	$ 244,900	$ 13,500	$ 394,000	$ 1,600,696	$ 240,104	$ 1,840,800	$ 368,160	$ 80,035	$ 80,035	$ 2,369,030	2	Mmlb BLS/day	$ -	-	NA	NA	-
17	Good	PM	Lime Kilns	240 tons CaO/day	0.064 gr/dscf @ 10% oxy	0.0%	$ -	6,529	$ 58.62	$ 382,730	$ 70,700	$ 425,600	$ 1,022,900	$ 1,901,930	$ 285,289	$ 2,187,219	$ 437,444	$ 95,096	$ 95,096	$ 2,814,856	540	TPD CaO	$ -	-	NA	NA	-
18	Best	PM	Lime Kilns	240 tons CaO/day	0.01 gr/dscf @ 10%oxy	0.0%	$ -	6,633	$ 58.62	$ 388,826	$ 70,700	$ 526,600	$ 1,280,200	$ 2,266,326	$ 339,949	$ 2,606,275	$ 521,255	$ 113,316	$ 113,316	$ 3,354,163	540	TPD CaO	$ -	-	NA	NA	-
19	Best	NOx	Lime Kilns	240 tons CaO/day	Route stripper off-gas to new thermal oxidizer	0.0%	$ -	10,126	$ 58.62	$ 593,586	$ 272,500	$ 233,600	$ 870,100	$ 1,969,786	$ 295,468	$ 2,265,254	$ 453,051	$ 98,489	$ 98,489	$ 2,915,283	20,000	ACFM	$ -	-	gpm	Net reclaim for NaOH	-
20	Best	NOx	Lime Kilns	240 tons CaO/day	Low-NOx burners & SCR.	1.0%	$ 43,387	7,438	$ 58.62	$ 436,016	$ 367,600	$ 525,800	$ 3,009,300	$ 4,382,103	$ 657,315	$ 5,039,418	$ 1,007,884	$ 219,105	$ 219,105	$ 6,485,512	120,000	lb/hr stm	$ 113,113	113.51	tpy	urea	-
21	Good	PM	Coal Boiler	300,000 pph	ESP - 0.065 lb/106 Btu	0.0%	$ -	48,985	$ 58.62	$ 2,871,501	$ 1,207,300	$ 7,314,700	$ 694,900	$ 12,088,401	$ 1,813,260	$ 13,901,661	$ 2,780,332	$ 604,420	$ 604,420	$ 17,890,833	600,000	lb/hr stm	$ -	-	NA	NA	-
22	Best	PM	Coal Boiler	300,000 pph	ESP - 0.04 lb/106 Btu	0.0%	$ -	48,985	$ 58.62	$ 2,871,501	$ 1,207,300	$ 8,928,000	$ 867,000	$ 13,873,801	$ 2,081,070	$ 15,954,871	$ 3,190,974	$ 693,690	$ 693,690	$ 20,533,225	600,000	lb/hr stm	$ -	-	NA	NA	-
23	Good	HCl	Coal Boiler	300,000 pph	Wet scrubber - 0.048 lb/106 Btu	0.0%	$ -	26,215	$ 58.62	$ 1,536,723	$ 447,400	$ 715,100	$ 1,832,500	$ 4,531,723	$ 679,758	$ 5,211,482	$ 1,042,296	$ 226,586	$ 226,586	$ 6,706,950	300,000	lb/hr stm	$ -	8.47	lb/hr	caustic soda	-
24	Best	HCl	Coal Boiler	300,000 pph	Wet scrubber - 0.015 lb/106 Btu	0.0%	$ -	26,215	$ 58.62	$ 1,536,723	$ 447,400	$ 715,100	$ 1,832,500	$ 4,531,723	$ 679,758	$ 5,211,482	$ 1,042,296	$ 226,586	$ 226,586	$ 6,706,950	300,000	lb/hr stm	$ -	25	lb/hr	caustic soda	-
25	Good	PM	Coal/Wood Boiler (50/50)	300,000 pph	ESP - 0.065 lb/106 Btu	0.0%	$ -	48,985	$ 58.62	$ 2,871,501	$ 1,207,300	$ 7,314,700	$ 694,900	$ 12,088,401	$ 1,813,260	$ 13,901,661	$ 2,780,332	$ 604,420	$ 604,420	$ 17,890,833	600,000	lb/hr stm	$ -	-	NA	NA	-
26	Best	PM	Coal/Wood Boiler (50/50)	300,000 pph	ESP - 0.04 lb/106 Btu	0.0%	$ -	48,985	$ 58.62	$ 2,871,501	$ 1,207,300	$ 8,928,000	$ 867,000	$ 13,873,801	$ 2,081,070	$ 15,954,871	$ 3,190,974	$ 693,690	$ 693,690	$ 20,533,225	600,000	lb/hr stm	$ -	-	NA	NA	-
27	Good	SO2	Coal or Coal/Wood boiler (50/50)	300,000 pph	50% reduction, max. 0.6 lb/106 Btu	0.0%	$ -	26,215	$ 58.62	$ 1,536,723	$ 447,300	$ 715,100	$ 2,305,000	$ 5,004,123	$ 750,618	$ 5,754,742	$ 1,150,948	$ 250,206	$ 250,206	$ 7,406,102	600,000	lb/hr stm	$ -	0.57	gpm	50% NaOH	-
28	Best	SO2	Coal or Coal/Wood boiler (50/50)	300,000 pph	Scrubber - 90% reduction, max. 0.12 lb/106 Btu	0.0%	$ -	26,215	$ 58.62	$ 1,536,723	$ 447,300	$ 715,100	$ 2,305,000	$ 5,004,123	$ 750,618	$ 5,754,742	$ 1,150,948	$ 250,206	$ 250,206	$ 7,406,102	600,000	lb/hr stm	$ -	1.14	gpm	50% NaOH	-
29	Good	NOx	Coal or Coal/Wood boiler (50/50)	300,000 pph	Low-NOx burners max. 0.3 lb/10^6 Btu	0.0%	$ -	2,883	$ 58.62	$ 169,001	$ 151,400	$ 216,500	$ 1,428,400	$ 1,965,301	$ 294,795	$ 2,260,097	$ 452,019	$ 98,265	$ 98,265	$ 2,908,646	420,000	lb/hr stm	$ -	-	NA	NA	-
30	Best	NOx	Coal or Coal/Wood boiler (50/50)	300,000 pph	SCR - 0.17 lb/106 Btu, 30-day average	0.5%	$ 81,841	28,068	$ 58.62	$ 1,645,346	$ 1,386,500	$ 1,983,500	$ 11,352,800	$ 16,449,987	$ 2,467,498	$ 18,917,485	$ 3,783,497	$ 822,499	$ 822,499	$ 24,345,981	120,000	lb/hr stm	$ 426,728	428.21	tpy	urea	-
31	Best	NOx	Coal or Coal/Wood boiler (50/50)	300,000 pph	Switch from coal to gas	0.0%	$ -	7,262	$ 58.62	$ 425,698	$ 261,100	$ 541,400	$ 709,100	$ 1,937,298	$ 290,595	$ 2,227,893	$ 445,579	$ 96,865	$ 96,865	$ 2,867,202	420,000	lb/hr stm	$ -	-	NA	NA	-
32	Best	Hg	Coal or Coal/Wood boiler (50/50)	300,000 pph	Carbon injection and fabric filter	1.5%	$ 83,294	15,168	$ 58.62	$ 889,148	$ 274,900	$ 1,253,900	$ 3,135,000	$ 5,636,242	$ 845,436	$ 6,481,679	$ 1,296,336	$ 281,812	$ 281,812	$ 8,341,639	300,000	lb/hr stm	$ -	0.08	tpd	activated carbon	3,750
33	Best	CO	Coal or Coal/Wood boiler (50/50)	300,000 pph	Combustion controls to achieve a 200 ppm (24-hour average)	0.0%	$ -	402	$ 58.62	$ 23,565	$ 20,000	$ 1,852,000	$ 346,000	$ 2,241,565	$ 336,235	$ 2,577,800	$ 515,560	$ 112,078	$ 112,078	$ 3,317,517	300,000	lb/hr stm	$ -	-	NA	NA	-
34	Good	NOx	Gas boiler	120,000 pph	Combustion modification - low-Nox burners, FGR - 0.05 lb /106Btu, 30-day average	0.0%	$ -	1,928	$ 58.62	$ 113,019	$ 102,100	$ 126,100	$ 865,800	$ 1,207,019	$ 181,053	$ 1,388,072	$ 277,614	$ 60,351	$ 60,351	$ 1,786,389	420,000	lb/hr stm	$ -	-	NA	NA	-
35	Best	NOx	Gas boiler	120,000 pph	SCR- 0.015 lb/106 Btu, 30-day average	0.0%	$ -	10,682	$ 58.62	$ 626,179	$ 528,000	$ 755,200	$ 4,322,200	$ 6,231,579	$ 934,737	$ 7,166,316	$ 1,433,263	$ 311,579	$ 311,579	$ 9,222,737	120,000	lb/hr stm	$ 162,469	163.03	tpy	urea	-
36a	Good	NOx	Gas turbine	30 MW	Water injection - 25 ppm @15% Oxygen, 30-day average	0.0%	$ -	1,752	$ 58.62	$ 102,702	$ 17,100	$ 2,637,200	$ -	$ 2,757,002	$ 413,550	$ 3,170,553	$ 634,111	$ 137,850	$ 137,850	$ 4,080,363	30	MW	$ -	-	NA	NA	-
36b	Good	NOx	Gas turbine	30 MW	Steam injection - 25 ppm @15% Oxygen, 30-day average	0.0%	$ -	1,332	$ 58.62	$ 78,082	$ 14,700	$ 4,299,000	$ -	$ 4,391,782	$ 658,767	$ 5,050,549	$ 1,010,110	$ 219,589	$ 219,589	$ 6,499,837	30	MW	$ -	-	NA	NA	-
37	Best	NOx	Gas turbine	30 MW	SCR - 5 ppm @ 15% Oxygen, 30-day average	0.0%	$ -	-	$ 58.62	$ -	$ -	$ 2,182,900	$ 2,467,400	$ 4,650,300	$ 697,545	$ 5,347,845	$ 1,069,569	$ 232,515	$ 232,515	$ 6,882,444	30	MW	$ 104,393	104.76	tpy	urea	-
38	Good	PM	Oil boiler	135,000 pph	Switch to low-sulfur oil	0.0%	$ -	408	$ 58.62	$ 23,917	$ 2,000	$ 63,000	$ 9,400	$ 98,317	$ 14,748	$ 113,065	$ 22,613	$ 4,916	$ 4,916	$ 145,509	420,000	lb/hr stm	$ -	-	NA	NA	-
39	Best	PM	Oil boiler	135,000 pph	ESP - 0.02 lb/106 Btu	0.0%	$ -	32,240	$ 58.62	$ 1,889,909	$ 794,600	$ 4,763,900	$ 571,700	$ 8,020,109	$ 1,203,016	$ 9,223,125	$ 1,844,625	$ 401,005	$ 401,005	$ 11,869,761	600,000	lb/hr stm	$ -	-	NA	NA	-
40	Good	SO2	Oil boiler	135,000 pph	Scrubbing, 50% reduction, max 0.4 lb/106 Btu, 30-day average	0.0%	$ -	23,831	$ 58.62	$ 1,396,973	$ 406,700	$ 601,900	$ 1,670,600	$ 4,076,173	$ 611,426	$ 4,687,599	$ 937,520	$ 203,809	$ 203,809	$ 6,032,736	600,000	lb/hr stm	$ -	0.26	gpm	50% NaOH	-
41	Best	SO2	Oil boiler	135,000 pph	Scrubber - 90% reduction, max. 0.08 lb/106 Btu, 30-day average	0.0%	$ -	23,831	$ 58.62	$ 1,396,973	$ 406,700	$ 601,900	$ 1,670,600	$ 4,076,173	$ 611,426	$ 4,687,599	$ 937,520	$ 203,809	$ 203,809	$ 6,032,736	600,000	lb/hr stm	$ -	0.34	gpm	50% NaOH	-
42	Good	NOx	Oil boiler	135,000 pph	Combustion modification, 50% reduction, max 0.2 lb/106 Btu, 30-day average	0.0%	$ -	1,786	$ 58.62	$ 104,695	$ 94,000	$ 134,100	$ 884,700	$ 1,217,495	$ 182,624	$ 1,400,120	$ 280,024	$ 60,875	$ 60,875	$ 1,801,893	420,000	lb/hr stm	$ -	-	NA	NA	-
43	Best	NOx	Oil boiler	135,000 pph	SCR- 90% reduction, max 0.04 lb/106 Btu, 30-day average	0.5%	$ 45,560	15,620	$ 58.62	$ 915,644	$ 772,100	$ 1,104,200	$ 6,320,000	$ 9,157,504	$ 1,373,626	$ 10,531,130	$ 2,106,226	$ 457,875	$ 457,875	$ 13,553,106	120,000	lb/hr stm	$ 237,563	228.00	tpy	urea	-
44	Good	PM	Wood boiler	300,000 pph	Replace scrubber with ESP - 0.065 lb/10^6 Btu	0.0%	$ -	58,214	$ 58.62	$ 3,412,505	$ 1,434,700	$ 7,044,000	$ 763,000	$ 12,654,205	$ 1,898,131	$ 14,552,335	$ 2,910,467	$ 632,710	$ 632,710	$ 18,728,223	600,000	lb/hr stm	$ -	-	NA	NA	-
45	Best	PM	Wood boiler	300,000 pph	ESP - 0.04 lb/106 Btu	0.0%	$ -	58,214	$ 58.62	$ 3,412,505	$ 1,434,700	$ 8,589,300	$ 955,800	$ 14,392,305	$ 2,158,846	$ 16,551,150	$ 3,310,230	$ 719,615	$ 719,615	$ 21,300,611	600,000	lb/hr stm	$ -	-	NA	NA	-
46	Best	PM	Wood boiler	300,000 pph	Upgrade existing ESP from 0.1 to 0.04 lb/106 Btu	0.0%	$ -	3,074	$ 58.62	$ 180,198	$ 86,000	$ 1,305,000	$ 905,000	$ 2,476,198	$ 371,430	$ 2,847,628	$ 569,526	$ 123,810	$ 123,810	$ 3,664,773	310,000	lb/hr stm	$ -	-	NA	NA	-
47	Good	NOx	Wood boiler	300,000 pph	Combustion Controls - 0.25 lb/106 Btu	0.0%	$ -	402	$ 58.62	$ 23,565	$ 20,000	$ 1,776,500	$ 359,000	$ 2,179,065	$ 326,860	$ 2,505,925	$ 501,185	$ 108,953	$ 108,953	$ 3,225,017	120,000	lb/hr stm	$ -	-	NA	NA	-
48	Best	NOx	Wood boiler	300,000 pph	SNCR - 0.20 lb/106 Btu - 40% reduction	0.0%	$ -	2,618	$ 58.62	$ 153,467	$ 26,500	$ 477,600	$ 359,200	$ 1,016,767	$ 152,515	$ 1,169,282	$ 233,856	$ 50,838	$ 50,838	$ 1,504,815	400,000	lb/hr stm	$ -	165.16	tpy	urea	-
49	Best	NOx	Wood boiler	300,000 pph	SCR- 0.17 lb/106 Btu - 50% reduction	0.5%	$ 55,525	19,038	$ 58.62	$ 1,116,008	$ 940,900	$ 1,345,700	$ 7,702,400	$ 11,160,533	$ 1,674,080	$ 12,834,612	$ 2,566,922	$ 558,027	$ 558,027	$ 16,517,588	120,000	lb/hr stm	$ 287,197	287.09	tpy	urea	-
50	Best	Hg	Wood boiler	300,000 pph	Carbon injection and fabric filter	1.5%	$ 95,964	15,734	$ 58.62	$ 922,327	$ 305,100	$ 1,269,900	$ 3,900,300	$ 6,493,591	$ 974,039	$ 7,467,630	$ 1,493,526	$ 324,680	$ 324,680	$ 9,610,515	300,000	lb/hr stm	$ -	0.003962	tpd	activated carbon	375.00
51	Best	CO	Wood boiler	300,000 pph	Combustion controls to achieve a 200 ppm (24-hour average)	0.0%	$ -	402	$ 58.62	$ 23,565	$ 20,000	$ 1,776,500	$ 359,000	$ 2,179,065	$ 326,860	$ 2,505,925	$ 501,185	$ 108,953	$ 108,953	$ 3,225,017	350,000	lb/hr stm	$ -	-	NA	NA	-
52	Good	VOC	Paper machines	1000 tpd	Installation of screw press prior to high-density storage in pulp mill for unbleached Kraft and OCC recycle mills.	0.0%	$ -	25,575	$ 58.62	$ 1,499,207	$ 904,100	$ 235,000	$ 1,464,300	$ 4,102,607	$ 615,391	$ 4,717,997	$ 943,599	$ 205,130	$ 205,130	$ 6,071,858	1,000	ton/day	$ -	-	NA	NA	-
53	Best	VOC	Paper machines	1000 tpd	Collect & incinerate wet-end vent gases	1.5%	$ 35,750	5,719	$ 58.62	$ 335,248	$ 101,300	$ 940,800	$ 1,005,976	$ 2,419,074	$ 362,861	$ 2,781,935	$ 556,387	$ 120,954	$ 120,954	$ 3,580,229	1,000	ton/day	$ -	-	NA	NA	-
54	Best	VOC	Paper machines	1000 tpd	Collect & incinerate dry-end vent gases	1.5%	$ 51,303	5,700	$ 58.62	$ 334,134	$ 98,700	$ 1,410,400	$ 1,576,998	$ 3,471,535	$ 520,730	$ 3,992,265	$ 798,453	$ 173,577	$ 173,577	$ 5,137,872	1,000	ton/day	$ -	-	NA	NA	-
55	Good	VOC	Mechanical pulping	500 tpd	Better heat recovery from TMP mill to condense VOCs to < 0.5 lb C/ODTP	0.0%	$ -	11,908	$ 58.62	$ 698,047	$ 268,400	$ 197,800	$ 742,900	$ 1,907,147	$ 286,072	$ 2,193,219	$ 438,644	$ 95,357	$ 95,357	$ 2,822,578	500	ton/day	$ -	-	NA	NA	-
56	Best	VOC	Mechanical pulping	500 tpd	Collect & incinerate heat recovery vent gases from TMP mill	0.0%	$ -	5,473	$ 58.62	$ 320,827	$ 143,400	$ 122,900	$ 457,800	$ 1,044,927	$ 156,739	$ 1,201,666	$ 240,333	$ 52,246	$ 52,246	$ 1,546,492	500	ton/day	$ -	-	NA	NA	-
57	Best	Various	Recovery Furnace	3.7x 106 lb BLS/day	Black liquor gasifier utilizing Pulse Enhanced Steam reformation	1.5%	$1,645,212	105,780	$ 58.62	$ 6,200,824	$ 2,808,000	$ 23,712,000	$ 76,960,000	$ 111,326,036	$ 8,906,083	$ 120,232,119	$ 24,046,424	$ 5,566,302	$ 445,304	$ 150,290,149	3.7	Mmlb BLS/day	$ -	-	NA	NA	-
58	Best	PM	NDCE Kraft Recovery Furnace	3.7x 106 lb BLS/day	Add two parallel fields to upgrade ESP to Best technology	0.0%	$ -	-	$ 58.62	$ -	$ -	$ 3,630,000	$ -	$ 3,630,000	$ 544,500	$ 4,174,500	$ 834,900	$ 181,500	$ 181,500	$ 5,372,400	2.7	Mmlb BLS/day	$ -	-	NA	NA	-
59	Good	PM	NDCE Kraft Recovery Furnace	3.7x 106 lb BLS/day	Add two parallel fields to upgrade ESP to Good technology	0.0%	$ -	-	$ 58.62	$ -	$ -	$ 3,040,000	$ -	$ 3,040,000	$ 456,000	$ 3,496,000	$ 699,200	$ 152,000	$ 152,000	$ 4,499,200	2.7	Mmlb BLS/day	$ -	-	NA	NA	-
60	Best	PM	Lime Kilns	240 tons CaO/day	Add single field to upgrade ESP to Best technology	0.0%	$ -	-	$ 58.62	$ -	$ -	$ 536,000	$ 325,000	$ 861,000	$ 129,150	$ 990,150	$ 198,030	$ 43,050	$ 43,050	$ 1,274,280	540	TPD CaO	$ -	-	NA	NA	-
61	Best	PM	Coal Boiler	300,000 pph	Add single field in two chambers to upgrade ESP to Best technology	0.0%	$ -	-	$ 58.62	$ -	$ -	$ 1,992,000	$ 1,250,000	$ 3,242,000	$ 486,300	$ 3,728,300	$ 745,660	$ 162,100	$ 162,100	$ 4,798,160	600,000	lb/hr stm	$ -	-	NA	NA	-
62	Best	PM	Coal/Wood Boiler (50/50)	300,000 pph	Add single field in two chambers to upgrade ESP to Best technology	0.0%	$ -	-	$ 58.62	$ -	$ -	$ 2,153,000	$ 1,550,000	$ 3,703,000	$ 555,450	$ 4,258,450	$ 851,690	$ 185,150	$ 185,150	$ 5,480,440	600,000	lb/hr stm	$ -	-	NA	NA	-
63	Best	NOx	NDCE Kraft Recovery Furnace	3.7x 106 lb BLS/day	SCR - 80% reduction	1.5%	$ 196,955	-	$ 58.62	$ -	$ -	$ 13,130,300	$ -	$ 13,327,255	$ 1,999,088	$ 15,326,343	$ 3,065,269	$ 666,363	$ 666,363	$ 19,724,337	120,000	lb/hr stm- Coal boiler	$ 375,251	376.56	tpy	urea	-
64	Best	NOx	DCE Kraft Recovery Furnace	1.7x 106 lb BLS/day	SCR - 80% reduction	1.5%	$ 128,061	-	$ 58.62	$ -	$ -	$ 8,537,400	$ -	$ 8,665,461	$ 1,299,819	$ 9,965,280	$ 1,993,056	$ 433,273	$ 433,273	$ 12,824,882	120,000	lb/hr stm- Coal boiler	$ 243,990	244.84	tpy	urea	-
65	Best	VOC	Mechanical pulping	500 tpd	Heat recovery system from TMP mill to condense VOCs. Then collection and incineration of the NCGs.	0.0%	$ -	17,381	$ 58.62	$ 1,018,874	$ 411,800	$ 320,700	$ 1,200,700	$ 2,952,074	$ 442,811	$ 3,394,885	$ 678,977	$ 147,604	$ 147,604	$ 4,369,070	500	ton/day	$ -	-	NA	NA	-
66	Good	VOC	Mechanical pulping	500 tpd	Heat recovery system from pulping processes to condense VOCs from a pressurized groundwood	0.0%	$ -	11,908	$ 58.62	$ 698,047	$ 268,400	$ 197,800	$ 742,900	$ 1,907,147	$ 286,072	$ 2,193,219	$ 438,644	$ 95,357	$ 95,357	$ 2,822,578	500	ton/day	$ -	-	NA	NA	-
67	Best	VOC	Mechanical pulping	500 tpd	Heat recovery system from pulping processes to condense VOCs from a pressurized groundwood Then collection & incineration of the NCGs	0.0%	$ -	20,202	$ 58.62	$ 1,184,220	$ 487,600	$ 384,946	$ 1,436,877	$ 3,493,643	$ 524,046	$ 4,017,689	$ 803,538	$ 174,682	$ 174,682	$ 5,170,591	500	ton/day	$ -	-	NA	NA	-
68	Best	VOC	Mechanical pulping	500 tpd	Collection & incineration of NCGs from an atmospheric groundwood	0.0%	$ -	29,599	$ 58.62	$ 1,612,370	$ 782,300	$ 667,900	$ 2,476,719	$ 5,539,289	$ 830,893	$ 6,370,182	$ 1,274,036	$ 276,964	$ 276,964	$ 8,198,148	500	ton/day	$ -	-	NA	NA	-

No.	Good / Best	Pollutant	Equipment	Units	Type of chemical	Maintenance labor & materials, % of TIC	Energy, kw/feed rate at design rate	units	Usage Factor	Manpower hr/dy	Testing	Water, gpm at design rate	wastewater, gpm at design rate	Steam at steam rate	units	Compress air at design rate	units	Fuel cost	units	Natural gas usage	units	General Utilities	Units	Incremental Solid Waste Disposal	Units	Downtime Net downtime assumes that outage can be coordinated with scheduled equipment downtime: net downtime is additional downtime beyond the normal scheduled outage - days
1	Good	PM	NDCE Kraft Recovery Furnace	NA	NA	3.50%	546.63983	kw/Mmlb BLS	70%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
2	Best	PM	NDCE Kraft Recovery Furnace	NA	NA	3.50%	683.29978	kw/Mmlb BLS	80%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
3	Good	SO2	NDCE Kraft Recovery Furnace	NA	NA	3.50%	440.92377	kw/Mmlb BLS	70%	3.00	$ 5,000	148.00	14.80	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
4	Best	SO2	NDCE Kraft Recovery Furnace	NA	NA	3.50%	440.92377	kw/Mmlb BLS	80%	3.00	$ 5,000	148.00	14.80	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
5	Good	NOx	NDCE Kraft Recovery Furnace	NA	NA	1.00%	20.14061	kw/Mmlb BLS	70%	0.75	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
6	Best	NOx	NDCE Kraft Recovery Furnace	NA	NA	3.50%	4.26257	kw/Mmlb BLS	70%	3.00	$ 5,000	3.00	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
7	Best	VOC	NDCE Kraft Recovery Furnace	NA	NA	2.00%	4.03243	kw/Mmlb BLS	70%	1.50	$ 5,000	-	-	$ -	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
8	Good	PM	DCE Kraft Recovery Furnace	NA	NA	3.50%	746.10919	kw/Mmlb BLS	70%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
9	Best	PM	DCE Kraft Recovery Furnace	NA	NA	3.50%	932.63649	kw/Mmlb BLS	80%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
10	Good	SO2	DCE Kraft Recovery Furnace	NA	NA	3.50%	601.81726	kw/Mmlb BLS	70%	3.00	$ 5,000	68.00	6.80	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
11	Best	SO2	DCE Kraft Recovery Furnace	NA	NA	3.50%	601.81726	kw/Mmlb BLS	80%	3.00	$ 5,000	68.00	6.80	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
12	Best	NOx	DCE Kraft Recovery Furnace	NA	NA	3.50%	9.27736	kw/Mmlb BLS	70%	3.00	$ 5,000	3.00	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
13	Good	VOC	DCE Kraft Recovery Furnace	NA	NA	3.00%	88.64235	kw/Mmlb BLS	70%	3.00	$ 5,000	-	-	294.12	lb/hr/Mmlb BLS/day	-	NA	$ -	NA	-	NA	-	NA	-	NA	4
14	Best	VOC	DCE Kraft Recovery Furnace	NA	NA	3.00%	264.96165	kw/Mmlb BLS	70%	3.00	$ 5,000	-	-	(15,873)	lb/hr/Mmlb BLS/day	-	NA	$ -	NA	-	NA	-	NA	-	NA	20
15	Good	PM	Smelt Dissolving tank	NA	NA	2.00%	77.47584	kw/Mmlb BLS	70%	1.50	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
16	Best	PM	Smelt Dissolving tank	NA	NA	2.00%	85.22343	kw/Mmlb BLS	80%	1.50	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
17	Good	PM	Lime Kilns	NA	NA	3.00%	0.77961	kw/tpd CaO	70%	2.25	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
18	Best	PM	Lime Kilns	NA	NA	3.00%	0.97451	kw/tpd CaO	80%	2.25	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
19	Best	NOx	Lime Kilns	NA	NA	3.50%	0.31083	kw/tpd CaO	70%	3.00	$ 5,000	35.00	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
20	Best	NOx	Lime Kilns	NA	NA	2.00%	0.68643	kw/tpd CaO	70%	28.57	$ 5,000	1.97	-	2.30	lb/hr/tpd CaO	0.05	cfm/tpd CaO	$ -	NA	-	NA	-	NA	-	NA	5
21	Good	PM	Coal Boiler	NA	NA	3.00%	0.00444	hp/lb/hr stm	70%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	39.00	tpy of ash	3
22	Best	PM	Coal Boiler	NA	NA	3.00%	0.00555	kw/lb/hr/stm	80%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	77.00	tpy of ash	3
23	Good	HCl	Coal Boiler	NA	NA	5.00%	0.00270	kw/lb/hr/stm	70%	3.00	$ 5,000	64.00	20.00	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
24	Best	HCl	Coal Boiler	NA	NA	5.00%	0.00270	kw/lb/hr/stm	80%	3.00	$ 5,000	64.00	20.00	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
25	Good	PM	Coal/Wood Boiler (50/50)	NA	NA	3.00%	0.00444	kw/lb/hr/stm	70%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	94.00	tpy of ash	3
26	Best	PM	Coal/Wood Boiler (50/50)	NA	NA	3.00%	0.00555	kw/lb/hr/stm	80%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	137.00	tpy of ash	3
27	Good	SO2	Coal or Coal/Wood boiler (50/50)	NA	NA	3.50%	0.00381	kw/lb/hr/stm	70%	3.00	$ 5,000	142.86	14.29	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
28	Best	SO2	Coal or Coal/Wood boiler (50/50)	NA	NA	3.50%	0.00508	kw/lb/hr/stm	80%	3.00	$ 5,000	142.86	14.29	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
29	Good	NOx	Coal or Coal/Wood boiler (50/50)	NA	NA	2.00%	0.00081	kw/lb/hr/stm	70%	1.50	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
30	Best	NOx	Coal or Coal/Wood boiler (50/50)	NA	NA	2.00%	0.00207	kw/lb/hr/stm	70%	28.57	$ 5,000	7.43	-	0.006939	lb/hr/lb/hr stm	0.00015	cfm/lb/hr stm	$ -	NA	-	NA	-	NA	-	NA	5
31	Best	NOx	Coal or Coal/Wood boiler (50/50)	NA	NA	1.00%	-	NA	0%	1.50	$ 5,000	-	-	-	-	-	-	$ -	NA	0.00120	Mmbtu/hr /Mlb/hr steam	-	NA	-	NA	3
32	Best	Hg	Coal or Coal/Wood boiler (50/50)	lb/hr	lime	5.00%	0.00109	kw/lb/hr/stm	70%	3.00	$ 5,000	64.00	20.00	-	-	-	-	$ -	NA	-	NA	-	NA	15,779.65	tpy of lime & carbon	5
33	Best	CO	Coal or Coal/Wood boiler (50/50)	NA	NA	3.00%	0.00099	kw/lb/hr/stm	70%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
34	Good	NOx	Gas boiler	NA	NA	3.00%	0.00147	kw/lb/hr/stm	70%	1.50	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
35	Best	NOx	Gas boiler	NA	NA	2.00%	0.00197	kw/lb/hr/stm	70%	28.57	$ 5,000	2.83	-	0.00660	lb/hr/lb/hr stm	0.000142	cfm/lb/hr stm	$ -	NA	-	NA	-	NA	-	NA	5
36a	Good	NOx	Gas turbine	NA	NA	2.00%	0.06667	kw/MW	70%	1.50	$ 5,000	10.00	-	-	-	-	-	$ -	NA	-	NA	-	NA	-	NA	5
36b	Good	NOx	Gas turbine	NA	NA	2.00%	0.06667	kw/MW	70%	1.50	$ 5,000	4.76	-	79.3800	lb/hr/MW	-	-	$ -	NA	-	NA	-	NA	-	NA	5
37	Best	NOx	Gas turbine	NA	NA	2.00%	13.93333	kw/MW	70%	3.00	$ 5,000	5.00	-	46.67	lb/hr/MW	1.00	cfm/MW	$ -	NA	-	NA	-	NA	-	NA	5
38	Good	PM	Oil boiler	NA	NA	3.00%	-	NA	0%	-	$ 5,000	-	-	-	-	-	-	$ 21.21	$/yr/lb/hr st	-	NA	-	NA	-	NA	3
39	Best	PM	Oil boiler	NA	NA	3.00%	0.00813	kw/lb/hr/stm	70%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	99.00	tpy of ash	3
40	Good	SO2	Oil boiler	NA	NA	3.00%	0.00411	kw/lb/hr/stm	70%	3.00	$ 5,000	42.86	4.29	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
41	Best	SO2	Oil boiler	NA	NA	3.00%	0.00548	kw/lb/hr/stm	80%	3.00	$ 5,000	42.86	4.29	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
42	Good	NOx	Oil boiler	NA	NA	3.00%	0.00112	kw/lb/hr/stm	70%	1.50	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
43	Best	NOx	Oil boiler	NA	NA	2.00%	0.00256	kw/lb/hr/stm	70%	28.57	$ 5,000	4.14	-	0.00858	lb/hr/lb/hr stm	0.00018	cfm/lb/hr stm	$ -	NA	-	NA	-	NA	-	NA	5
44	Good	PM	Wood boiler	NA	NA	3.50%	0.00304	kw/lb/hr/stm	70%	3.00	$ 5,000	(200.00)	(20.00)	-	NA	-	NA	$ -	NA	-	NA	-	NA	551.00	tpy of ash	5
45	Best	PM	Wood boiler	NA	NA	3.50%	0.00659	kw/lb/hr/stm	70%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	599.00	tpy of ash	3
46	Best	PM	Wood boiler	NA	NA	2.00%	0.00083	kw/lb/hr/stm	70%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	116.00	tpy of ash	5
47	Good	NOx	Wood boiler	NA	NA	3.00%	0.00099	kw/lb/hr/stm	70%	1.50	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
48	Best	NOx	Wood boiler	NA	NA	3.50%	0.00004	kw/lb/hr/stm	80%	3.00	$ 5,000	3.00	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
49	Best	NOx	Wood boiler	NA	NA	2.00%	0.00140	kw/lb/hr/stm	75%	28.57	$ 5,000	5.00	-	0.004676	lb/hr/lb/hr stm	0.00010	cfm/lb/hr stm	$ -	NA	-	NA	-	NA	-	NA	5
50	Best	Hg	Wood boiler	lb/hr	pebble lime	5.00%	0.00087	kw/lb/hr/stm	70%	3.00	$ 5,000	89.60	28.00	-	NA	-	NA	$ -	NA	-	NA	-	NA	1,576.39	tpy of lime & carbon	5
51	Best	CO	Wood boiler	NA	NA	3.00%	0.00099	kw/lb/hr/stm	70%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
52	Good	VOC	Paper machines	NA	NA	3.00%	0.86089	kw/tpd	70%	1.50	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	5
53	Best	VOC	Paper machines	NA	NA	3.00%	0.31160	kw/tpd	70%	1.50	$ 5,000	-	-	-	NA	-	NA	$ -	NA	0.00471	Mmbtu/hr/tpd	-	NA	-	NA	5
54	Best	VOC	Paper machines	NA	NA	3.00%	0.37975	kw/tpd	70%	1.50	$ 5,000	-	-	-	NA	-	NA	$ -	NA	0.00810	Mmbtu/hr/tpd	-	NA	-	NA	5
55	Good	VOC	Mechanical pulping	NA	NA	3.00%	0.32912	kw/tpd	70%	1.50	$ 5,000	192.00	194.00	(188.51)	lb/hr/tpd pulp	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
56	Best	VOC	Mechanical pulping	NA	NA	3.50%	0.04476	kw/tpd	70%	2.25	$ 5,000	10.00	10.00	-	NA	-	NA	$ -	NA	0.00371	Mmbtu/hr/tpd	-	NA	-	NA	3
57	Best	Various	Recovery Furnace	NA	NA	3.00%	###################	kW/Mmlb BLS	70%	-	$ 5,000	-	650.00	########	lb/hr/Mmlb BLS/day	-	NA	$ -	NA	-	NA	0.10%	Of TIC	12.32	tons/day/Mm lb BLS	NA
58	Best	PM	NDCE Kraft Recovery Furnace	NA	NA	2.00%	81.08108	kw/Mmlb BLS	70%	1.50	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
59	Good	PM	NDCE Kraft Recovery Furnace	NA	NA	2.00%	74.32432	kw/Mmlb BLS	70%	1.50	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
60	Best	PM	Lime Kilns	NA	NA	1.00%	0.41667	kw/tpd CaO	70%	2.25	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
61	Best	PM	Coal Boiler	NA	NA	1.00%	0.00183	kw/lb/hr/stm	70%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	38.00	NA	3
62	Best	PM	Coal/Wood Boiler (50/50)	NA	NA	1.00%	0.00167	kw/lb/hr/stm	70%	3.00	$ 5,000	-	-	-	NA	-	NA	$ -	NA	-	NA	-	NA	43.00	NA	3
63	Best	NOx	NDCE Kraft Recovery Furnace	NA	NA	2.00%	147.71161	kw/Mmlb BLS	70%	28.57	$ 5,000	6.54	-	494.73	lb/hr/Mmlb BLS/day	10.60	cfm/Mmlb BLS/day	$ -	NA	-	NA	-	NA	-	NA	5
64	Best	NOx	DCE Kraft Recovery Furnace	NA	NA	2.00%	209.03447	kw/Mmlb BLS	70%	28.57	$ 5,000	4.25	-	700.12	lb/hr/Mmlb BLS/day	25.50	cfm/Mmlb BLS/day	$ -	NA	-	NA	-	NA	-	NA	5
65	Best	VOC	Mechanical pulping	NA	NA	3.50%	0.37388	kw/tpd	70%	2.25	$ 5,000	202.00	204.00	(188.51)	lb/hr/tpd pulp	-	NA	$ -	NA	-	NA	-	NA	-	NA	3
66	Good	VOC	Mechanical pulping	NA	NA	3.00%	0.32912	kw/tpd	70%	1.50	$ 5,000	192.00	38.80	(37.70)	lb/hr/tpd pulp	-	NA	$ -	NA	-	NA	-	NA	-	NA	
67	Best	VOC	Mechanical pulping	NA	NA	3.50%	0.39696	kw/tpd	70%	2.25	$ 5,000	202.00	48.80	(37.70)	lb/hr/tpd/pulp	-	NA	$ -	NA	0.00742	Mmbtu/hr/tpd	-	NA	-	NA	
68	Best	VOC	Mechanical pulping	NA	NA	3.50%	0.34847	kw/tpd	70%	2.25	$ 5,000	10.00	20.00	-	NA	-	NA	$ -	NA	0.03021	Mmbtu/hr/tpd	-	NA	-	NA	

October 23, 2020

Mr. Jeff Koerner, Director
Division of Air Resource Management
Florida Department of Environmental Protection
2600 Blair Stone Road, #5505
Tallahassee, FL 32399-2000

Sent via email: jeff.koerner@dep.state.fl.us

Re: Seminole Generating Station -- Regional Haze Reasonable Progress Analysis

Dear Mr. Koerner:

On August 18, 2020, the Department requested a reasonable progress analysis for Seminole Generating Station (SGS) Units 1 and 2 (EU ID Nos. 001 and 002). Seminole Electric Cooperative, Inc. (SECI) provides the following response.

Background

SGS Units 1 and 2 are described in the Title V Permit No. 1070025-034-AV, along with the major regulations they are subject to, as follows:

> The two-fossil fuel fired steam generators, designated as "Electric Utility Steam Generating Units 1 and 2," are coal-fired, dry-bottom wall-fired utility boilers. Each unit has maximum heat input rate of 7,172 MMBtu per hour and a nominal gross generator rating of 735.9 megawatts (MW). Each unit is equipped with the following air pollution control equipment: an electrostatic precipitator (ESP) to control particulate matter (PM) emissions; an upgraded wet limestone flue gas desulphurization (FGD) system to control sulfur dioxide (SO_2) emissions; a low-NOx burner (LNB) system, low excess air firing and an selective catalytic reduction (SCR) system to control NOx emissions; and, an alkali injection system. The alkali injection system is not required to meet current sulfuric acid mist (SAM) emissions limits but will be available for use if needed. Each unit is equipped with continuous emission monitoring systems (CEMS) to measure and record SO_2, NOx, & carbon dioxide (CO_2) emissions as well as a continuous opacity monitoring system (COMS) to measure and record the opacity of the exhaust gas.

Each unit has its own stack, with emissions exhausting through 695 foot stacks with exit diameters of 26.5 feet, 128 °F exit temperatures, and stack gas flow rates of 1,987,064 acfm as referenced in the original air construction permit application. Unit 1 began commercial operation in 1984 and Unit 2 began commercial operation in 1985.

{Permitting note(s): These emissions units are regulated under: Acid Rain, Phase II; 40 CFR 60 Subpart Da, Standards of Performance for Fossil-Fuel Fired Steam Generators; 40 CFR 63, Subpart UUUUU- National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units; Rule 62-296.405(2), F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input; Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD) [PSD-FL-018, as amended & PSD-FL-372/1070025-004-AC, as amended]; and, Rule 62-212.400(6), F.A.C., Best Available Control Technology (BACT) Determination.}

Regional Haze Requirements

As described in the Department's August 18, 2020 request, a VISTA (Visibility Improvement – State and Tribal Association of the Southeast) modeling analysis indicated that SGS could potentially influence visibility impairment in nearby Class I areas, specifically Okefenokee National Wildlife Refuge, and primarily with respect to SO_2. As such, FDEP is requesting information for the two boilers at SGS to determine if additional SO_2 emission control and reductions are cost-effective for this implementation period. In accordance with EPA Guidance[1], states should require such units to submit a four-factor analysis of feasible SO_2 control measures to determine whether additional reductions are cost-effective, but can exempt such units if they are determined to already be "effectively controlled" under an enforceable requirement. EPA's Guidance states that for electric generating units that have add-on FGD systems and that meet the 0.20 lb SO_2/mmBtu limit in the Mercury and Air Toxics Standard (MATS), it is reasonable for a state to determine that that unit is already "effectively controlled."

Permit Conditions

Specific Condition A.33. of Permit No. 1070025-034-AV is quoted below, which requires SGS Units 1 and 2 to comply with MATS and includes the option of complying with either an HCl limit or a SO_2 limit. In accordance with Seminole's most recent MATS Semi-Annual Compliance Reports (dated July 24, 2020), SGS has elected to comply with the MATS SO_2 limit. Note that the revised Notification of Compliance Status (NOCS) submitted per MATS on December 15, 2016 presents initial compliance test results of 0.154 SO_2 lb/mmBtu for Unit 1 and 0.161 lb SO_2/mmBtu for Unit 2.

NESHAP 40 CFR 63 Requirements – Subpart UUUUU. These emission units shall comply with all applicable provisions of 40 CFR 63, Subpart UUUUU, National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

[1] https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.

{also known as "MATS"}. This federal regulation has not been adopted by reference in Rule 62-204.800, F.A.C. Each emissions unit shall comply with Appendix 40 CFR 63 Subpart UUUUU attached to this permit no later than April 16, 2015. Each emissions unit is classified as an "existing" unit since each was constructed prior to May 3, 2011 and has not been reconstructed. In addition, each emissions unit is considered a coal-fired unit not using low rank virgin coal. Subpart UUUUU applies the following emission limits to each emissions unit:

1. Filterable Particulate Matter (PM). Emissions of PM shall not exceed either 0.030 pound/million British thermal unit (lb/MMBtu) or 0.30 pound per megawatt-hour (lb/MWh). In lieu of the filterable PM emission limit, the permittee may select to meet a total non-Hg HAP metals emission limit of either 5.0 x 10-5 lb/MMBtu or 0.50 pounds per gigawatt-hour (lb/GWH). Finally, in lieu of ether filterable PM or total non-Hg HAP metals emission limits the permittee my meet the following individual HAP metal emission limits:

a. Antimony (Sb) - 0.80 pounds per terra Btu (lb/TBtu) or 8.0 x 10-3 lb/GWh.
b. Arsenic (As) - 1.1 lb/TBtu or 0.020 lb/GWh.
c. Beryllium (Be) - 0.20 lb/TBtu or 2.0 x 10-3 lb/GWh.
d. Cadmium (Cd) - 0.30 lb/TBtu or 3.0 x 10-3 lb/GWh.
e. Chromium (Cr) - 2.8 lb/TBtu or 0.030 lb/GWh.
f. Cobalt (Co) - 0.80 lb/TBtu or 8.0 x 10-3 lb/GWh.
g. Lead (Pb) - 1.2 lb/TBtu or 0.020 lb/GWh.
h. Manganese (Mn) - 4.0 lb/TBtu or 0.050 lb/GWh.
i. Nickel (Ni) - 3.5 lb/TBtu or 0.040 lb/GWh.
j. Selenium (Se) - 5.0 lb/TBtu or 0.060 lb/GWh.

2. Hydrogen Chloride (HCl). Emissions of HCl shall not exceed either 2.0 x 10-3 lb/MMBtu or 0.020 lb/MWh. In lieu of HCl emission limit, the permittee may select to meet a SO_2 emission limit of either 0.20 lb/MMBtu or 1.5 lb/GWH.

3. Mercury (Hg). Emissions of Hg shall not exceed either 1.2 lb/TBtu or 0.013 lb/GWh. Compliance with the above emissions limits shall be demonstrated pursuant to one of the available options specified in 40 CFR 63, Subpart UUUUUU which is included as an appendix in the renewed Title V air operation permit. The permittee shall also comply with the recordkeeping and reporting requirements specified in the appendix.

[40 CFR 63, Subpart UUUUU.]

Conclusion

SGS Units 1 and 2 meet EPA's exemption from conducting a four-factor reasonable progress analysis, because they are subject to MATS, have add-on FGD systems, and are in compliance with the MATS SO_2 limit of 0.20 lb/mmBtu. Because MATS allows compliance with the SO_2 limit as a surrogate for compliance with the HCl limit, SECI will submit a permit application soon to expressly impose the 0.20 SO_2 limit on SGS Units 1 and 2.

If you have any questions regarding the information in this letter, or need any additional information, please contact me at (813) 440-8289 or cweber@seminole-electric.com.

Sincerely,

Chris Weber
Senior Environmental Regulatory Specialist – Air Quality Lead

cc: Lewis Snyder, SECI
Luis Guilbe, SECI
Micheal Rogero, SECI
John Townsend, SECI
Stuart Bartlett, FDEP