APPENDIX B

Florida Department of Environmental Protection
Division of Air Resource Management

Regional Haze Supplemental SIP – Four Factor Analyses and Documentation

Table A-1c

Fuel Switching Cost (No Solid Fuel) - WestRock Fernandina Beach No. 7 Power Boiler

CAPITAL COSTS			
Total Capital Investment for New ULSD 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	2.75%	of TCI			***$515,625***
(c)	Bark ash landfill disposal	[redacted]	tpy	[redacted]	/ton	***$295,466***
Fuel						
(d)	Additional natural gas cost - Tier 3 usage rate	[redacted]	MMBtu	[redacted]	/MMBtu	***$6,328,829***
(e)	Additional natural gas cost - elevated price days		MMBtu		/MMBtu	***$5,572,800***
(f)	ULSD cost		thousand gal		/gal	***$1,052,414***
(g)	Coal cost savings		tons		/ton	***-$6,683,215***
	Total Direct Annual Costs:				***DAC***	***$7,081,919***
Annual Operating Costs - Indirect Annual Costs						
(h)	Overhead	0%	of TCI			***$0***
(i)	Administrative Charges	2%	of TCI			***$375,000***
(i)	Property Taxes	0%	of TCI			***$0***
(i)	Insurance	1%	of TCI			***$187,500***
	Total Indirect Annual Costs:				***IDAC***	***$562,500***
	Total Annual Costs:				***TAC***	***$7,644,419***
Cost Effectiveness						
(i)	Expected lifetime of equipment, years	30				
(i)	Interest rate, %/yr	3.25%				
(i)	Capital recovery factor	0.053				
(i)	Total Capital Investment Cost	$18,750,000				
	Annualized Capital Investment Cost:					***$987,782***
	Total Annualized Cost:					***$8,632,201***
(j)	SO_2 Reduction	97.3%				
	Pre-retrofit SO_2	1,203	tons SO_2/yr			
	Post-retrofit SO_2 Using Burner System	32.8	tons SO_2/yr			
	SO_2 Removed	1,171	tons SO_2/yr			
	Annual Cost/Ton Removed:					***$7,374***

(a) Based on project estimate performed by WestRock.

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

(c) 2019 WestRock Fernandina Beach cost to dispose of bark ash.

(d) Projected WestRock Fernandina Beach fuel costs.

(e) Projected WestRock Fernandina Beach fuel costs. Projecting that natural gas costs will be elevated (but less than ULSD) at least 24 days/year (518,400 MMBtu of heat input for 20 days of operation).

(f) Projected 2022 WestRock Fernandina Beach fuel costs. WestRock expects that natural gas costs will spike and exceed ULSD costs at least 3 days/year, so that WestRock will fire ULSD instead of natural gas on those days (479 thousand gallons of ULSD for 2 days of operation).

(g) 2019 WestRock Fernandina Beach coal cost.

(h) No charge taken here due to operational cost savings from removing coal.

(i) U.S. EPA Air Pollution Control Cost Manual, Section 1, Chapter 2. Yellow-highlighted values were selected in order to conform to the values used by Florida DEP in their Regional Haze SIP submittal. WestRock believes the expected useful life of the equipment is no more than 20 years, but has utilized 30 years in this set of calculations to conform to Florida DEP's Regional Haze SIP submittal. WestRock believes that the appropriate interest rate is 4.75%, which was the rate prior to the COVID-19 pandemic, but has utilized 3.25% to conform to Florida DEP's Regional Haze SIP submittal. Any potential property tax costs have been excluded.

(j) Pre-retrofilt SO2 emissions estimated based on projected 2028 actual throughput/fuel usage. Post-retrofit SO2 emissions estimated based on equivalent heat input and replacment of coal and bark ash with natural gas and as noted in footnote (f), ULSD. See Table A-1d for emission factors and calculations.

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Fuel						
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	Total Direct Annual Costs:				***DAC***	***$7,081,919***
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(i)	Insurance	1%	of TCI			***$187,500***
	Total Indirect Annual Costs:				***IDAC***	***$562,500***
	Total Annual Costs:				***TAC***	***$7,644,419***
Cost Effectiveness						
(i)	Expected lifetime of equipment, years	20				
(i)	Interest rate, %/yr	4.75%				
(i)	Capital recovery factor	0.079				
(i)	Total Capital Investment Cost	$18,750,000				
	Annualized Capital Investment Cost:					***$1,472,821***
	Total Annualized Cost:					***$9,117,240***
(j)	SO_2 Reduction	97.3%				
	Pre-retrofit SO_2	1,203	tons SO_2/yr			
	Post-retrofit SO_2 Using Burner System	32.8	tons SO_2/yr			
	SO_2 Removed	1,171	tons SO_2/yr			
	Annual Cost/Ton Removed:					***$7,788***

(a) Based on project estimate performed by WestRock.
(b) Maintenance costs were estimated based on the U.S. EPA OAQPS Alternative Control Techniques Document - NOX Emissions from Process Heaters (Revised), Document No. EPA-453/R-93-034 (September 1993).
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(h) No charge taken here due to operational cost savings from removing coal.
(i) U.S. EPA Air Pollution Control Cost Manual, Section 1, Chapter 2. Any potential property tax costs have been excluded.
(j) Pre-retrofilt SO2 emissions estimated based on projected 2028 actual throughput/fuel usage. Post-retrofit SO2 emissions estimated based on equivalent heat input and replacment of coal and bark ash with natural gas and as noted in footnote (f), ULSD. See Table A-1d for emission factors and calculations.

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(a) Based on project estimate performed by WestRock.

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(j) Pre-retrofilt SO2 emissions estimated based on projected 2028 actual throughput/fuel usage. Post-retrofit SO2 emissions estimated based on equivalent heat input and replacment of coal and bark ash with natural gas and as noted in footnote (f), ULSD. See Table A-1d for emission factors and calculations.

Table A-1d

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 (No Change to Current Fuel Mix)				
Bark Ash	14,591	tpy	387	tpy
	265,554	MMBtu/yr		
Coal	51,572	tpy	784	tpy
	1,340,872	MMBtu/yr		
Natural Gas	5,810	MMscf/yr	1.7	tpy
	6,082,548	MMBtu/yr		
LVHC NCG	41,818	ADTUBP	31	tpy
Total Emissions			1,203	tpy
Total Heat Input	7,688,974	MMBtu/yr		
Post-change SO_2 (No Solid Fuel)				
Natural Gas	7,328	MMscf/yr	2.20	tpy
	7,672,367	MMBtu/yr		
ULSD (est. 3 days at 900 MMBtu/hr)	478,370	gal/yr	0.05	tpy
	64,800	MMBtu/yr		
LVHC NCG	41,818	ADTUBP	31	tpy
Total Emissions			33	tpy
Total Heat Input	7,737,167	MMBtu/yr		
SO_2 Removed			1,171	tpy

Heat Content		
Bark Ash[1]	9,100	Btu/lb
Coal[1]	13,000	Btu/lb
Natural Gas[1]	1,047	Btu/scf
ULSD	135,460	BTU/gal

1 - Mill Specific Information

Bark Ash Emissions Factor[2]		
Bark Ash Emission Factor	2.92	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	0.8	% weight max expected
Coal Emissions Factor	30.4	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

No. 2 Fuel Oil (ULSD) Emissions Factor[5]		
No. 2 Fuel Oil (ULSD) Emissions Factor	0.213	lb/10^3 gal

5 - AP-42 Section 1.4

NCG Emisions Factor[6]		
Emission factor for combustion of scrubbed NCG	1.46	lb/ADTUBP

6 - 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).

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

Draft

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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.

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[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

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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.

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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]

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[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

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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.

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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.

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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

[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.

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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.

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APPENDIX A

RBLC SEARCH RESULTS

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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

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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 $2NaOH + SO_2 \rightarrow Na_2SO_3 + H_2O$
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 (20
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.

gpcellulose
Foley Cellulose

ONE BUCKEYE DRIVE
PERRY, FLORIDA 32348-7702

August 30, 2022

Mr. Hastings Read
Division of Air Resources Management
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: Foley Cellulose LLC
Facility ID No. 1230001
Regional Haze Rule – Reasonable Progress Analysis

Dear Mr. Read:

Foley Cellulose LLC owns and operates a softwood Kraft pulp mill (referred to as "GP", the "Foley Mill" or the "Mill") located in Perry, Taylor County, Florida that manufactures 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. 1230001-106-AV), most recently issued by the Florida Department of Environmental Protection (FDEP) on March 22, 2022.

On June 22, 2020, FDEP issued a letter to the Foley Mill requesting a four-factor analysis for sulfur dioxide (SO_2) for the following emission units:

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

The Foley Mill submitted an initial analysis to FDEP on October 20, 2020. Based on discussions with FDEP and additional analyses conducted at the Foley Mill, GP submits this updated four factor analysis. Revised control costs for add-on pollution control devices for the Nos. 2, 3, and 4 Recovery Furnaces are provided in an attachment to this letter. The revised costs are based on more accurate sulfur dioxide (SO_2) emissions data and site-specific cost estimates for controls.

Based on the updated analyses, GP is proposing the following changes at the facility in support of the Regional Haze rule:

- Limit No. 6 fuel oil sulfur content to 1.02%, averaged over a 12-month period as purchased.
- Maintain pH of at least 8 for the No. 1 Bark Boiler's venturi scrubber when non-condensable gases (NCGs) are routed to the boiler for control, even when the TRS Pre-Scrubber is in service.
- Cap No. 6 fuel oil firing for No. 1 Power Boiler and Nos. 1 and 2 Bark Boilers. GP proposes a combined cap of 3,500,000 gallons/year, excluding usage necessitated by any natural gas curtailment. The cap will be demonstrated on a 12-month rolling basis.
- Based on the updated control cost analysis provided as an attachment to this letter, add-on controls are not cost-effective for the Nos. 2, 3 or 4 Recovery Furnaces.

If you have any questions about the attached analysis, please do not hesitate to contact Dean Ahrens at (850) 584-1608 or via email at jerry.ahrens@gapac.com or Maria Zufall at (404) 652-7256 or Maria.Zufall@gapac.com.

Sincerely,

Thomas Pazdera

Thomas Pazdera
Vice President – General Manager
Foley Cellulose LLC

Attachment

Capital & Operating Cost Evaluation for SO2 Scrubber for RF2

Cost Category	Value	Notes
BLS Analyzed (ton BLS/day) =	1,171	Permitted Capacity
Total Capital Investment (TCI)	**$22,000,000**	Andritz/GP estimate provided August 15, 2022
Capital Recovery		
Capital Recovery Factor (CRF) *	0.0651	CRF = 5% interest and 30-yr equipment life based on July 2020 Draft Section 5 Control Cost Manual
Capital Recovery Cost (CRC)	***$1,432,200***	***CRC = TCI × CRF***
Operating Costs		
Direct Operating Costs (DOC)		
Operating Labor	$15,306	A = Based on 0.5 hour per shift, 3 shifts per day
Supervisory Labor	$2,296	B = 15% of operating labor
Maintenance Labor	$17,780	C = Based on 0.5 hour per shift, 3 shifts per day
Maintenance Materials	$17,780	D = Equivalent to maintenance labor
Caustic Costs†	$1,085,018	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)
Sulfuric Acid Costs (for Neutralization)	$226,422	E = Mass of H2SO4 to neutralize NaOH times chemical cost plus 10% waste
Electricity Usage	1,033 kWh	Power (kWh) ratioed based on AFPA values.
Cost of Electricity Usage	$753,808	F = E × Electricity Cost
Fresh Water	$38,334	G = Freshwater use * water cost
Water Disposal	$3,139	H = Water disposal amount * disposal cost
Total Direct Operating Costs (DOC)	***$2,159,882***	***DOC = A + B + C + D +E + F + G + H***
Indirect Operating Costs (IOC)		
Overhead	$31,896	H = 60% × (A + B + C + D)
Property Tax	$220,000	I = 1% × TCI
Insurance	$220,000	J = 1% × TCI
Administrative Charges	$440,000	K = 2% × TCI
Total Indirect Operating Costs (IOC)	***$911,896***	***IOC = H + I + J + K***
Total Annualized Cost (AC) =	**$4,503,978**	*AC = CRC + DOC + IOC*
SO_2 Uncontrolled Emissions (tpy)	657.59	
SO_2 Removed (tpy)	591.83	90% Removal Efficiency
Cost per ton of SO2 Removed ($/ton)	**$7,610**	**$/ton = AC / Pollutant Removed**

* U.S. EPA OAQPS, EPA Air Pollution Control Cost Manual Draft, July 2020, Section 5 SO_2 and Acid Gas Controls.

† Caustic costs are highly variable in the current market. The basis of the value shown is the actual average cost for the Foley Mill for August 2021 through July 2022. During this timeframe, the monthly values have varied from $440/ton to $920/ton.

Capital & Operating Cost Evaluation for SO2 Scrubber for RF3

Cost Category	**Value**	**Notes**
BLS Analyzed (ton BLS/day) =	988	Permitted Capacity
Total Capital Investment (TCI)	**$22,000,000**	Andritz/GP estimate provided August 15, 2022
Capital Recovery		
Capital Recovery Factor (CRF) *	0.0651	CRF = 5% interest and 30-yr equipment life based on July 2020 Draft Section 5 Control Cost Manual
Capital Recovery Cost (CRC)	***$1,432,200***	***CRC = TCI × CRF***
Operating Costs		
Direct Operating Costs (DOC)		
Operating Labor	$15,306	A = Based on 0.5 hour per shift, 3 shifts per day
Supervisory Labor	$2,296	B = 15% of operating labor
Maintenance Labor	$17,780	C = Based on 0.5 hour per shift, 3 shifts per day
Maintenance Materials	$17,780	D = Equivalent to maintenance labor
Caustic Costs†	$1,924,725	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)
Sulfuric Acid Costs (for Neutralization)	$401,653	E = Mass of H2SO4 to neutralize NaOH times chemical cost plus 10% waste
Electricity Usage	871 kWh	Power (kWh) ratioed based on AFPA values.
Cost of Electricity Usage	$636,025	F = E × Electricity Cost
Fresh Water	$32,344	G = Freshwater use * water cost
Water Disposal	$2,648	H = Water disposal amount * disposal cost
Total Direct Operating Costs (DOC)	***$3,050,557***	***DOC = A + B + C + D +E + F + G + H***
Indirect Operating Costs (IOC)		
Overhead	$31,896	H = 60% × (A + B + C + D)
Property Tax	$220,000	I = 1% × TCI
Insurance	$220,000	J = 1% × TCI
Administrative Charges	$440,000	K = 2% × TCI
Total Indirect Operating Costs (IOC)	***$911,896***	***IOC = H + I + J + K***
Total Annualized Cost (AC) =	**$5,394,654**	*AC = CRC + DOC + IOC*
SO_2 Uncontrolled Emissions (tpy)	1,167	
SO_2 Removed (tpy)	1,050	90% Removal Efficiency
Cost per ton of SO2 Removed ($/ton)	**$5,138**	**$/ton = AC / Pollutant Removed**

* U.S. EPA OAQPS, EPA Air Pollution Control Cost Manual Draft, July 2020, Section 5 SO_2 and Acid Gas Controls.

† Caustic costs are highly variable in the current market. The basis of the value shown is the actual average cost for the Foley Mill for August 2021 through July 2022. During this timeframe, the monthly values have varied from $440/ton to $920/ton.

Capital & Operating Cost Evaluation for SO2 Scrubber for RF4

Cost Category	Value	Notes
BLS Analyzed (ton BLS/day) =	1,606	Permitted Capacity
Total Capital Investment (TCI)	**$22,000,000**	Andritz/GP estimate provided August 15, 2022
Capital Recovery		
Capital Recovery Factor (CRF) *	0.0651	CRF = 5% interest and 30-yr equipment life based on July 2020 Draft Section 5 Control Cost Manual
Capital Recovery Cost (CRC)	***$1,432,200***	***CRC = TCI × CRF***
Operating Costs		
Direct Operating Costs (DOC)		
Operating Labor	$15,306	A = Based on 0.5 hour per shift, 3 shifts per day
Supervisory Labor	$2,296	B = 15% of operating labor
Maintenance Labor	$17,780	C = Based on 0.5 hour per shift, 3 shifts per day
Maintenance Materials	$17,780	D = Equivalent to maintenance labor
Caustic Costs†	$1,524,270	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)
Sulfuric Acid Costs (for Neutralization)	$318,086	E = Mass of H2SO4 to neutralize NaOH times chemical cost plus 10% waste
Electricity Usage	1,416 kWh	Power (kWh) ratioed based on AFPA values.
Cost of Electricity Usage	$1,033,589	F = E × Electricity Cost
Fresh Water	$52,562	G = Freshwater use * water cost
Water Disposal	$4,304	H = Water disposal amount * disposal cost
Total Direct Operating Costs (DOC)	***$2,985,972***	***DOC = A + B + C + D +E + F + G + H***
Indirect Operating Costs (IOC)		
Overhead	$31,896	H = 60% × (A + B + C + D)
Property Tax	$220,000	I = 1% × TCI
Insurance	$220,000	J = 1% × TCI
Administrative Charges	$440,000	K = 2% × TCI
Total Indirect Operating Costs (IOC)	***$911,896***	***IOC = H + I + J + K***
Total Annualized Cost (AC) =	**$5,330,068**	*AC = CRC + DOC + IOC*
SO_2 Uncontrolled Emissions (tpy)	924	
SO_2 Removed (tpy)	831	90% Removal Efficiency
Cost per ton of SO2 Removed ($/ton)	**$6,411**	**$/ton = AC / Pollutant Removed**

* U.S. EPA OAQPS, EPA Air Pollution Control Cost Manual Draft, July 2020, Section 5 SO_2 and Acid Gas Controls.

† Caustic costs are highly variable in the current market. The basis of the value shown is the actual average cost for the Foley Mill for August 2021 through July 2022. During this timeframe, the monthly values have varied from $440/ton to $920/ton.

gpcellulose
Foley Cellulose

ONE BUCKEYE DRIVE
PERRY, FLORIDA 32348-7702

November 16, 2022

Mr. Hastings Read
Division of Air Resources Management
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: Foley Cellulose LLC
Facility ID No. 1230001
Regional Haze Rule – November 2022 Update

Dear Mr. Read:

Foley Cellulose LLC owns and operates a softwood Kraft pulp mill (referred to as "GP", the "Foley Mill" or the "Mill") located in Perry, Taylor County, Florida that manufactures 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. 1230001-106-AV), most recently issued by the Florida Department of Environmental Protection (FDEP) on March 22, 2022.

On June 22, 2020, under the Regional Haze regulation, 40 CFR 51.308, FDEP issued a letter to the Foley Mill requesting a four-factor analysis for sulfur dioxide (SO_2) for the following emission units:

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

The Foley Mill submitted an initial analysis to FDEP on October 20, 2020. An updated analysis was submitted on August 30, 2022. On September 20, 2022, representatives from FDEP met at the Foley Mill to discuss the four-factor analysis. Based on that meeting, the following updates are being submitted with this letter.

Revised Control Cost Analysis. Based on discussions with FDEP, review of recent EPA cost control manual guidance, and a detailed review of cost data, the following changes were made to the control cost estimates:

- Scrubber costs were provided by the vendor for each individual recovery furnace to reflect different costs based on size and configuration.
- The property tax, insurance, and administrative costs were removed from the analysis.
- Capital recovery factor was updated to the current prime rate and 30-year life.
- Maintenance costs were updated to reflect the most recent control cost manual guidance. These values were also confirmed with internal engineering resources.
- Material costs were updated with the most current data through October 2022.

The updated control costs for add-on pollution control devices for the Nos. 2, 3, and 4 Recovery Furnaces are provided as an attachment to this letter. The control costs are approximately \$7,800, \$5,200, and \$6,600 per ton, respectively for the Nos. 2, 3 and 4 Recovery Furnaces. Therefore, add-on controls are not cost-effective.

As requested, technical background information on the Foley recovery furnaces is also provided in an attachment.

Proposed Permit Conditions. Based on the updated analyses, GP is proposing the following permit conditions to reduce emissions and satisfy any additional requirements under the Regional Haze Rule:

- Limit No. 6 fuel oil sulfur content to 1.02%, averaged over a 12-month period as purchased.
- Maintain pH of at least 8.0 for the No. 1 Bark Boiler's venturi scrubber when non-condensable gases (NCGs) are being routed to the boiler for control, even when the TRS Pre-Scrubber is in service.
- Cap No. 6 fuel oil firing for No. 1 Power Boiler and Nos. 1 and 2 Bark Boilers. GP proposes a combined cap of 3,500,000 gallons/year, excluding usage necessitated by any natural gas curtailment. The cap will be demonstrated on a 12-month rolling basis.
- Cap the combined Nos. 2, 3, and 4 Recovery Furnace SO_2 emissions at 3,325 tons per year.

GP will submit a permit application to incorporate these conditions into the permit pending FDEP's concurrence. If you have any questions about the attached analysis, please do not hesitate to contact Dean Ahrens at (850) 584-1608 or via email at jerry.ahrens@gapac.com or Maria Zufall at (404) 652-7256 or Maria.Zufall@gapac.com.

Sincerely,

Thomas Pazdera
Vice President – General Manager
Foley Cellulose LLC

Attachments

Attachment 1
Control Cost Calculations

Total Capital Investment (TCI) - No. 2 Recovery Furnace

Cost Category	Cost
Total Project Cost	**$22,000,000**
Equipment	
Andrtiz SO2 Scrubber Package	$5,735,000
RO System	$900,000
Chemical Skids	$175,000
Freight	$544,800
	$7,354,800
Installation	
Demolition for Construction	$150,000
Civil Structural Scrubber Adjustment	$525,000
Mechanical Installation on RO System	$800,000
Scrubber Electrical OSBL	$1,100,000
Mechanical Installation Scrubber OSBL	$5,250,000
	$7,825,000
Balance of Plant (7%)	**$1,062,586**
Project Costs	
Engineering (10%)	$1,624,239
Project Management (5%)	$812,119
Construction Management (2.5%)	$406,060
Escalation (8%)	$1,299,391
Contingency (10%)	$1,624,239
	$5,766,047

Capital & Operating Cost Evaluation for SO2 Scrubber for No. 2 Recovery Furnace

Cost Category	Value	Notes
BLS Analyzed (ton BLS/day) =	1,171	Permitted Capacity
Total Capital Investment (TCI)	**$22,000,000**	Andritz/GP estimate provided August 15, 2022
Capital Recovery		
Capital Recovery Factor (CRF) *	0.0806	CRF = 7% interest and 30-yr equipment life
Capital Recovery Cost (CRC)	***$1,772,901***	***CRC = TCI × CRF***
Operating Costs		
Direct Operating Costs (DOC)		
Operating Labor	$15,306	A = Based on 0.5 hour per shift, 3 shifts per day
Supervisory Labor	$2,296	B = 15% of operating labor
Maintenance Costs	$330,000	C = Based 0.015 TCI, per May 2021 FGD control cost manual
Caustic Costs†	$1,201,657	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)
Sulfuric Acid Costs (for Neutralization)	$265,339	E = Mass of H2SO4 to neutralize NaOH times chemical cost plus 10% waste
Electricity Usage	1,033 kWh	Power (kWh) ratioed based on AFPA values.
Cost of Electricity Usage	$766,504	F = E × Electricity Cost
Fresh Water	$38,334	G = Freshwater use * water cost
Water Disposal	$3,139	H = Water disposal amount * disposal cost
Total Direct Operating Costs (DOC)	***$2,622,575***	***DOC = A + B + C + D +E + F + G + H***
Indirect Operating Costs (IOC)		
Overhead	$208,561	H = 60% × (A + B + C + D)
Property Tax		I = 1% × TCI
Insurance		J = 1% × TCI
Administrative Charges		K = 2% × TCI
Total Indirect Operating Costs (IOC)	***$208,561***	***IOC = H + I + J + K***
Total Annualized Cost (AC) =	**$4,604,037**	*AC = CRC + DOC + IOC*
SO_2 Uncontrolled Emissions (tpy)	657.59	
SO_2 Removed (tpy)	591.83	90% Removal Efficiency
Cost per ton of SO2 Removed ($/ton)	**$7,779**	**$/ton = AC / Pollutant Removed**

* U.S. EPA OAQPS, EPA Air Pollution Control Cost Manual Draft, July 2020, Section 5 SO_2 and Acid Gas Controls.

† Caustic costs are highly variable in the current market. The basis of the value shown is the actual average cost for the Foley Mill for the 12-month period ending October 2022. During this timeframe, the monthly values have varied from $460/ton to $920/ton.

Total Capital Investment (TCI) - No. 3 Recovery Furnace

Cost Category	Cost
Total Project Cost	**$20,500,000**
Equipment	
Andrtiz SO2 Scrubber Package	$4,998,000
RO System	$900,000
Chemical Skids	$175,000
Freight	$485,840
	$6,558,840
Installation	
Demolition for Construction	$150,000
Civil Structural Scrubber Adjustment	$505,200
Mechanical Installation on RO System	$800,000
Scrubber Electrical OSBL	$1,100,000
Mechanical Installation Scrubber OSBL	$5,052,000
	$7,607,200
Balance of Plant (7%)	**$991,623**
Project Costs	
Engineering (10%)	$1,515,766
Project Management (5%)	$757,883
Construction Management (2.5%)	$378,942
Escalation (8%)	$1,212,613
Contingency (10%)	$1,515,766
	$5,380,970

Capital & Operating Cost Evaluation for SO2 Scrubber for No. 3 Recovery Furnace

Cost Category	Value	Notes
BLS Analyzed (ton BLS/day) =	988	Permitted Capacity
Total Capital Investment (TCI)	**$20,500,000**	Andritz/GP estimate provided August 15, 2022
Capital Recovery		
Capital Recovery Factor (CRF) *	0.0806	CRF = 7% interest and 30-yr equipment life
Capital Recovery Cost (CRC)	***$1,652,021***	***CRC = TCI × CRF***
Operating Costs		
Direct Operating Costs (DOC)		
Operating Labor	$15,306	A = Based on 0.5 hour per shift, 3 shifts per day
Supervisory Labor	$2,296	B = 15% of operating labor
Maintenance Costs	$307,500	C = Based 0.015 TCI, per May 2021 FGD control cost manual
Caustic Costs†	$2,131,633	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)
Sulfuric Acid Costs (for Neutralization)	$470,687	E = Mass of H2SO4 to neutralize NaOH times chemical cost plus 10% waste
Electricity Usage	871 kWh	Power (kWh) ratioed based on AFPA values.
Cost of Electricity Usage	$646,738	F = E × Electricity Cost
Fresh Water	$32,344	G = Freshwater use * water cost
Water Disposal	$2,648	H = Water disposal amount * disposal cost
Total Direct Operating Costs (DOC)	***$3,609,153***	***DOC = A + B + C + D +E + F + G + H***
Indirect Operating Costs (IOC)		
Overhead	$195,061	H = 60% × (A + B + C + D)
Property Tax		I = 1% × TCI
Insurance		J = 1% × TCI
Administrative Charges		K = 2% × TCI
Total Indirect Operating Costs (IOC)	***$195,061***	***IOC = H + I + J + K***
Total Annualized Cost (AC) =	**$5,456,235**	*AC = CRC + DOC + IOC*
SO_2 Uncontrolled Emissions (tpy)	1,167	
SO_2 Removed (tpy)	1,050	90% Removal Efficiency
Cost per ton of SO2 Removed ($/ton)	**$5,197**	**$/ton = AC / Pollutant Removed**

* U.S. EPA OAQPS, EPA Air Pollution Control Cost Manual Draft, July 2020, Section 5 SO_2 and Acid Gas Controls.

† Caustic costs are highly variable in the current market. The basis of the value shown is the actual average cost for the Foley Mill for the 12-month period ending October 2022. During this timeframe, the monthly values have varied from $460/ton to $920/ton.

Total Capital Investment (TCI) - No. 4 Recovery Furnace

Cost Category	Cost
Total Project Cost	**$21,800,000**
Equipment	
Andrtiz SO2 Scrubber Package	$5,614,000
RO System	$900,000
Chemical Skids	$175,000
Freight	$535,120
	$7,224,120
Installation	
Demolition for Construction	$150,000
Civil Structural Scrubber Adjustment	$521,800
Mechanical Installation on RO System	$800,000
Scrubber Electrical OSBL	$1,100,000
Mechanical Installation Scrubber OSBL	$5,218,000
	$7,789,800
Balance of Plant (7%)	**$1,050,974**
Project Costs	
Engineering (10%)	$1,606,489
Project Management (5%)	$803,245
Construction Management (2.5%)	$401,622
Escalation (8%)	$1,285,192
Contingency (10%)	$1,606,489
	$5,703,038

Capital & Operating Cost Evaluation for SO2 Scrubber for No. 4 Recovery Furnace

Cost Category	Value	Notes
BLS Analyzed (ton BLS/day) =	1,606	Permitted Capacity
Total Capital Investment (TCI)	**$21,800,000**	Andritz/GP estimate provided August 15, 2022
Capital Recovery		
Capital Recovery Factor (CRF) *	0.0806	CRF = 7% interest and 30-yr equipment life
Capital Recovery Cost (CRC)	***$1,756,784***	***CRC = TCI × CRF***
Operating Costs		
Direct Operating Costs (DOC)		
Operating Labor	$15,306	A = Based on 0.5 hour per shift, 3 shifts per day
Supervisory Labor	$2,296	B = 15% of operating labor
Maintenance Costs	$327,000	C = Based 0.015 TCI, per May 2021 FGD control cost manual
Caustic Costs†	$1,688,129	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)
Sulfuric Acid Costs (for Neutralization)	$372,757	E = Mass of H2SO4 to neutralize NaOH times chemical cost plus 10% waste
Electricity Usage	1,416 kWh	Power (kWh) ratioed based on AFPA values.
Cost of Electricity Usage	$1,050,998	F = E × Electricity Cost
Fresh Water	$52,562	G = Freshwater use * water cost
Water Disposal	$4,304	H = Water disposal amount * disposal cost
Total Direct Operating Costs (DOC)	***$3,513,352***	***DOC = A + B + C + D +E + F + G + H***
Indirect Operating Costs (IOC)		
Overhead	$206,761	H = 60% × (A + B + C + D)
Property Tax		I = 1% × TCI
Insurance		J = 1% × TCI
Administrative Charges		K = 2% × TCI
Total Indirect Operating Costs (IOC)	***$206,761***	***IOC = H + I + J + K***
Total Annualized Cost (AC) =	**$5,476,896**	*AC = CRC + DOC + IOC*
SO_2 Uncontrolled Emissions (tpy)	924	
SO_2 Removed (tpy)	831	90% Removal Efficiency
Cost per ton of SO2 Removed ($/ton)	**$6,587**	**$/ton = AC / Pollutant Removed**

* U.S. EPA OAQPS, EPA Air Pollution Control Cost Manual Draft, July 2020, Section 5 SO_2 and Acid Gas Controls.

† Caustic costs are highly variable in the current market. The basis of the value shown is the actual average cost for the Foley Mill for the 12-month period ending October 2022. During this timeframe, the monthly values have varied from $460/ton to $920/ton.

ATTACHMENT 2
REFERENCE INFORMATION FOR RECOVERY FURNACES

Foley SO2 Mitigation

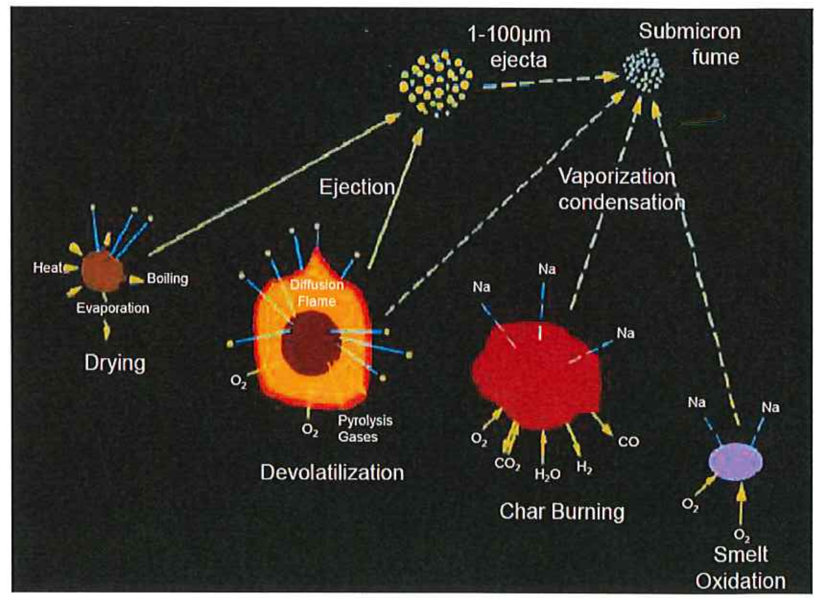
Georgia-Pacific
Packaging & Cellulose

Recovery Boiler SO2 Emissions 101

How is it formed

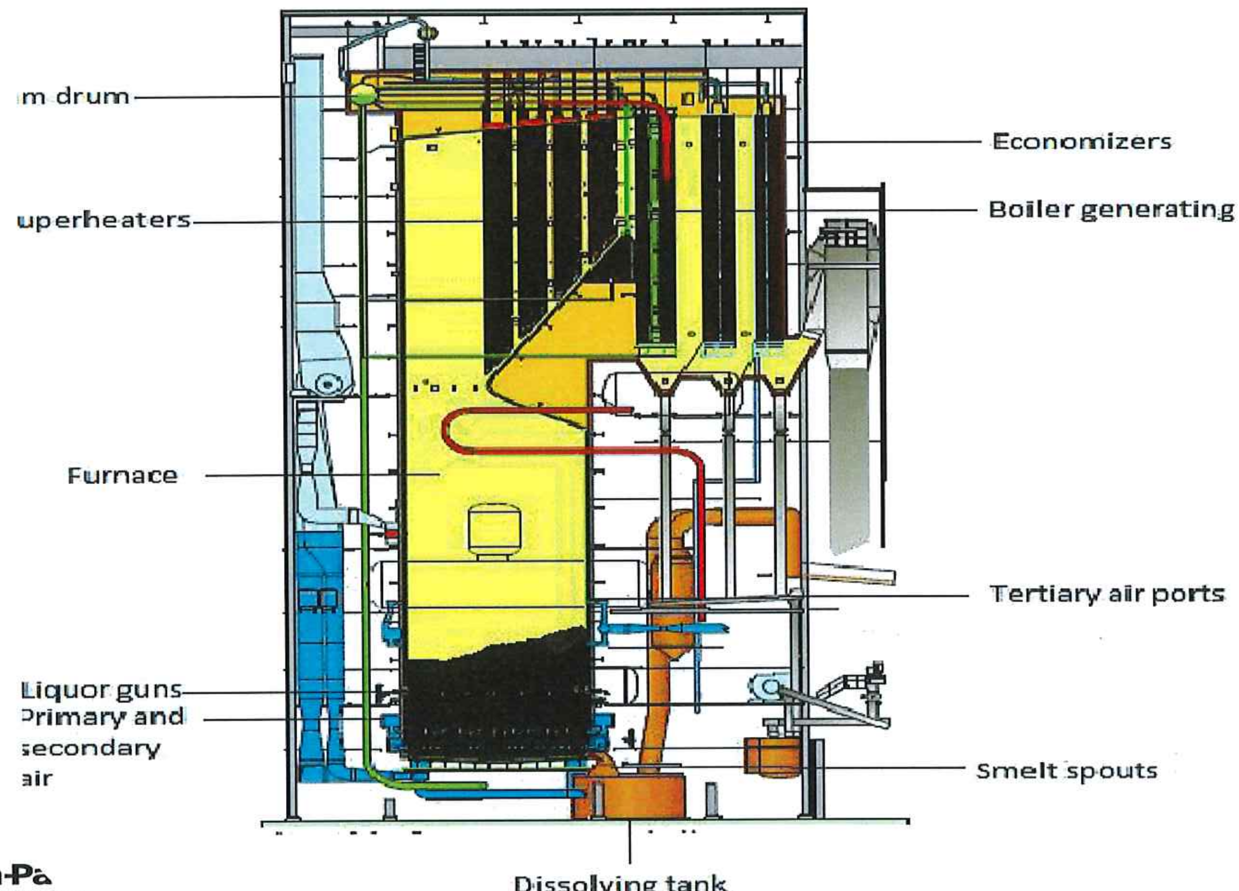
- SO2 is formed from sulfur in the Black Liquor
- Sulfur is released during combustion
- Sulfur capture is determined by
  - Hearth Temperature
  - Sodium Fuming
- High Bed Temperatures drive greater sulfur capture
- Higher Solids firing liquor results in higher bed temperature
- Air Distribution is essential to stage combustion and drive sulfur to the smelt

Black Liquor Combustion and Fume Formation



Georgia-Pacific
Packaging & Cellulose

Kraft Recovery Boiler – Terminology



Levers to Affect SO2 Emissions in a Recovery Boiler

- Increasing Firing Solids
  - The #5 BLE that was installed in 2017 was designed to produce 70% solids which matches the capability of the existing recovery furnaces
  - Modern recovery boilers operate closer to 75%+ solids which lowers SO2 generation
    - Increasing the Solids on the recovery boilers is not practical above 72% due to the limitations on the firing system, liquor heater system and storage capabilities
    - With increased firing solids the heat input to the lower furnace exceeds the mechanical design of the lower furnace which could result in premature failure of the lower furnace tubes

- Air Systems
  - Modern air systems distribute air at three levels to ensure sulfur is sequestered in the smelt and not released in the fume
  - Foley Recovery furnaces are not this design

Levers for Lower SO_2 Conditions

- High Furnace Loading
  - The higher the loading on the boiler the lower the SO_2 emissions
  - This is because the bed temperature increases which causes the sequestration of sulfur
  - Furnace Design Consideration
    - #2 and #3 Recovery Furnaces have what is considered a "short" furnace design which was common for their vintage as direct contact design recovery boilers
    - This short furnace causes there to be a low residence time over the nose arch of the furnace
    - Short residence time means that you are limited in the amount of sodium fume that is available to capture sulfur in the lower furnace
    - As you increase the furnace load/temperature the boiler will carryover plugging the boiler reducing its capability to operate at a sustainable rate increasing SO_2 emissions

Questions ?

Georgia-Pacific
Packaging & Cellulose

7.8.3 Foley Mill Four-Factor Analysis

G-P Cellulose/Foley Cellulose LLC owns and operates a softwood Kraft pulp mill (referred to as the "Foley Mill") located in Perry, Taylor County, Florida that manufactures 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. 1230001-106-AV), most recently issued by the Department on March 22, 2022.

Pursuant to EPA's Regional Haze requirements in 40 CFR 51.308, the Department sent a letter to the Foley Mill on June 22, 2020, requesting a four-factor analysis for SO_2 emissions from following existing units:

- Power Boiler No. 1 (EU-002);
- Bark Boilers No. 1 (EU-004) and No. 2 (EU-019); and
- Recovery Furnaces No. 2 (EU-006), No. 3 (EU-007), and No. 4 (EU-0011).

Note that Power Boiler No. 2 was not requested because it is now permitted to fire only natural gas and annual SO_2 emissions are much less than five tons/year. The table below shows only those sources of SO_2 emissions at the facility that have been greater than 5 tons/year of SO_2 emissions during the last ten years.

In March of 2021, the Department sent a Request for Additional Information primarily concerning SO_2 emissions from the recovery furnaces. A part of the request focused on comparing SO_2 from the Foley Mill with other Florida mills. Based on the factor of "SO_2 emissions per ton of black liquor fired", the Foley Mill recovery furnaces were much less efficient at recovering the "smelt" (sodium carbonate and sodium sulfide) needed for the Kraft pulping process. This means that additional chemicals must be purchased to replace the loss constituents. There were several discussions with the Foley Mill who agreed to certify the existing SO_2 CEMS for the recovery furnaces by conducting Relative Accuracy Test Assessments (RATAs) and explore operational changes for the recovery furnaces that could reduce SO_2 emissions, resubmit the four-factor analysis for the recovery furnaces, reduce the maximum sulfur content for fuels, and cap SO_2 emissions.

Although the existing SO_2 CEMS for the recovery furnaces were not considered "regulatory" CEMS, they were used for process feedback and reporting emissions. After conducting the RATAs, the Foley also Mill identified two issues that required resolution to ensure the accuracy of recorded data. Specifically, it was determined that the span values and relative accuracy of the CEMS were not acceptable. These issues were resolved in August of 2021 and data collected since then are believed to be accurate. Based on this study, the Foley Mill developed SO_2 emissions factors for the three recovery furnaces:

- No. 2 Recovery Furnace: 0.359 lb/MMBtu
- No. 3 Recovery Furnace: 0.714 lb/MMBtu
- No. 4 Recovery Furnace: 0.421lb/MMBtu

The Foley Mill believes the wide range of SO_2 emissions factors to be the result of the inherent design and age of each furnace. Since corrected SO_2 emissions were much greater than previously reported, the Foley Mill also submitted an air quality analysis that demonstrated compliance with the 1-hour SO_2 NAAQS based on actual emissions.

The Foley Mill submitted a revised four-factor analysis to the Department on October 20, 2020. An updated analysis was submitted on August 30, 2022. On September 20, 2022, representatives from the Department met at the Foley Mill to discuss the four-factor analysis, cost data, guidance from the EPA cost control manual, and, specifically, the inherent design of the recovery furnaces as well as potential operational improvements to reduce SO_2 emissions. On November 16, 2022, the Foley Mill submitted a final revised four-factor analysis for the recovery furnaces.

The following table shows the annual SO_2 emissions for the emissions units included in the latest four-factor analysis, including the corrected emissions from the recovery furnaces.

Table A. Actual SO_2 Emissions (Tons/Year), 2012 – 2021 Based on AORs

Year	Total	PB No. 1	BB No. 1	RF No. 2	RF No. 3	RF No. 4	BB No. 2
2012	3896.4	15.2	730.9	785.8	1206.9	1143.5	14.1
2013	4010.1	23.7	728.8	805.6	1195.7	1242.5	13.8
2014	3848.9	32.1	902.2	693.3	1095.7	1092.2	33.4
2015	4072.5	52.5	863.6	721.2	1239.0	1183.1	13.1
2016	4050.4	105.9	677.1	790.2	1248.5	1143.2	85.4
2017	3145.4	60.2	192.4	698.0	1277.0	914.0	3.8
2018	3023.4	114.0	175.8	624.0	1087.0	1020.0	2.6
2019	2891.6	69.8	195.3	650.8	1135.5	837.4	2.8
2020	2310.1	29.3	155.2	332.1	948.4	842.6	2.5
2021	2767.6	49.0	172.5	627.2	1056.8	859.1	3.1

7.8.3.1 Power Boiler No. 1 (EU-002)

This unit is capable of producing 195,000 lb/hour of steam firing variety of fuels including natural gas, No. 6 fuel oil, on-specification used oil, and onsite/offsite-generated tall oil. The exhaust flue shares a common stack along with Power Boiler No. 2 and Bark Boilers Nos. 1 and 2. The boiler was designed by Babcock & Wilcox Company and constructed in 1953.

The liquid fuels share a common storage tank. The current Title V permit allows a maximum fuel sulfur content of 2.5% by weight for No. 6 fuel oil and tall oil. Note that the sulfur content of the facility-generated tall oil is typically 0.065 to 0.08% by weight as determined by a 2003 composite sample.

The boiler also serves as a backup control system for Bark Boiler No. 1 to combust low-volume, high-concentration non-condensable gases (LVHC-NCG) from the Pulping System (EU 046) for up to 2800 hours per year. In accordance with the current Title V permit, the LVHC-NCG gas are collected and routed to a TRS pre-scrubber prior to entering either boiler to control total reduced sulfur (TRS) compounds. The TRS pre-scrubber is required to remove 50% of the TRS compounds from the LVHC-NCG.

Between 2016 and 2021, Power Boiler No. 1 fired no fuel oil, but averaged 65.5 tons per year. The Department assumes the SO_2 emissions are primarily from firing LVHC-NCG as a backup control device. The Foley Mill identified a wet scrubber, a dry sorbent injection system, and low sulfur fuels along with good operating practices as available and feasible controls.

7.8.3.1.1 Estimated Cost of Compliance

The following table summarizes the general costs for the analyses provided.

Table B. General Costs for Supporting Data

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 $2NaOH + SO_2 \rightarrow Na_2SO_3 + H_2O$
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.

<u>Wet Scrubber</u>

The Foley Mill used a recent cost estimate developed in 2020 for a wet scrubber to control exhaust from a lime kiln at a facility in Oregon. This cost estimate was adjusted for the Power Boiler No. 1 by ratioing the flow rates to the 0.6 power (an engineering estimating technique known as the Rule of Six Tenths). Caustic use was based on the molar ratio of sodium hydroxide to SO_2 emitted as well as an assumed 10% loss. Electricity requirements, water use, and waste generation costs were based on a detailed vendor quote for a similar system at a facility in Georgia. These usage rates were scaled again based on air flow rates. Facility costs for labor, water, waste, and caustic were based on the Mill's site-specific data or data from other similar facilities as identified in the above table for general costs. 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.* The actual SO_2 emissions were estimated based on an average of 81.35 tons/year (2015 – 2019) and a wet scrubber removal efficiency of 98%.

A table summarizing the capital, operating, and estimated cost-effectiveness to install and operate a wet scrubber is provided on the following page. Based on this analysis, a total capital investment of almost $7 million and the accompanying annual operating costs result in an estimated cost effectiveness of $13,547/ton to reduce actual SO_2 emissions by approximately 80 tons. The Department agrees that this level is not cost effective for this regional haze analysis.

<u>Dry Sorbent Injection System</u>

The Foley Mill also estimated the capital cost for a system to inject milled trona using an April 2017 Sargent and Lundy report prepared under a U.S. EPA contract. Facility labor, chemical, and utility costs were used to estimate the capital and annualized costs 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. Approximately 73 tons/year of actual SO_2 emissions could be removed based on an average of 81.3 tons of SO_2/year (2015 – 2019) and a removal efficiency of 90%. The capital recovery factor for annualizing the capital costs was based on 5% interest and 30-year life for boiler.

Table C. Estimated Costs for a Wet Scrubber Installed on Power Boiler No. 1

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.

Table D. Estimated Costs for a Dry Sorbent Injection Installed on Power Boiler No. 1

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.

Based on this analysis, a total capital investment of more than \$7 million to install a dry sorbent injection system and the accompanying operating costs result in an annualized cost effectiveness of \$21,727/ton to reduce actual SO_2 emissions by approximately 73 tons/year. The Department agrees that this level is not cost effective for this regional haze analysis.

Low Sulfur Fuel and Good Operating Practices

The Foley Mill proposed to:

- Reduce the maximum sulfur content of No. 6 fuel oil from 2.5% to 1.02% by weight.
- Cap No. 6 fuel oil use to 3,500,000 gallons/year for the combination of Power Boiler No. 1 and Bark Boilers Nos. 1 and 2, excluding usage necessitated by any natural gas curtailment.

The Department notes that setting a maximum fuel sulfur specification of 1.02% by weight will likely result in fuel purchases well below 1% sulfur. The Department will not impose the multi-unit fuel cap because this level is much higher than actual fuel oil use for these units in each of the last ten years. Instead, the Regional Haze air construction permit requires the use of natural gas except for periods of natural gas curtailments, pipeline disruptions, and physical mill problems that otherwise prevent the firing of natural gas in Power Boiler No. 1.

7.8.3.1.2 Time Necessary for Compliance

Since Power Boiler No. 1 has fired only natural gas during that last six years, this could be implemented immediately. The reduction in maximum fuel sulfur could be implemented for future purchases.

7.8.3.1.3 Energy and Non-Air Quality Impacts of Compliance

There are no energy or non-air quality impacts associated with these specifications and work practices.

7.8.3.1.4 Remaining Useful Life

Power Boiler No. 1 was assumed to have a remaining useful life of 30 years or more.

7.8.3.1.5 Summary of Findings for No. 1 Power Boiler

Again, Power Boiler No. 1 has not fired No. 6 fuel oil since 2015. The SO_2 emissions reported since 2016 are likely from periods when this unit is used as the backup control for combusting LVHC-NCG from the Pulping System. The Regional Haze air construction permit:

- Power Boiler No. 1 shall fire only natural gas except for periods of natural gas curtailment, pipeline disruptions, or physical mill problems that otherwise prevent the firing of natural gas in this unit. When necessary, liquid fuels from the common tank may be fired during these exceptional periods.
- For future additions of No. 6 fuel oil and tall oil to the common tank, the maximum sulfur content shall be 1.02% by weight with compliance determined by maintaining records of fuel delivery receipts and/or sampling and analysis.

7.8.3.2 Bark Boiler No. 1 (EU004)

Bark Boiler No. 1 is capable of producing 200,000 lb/hour of steam while firing a variety of fuels including wood materials (bark, chips, sawdust, etc.), natural gas, No. 6 fuel oil, facility generated on-specification used oil, and onsite/offsite-generated tall oil. The exhaust flue shares a common stack along with Power Boiler Nos. 1 and 2 and Bark Boiler No. 2.

Particulate matter emissions are controlled by a cyclone collector and a wet venturi scrubber. Particles collected by the cyclone collector are recirculated back to the boiler. Although some control of SO_2 emissions results from absorption onto fly ash and particle removal through the wet venturi scrubber, caustic is also added to the wet scrubbing media adjust the pH level to further control SO_2 emissions. Following the scrubber is a chevron type demister to trap and remove entrained water droplets.

Bark Boiler No. 1 is the primary control device for combusting LVHC-NCG from the Pulping System (EU 046). The LVHC-NCG are collected and routed through the spray nozzle-type TRS pre-scrubber prior to this boiler for destruction. As previously described, Power Boiler No. 1 is used as the backup control system for the Pulping System (EU 046).

Over the last five years, SO_2 emissions have averaged about 178 tons/year. Since the annual average No. fuel oil firing rate has been less than 1000 gallons per year, most of the SO_2 emissions are likely from combusting LVHC-NCG from the Pulping System (EU 046). For the similarly sized Power Boiler No. 1, total capital investment of more than $7 million to install a new wet scrubber ($13,547/ton) or dry sorbent injection ($21,700/ton) and the accompanying operating costs even at twice the emissions reductions are not cost effective for this regional haze analysis. However, the Foley Mill did propose operational changes to the existing wet scrubber to increase caustic to the existing wet scrubber to maintain the pH level as an available and feasible control.

7.8.3.2.1 Estimated Costs of Compliance

Increasing caustic to the wet scrubber to maintain the pH level at 8.0 for SO_2 control also requires addition of an antiscalant to minimize fouling and scaling due to caustic buildup in the boiler. The Foley Mill used current caustic and antiscalant costs with the molar ratio of sodium hydroxide to SO_2 emissions to estimate the costs. The achievable control efficiency for this change was estimated to be approximately 51% reduction from the average SO_2 emissions of 188 tons/year (2017 – 2019).

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.

This operational change results in an estimated annualized cost effectiveness of $2627/ton to remove 96 tons/year and is cost effective for this regional haze analysis.

7.8.3.2.2 Time Necessary for Compliance

The Foley Mill currently adds weak wash to the existing wet scrubber media as an SO_2 control measure under a Title V Compliance Assurance Monitoring Plan. The proposed reduction in fuel sulfur could be implemented for all future purchases.

7.8.3.2.3 Energy and Non-Air Quality Impacts of Compliance

The existing wet scrubber would continue to operate in the same general manner without any significant energy or non-air quality impacts for implementing this control measure.

7.8.3.2.4 Remaining Useful Life

Bark Boiler No. 1 was assumed to have a remaining useful life of 30 years or more.

7.8.3.2.5 Summary of Findings for Bark Boiler No. 1

The Regional Haze air construction permit requires the:

- Bark Boiler No. 1 shall fire only wood materials and natural gas except for periods of natural gas curtailment, pipeline disruptions, or physical mill problems that otherwise prevent the firing of natural gas in this unit. When necessary, liquid fuels from the common tank may be fired during these exceptional periods.
- For future additions of No. 6 fuel oil and tall oil to the common tank, the maximum sulfur content shall be 1.02% by weight with compliance determined by maintaining records of fuel delivery receipts and/or sampling and analysis.
- Wet Venturi Scrubber. Prior to combustion in Bark Boiler No. 1, LVHC-NCG shall be directed through the TRS pre-scrubber. At all times that LVHC-NCG or No. 6 fuel oil is fired, caustic or weak wash shall be added to the wet venturi scrubbing media to maintain a pH level of at least 8.0 (3-hour block average) and a wet scrubber flow rate of 1000 gpm (3-hour block average) for the control of SO_2 emissions. The permit specifies the parametric monitoring frequency and requirements.

7.8.3.3 Bark Boiler No. 2 (EU-019)

Bark Boiler No. 2 is capable of producing 395,000 lb/hour of steam and fires a variety of wood materials (bark, chips, sawdust, etc.) natural gas, No. 6 fuel oil, facility-generated on-specification used oil, and onsite/offsite-generated tall oil. Flue gases are split into two streams. One stream flows through the economizer, wet venturi scrubber, demister and then out the stack. The other stream bypasses the economizer and goes directly to a cyclone collector and second wet venturi scrubber. Both scrubbers utilize water as the scrubbing media. Collected particulate is re-injected into the boiler. The bark boiler commenced operation in 1954.

From 2017 through 2021, the Foley Mill fired primarily natural gas along with wood materials, which maintained SO_2 emissions below 5 tons/year. For SO_2 emissions below 5 tons/year, there are no add-on controls that are cost effective. Therefore, the only available and feasible options are to optimize the firing of natural gas with wood materials and reducing liquid fuel sulfur from 2.5% to 1.02% by weight. However, should the facility return to firing fuel oil, caustic could be added to the existing wet scrubbers in a cost-effective manner.

7.8.3.3.1 Estimated Costs of Compliance

Bark Boiler No. 1 has not fired substantial amounts of No. 6 oil since 2016, when the unit began firing natural gas.

7.8.3.3.2 Time Necessary for Compliance

The Foley Mill could optimize the firing of natural gas with wood materials could be implemented immediately. The proposed reduction in fuel sulfur could be implemented for all future purchases. Should the facility return to firing significant amounts of fuel oil, the Foley

Mill would only need to purchase the additional caustic and other chemicals necessary to further control SO_2 emissions.

7.8.3.3.3 Energy and Non-Air Quality Impacts of Compliance

There would be no adverse energy or non-air quality impacts for implementing these control measures.

7.8.3.3.4 Remaining Useful Life

Bark Boiler No. 2 is assumed to have a remaining useful life of 30 years or more.

7.8.3.3.5 Summary of Findings for Bark Boiler No. 2

The Regional Haze air construction permit requires the following:

- Bark Boiler No. 2 shall fire only wood materials and natural gas except for periods of natural gas curtailment, pipeline disruptions, or physical mill problems that otherwise prevent the firing of natural gas in this unit. When necessary, liquid fuels from the common tank may be fired during these exceptional periods.
- For future additions of No. 6 fuel oil and tall oil to the common tank, the maximum sulfur content shall be 1.02% by weight with compliance determined by maintaining records of fuel delivery receipts and/or sampling and analysis.

7.8.3.4 Recovery Furnaces Nos. 2, 3, and 4 (EU006, EU007, EU011)

Recovery Furnace No. 2 is a low-odor, non-direct contact evaporator unit that produces a nominal 380,000 lb/hour of steam by firing black liquor. The furnace was originally constructed by Babcock & Wilcox in 1957 as a direct-contact evaporator design recovery furnace and later modified. Particulate matter emissions are controlled by an electrostatic precipitator. The exhaust stack is equipped with a CEMS to continuously monitor CO, NOx, SO_2 and TRS. Opacity is continuously monitored by a COMS.

Recovery Furnace No. 3 is a low-odor non-direct contact evaporator unit that produces approximately 325,000 lb/hour of steam by firing black liquor. The furnace was originally constructed by Combustion Engineering in 1964 as a direct-contact evaporator design recovery furnace. Particulate matter emissions are controlled by an electrostatic precipitator. The exhaust stack is equipped with a CEMS to continuously monitor CO, NOx, SO_2 and TRS. Opacity is continuously monitored by a COMS.

Recovery Furnace No. 4 is a low-odor non-direct contact evaporator unit that produces approximately 450,000 lb/hour of steam by firing black liquor. The furnace was originally constructed by Babcock & Wilcox in 1973 with a membrane wall construction to minimize air in-leakage. Particulate matter emissions are controlled by an electrostatic precipitator. The exhaust stack is equipped with a CEMS to continuously monitor SO_2 and TRS. Opacity is continuously monitored by a COMS.

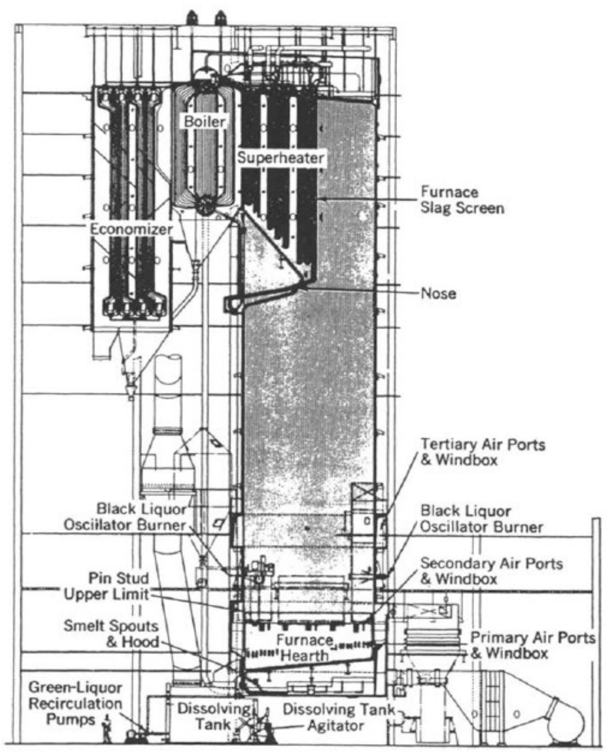
In addition to black liquor with a solids content of approximately 70%, each boiler is authorized to fire the following fuels for startup, shutdown, and as a supplemental fuel to maintain flame stability in the furnace.

- No. 6 fuel oil with a maximum sulfur content of 2.5% by weight;

- Onsite or offsite-generated tall oil with a maximum sulfur content of 2.5% by weight;
- On-specification used oil that meets the applicable requirements of 40 CFR 279;
- Natural gas; and
- Ultra-low sulfur distillate oil.

Recovery furnaces fire black liquor, which contains lignin (solids) from previously processed wood. This process recovers inorganic chemicals as smelt (sodium carbonate and sodium sulfide), combusts the organic chemicals so they are not discharged as pollutants, and recovers the heat of combustion in the form of steam. Particles captured in the furnace exhaust by the electrostatic precipitator also contain sodium carbonate and sodium sulfide and are returned to the recovery furnace. The chemicals recovered in the smelt are dissolved in water to make green liquor which is typically reacted with lime to regenerate white liquor. White liquor is used in the pulping process to separate lignin and hemicellulose from the cellulose fiber in wood chips for the production of pulp. Inefficient recovery furnaces require the purchase of raw materials to make up for the lost chemicals.

Sulfur dioxide forms during combustion when some of the sulfur in the black liquor is oxidized. High bed temperatures cause sodium fuming which retains sulfur in the bed. A higher solids content and firing rate of black liquor generates higher bed temperatures. A higher solids content can be achieved by increasing capacity of evaporator equipment. Proper air distribution will also drive sulfur to the smelt reducing SO_2 emissions. Fuels containing sulfur may also generate SO_2 emissions.



Although modern recovery furnaces operate with a black liquor solids content of 75% or more which reduces the generation of SO_2 emissions, the three existing recovery furnaces were designed for a maximum solids content of only 70% solids. Modern furnaces also employ air systems that distribute air at three levels to ensure sulfur is driven to the smelt and not released in the fume. The existing units at the Foley Mill do not have this air distribution system.

In 2017, the Foley Mill installed the No. 5 black liquor evaporator designed to produce 70% solids and match requirements of the existing recovery furnaces. Increasing the solids content above about 72% is not practical and results in issues with the current firing system, liquor heater system, and existing storage capacities. Also, constructed in the 1950's, increasing the firing rate and temperatures to the existing recovery furnaces can exceed the mechanical design of the lower furnace and result in premature failure of the lower furnace tubes.

Other design limitations for Recovery Furnaces Nos. 2 and 3 are the “short” furnace design that is a common design for this vintage of direct-contact furnaces, despite the modifications to non-direct contact evaporator units. A short furnace design results in a low residence time over the nose arch of the furnace. This means that there is less contact time with sodium fumes that capture the sulfur in the lower furnace. As the black liquor rate and bed temperature increases, carryover will plug the furnace reducing the capability to sustain operation at a given rate and increasing SO_2 emissions.

The Department requested the Foley Mill to considering improving operational characteristics that may, on their own or in combination, help reduce SO_2 emissions and increase recovery efficiency such as boiler design, increasing the solids content for black liquor to increase the bed temperature, sulfidity (sulfur-to-sodium ratio), air distribution and stack oxygen content, etc. Typically, SO_2 emissions from recovery furnaces are minimized by equipment design and operational considerations.

Essentially, the Foley Mill ruled out such changes concluding that the existing recovery furnaces are physically limited by the inherent “short” furnace design, original metals used from the 1950’s , designed metal thickness, etc. For example, attempting to increase the narrow nose arch could increase the exhaust retention time but also cause more fouling. More fouling requires more shutdowns to conduct washes which add thermal stress cycles to the unit. For recovery furnaces, safety is a critical concern when considering major physical changes to such vintage units because the combination of molten smelt and large quantities of water in the heat exchanger tubes make these furnaces potentially explosive, a critical concern at all times.

Foley consider the list of common flue gas desulfurization systems: spray dryer absorbers, dry sorbent injection, and conventional wet scrubbers. Each of the recovery furnaces currently use electrostatic precipitators to control particulate matter, which is common in the industry. To be cost effective, the spray dryer absorber and dry sorbent injection systems would inject caustic materials upstream of the ESP to neutralize sulfur dioxide and remove the resulting solids formed as well as any excess caustic materials. However, this would contaminate and adversely impact the recovery process such that these systems are not considered feasible for recovery furnaces. The Foley Mill evaluated a wet scrubber installed after the ESP for each existing unit as described in a revised four-factor analysis submitted November 16, 2022 with the following changes:

- A unit-specific wet scrubber capital cost was provided by an equipment vendor for each recovery furnace that reflects its size and configuration.
- The property tax, insurance, and administrative costs were removed from the analysis.
- Capital recovery factor was updated to reflect an interest rate of 7% and a 30-year life.
- Maintenance costs were updated to reflect the most recent control cost manual guidance and confirmed with internal engineering resources.
- Material costs were updated with the most current data.

7.8.3.4.1 Estimated Costs of Compliance - Recovery Furnaces Nos. 2, 3, and 4

For each recovery furnace, the following tables summarize the total capital investment, the annualized capital and operating costs, and the cost-effectiveness in terms of dollars per ton of SO_2 removed.

Wet Scrubber

Total Capital Investment (TCI) - No. 2 Recovery Furnace

Cost Category	Cost
Total Project Cost	**$22,000,000**
Equipment	
Andrtiz SO2 Scrubber Package	$5,735,000
RO System	$900,000
Chemical Skids	$175,000
Freight	$544,800
	$7,354,800
Installation	
Demolition for Construction	$150,000
Civil Structural Scrubber Adjustment	$525,000
Mechanical Installation on RO System	$800,000
Scrubber Electrical OSBL	$1,100,000
Mechanical Installation Scrubber OSBL	$5,250,000
	$7,825,000
Balance of Plant (7%}	**$1,062,586**
Project Costs	
Engineering (10%)	$1,624,239
Project Management (5%)	$812,119
Construction Management (2.5%)	$406,060
Escalation (8%)	$1,299,391
Contingency (10%)	$1,624,239
	$5,766,047

Capital & OperatingCost Evaluation for 502 Scrubber for No. 2 Recovery Furnace

Cost Category	Value	Notes
BLS Analyzed (ton BLS/day) =	1,171	Permitted Capacity
Total Capital Investment (TCI)	$22,000,000	Andritz/GP estimate provided August 15, 2022
Capital Recovery		
Capital Recovery Factor (CRF)	0.0806	CRF = 7% interest and 30-yr equipment life
Capital Recovery Cost {CRC}	*$1,772,901*	*CRC= TC/ x CRF*
Operating Costs		
Direct Operating Costs (DOC)		
Operating Labor	$15,306	A= Based on 0.5 hour per shift, 3 shifts per day
Supervisory Labor	$2,296	B = 15% of operating labor
Maintenance Costs	$330,000	C = Based 0.015 TCI, per May 2021FGD control cost manual
Caustic Costst	$1,201,657	E = Mass of NaOH to neutralize 502 times chemical cost plus 10% waste (based on example in July 2020 Draft Section 5 Control Cost Manual)
Sulfuric Acid Costs (for Neutralization)	$265,339	E = Mass of H2504to neutralize NaOH times chemical cost plus 10% waste
Electricity Usage	1,033 kWh	Power (kWh) ratioed based on AFPA values.
Cost of Electricity Usage	$766,504	F = E x Electricity Cost
Fresh Water	$38,334	G= Freshwater use • water cost
Water Disposal	$3,139	H = Water disposal amount• disposal cost
Total Direct Operating Costs (DOC)	*$2,622,575*	*DOC=A + B+ C+ D +E+ F+ G+H*
Indirect Operating Costs {IOC)		
Overhead	$208,561	H = 60% x (A+ B + C+ D)
Property Tax		I= 1%xTCI
Insurance		J= 1% xTCI
Administrative Charges		K=2%xTCI
Total Indirect Operating Costs (JOC)	*$208,561*	*IOC= H+ /+J+ K*
Total Annualized Cost (AC)=	$4,604,037	*AC= CRC+ DOC+ IOC*
50_2 Uncontrolled Emissions (tpy)	657.59	
50_2 Removed (tpy)	591.83	90% Removal Efficiency
Cost per ton of 502 Removed ($/ton)	$7,779	$/ton= AC/ Pollutant Removed

• U.S. EPA OAQPS, EPA Air Pollution Control Cost Manual Draft, July 2020, Section 5 50_2 and Acid Gas Controls.

t Caustic costs are highly variable in the current market. The basis of the value shown is the actual average cost for the Foley Mill for the 12-month period ending October 2022. Duringthis timeframe, the monthly values have varied from $460/ton to $920/ton.

Total Capital Investment (TCI} - No. 3 Recovery Furnace

Cost Category	Cost
Total Project Cost	**$20,500,000**
Equipment	
Andrtiz SO2 Scrubber Package	$4,998,000
RO System	$900,000
Chemical Skids	$175,000
Freight	$485,840
	$6,558,840
Installation	
Demolition for Construction	$150,000
Civil Structural Scrubber Adjustment	$505,200
Mechanical Installation on RO System	$800,000
Scrubber Electrical OSBL	$1,100,000
Mechanical Installation Scrubber OSBL	$5,052,000
	$7,607,200
Balance of Plant (7%}	**$991,623**
Project Costs	
Engineering (10%)	$1,515,766
Project Management (5%)	$757,883
Construction Management (2.5%)	$378,942
Escalation (8%)	$1,212,613
Contingency (10%)	$1,515,766
	$5,380,970

Capital & Operating Cost Evaluation for S02 Scrubber for No. 3 Recovery Furnace

Cost Category	Value	Notes
BLS Analyzed (ton BLS/day) =	988	Permitted Capacity
Total Capital Investment (TCI)	$20,500,000	Andritz/GP estimate provided August 15, 2022
Capital Recovery		
Capital Recovery Factor (CRF)	0.0806	CRF = 7% interest and 30-yr equipment life
Capitol Recovery Cost {CRC)	***$1,652,021***	*CRC= TC/ x CRF*
Operating Costs		
Direct Operating Costs (DOC)		
Operating Labor	$15,306	A= Based on 0.5 hour per shift, 3 shifts per day
Supervisory Labor	$2,296	B = 15%*of* operating labor
Maintenance Costs	$307,500	C = Based 0.015 TCI, per May 2021FGD control cost manual
Caustic Costst	$2,131,633	E= Mass of NaOH to neutralize S02 times chemical cost plus 10% waste (based on example in July 2020 Draft Section 5 Control Cost Manual)
Sulfuric Acid Costs (for Neutralization)	$470,687	E= Mass of H2504 to neutralize NaOH times chemical cost plus 10% waste
Electricity Usage	871 kWh	Power (kWh) ratioed based on AFPA values.
Cost of Electricity Usage	$646,738	F= E x Electricity Cost
Fresh Water	$32,344	G= Freshwater use • water cost
Water Disposal	$2,648	H = Water disposal amount• disposal cost
Toto/ Direct Operating Costs /DOC)	*$3,609,153*	*DOC=A + B+ C+D +E+ F+ G+ H*
Indirect Operating Costs /JOC)		
Overhead	$195,061	H = 60% x (A+ B + C+ D)
Property Tax		I= 1%xTCI
Insurance		J = 1% xTCI
Administrative Charges		K= 2% xTCI
Toto/ Indirect Operating Costs (JDC)	*$195,061*	*JDC= H+ /+J+ K*
Total Annualized Cost (AC) =	$5,456,235	*AC= CRC+ DOC+ /DC*
50_2 Uncontrolled Emissions (tpy)	1,167	
$S0_2$ Removed (tpy)	1,050	90% Removal Efficiency
Cost per ton of S02 Removed ($/ton)	$5,197	$/ton= AC/ Pollutant Removed

• U.S. EPA OAQPS, EPA Air Pollution Control Cost Manual Draft, July 2020, Section S 50_2 and Acid Gas Controls.

t Caustic costs are highly variable in the current market. The basis of the value shown is the actual average cost for the Foley Mill for the 12-month period ending October 2022. Duringthistimeframe, the monthly values have varied from $460/ton to $920/ton.

Total Capital Investment (TCI) - No. 4 Recovery Furnace

Cost Category	Cost
Total Project Cost	**$21,800,000**
Equipment	
Andrtiz 502 Scrubber Package	$5,614,000
RO System	$900,000
Chemical Skids	$175,000
Freight	$535,120
	$7,224,120
Installation	
Demolition for Construction	$150,000
Civil Structural Scrubber Adjustment	$521,800
Mechanical Installation on RO System	$800,000
Scrubber Electrical OSBL	$1,100,000
Mechanical Installation Scrubber OSBL	$5,218,000
	$7,789,800
Balance of Plant (7%)	**$1,050,974**
Project Costs	
Engineering (10%)	$1,606,489
Project Management (5%)	$803,245
Construction Management (2.5%)	$401,622
Escalation (8%)	$1,285,192
Contingency (10%)	$1,606,489
	$5,703,038

Capital & Operating Cost Evaluation for SO2 Scrubber for No. 4 Recovery Furnace

Cost Category	Value	Notes
BLS Analyzed (ton BLS/day) =	1,606	Permitted Capacity
Total Capital Investment (TCI)	$21,800,000	Andritz/GP estimate provided August 15, 2022
Capital Recovery		
Capital Recovery Factor (CRF)	0.0806	CRF = 7% interest and 30-yr equipment life
Capital Recovery Cast (CRC)	*$1,756,784*	*CRC= TC/" CRF*
Operating Costs		
Direct Operating Costs(DOC)		
Operating Labor	$15,306	A= Based on 0.5 hour per shift, 3 shifts per day
Supervisory Labor	$2,296	B= 15% of operating labor
Maintenance Costs	$327,000	C= Based 0.015 TCI, per May 2021 FGD control cost manual
Caustic Costst	$1,688,129	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)
Sulfuric Acid Costs (for Neutralization)	$372,757	E= Mass of H2SO4 to neutralize NaOH times chemical cost plus 10% waste
Electricity Usage	1,416 kWh	Power (kWh) ratioed based on AFPA values.
Cost of Electricity Usage	$1,050,998	F= E x Electricity Cost
Fresh Water	$52,562	G= Freshwater use • water cost
Water Disposal	$4,304	H = Water disposal amount• disposal cost
Total Direct Operating Costs (DOC)	*$3,513,352*	*DOC=A + B+ C+ D+E+ F+ G+ H*
Indirect Operating Costs (IOC)		
Overhead	$206,761	H= 60% x (A+ B+ C+ D)
Property Tax		I= 1% xTCI
Insurance		J= 1% xTCI
Administrative Charges		K= 2%xTCI
Total Indirect Operating Costs {IOC}	*$206,761*	*IOC= H+ I+I+K*
Total Annualized Cost (AC)=	$5,476,896	*AC=CRC+ DOC+ IOC*
SO_2 Uncontrolled Emissions (tpy)	924	
SO_2 Removed (tpy)	831	90% Removal Efficiency
Cost per ton of SO2 Removed ($/ton)	$6,587	$/ton= AC/Pollutant Removed

• U.S. EPA OAQPS, EPA Air Pollution Control Cost Manual Draft, July 2020, Section 5 SO, and Acid Gas Controls.

t Caustic costs are highly variable in the current market. The basis of the value shown is the actual average cost for the Foley Mill for the 12-month period ending October 2022. During this timeframe, the monthly values have varied from $460/ton to $920/ton.

The Department is unaware of any facility with a wet scrubber installed for SO_2 control on a recovery furnace. In its Second Regional Haze Plan (2018 – 2028), the Department of Ecology State of Washington State indicated, "The cost of installing a wet scrubber is not considered cost effective for any mill as the cost effectiveness values are in excess of $27,000/ton of pollutant removed. (We note that the estimated costs are less than those included in the 2016 Ecology RACT analysis and may be lower than the true cost needed to install such a control device.)" See page O-32 in Appendix O of the plan.

Based on the estimated high capital and operating costs, the Foley Mill does not consider the installation of a wet scrubber to be cost effective. After conducting a site visit, discussing the physical constraints, and reviewing the costs, the Department agrees that this option is not cost effective for this regional haze analysis. This leaves only the use of lower sulfur fuels and good operating practices as the only available, cost-effective measures.

7.8.3.4.2 Time Necessary for Compliance - Recovery Furnace Nos. 2, 3, and 4

The use of lower sulfur fuels and good operating practices can be implemented almost immediately.

7.8.3.4.3 Energy and Non-Air Quality Impacts of Compliance - Recovery Furnaces Nos. 2, 3, and 4

There are no energy or non-air quality impacts associated with the use of lower sulfur fuels and good operating practices.

7.8.3.4.4 Remaining Useful Life - Recovery Furnaces Nos. 2, 3, and 4

The analysis assumed a remaining useful life of at least 30 years for the recovery furnaces.

7.8.3.4.5 Summary of Findings - Recovery Furnaces Nos. 2, 3, and 4

The Foley Mill proposed reducing the maximum content of No. 6 fuel oil from 2.5% to 1.02% by weight and establishing an SO_2 emissions cap of 3325 tons per year for Recovery Furnaces Nos. 2, 3, and 4.

The Regional Haze air construction permit requires the following:

- For future additions of No. 6 fuel oil and tall oil to the common tank, the maximum sulfur content shall be 1.02% by weight with compliance determined by maintaining records of fuel delivery receipts and/or sampling and analysis.
- The permittee shall continue to use, calibrate, maintain, and operate continuous emissions monitoring systems (CEMS) installed on each of the three recovery furnaces to measure and record SO_2 emissions. Each CEMS shall be certified to meet the quality assurance requirements of Appendix CEMS including conducting the required periodic Relative Accuracy Test Assessments (RATA). Each certified CEMS shall be used to determine the SO_2 emissions for payment of Title V annual fees.
- Combined SO_2 emissions from Recovery Furnace Nos. 2, 3 and 4 are capped at 3,200.0 tons per consecutive 12 months from 2024 through 2025. The cap decreases to 3000.0 tons per consecutive 12 months from 2026 through 2027. The cap decreases again to 2800.0 tons per consecutive 12 months beginning in 2028. Besides being representative of more recent SO_2 emissions, these graduated emissions caps allow time for the Foley Mill to develop improved operating techniques that improved chemical recovery while minimizing emissions.
- The permittee shall have an engineering study conducted by an independent professional engineer to evaluate the following parameters for each recovery furnace: liquor sulfidity, liquor solids content, bed temperature, stack oxygen content, furnace load, auxiliary fuel use, sodium salt fume in the upper furnace, furnace design, and SO_2 emissions. The study shall collect parametric operating data for at least 400 hours on each recovery furnace. Based on an analysis of the data collected, the study shall determine which parameters, and which combination of parameters, have the biggest impact on SO_2 emissions. The study shall recommend a set of parameters and appropriate operating ranges to minimize SO_2 emissions.

REGIONAL HAZE RULE FOUR-FACTOR ANALYSIS FOR THE WESTROCK PANAMA CITY MILL

OCTOBER 2020

DRAFT

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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.

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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.

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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.

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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**

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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

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Table 2-1
Control Technology Summary

Pollutant	Controls on Industrial Boilers
SO_2	Low-sulfur fuels Wet scrubbers Dry scrubbing systems

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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.

<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 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

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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.

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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.

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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.

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Dry Scrubbing

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

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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.

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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.

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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.

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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.

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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)

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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

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. 4 Combination Boiler is equipped with a venturi scrubber.

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<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

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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%.

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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

<ins>Wet Scrubbers</ins>

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

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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

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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)

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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.

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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.

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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.

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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.

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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

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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.

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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.

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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.

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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.

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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.

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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.

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Table 5-1
Control Technology Summary

Pollutant	Controls on Recovery Boilers
SO_2	Good operating practices Low-sulfur fuel for startup Wet scrubber

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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.

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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.

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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.

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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

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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.

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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

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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.

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APPENDIX A -
CONTROL COST ESTIMATES

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NO. 3 COMBINATION BOILER CONTROL COST ESTIMATES

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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.

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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).

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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

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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**	

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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.

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NO. 4 COMBINATION BOILER CONTROL COST ESTIMATES

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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.

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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).

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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

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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]	
Waste Disposal Cost	Q	$/ton		
Aux Power Cost	R	$/kWh		
Makeup Water Cost	S	$/kgal		
Operating Labor Rate	T	$/hr		

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**	

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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.

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NO. 1 RECOVERY BOILER
CONTROL COST ESTIMATES

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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.

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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	[redacted]	[redacted]	*-$925,733*
	No. 6 fuel oil cost savings	[redacted]	[redacted]	*-$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.

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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

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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] [d]	$15,686
(b)	Supervisor	15% of operator labor		$2,353
	Maintenance			
(b)	Maintenance labor[c]	[redacted]	[redacted] [d]	$18,971
(b)	Maintenance materials	100% of maintenance labor		$18,971
	Utilities			
	Electricity	[redacted]	[redacted] [d]	$866,263
	Chemicals	[redacted]	[redacted] [d]	$1,362,332
	Fresh water usage	[redacted]	[redacted]	$28,888
	Wastewater disposal	[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.

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NO. 2 RECOVERY BOILER
CONTROL COST ESTIMATES

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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.

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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			*-$1,203,453*
	No. 6 fuel oil cost savings			*-$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.

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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

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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] [d]	$15,686
(b)	Supervisor	15% of operator labor		$2,353
	Maintenance			
(b)	Maintenance labor[c]	[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***

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[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

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IPM Model – Updates to Cost and Performance for APC Technologies

SDA FGD Cost Development Methodology

Final

January 2017

Project 13527-001

Eastern Research Group, Inc.

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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.

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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

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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

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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.

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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

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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**	

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AF&P A®

Emission Control Study – Technology Cost Estimates

American Forest & Paper Association
Washington, D.C.

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

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1. Results

See “AF&PA Emission Control Summary Sheet” Excel Spreadsheet

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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:

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- ✓ 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.

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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

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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

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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

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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

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- ✓ 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

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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

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- ✓ 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

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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.

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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

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- ✓ 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.

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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

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- ✓ 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.

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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

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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

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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

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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

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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

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- ✓ 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.

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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

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- ✓ 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

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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

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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

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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

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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

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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

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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

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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.

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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

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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

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- ✓ 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

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- ✓ Power usage factor: 70%
- ✓ Workhours: 3 hours per day
- ✓ Testing: $5,000 per year
- ✓ Water: 90 gpm
- ✓ Wastewater: 28 gpm
- ✓ Incremental waste disposal: 1,576 tpy of carbon and lime

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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

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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

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- ✓ 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.

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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

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- ✓ 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

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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.

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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.

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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

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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

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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

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- ✓ 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.

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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.

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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

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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

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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

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- ✓ 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

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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

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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

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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

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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

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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

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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

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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

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- ✓ 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.)

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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.)

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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

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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

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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

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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

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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.

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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)

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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%

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- ✓ Workhours: 2.25 hours per day
- ✓ Testing: $5,000 per year
- ✓ Water: 202gpm
- ✓ Wastewater: 49 gpm
- ✓ Steam: (18,851 lb/hr) (This is projected amount of steam to be recovered and assumes that the heat recovery would be 20% of that for a comparable TMP plant.)

15.8. Mechanical Pulping – Atmospheric Groundwood

15.8.1. Description

Collection and incineration of the NCGs from a atmospheric groundwood system. The system was sized for a 500 ADTPD mechanical pulp mill. The estimated emission was 20,000 ACFM.

15.8.2. Major Equipment

- ✓ Hoods
- ✓ Duct work
- ✓ Combustion blower
- ✓ Thermal oxidizer

15.8.3. Basis for Estimate

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

15.8.4. Capital Cost Estimate Assumptions

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

15.8.5. Operating Cost Estimate Assumptions

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

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- ✓ Testing: $5,000 per year
- ✓ Water: 10gpm
- ✓ Wastewater: 10 gpm

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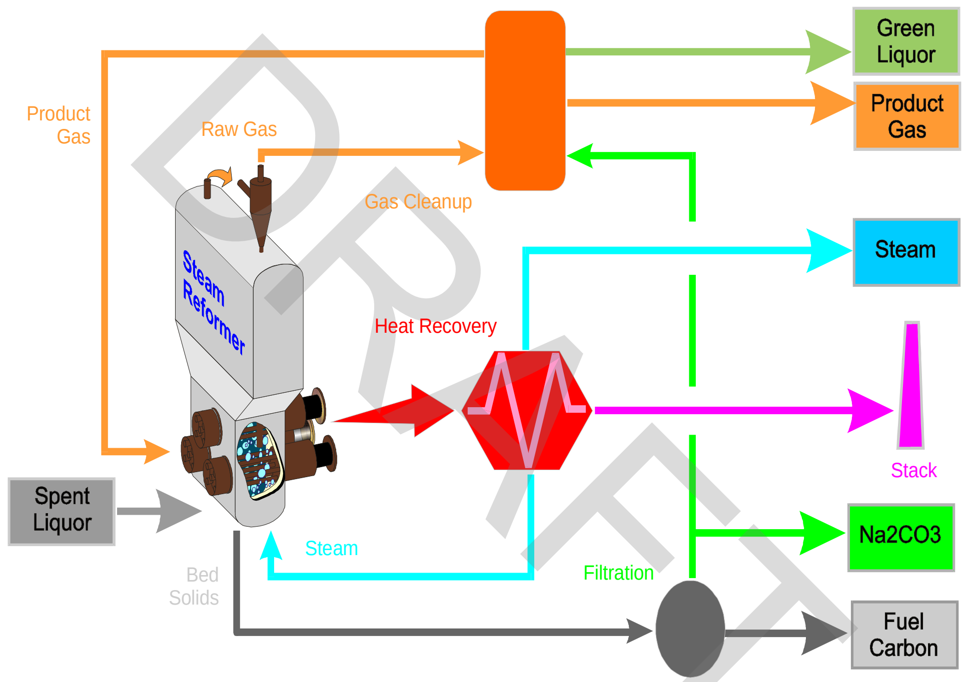
16. Gasification

16.1. Description of Technology

For this study, chemical recovery via gasification is based on the PulseEnhanced™ Steam Reformation technology developed by MTCI/ThermoChem, which is designed to process spent liquor and recover its chemical and energy value. A simplified diagram of the technology is shown below.

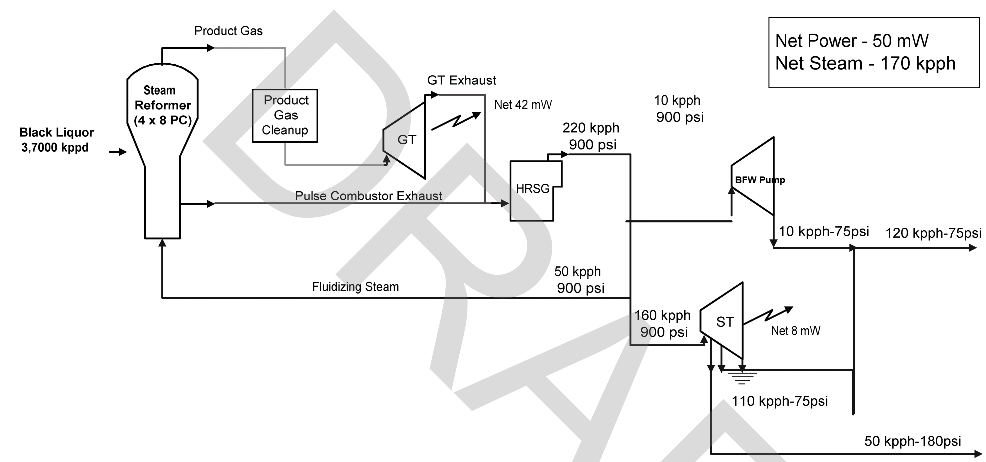


The recovery of chemicals and energy from spent liquor is effected by an indirectly heated steam-reforming process which results in the generation of a hydrogen-rich, medium-Btu product gas and bed solids, a dry alkali, which flow from the bottom of the reformer. Neither direct combustion nor alkali salt smelt formation occurs in this steam-reforming process.

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

The product gas is cleaned, compressed, and then sent to the pulse heaters to provide the indirect heat in the reformer and to a combustion turbine to produce electricity. The combustion turbine exhaust is combined with the pulse heater exhaust and then sent to a heat recovery steam generator. The resulting high-pressure steam is then sent to an extraction/condensing steam turbine where addition electricity is produced and lower pressure steam is made available to the mill. A process flow diagram showing the complete system is shown on the following page.

AF&PA/BE&K **Black Liquor Gasification Combined Cycle System Block Flow diagram** **Project 12104 23 June, 2001**



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The scope developed assumes that the mill can supply concentrated black liquor (80% solids). Since the costs for doing this can vary widely between mills and modern recovery boilers would require a similar concentration, these costs have been omitted from this study.

We recognize that the steam produced by this system is probably not sufficient for a typical Kraft mill. The additional steam requirements will either need to be provided by a biomass gasifier or boiler or a power boiler. These additional systems offer the opportunity for further power generation as well as steam production. This too is site specific and not included in this study.

16.2. Major Equipment

The major subsystems include liquor injection, steam reformer, gas cleanup, combustion turbine, heat recovery and steam generation, steam turbine, bed solids dissolution, sodium carbonate solution filter, and bed solids storage.

16.2.1. Black Liquor Supply and Steam Reformer

High solids black liquor is supplied to the reformer via a recirculation line feeding multiple steam jacketed injectors. Four reformers each containing 8-pulse heaters are required for this size plant. Each steam reformer is a carbon steel; fabricated vessel lined with refractory. The upper region of the vessel is expanded to reduce gas velocity, permitting entrained particles to disengage and fall back to the fluid bed. Internal stainless cyclones, mounted from the roof of the reformer, provide primary dust collection and a second set of external cyclones further captures fines. The reformer is fluidized with superheated steam using stainless fluidizer headers that are located just above the refractory floor. Bed drains penetrate the refractory floor for removal of bed solids via lock hoppers during normal operation.

Pulsed jet heater modules (fired heat exchangers) are used to indirectly heat the reformer. Pulsed heater modules are cantilever-mounted in the reformer utilizing a flange located on the front of the vessel. Each module extends through the reformer with it resonance tubes in contact with the fluid bed particles inside the vessel.

16.2.2. Product Gas Cleanup

Cyclone-cleaned product gas exits the reformer and enters a product gas heat recovery steam generator (HRSG) which cools the gas prior to entering a venturi separator, which further cools the gas and washes out any solids carryover. A packed gas cooler follows the venturi separator. Once the gas is cooled, it enters the H2S absorber (green liquor column). The absorber is a carbon steel cylinder with two packed stages.

16.2.3. Product Gas Combustion

The clean/cool product gas is sent to the pulse heaters and to a compressor, which then feeds a combustion turbine. The CT generates 50mW of net power.

16.2.4. Heat Recovery and Steam Generation

Steam is generated in both the product gas HRSG and the waste heat boiler. The product gas HRSG consists of a vertical shell and tube generating section and an external steam drum. The product gas HRSG also serves as a source of cooling water for the pulsed heaters.

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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.

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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

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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

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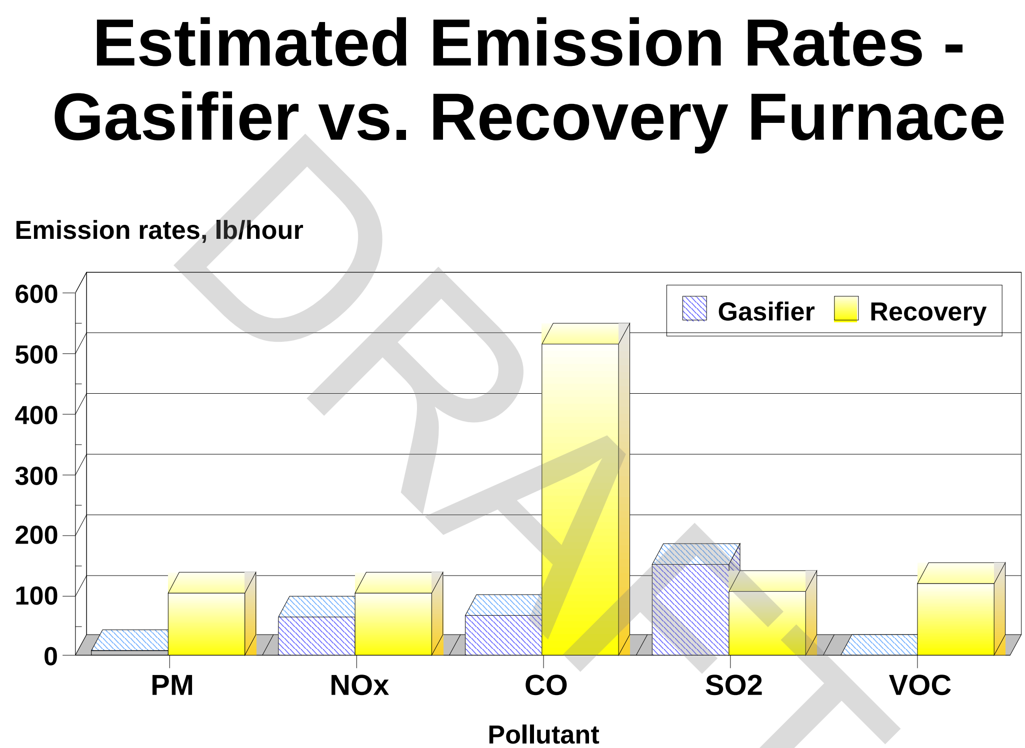
Additionally for carbon dioxide the black liquor gasification emission rate is estimated to be 240,400 lb/hr for a 4 Mm lb BLS/day unit, while a comparable Tomilson unit would discharge 318,600 lb/hour.

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.

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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**	

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- ✓ 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.

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- ✓ The steam and compressed air usage was calculated by multiplying the usage per feed rate x feed rate per day x 350 dy/yr.
- ✓ The estimated cost for process water was $0.58 per thousand gallons.
- ✓ The estimated cost for wastewater treatment was $0.41 per thousand gallons.
- ✓ The estimated cost for caustic soda was $0.17 per lb.
- ✓ The estimated cost for urea was $225 per ton
- ✓ The estimated cost for activated carbon is $0.58 per lb
- ✓ The estimated cost for pebble lime is $56.50 per ton
- ✓ The differential price between No. 2 and No. 6 fuel oil is $0.84 per Mmbtu (assumes a cost of $4.32 /Mmbtu for No. 6 fuel oil and $5.16 / MmBtu for No. 2 fuel oil)
- ✓ The energy usage was first calculated in kWh/year and is based upon the estimated connected kilowatts x 24/hr/day times 350 days times usage factor (typically 70 to 80%).
- ✓ The price of electricity was assumed to $0.05/kwhr and was multiplied by the kWh/year.
- ✓ The price of steam was assumed to be $0.00500 per lb of steam and was multiplied by the steam usage in lb/hr per year. For any recovered steam, a recovered steam factor times the price of steam was used to determine the value of the steam.
- ✓ The price of compressed air was assume to be $0.00010 per cfm and was multiplied by the compressed air usage in cfm/year.
- ✓ The utilities category totals the costs for compressed air, water, wastewater, steam, and solid waste disposal.
- ✓ The price of natural gas was assumed to be $4.00 per Mmbtu.
- ✓ The landfill cost for hauling and disposal was assumed to be $25 per ton of solid waste.
- ✓ An annual testing cost of $5,000 was assumed for each technology applied and was assumed constant independent of the size of the facility.
- ✓ The workhours were reported in $ /year based upon hours / day x 350 operating days/year x the hourly rate. <u>The hourly rate was obtained from AF&PA Labor</u>

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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.

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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:

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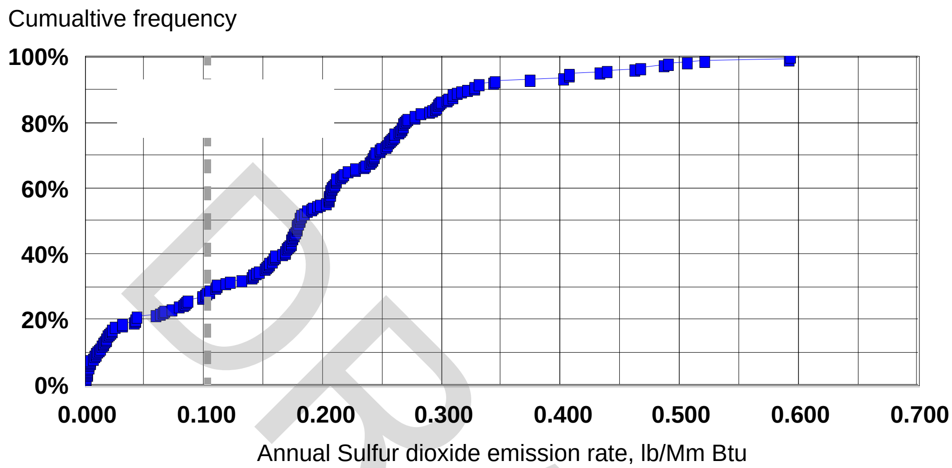
Recovery Furnace SO2 Emission Distribution



Basis: 1995 NCASI emission data base
Good technology limit is based upon 30-day average time 0.8

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- ✓ For recovery furnaces with up to four-times the adjusted SO_2 limit (i.e., 0.3628 lb/Mm Btu), combustion control modifications (**these are the same as what was estimated for good controls for NO_x**) would be implemented. For recovery furnaces with SO_2 limits greater than 0.3628 lb/Mm Btu, a new scrubber would be installed. In either case, the controlled emission rate would be equivalent to an annual average of 40 ppm (i.e., 50 ppm x 80%).
- ✓ If no emissions were indicated for 1995, then no treatment estimate was made for the furnace.
- ✓ For both technologies, if a given furnace did not meet the adjusted limit, then its emission rate was assumed to average the adjusted limit. The adjustment of 80% represents a compliance safety margin.

17.3.4. PM Control Technology

- ✓ Any recovery furnace ESP built or rebuilt after 1990 but before 1998 was assumed capable of meeting the good PM technology limit.

- ✓ Any recovery furnace ESP built after 1990 but before 1998 will be upgraded with additional fields for best PM technology limits.
- ✓ Any NDCE recovery furnace ESP built or rebuilt before 1980 will be upgraded with additional field for the good PM technology limit and be replaced for the best PM technology limit.
- ✓ Any NDCE recovery furnace ESP built or rebuilt after 1980 will meet the good technology limits.
- ✓ Any non-NDCE recovery furnace ESP or scrubber built before 1990 will be replaced with a new ESP for either good or best PM technology.
- ✓ Any recovery furnace ESP built or rebuilt after 1998 was assumed to comply with the best PM technology limit.

17.3.5. VOC Control Technology

- ✓ Good VOC technology limit consists of collecting and incinerating the BLO vent gas from any non-NDCE recovery furnace.
- ✓ Best VOC technology consists of converting any NDCE recovery furnace ESPs from wet to dry bottom and converting any non-NDCE to a NDCE recovery furnace

17.3.6. Smelt Dissolving Tank Scrubber - PM Technology

- ✓ Number of smelt dissolving tank was determined based upon the manufacturer. Combustion Engineering furnaces with greater than a 3.5 Mm lb BLS/ day firing rates are assumed to have two smelt dissolving tanks and the other manufacturer's have one smelt dissolving tank. For the case of the two smelt dissolving tank scrubbers, the initial scrubber was factored based on half the black liquor-firing rate and then multiplied by two.
- ✓ Any recovery furnace built before 1976 will require a new smelt dissolving tank scrubber.
- ✓ Any recovery furnace built or rebuilt after 1976 but before 1990 was assumed to meet the good PM technology limit
- ✓ Any recovery furnace built or rebuilt after 1990 was assumed to meet the best PM technology limit

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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,

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- ✓ The fuel usage for each boiler from the NCASI database was multiplied by the following heating values:

Coal	25,000	MmBtu/1000 ton
Residual Oil (No.6)	5,920	MmBtu/1000 bbl
Distillate Oil (No.2)	5,376	MmBtu/1000 bbl
Natural gas	950	MmBtu/MmCF
Wood	9,000	MmBtu/1000 ton
Sludge	10,000	MmBtu/1000 ton

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- ✓ 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).

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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.

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- ✓ 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.

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- ✓ 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).

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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.

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- ✓ 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.

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18. Appendix

18.1. MEANS and BE&K Labor Rate Factors by State

The following presents the state factors for the RS Means Open Shop Building Construction Cost Data 17th edition location factors for materials and subcontracting (or total) and the BE&K construction labor factors:

	Materials Factor	Subcontracting Factor	BE&K Construction Labor Factor
Alabama	0.967	0.823	1.000
Alaska	1.354	1.254	0.959
Arizona	0.989	0.876	0.975
Arkansas	0.957	0.778	0.970
California	1.076	1.119	0.983
Colorado	1.019	0.937	0.974
Connecticut	1.028	1.054	0.979
Delaware	0.992	1.009	0.968
Florida	0.987	0.841	0.992
Georgia	0.967	0.840	0.979
Idaho	1.021	0.938	0.960
Illinois	0.970	1.041	0.997
Indiana	0.975	0.957	0.958
Iowa	0.996	0.918	0.995
Kansas	0.966	0.864	0.961
Kentucky	0.955	0.895	0.992
Louisiana	0.989	0.824	0.990
Maine	0.996	0.824	1.003
Massachusetts	0.997	1.043	0.975
Maryland	0.937	0.884	0.973

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	Materials Factor	Subcontracting Factor	BE&K Construction Labor Factor
Michigan	0.970	0.948	0.973
Minnesota	0.984	1.073	0.983
Mississippi	0.985	0.739	0.977
Missouri	0.962	0.950	0.987
Montana	0.995	0.938	0.977
Nebraska	0.978	0.828	0.962
Nevada	1.020	0.993	0.967
New Hampshire	0.983	0.913	0.982
New Jersey	1.028	1.125	0.965
New Mexico	1.006	0.912	0.972
New York	0.968	0.945	0.977
North Carolina	0.959	0.734	0.982
North Dakota	1.008	0.849	0.939
Ohio	0.967	0.944	0.954
Oklahoma	0.971	0.789	0.990
Oregon	1.044	1.060	0.967
Pennsylvania	0.975	0.982	0.982
Rhode Island	1.001	1.040	0.980
South Carolina	0.954	0.726	0.970
South Dakota	0.989	0.778	0.970
Tennessee	0.968	0.803	0.998
Texas	0.965	0.807	0.991
Utah	1.018	0.899	0.951
Vermont	1.010	0.855	0.973
Virginia	0.972	0.838	0.966
Washington	1.062	1.016	0.964
West Virginia	0.970	0.937	1.005

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	Materials Factor	Subcontracting Factor	BE&K Construction Labor Factor
Wisconsin	0.984	0.959	0.979
Wyoming	1.003	0.826	0.939

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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

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Good / Best Technology	Pollutant	Equipment	Net Downtime, days
Good	HCl	Coal Boiler	3
Best	HCl	Coal Boiler	3
Good	PM	Coal/Wood Boiler (50/50)	3
Best	PM	Coal/Wood Boiler (50/50)	3
Good	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

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Good / Best Technology	Pollutant	Equipment	Net Downtime, days
Best	NOx	Wood boiler	5
Best	Hg	Wood boiler	5
Best	CO	Wood boiler	3
Good	VOC	Paper machines	3
Best	VOC	Paper machines	3
Best	VOC	Paper machines	3
Good	VOC	Mechanical pulping	3
Best	VOC	Mechanical pulping	3
Best	Various	Recovery Furnace	NA
Best	PM	NDCE Kraft Recovery Furnace	3
Good	PM	NDCE Kraft Recovery Furnace	3
Best	PM	Lime Kilns	3
Best	PM	Coal Boiler	3
Best	PM	Coal/Wood Boiler (50/50)	3
Best	NOx	NDCE Kraft Recovery Furnace	5
Best	NOx	DCE Kraft Recovery Furnace	5
Best	VOC	Mechanical Pulp	3

DRAFT

															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		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	-

DRAFT

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	

DRAFT

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

February 28, 2023

ELECTRONIC SUBMITTAL

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

RE: **Response to February 1, 2023 Regional Haze Rule Reasonable Progress Analysis Request Letter**
Mosaic South Pierce Facility
Permit Nos. 1050055-035-AV

Dear Mr. Read:

This submittal serves as the Regional Haze Rule Reasonable Progress Analysis for the Mosaic Fertilizer, LLC (Mosaic) South Pierce facility in response to the February 1, 2023 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 February 1, 2023 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 South Pierce facility is located in South Pierce, Polk County, Florida and is currently operating under Title V Air Operation Permit No. 1050055-035-AV. The South Pierce facility is classified as a phosphate fertilizer manufacturing facility consisting of two sulfuric acid plants (SAPs). The SAPs manufacture sulfuric acid (H_2SO_4) that is then reacted with phosphate rock (P_2O_5) at nearby Mosaic phosphate fertilizer manufacturing facilities to produce phosphoric acid, which is then ammoniated and granulated to produce fertilizers and animal feed ingredients.

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 004 – Sulfuric Acid Plant No. 10
- EU 005 – Sulfuric Acid Plant No. 11

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

Regional Haze Rule Reasonable Progress Analysis Subject Emission Units

Within the SAP process at the South Pierce 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: South Pierce SAP Production Capacities & SO_2 Emission Limits

	SAP # 10 (EU 004)	SAP # 11 (EU 005)
Maximum Production Rate - TPD of 100% H_2SO_4	3,000	3,000
SO_2 Emission Limit - lb/ton of 100% H_2SO_4	4	4
SO_2 Emission Limit - lb/hr of 100% H_2SO_4	500	500
SO_2 Emission Limit - ton/year	2,190	2,190
SO_2 Emission Limit- lb/hr CAP	750[a] CAP, 24-hour block average (6:00 a.m. to 6:00 a.m.)	

[a]SO_2 CAP effective April 1, 2023 (Construction Permit No. 1050055-037-AC)

Effectively Controlled Units

Mosaic has determined that the South Pierce SAPs are 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 South Pierce SAPs 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.

Permit No. 1050055-037-AC added a voluntary SO_2 lb/hr 24-hour block average facility cap that will assist towards the goal of the Regional Haze Rule during the second implementation period, the goal of the EPA's June 12, 2015 Startup, Shutdown, and Malfunction (SSM) SIP Call, and the continued assurance of the National Ambient Air Quality Standards (NAAQS) attainment. 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 South Pierce SAPs, 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.

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 South Pierce 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
SAP # 10 (EU 004)	1050055-030-AC
	1050055-037-AC
SAP # 11 (EU 005)	1050055-026-AC & 1050055-027-AC
	1050055-036-AC

In summary, sulfur dioxide emissions from the South Pierce SAPs are effectively controlled by the 750 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.

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
Engineer Lead, Air Permitting & Compliance

enc.

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Appendix 1
Catalyst Improvement Summary

No. 10 SAP (EU 004) Catalyst Conversion Completion Date: March 2019

No. 10 SAP (EU 004) Bed	Catalyst Amount (Liters)	Manufacturer and Type
A	127,000	GR-330
B	154,000	XLP-110
C	167,000	XLP-110
D	207,000	VK-69

No. 11 SAP (EU 005) Catalyst Conversion Completion Date: December 2021

No. 11 SAP (EU 005) Bed	Catalyst Amount (Liters)	Manufacturer and Type
A	105,600	GR-330
B	96,000	GR-310
C	114,000	XLP-310
D	164,400	SCX-2000

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)	sulfur and air	1,800	T/D	Sulfur Dioxide (SO2)	This is a dual absorption plant with a 2-2 converter design. MPC will replace the vanadium catalyst with cesium catalyst in the 3rd and 4th 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)	sulfur and air	1,800	T/D	Sulfur Dioxide (SO2)	Dual absorption. Replacing vanadium catalyst with cesium catalyst in 3rd and 4th passes of the 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		1,850	T/D	Sulfur Dioxide (SO2)	DUAL ABSORPTION CATALYST	3.7	LB/T	BACT-PSD	
NC-0099	PCS PHOSPHATE	PCS PHOSPHATE	7/14/2000	SULFURIC ACID PLANT NO. 3		2,000	T/D	Sulfur Dioxide (SO2)	Double-absorption sulfuric acid plant	4	LB/T	BACT-PSD	
TX-0519	AGRIFOS SULFURIC ACID PLANT	AGRIFOS FERTILIZER	11/10/2005	H2SO4 PLANT STACK (INCLUDING MSS)				Sulfur Dioxide (SO2)		525	LB/H	BACT-PSD	