STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

SUPPLEMENT TO
FLORIDA REGIONAL HAZE PLAN FOR
THE SECOND IMPLEMENTATION PERIOD FOR
FLORIDA CLASS I AREAS

Pre-Hearing Submittal

January 19, 2024

State of Florida
Department of Environmental Protection

Supplement to Florida's Regional Haze Plan for the Second Implementation Period for Florida Class I Areas

Introduction

The Florida Department of Environmental Protection (Department) is proposing to supplement Florida's pending Regional Haze Plan and proposed State Implementation Plan (SIP) Amendment under the federal Clean Air Act (CAA). Pursuant to the requirements of CAA sections 169A and 169B, and the U.S. Environmental Protection Agency's (EPA) implementing regulations at 40 CFR 51.308, the Department has prepared this supplement to Florida's pending Regional Haze Plan and proposed SIP Amendment for EPA's approval. This proposed supplement to Florida's pending Regional Haze Plan and proposed SIP revision addresses commitments and enforceable actions that the state did not include in its submittal dated October 8, 2021. Florida's pending Regional Haze Plan and proposed SIP revision, together with this supplement, address all of the requirements of EPA's Regional Haze regulations applicable to the second implementation period, from 2019 to 2028, towards the goal of attaining natural visibility conditions in Florida's designated federal Class I areas.

SIP Submittal Package

On October 8, 2021, Florida submitted to EPA its Regional Haze Plan and associated proposed SIP revision for the second implementation period. This submittal included permits, technical analyses, and commitments addressing specific requirements of the applicable federal regulations.

This supplement to Florida's pending Regional Haze Plan and SIP revision addresses the following elements that were not included in Florida's October 8, 2021, submittal:

- A supplemental four-factor analysis for WestRock Fernandina Beach Mill, which includes an analysis of whether the use of 100% natural gas in the No. 7 Power Boiler constitutes reasonable progress (see new Section 7.8.2.5 and Appendix B-1);

- An air construction permit for WestRock Fernandina Beach (Permit No. 0890003-074-AC) to add monitoring and recordkeeping requirements on coal consumption which were not included in the permit included in Florida's 2021 submittal (see Appendix A-2); and
- A four-factor analysis for WestRock Panama City Mill (see revised Section 7.8.3 and Appendix B-3);
- An air construction permit for WestRock Panama City Mill (Permit No. 0050009-47-AC) based on the results of the four-factor analysis, which represents reasonable progress (see Appendix A-3);
- A four-factor analysis for Georgia-Pacific Foley Mill (see revised Section 7.8.4 and Appendix B-2);
- An air construction permit for Georgia-Pacific Foley Mill (Permit No. 1230001-121-AC) based on the results of the four-factor analysis, which represents reasonable progress (see Appendix A-1);
- An air construction permit for Mosaic South Pierce (Permit No 1050055-037-AC) which codifies emission limits reflective of the effective controls demonstration, which represents reasonable progress (see revised Section 7.4.1, Appendix A-7, and Appendix B-4).
- An air construction permit for JEA Northside Units 1 and 2 codifying the Mercury and Air Toxics Standards (MATS) sulfur dioxide (SO_2) limit (Permit No. 0310045-059-AC), which supplements the proposed SIP limit in Florida's 2021 submittal (see Appendix A-4).
- An administrative correction to the JEA Northside Unit 3 permit (Permit No. 0310045-062) establishing additional recordkeeping requirements for fuel oil shipments (see Appendix A-5).

Appendix ID	Description and File Names
Appendix A	**Air Construction Permits**
A-1	Georgia-Pacific Foley Mill (Permit No. 1230001-121-AC)
A-2	WestRock Fernandina Beach (Permit No. 0890003-074-AC)
A-3	WestRock Panama City Mill (Permit No. 0050009-47-AC)
A-4	JEA Northside Units 1 and 2 (Permit No. 0310045-059-AC)
A-5	JEA Northside Unit 3 permit (Permit No. 0310045-062-AC)
A-6	Nutrien White Springs (Permit No. 0470002-132-AC)
A-7	Mosaic South Pierce (Permit No 1050055-037-AC)
A-8	WestRock Fernandina Beach (Permit No. 0890003-072-AC)
Appendix B	**Four Factor Analyses**
B-1	WestRock Fernandina Beach Mill Supplemental
B-2a - 2d	Georgia-Pacific Foley Mill
B-3	WestRock Panama City Mill
B-4	Mosaic South Pierce Effectively Controlled Unit Analysis

This action completes the commitments that the Department made in Florida's proposed Regional Haze Plan for the second Implementation Period, dated October 8, 2021. This submittal is organized to reflect specific changes that the Department is making to various elements of Florida's 2021 submittal. The Department has not included in this document sections of the 2021 submittal that are complete and do not require any supplementation. The Department notes below the section headings in Florida's pending Regional Haze Plan under which the Department has added supplemental information or updates.

7.6.4 Selection of Sources for Reasonable Progress Evaluation

The Department is revising this section to remove the Department's justification for not including Mosaic South Pierce among the sources for which the Department conducted a reasonable progress evaluation. The Department subsequently determined that increases in SO_2 emissions from the Mosaic South Pierce facility since the 2011 baseline period warranted a reasonable progress analysis. Emissions were as high as 2,248 tpy in 2018, which the Department determined was due, in part to a shift in production from other regional facilities.

The significant difference between this figure and the figure that the Department used in setting the baseline (1,123 tpy) motivated the Department to include Mosaic South Pierce in its analysis. The Department is also updating this section to provide new effective controls analyses and effective controls demonstrations incorporated by permit for specified sources.

7.6.4.1 Effective Controls Analysis

The Department is revising Florida's 2021 submittal to update the section that addresses the effective controls analyses for sources in Florida for which the Department conducted a reasonable progress evaluation. Specifically, the Department is revising this section to supplement the effective controls analysis for JEA Northside Units 1 and 2 to include the facility's MATS limit, which applies at all times, including during startup and shutdown, and to include an effective controls analysis for Mosaic South Pierce. The Department has also updated information for Nutrien White Springs to include monitoring, recordkeeping, and reporting requirements applicable to that source. Note that, consistent with the Department's focus on SO_2 in the second planning period, as discussed in Section 7.4, the Department's effective controls analyses were specific to SO_2.

Mosaic South Pierce (Permit No. 1050055-037-AC) (Appendix A-7) – On February 1, 2023, the Department requested that Mosaic evaluate whether any additional measures were available to reduce SO_2 emission from the Mosaic South Pierce facility. Specifically, the Department requested that Mosaic either complete a four-factor analysis for Sulfuric Acid Plants Nos. 10 and 11 (EU 004 and 005) or demonstrate that those units were already effectively controlled. In response to the Department's request, Mosaic developed and submitted to the Department an effective control demonstration.

Sulfuric Acid Plants Nos. 10 and 11 are double absorption sulfuric acid systems equipped with two absorption towers in series to react sulfur trioxide (SO_3) with water to produce 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 (99.7% or greater), which results in relatively low SO_2 emissions as compared to a single absorption system. The second bed uses a cesium-promoted catalyst, which increases the overall SO_2-to-SO_3 conversion rate. Based on a review of EPA's

Reasonably Available Control Technology/Best Available Control Technology/Lowest Achievable Emission Rate (RACT/BACT/LAER) Clearinghouse (RBLC) database, the combination of dual absorption design and cesium-promoted catalysts represents BACT for sulfur-burning, non-single absorption column sulfuric acid plants.

The Department reviewed Mosaic's submission (Appendix B-4) and agreed that the Sulfuric Acid Plants at Mosaic South Pierce are effectively controlled and are therefore unlikely to have additional controls identified as part of a four-factor analysis. To codify these effective controls, Mosaic has accepted the following specific conditions for Sulfuric Acid Plants Nos. 10 and 11 (EU 004 and 005) in Permit No. 1050055-037-AC which the Department issued on September 22, 2022: As determined by continuous emission monitoring systems (CEMS), the combined SO_2 emissions shall not exceed 750 pounds SO_2 per hour on a 24-hour block average.

The Department has determined that the existing measures at Sulfuric Acid Plants Nos. 10 and 11 ***are necessary*** for reasonable progress and emissions limits and associated supporting conditions are required to be adopted into the SIP. The Department has already proposed that the following permit conditions from Permit No. 1050055-037-AC, issued to Mosaic South Pierce on September 22, 2022, be incorporated into Florida's SIP. The Department finds that this permitted SO_2 emissions limit represents reasonable progress for Sulfuric Acid Plants Nos. 10 and 11. These SO_2 emission limits are already approved by EPA as components in Florida's Startup, Shutdown, and Malfunction SIP. These SO_2 emission limits and associated monitoring, recordkeeping, and reporting requirements also function as a component of Florida's Regional Haze SIP. The Department has attached to this submittal Permit No. 1050055-037-AC (Appendix A-7) for informational purposes only.

Nutrien White Springs (Permit Nos. 0470002-122-AC and 0470002-132-AC) (Appendix A-6) – This facility is subject to the following conditions from Permit Nos. 0470002-122-AC and 0470002-132-AC, which the Department issued on December 21, 2018 and September 22, 2022, respectively, for Sulfuric Acid Plants Nos. "E" and "F" (EU 066 and EU 067): Sulfur dioxide (SO_2) emissions shall not exceed: 2.6 lb/ton, 3-hr rolling average (not including startup and shutdown periods) and 2.3 lb/ton, 365 day rolling average (including startup and shutdown periods). Effective January 1, 2023, the following SO_2 emission cap applies to the combined

CEMs-measured emissions from SAP E and F: 840 lb/hr on 24-hour block averaging period (6:00 a.m. to 6:00 a.m.).

The Department has determined that the existing measures at Sulfuric Acid Plants Nos. "E" and "F" ***are necessary*** for reasonable progress and emissions limits and associated supporting conditions are required to be adopted into the SIP. The Department has already proposed that the following permit conditions from Permits No. 0470002-122-AC and 0470002-132-AC, issued to Nutrien White Springs on December 21, 2018, and September 22, 2022, respectively, be incorporated into Florida's SIP. The Department finds that these permitted SO_2 limits represent reasonable progress for Sulfuric Acid Plants Nos. "E" and "F" at the Nutrien White Springs facility. The permit that the Department issued on September 22, 2022, includes detailed monitoring, recordkeeping, and reporting requirements. These SO_2 emission limits, together with the associated monitoring, recordkeeping and reporting requirements, are components of Florida's Startup, Shutdown, and Malfunction SIP as approved by EPA on August 4, 2023, at 88 Fed. Reg. 51,702. These SO_2 emission limits and associated monitoring, recordkeeping, and reporting requirements also function as a component of Florida's Regional Haze SIP. The Department has attached to this submittal Permit No. 0470002-132-AC (Appendix A-6) for informational purposes only.

JEA Northside Units 1 and 2 (Permit No. 0310045-059-AC) (Appendix A-4) – During the public comment period for the Department's 2021 submittal, one commenter noted that the proposed limits reflecting effective controls for JEA Northside Units 1 and 2 had exemptions during period of startup, shutdown, and malfunction. To ensure that the facility is subjected to SO_2 emission limits that apply continuously, JEA agreed to supplement the SO_2 emission limit of 0.15 lb/MMBtu, which Florida included in its 2021 Regional Haze submittal, with the MATS-based SO_2 emission limit of 0.20 lb/MMBtu, which applies continuously on a heat input-weighted 30-boiler operating day rolling average. The supplemental permit incorporating the MATS-based SO_2 limit includes work practice standards that apply during periods of startup and shutdown.

The Department has determined that the existing measures at the JEA Northside Units 1 and 2 ***are necessary*** for reasonable progress and emissions limits and associated supporting conditions are required to be adopted into the SIP. The Department is proposing that the following permit conditions from Permit No. 0310045-059-AC, issued to JEA Northside Units 1 and 2 on February 16, 2023, be incorporated into Florida's SIP. The Department finds that the current suite of permitted SO_2 emission limits represent reasonable progress for Units 1 and 2 at the JEA Northside facility. Florida proposes that EPA include both the existing SO_2 emission limit of 0.15 lb/MMBtu and the new MATS-based SO_2 limit as components of Florida's Regional Haze SIP. The Department has attached to this submittal Permit No. 0310045-059-AC (Appendix A-4) for informational purposes.

7.7 Evaluating the Four Statutory Factors for Specific Emissions Sources

Section 169A(g)(1) of the CAA and EPA's Regional Haze Rule at 40 CFR 51.308(f)(2)(i) require a state to evaluate the following four "statutory" factors when establishing the reasonable progress goal for any Class I area within a state: (1) cost of compliance; (2) time necessary for compliance; (3) energy and non-air quality environmental impacts of compliance; and (4) remaining useful life of any existing source subject to such requirements.

As noted in Florida's 2021 submittal, on August 20, 2019, EPA issued a memorandum entitled "Guidance on Regional Haze State Implementation Plan for the Second Implementation Period." This memorandum included guidance for characterizing the four statutory factors including which emission control measures to consider, selection of emission information for characterizing emissions-related factors, characterizing the cost of compliance, characterizing the time necessary for compliance, characterizing energy and non-air environmental impacts, characterizing remaining useful life of the source, characterizing visibility benefits, and reliance on previous analysis and previously approved approaches. The Department used this guidance evaluating the four statutory factors for facilities selected for reasonable progress analysis.

On July 8, 2021, EPA issued additional guidance for states to use in developing their Regional Haze SIPs. This guidance noted opportunities for states to leverage both ongoing and upcoming emission reductions under other CAA programs. EPA did reiterate, however, that it expected states to undertake reasonable progress analyses that identify opportunities to advance the national visibility goal consistent with the statutory and regulatory requirements. The guidance focused on factors to consider for source selection, noting that states should select sources for four-factor analysis while setting the threshold at a level that captures a meaningful portion of the state's total contribution to visibility impairment to Class I areas. EPA also discussed the process for refining existing effective controls and characterizing factors for emission control measures and reviewed what control measures were necessary to make reasonable progress. The Department used this guidance in developing this Amendment to Florida's pending Regional Haze Plan.

7.8 Control Measures Representing Reasonable Progress for Individual Sources to be Included in the Long-Term Strategy

The following summarizes the Department's process for determining reasonable progress for Florida sources and whether to implement reasonable progress controls or measures.

For Florida's 2021 submittal, the Department requested that eleven facilities in Florida complete a reasonable progress analysis. Pursuant to EPA's 2019 Regional Haze Guidance, the Department allowed these facilities either to demonstrate that units that are large sources of SO_2 (i.e., those with emissions greater than five tons per year) were already effectively controlled or to complete a four-factor analysis. Many of these facilities provided the Department an analysis demonstrating that units that were large sources of SO_2 at these facilities were effectively controlled. When necessary, these facilities applied for air construction permits to codify those controls as reasonable progress limits (these analyses are documented in Section 7.6.4.1 of Florida's 2021 submittal).

Four-factor analyses were completed for units at four facilities, consistent with EPA's Cost Control Manual and EPA's 2019 and 2021 Regional Haze guidance documents. The Department used these analyses to determine whether a given control measure was cost-effective. Florida's 2021 submittal included results of the four-factor analysis for JEA Northside and WestRock Fernandina Beach.

This proposed Amendment to Florida's pending Regional Haze Plan includes the results of an updated four-factor analyses for the No. 7 Power Boiler (EU 015) at the WestRock Fernandina Beach Mill, together with new analyses for emissions units at the Georgia-Pacific Foley Mill and the WestRock Panama City Mill. The Department has summarized each of these four-factor analyses below and included supporting documentation in Appendix B.

7.8.2 WestRock Fernandina Beach Mill Updated Four-Factor Analysis

7.8.2.5 Supplemental Analysis on No. 7 Power Boiler (EU 015)

As noted in Section 7.8.2 of the 2021 Regional Haze Plan, process changes made in 2016-2017 to facility emission units for demonstrating compliance with the 2010 1-Hour Primary SO_2 NAAQS resulted in decreased emissions. These changes were already included in the SO_2 Nassau County Attainment Plan SIP approved by EPA on 9/30/2016 (81 FR 67179). For the 2021 Regional Haze Plan, WestRock Fernandina Beach prepared four-factor analyses for each of these units. For the No. 5 Power Boiler, the Department determined that installing a wet scrubber or DSI system would not be cost-effective. Likewise, for the Nos. 4 and 5 Recovery Boilers, the Department determined that installing an FGD system would not be cost-effective. The Department has, however, determined that the existing measures at the No. 5 Power Boiler and the Nos. 4 and 5 Recovery Boilers included in the SO_2 Implementation SIP approved by EPA on 9/30/2016 (81 FR 67179) ***are necessary*** for reasonable progress, and those emissions limits and associated supporting conditions previously adopted into Florida's SIP should be incorporated into Florida's Regional Haze Plan.

During the 2021 SIP submission process, the Department received a public comment regarding the four-factor analysis for the No. 7 Power Boiler at the Westrock Fernandina Beach Mill. The commenter noted that the facility and Department had not considered whether removing all coal firing from the No.7 Power Boiler was cost-effective. The Department subsequently requested that Westrock supplement its four-factor analysis to address this issue. On June 24, 2022, The Department received a supplemental four-factor analysis from WestRock addressing this issue (Appendix B-1).

7.8.2.5.1 Estimated Costs of Compliance

Removing Coal Firing – The estimated annual cost of removing all coal firing and using natural gas (with a backup fuel source) is based on operating data, current fuel costs (which vary based on the amount of gas consumed), and projected 2028 actual emissions. WestRock estimates that there will be a total capital investment of $18,750,000 for the new ultra-low sulfur diesel (USLD) burners and required infrastructure for that backup fuel. The total annualized cost for removing all coal firing in the No. 7 Power Boiler would be $9,117,240.

WestRock's initial cost effectiveness value for removing all coal-firing at the Westrock Fernandina Beach Mill was $7,788/ton of SO_2 removed. **Table 7-32a** shows the initial WestRock cost calculation for removing all coal firing.

Table 7-32a. WestRock Fernandina Beach No. 7 Power Boiler

Initial Cost Effectiveness Analysis for Removing all Coal Firing

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	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).
(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. 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.

The Department reviewed Westrock's analysis for consistency with EPA's Cost Control Manual. In the control equipment calculations, WestRock used a 4.75% interest rate. This value is now closer to the current bank prime interest rate than the value recommended in the Cost Control Manual. WestRock assumed a 20-year equipment lifetime. This assumption may result in a slightly higher cost effectiveness value. The Department revised the cost effectiveness calculations, using the 3.25% bank prime interest rate per the Manual and assumed a 30-year equipment lifetime. **Table 7-32b** shows the revised WestRock cost calculation for removing all coal firing.

Table 7-32b. WestRock Fernandina Beach No. 7 Power Boiler

Revised Cost Effectiveness Analysis for Removing all Coal Firing

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.

Based on the revised cost information and emissions, removing all coal firing in the No. 7 Power Boiler would cost approximately $7,374 per ton of SO_2 removed. The Department determined that both values show that removing all coal firing in the No. 7 Power Boiler at the Westrock Fernandina Beach Mill is not cost effective.

7.8.2.5.2 Time Necessary for Compliance

WestRock would need a minimum of four years to remove all coal firing for the No. 7 Power Boiler. This would include securing funding for the additional fuel costs associated with natural gas supplies.

7.8.2.5.3 Energy and Non-Air Quality Impacts of Compliance

WestRock identified one energy or non-air related impact for removing all coal firing: bark ash currently fired in the boiler would be sent for disposal to a permitted landfill. Ash disposal costs at the landfill would have to be covered by the facility.

7.8.2.5.4 Remaining Useful Life

The No. 7 Power Boiler is assumed to have a remaining useful life of thirty years or more. The Department conservatively used a lifetime of thirty years to annualize costs.

7.8.2.5.5 Summary of Findings for No. 7 Power Boiler

The primary factor that the Department used to determine whether a control measure is necessary for reasonable progress was the cost of compliance. The Department then further considered the other three factors (time necessary for compliance, energy and non-air quality impacts, and remaining useful life). In some cases, the other factors are already considered in assessing the costs, such as remaining useful life through annualizing the costs of compliance, or energy and non-air quality impacts being considered among the costs, such as increased water usage or electricity usage.

The Department finds that removing all coal firing at the No. 7 Power Boiler at the Westrock Fernandina Beach Mill would not be cost-effective. Given the extent to which coal usage caps in current permits already reduce SO_2 emissions, the Department finds that eliminating coal as a fuel source is not necessary for reasonable progress.

Permit No. 0890003-072-AC, which the Department issued to Westrock on June 24, 2021, commits to a coal cap of 250 tons/day, 30-day rolling average for the No. 7 Power Boiler (EU 015), excluding days of natural gas curtailment or supply interruption. Effective April 1, 2024, this coal cap is further reduced to 125 tons/day, excluding days of natural gas curtailment or supply interruption. Florida proposes that these requirements, together with associated monitoring, reporting, and recordkeeping requirements (Permit No. 0890003-074-AC, issued on December 16, 2021, and attached to this submittal as Appendix A-2) be included as components of Florida's Regional Haze SIP. The Department has determined that the existing measures at the No. 7 Power Boiler ***are necessary*** for reasonable progress and proposes that these permit conditions from Permit No. 0890003-074-AC issued to WestRock Fernandina Beach Mill on December 16, 2021, respectively, to be incorporated into Florida's SIP.

7.8.3 Georgia-Pacific Foley Mill Four-Factor Analysis

Georgia-Pacific Cellulose/Foley Cellulose, LLC, owns and operates a softwood Kraft pulp mill (referred to as the "Foley Mill") located in Perry, Florida, which manufactures bleached market, fluff, and specialty dissolving cellulose pulp. The Foley Mill operates under a Title V Major Source Operating Permit (No. 1230001-126-AV), which the Department most recently issued on September 20, 2023. In September of 2023, Georgia-Pacific announced that the Foley Mill will be shutdown. Georgia-Pacific has stated that it will explore selling of the mill to potential investors. Because Georgia-Pacific may sell the mill to investors who may restart the facility in the future, permanent retirement of the emissions units is not a feasible path forward. As such, the Foley Mill will accept emission-limiting standards under the Regional Haze program that will apply if and when the mill is restarted under new ownership.

Pursuant to EPA's Regional Haze requirements under 40 CFR 51.308, on June 22, 2020, the Department requested that Georgia-Pacific conduct a four-factor analysis for SO_2 emissions from the following emissions units at the Foley Mill:

- 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).

On October 20, 2020, Georgia-Pacific submitted to the Department a four-factor analysis assessing whether any cost-effective controls were available for the facility (Appendix B-2a). Georgia-Pacific's four-factor analysis did not include a review of Bark Boiler No. 2. The Department determined that a four-factor analysis was not needed for Bark Boiler No. 2 because annual SO_2 emissions from this unit are significantly lower than five tons per year.

In March 2021, the Department sent Georgia-Pacific a Request for Additional Information (RAI) concerning SO_2 emissions from the facility's recovery furnaces. The Department requested information comparing SO_2 emissions from the Foley Mill with SO_2 emissions from other Florida mills. Based on the factor of "SO_2 emissions per ton of black liquor fired," it became evident that the recovery furnaces at the Foley Mill were much less efficient at recovering the "smelt" (sodium carbonate and sodium sulfide) needed for the Kraft pulping process. As a result, the Foley Mill must purchase additional chemicals to replace the lost constituents. Discussions between Georgia-Pacific and the Department led to an agreement to certify the facility's existing SO_2 CEMS for the recovery furnaces by conducting Relative Accuracy Test Assessments (RATAs). The updated emissions data would allow Georgia-Pacific to explore operational changes for the recovery furnaces that could reduce 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, Georgia-Pacific identified two issues that required resolution to ensure the accuracy of recorded data. Specifically, Georgia-Pacific 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: 0.421 lb/MMBtu

Georgia-Pacific believes the wide range of SO_2 emissions factors to be the result of the inherent design and age of each furnace.

On August 30, 2022, Georgia-Pacific submitted to the Department a supplemental four-factor analysis, which updated the control reviews and incorporated the more accurate SO_2 emissions that were discovered through the RAI process (Appendix B-2b).

On September 20, 2022, representatives from the Department and Georgia-Pacific met at the Foley Mill to discuss the four-factor analysis, cost data, guidance from EPA's Cost Control Manual, and the inherent design of the recovery furnaces, as well as potential operational improvements that Georgia-Pacific could implement at the Foley Mill to reduce SO_2 emissions.

On November 16, 2022, Georgia-Pacific submitted to the Department a revised four-factor analysis (Appendix B-2c) from which the Department developed a final four-factor analysis (Appendix B-2d). **Table 7-35** shows the annual SO_2 emissions for the emissions units included in the latest four-factor analysis, which includes the corrected emissions from the recovery furnaces.

Table 7-35. Actual SO_2 Emissions (Tons/Year) for 2012-2021
Based on Revised 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)

Power Boiler No. 1 is capable of producing 195,000 lb/hour of steam firing a 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 together with Power Boiler No. 2 and Bark Boilers Nos. 1 and 2. Power Boiler No. 1 was designed by Babcock & Wilcox Company and constructed in 1953.

The liquid fuels share a common storage tank. The current Title V permit for the Foley Mill 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 2,800 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 the 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 SO_2 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 and a dry sorbent injection system as available and feasible controls.

7.8.3.1.1 Estimated Cost of Compliance

Table 7-35a summarizes the general costs for the analyses provided.

Table 7-35a. Foley Mill Power Boiler No. 1

Caustic Cost Effective Analysis

Supporting Data for Control Device Cost Effectiveness Calculations

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

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

Chemical, Energy, Water Use Basis

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

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

Wet Scrubber – 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 Foley Mill's site-specific data or data from other similar facilities as identified in **Table 7-35a** 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%.

Table 7-35b summarizes the capital, operating, and estimated cost-effectiveness to install and operate a wet scrubber. 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 determined that installation of a wet scrubber on Power Boiler No. 1 at the Foley Mill is not cost effective.

Table 7-35b. Foley Mill Power Boiler No. 1
Wet Scrubber Cost Effective Analysis

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.

Dry Sorbent Injection System – 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 (see **Table 7-35c**). 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 the boiler.

Table 7-35c. Foley Mill Power Boiler No. 1

Dry Sorbent Injection System Cost Effective Analysis

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**	

[B]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.

Foley Mill's initial cost effectiveness values were:

- Installing and operating a wet scrubber - $13,547/ton of SO_2 removed;
- Using a dry sorbent injection system - $21,727/ton of SO_2 removed.

The Department determined that neither of these values were cost effective. EPA's Regional Haze Guidance requires states to impose SIP emission limits that reduce the unit's potential to emit to levels that are slightly higher than the historical emission levels. Since the evaluated controls were not cost-effective, the Department is proposing to impose low-sulfur fuel restrictions on this unit as a practical means of reducing SO_2 emissions.

7.8.3.1.2 Time Necessary for Compliance

Installation of wet scrubbers and dry sorbent injection systems at power boiler systems can require up to four years to secure funding, make the required technical changes, and perform testing and monitoring to ensure proper system operation. Power Boiler No. 1 has fired only natural gas during the last six years, and permit restrictions requiring low-sulfur fuels could be implemented immediately. Also, the reduction in maximum fuel oil sulfur content of No. 6 fuel oil could be implemented for future purchases.

7.8.3.1.3 Energy and Non-Air Quality Impacts of Compliance

Typical energy and non-air quality impacts of compliance include sorbent, caustic, and sulfuric acid costs, additional electrical costs associated with scrubber and dry sorbent injection operation, additional fresh water for scrubber needs and wastewater disposal. There are no energy impacts associated with using lower sulfur fuel oil since the heating value is expected to remain the same with lower sulfur content. Use of lower sulfur fuel oil also does not result in any non-air quality environmental impacts.

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

The Department determined that there were no cost-effective emission reductions for Power Boiler No. 1. Revised calculations for the wet scrubber or DSI are not included because the updated costs remain an order of magnitude above a reasonable cost-effectiveness threshold. EPA's Regional Haze Guidance requires states to impose SIP emission limits that reduce the unit's potential to emit to levels that are slightly higher than the historic emissions for that unit. The Department has determined that the existing measures at the No. 1 Power Boiler ***are necessary*** for reasonable progress and emissions limits and associated supporting conditions are required to be adopted into the SIP. Therefore, the Department is proposing to impose low-sulfur fuel restrictions on Power Boiler No. 1 and a requirement that the unit fires only natural gas except under certain limited circumstances.

The Department has proposed in Permit No. 1230001-121-AC (see Appendix A-1) that the Foley Mill's 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 may be fired during these exceptional periods.

- For future additions of No. 6 fuel oil to the common tank, the maximum sulfur content shall be 1.02% by weight with compliance determined by maintaining records of fuel deliveries, analytical methods and results of analysis.
- Tall oil is no longer an authorized fuel.
- The No. 1 Power Boiler shall only combust the LVHC-NCG gases when the No. 1 Bark Boiler is offline, unavailable to burn NCG gases, or as necessary for compliance with the requirements of 40 CFR 63, Subpart S or other rules such as monitoring for detectable leaks in a closed vent system.

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 considers switching to a lower sulfur No. 6 fuel oil (1.0% or less) to be cost-effective and necessary for reasonable progress. The Regional Haze air construction permit includes the following permit conditions for inclusion into Florida's Regional Haze SIP:

- 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 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.
- Tall oil is no longer an authorized fuel for this unit.

These permit conditions represent reasonable progress for SO_2 reduction. These requirements will be included as part of Florida's Regional Haze SIP.

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 together with Power Boiler Nos. 1 and 2 and Bark Boiler No. 2.

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). 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 can also be added to the wet scrubbing media to adjust the pH level to further control SO_2 emissions. The current permit conditions for Bark Boiler No. 1 requires adding caustic to the wet venturi scrubber only when the TRS pre-scrubber is not operational. Following the scrubber is a chevron type demister to trap and remove entrained water droplets.

Over the last five years, SO_2 emissions have averaged about 178 tons/year. Since the annual average No. 6 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). Foley Mill has proposed cost-effective operational changes to the Bark Boiler No. 1. Specifically, the Foley Mill has proposed to run the existing wet venturi scrubber with added caustic at all times NCG gases are being combusted in the Bark Boiler No. 1, not just when the TRS pre-scrubber is unavailable.

7.8.3.2.1 Estimated Costs of Compliance

Increasing the amount of time caustic is added 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 (see **Table 7-35d**). 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).

Table 7-35d. Foley Mill Bark Boiler No. 1
Caustic Cost Effective Analysis

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 $2,627/ton to remove approximately 96 tons/year of SO_2 emissions, which the Department determined to be cost effective for this Regional Haze analysis. The estimate of a 51 percent control was determined through engineering tests that demonstrated that use of the wet venturi scrubber with caustic was a more effective control device for SO_2 than the use of the TRS pre-scrubber.

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. Caustic and scalant could be added to the scrubber control system within 12 months.

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 from 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 primary factor that the Department used to determine whether a control measure is necessary for reasonable progress was the cost of compliance. The Department then further considered the other three factors (time necessary for compliance, energy and non-air quality impacts, and remaining useful life). Remaining useful life in this case is already considered in the costs factor through annualizing the costs of compliance. For the Bark Boiler No. 1, the Department has determined that adding caustic and scalant to the scrubber system is cost-effective and, therefore, the Department has determined that these controls are necessary for reasonable progress. The Department is also proposing to impose low-sulfur fuel restrictions on Bark Boiler No. 1.

The Department has determined that the existing measures at the Number 1 Bark Boiler ***are necessary*** for reasonable progress and emissions limits and associated supporting conditions are required to be adopted into the SIP. The Regional Haze air construction permit (Permit No. 1230001-121-AC) for the Foley Mill requires:

- Bark Boiler No. 1 shall fire only wood materials and natural gas except for periods of natural gas curtailment, pipeline disruptions, system readiness testing 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 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.
- Tall oil is no longer an authorized fuel for this unit.
- At all times that LVHC-NCG or No. 6 fuel oil is fired, the Wet Venturi Scrubber shall be

operational. 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 1,000 gpm (3-hour block average) for the control of SO_2 emissions. Recordkeeping and reporting requirements for this condition are included in the permit.

These permit conditions represent reasonable progress for SO_2 reduction. Florida proposes that these requirements, together with associated monitoring, reporting, and recordkeeping requirements (Permit No. No. 1230001-121-AC) be included as a component of Florida's Regional Haze SIP.

7.8.3.3 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, NO_x, 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, NO_x, 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 65-72%, 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, No. 2 distillate oil, onsite or offsite-generated tall oil, on-specification used oil that meets the applicable requirements of 40 CFR Part 279; natural gas; ultra-low sulfur distillate oil and methanol (No. 2 Recovery Furnace only).

Recovery furnaces fire black liquor as the primary fuel for recovery operations. Black liquor 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 the 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 that 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. For units constructed in the 1950s, 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 common 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 (i.e., there is less contact time with sodium fumes that capture the sulfur in the lower furnace). As the black liquor rate and bed temperature increase, carryover will plug the furnace, reducing the capability to sustain operation at a given rate and increasing SO_2 emissions.

The Department requested that Georgia Pacific consider improving operational characteristics that may, on their own or in combination, contribute to a reduction in SO_2 emissions and increased recovery efficiency. Such operational characteristics could include increasing the solids content for black liquor to increase the bed temperature, sulfidity (sulfur-to-sodium ratio), air distribution, or stack oxygen content. Typically, SO_2 emissions from recovery furnaces are minimized by equipment design and operational considerations.

Georgia-Pacific concluded that the existing recovery furnaces are physically limited by the inherent “short” furnace design, original metals used in the 1950s, and designed metal thickness. 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.

Georgia-Pacific considered the potential application of several common flue gas desulfurization systems to the recovery furnaces, including spray dryer absorbers, dry sorbent injection, and conventional wet scrubbers. Each of the recovery furnaces currently use electrostatic precipitators (ESP) 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. This would, however, 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 remaining useful 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.

7.8.3.3.1 Estimated Costs of Compliance – Recovery Furnaces Nos. 2, 3, and 4

For each recovery furnace, the tables below 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.

Table 7-35e-1. Foley Mill Recovery Furnace No. 2

Scrubber Cost Effective Analysis

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

Table 7-35e-2. Foley Mill Recovery Furnace No. 2

Scrubber Cost Effective Analysis

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.

Table 7-35f-1. Foley Mill Recovery Furnace No. 3

Scrubber Cost Effective Analysis

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

Table 7-35f-2. Foley Mill Recovery Furnace No. 3

Scrubber Cost Effective Analysis

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 TC!, 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.

Table 7-35g-1. Foley Mill Recovery Furnace No. 4

Scrubber Cost Effective Analysis

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

Table 7-35g-2. Foley Mill Recovery Furnace No. 4

Scrubber Cost Effective Analysis

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 2021FGD 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 Region Haze Plan, 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.)"

The cost effectiveness values for installing a wet scrubber on each recovery furnace were:

- No. 2 Recovery Furnace - \$7,779/ton of SO_2 removed;
- No. 3 Recovery Furnace - \$5,197/ton of SO_2 removed;
- No. 4 Recovery Furnace - \$6,587/ton of SO_2 removed.

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 did not revise the cost effectiveness values and agrees that the wet scrubber option is not cost effective for this regional haze analysis.

7.8.3.3.2 Time Necessary for Compliance – Recovery Furnace Nos. 2, 3, and 4

Installation of wet scrubbers at recovery furnaces can require up to four years to secure funding, make the required technical changes, and perform testing and monitoring to ensure proper system operation.

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

Typical energy and non-air quality impacts of compliance include caustic and sulfuric acid costs, additional electrical costs associated with scrubber operation, additional fresh water for scrubber needs and wastewater disposal.

7.8.3.3.4 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.

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

The primary factor that the Department used to determine whether a control or measure is necessary for reasonable progress was the cost of compliance. The Department then further considered the other three factors (time necessary for compliance, energy and non-air quality impacts, and remaining useful life). Remaining useful life in this case is already considered in the costs factor through annualizing the costs of compliance. For the Nos. 2, 3 and 4 Recovery Furnaces, the Department does not consider installation of a wet scrubber located after the ESP to be cost-effective. The Department determined, therefore, that these controls are not necessary for reasonable progress.

The Department has determined that the existing measures at the Nos. 2, 3 and 4 Recovery Furnaces ***are necessary*** for reasonable progress and emissions limits and associated supporting conditions are required to be adopted into the SIP. In order to establish reasonable progress limits for these three units, the Department has established by permit emission limits (Permit No. 1230001-121-AC) that require:

- The recovery furnaces shall fire black liquor as the primary fuel for recovery operations. Natural gas and authorized liquid fuels may be fired to supplement recovery operations when necessary. Tall oil is no longer an authorized fuel.
- All future additions of No. 6 fuel oil to the common tank shall have a maximum sulfur content of 1.02% by weight with compliance determined by maintaining records of fuel deliveries, analytical methods, and results of analysis.
- At least once per month, a representative sample shall be taken from the common tank and analyzed to determine the fuel sulfur content. The sample shall be analyzed for the sulfur content using the methods specified in this permit. A certified vendor analysis of the sulfur content may be used to satisfy these requirements.
- Combined SO_2 emissions from Recovery Furnace Nos. 2, 3 and 4 are capped at 3,200 tons per consecutive twelve (12) operating months, rolled monthly, beginning January 1, 2024. An operating month is defined as a month where one, two, or all three furnaces operate for a minimum of one cumulative hour.
- 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 calibrated and maintained to meet the quality assurance requirements specified in Appendix D of this permit including conducting the required periodic Relative Accuracy Test Assessments (RATA). Each certified CEMS shall be used to determine compliance with the SO_2 emissions cap and to report emissions for the purposes of Title V annual fees.

These permit conditions represent reasonable progress for SO_2 reduction. Florida proposes that these requirements, together with associated monitoring, reporting, and recordkeeping requirements (as reflected in Permit No. No. 1230001-121-AC, and attached to this submittal as Appendix A-1) be included as components of Florida's Regional Haze SIP.

7.8.4 WestRock Panama City Mill Four-Factor Analysis

WestRock CP, LLC Panama City Mill is a Kraft pulp and paper production facility in Panama City, Florida. Wood is ground into chips and digested in a caustic solution to break down the lignin binding the cellulosic wood fibers. The wood fibers are washed, bleached, and formed into paper or linerboard. Panama City Mill is comprised of major activities areas such as: wood handling, pulping, bleaching, chemical recovery, powerhouse, paper machines, and associated processes and equipment.

In the Kraft process, the digesting liquor (white liquor) is a solution of sodium hydroxide and sodium sulfide that is mixed with wood chips and cooked under pressure. The spent liquor, known as weak black liquor, is concentrated and sodium sulfate is added to make up for chemical losses. The black liquor solids (BLS) are burned in the recovery furnaces to produce a smelt of sodium carbonate and sodium sulfide. The smelt is dissolved in water to form green liquor to which quicklime (calcium oxide) is added to convert the sodium carbonate back to sodium hydroxide, which reconstitutes the cooking liquor. The spent lime cake (calcium carbonate) is recalcined in a rotary lime kiln to produce quicklime, which is used to convert the green liquor to cooking liquor. Steam and energy needed at the plant are met by the combination boilers, which burn bark/wood, secondary solids (residuals) from the aerated stabilization basin, natural gas, No. 2 fuel oil, No. 6 fuel oil, and one of the combination boilers fires coal. The significant sources of SO_2 at the Panama City Mill are the No. 3 and No. 4 Combination Boilers (EU015 and EU016) and the No. 1 and No. 2 Recovery Boilers (EU001 and EU019).

The No. 3 and No. 4 combination boilers burn wood, bark, primary clarified wood fibers, secondary solids (residuals) from the aerated stabilization basin, natural gas, No. 2 fuel oil, and No. 6 fuel oil. Off-gases from the condensate stripper are transported to the No. 3 boiler for thermal destruction of TRS, HAP and VOC. The No. 4 Combination boiler serves as a backup control device for this purpose. Both No. 3 and No. 4 combination boilers serve as a backup control device to the lime kiln for the NCG from the Multiple Effect Evaporator (MEE) System and from the batch digester system. SO_2 emissions from each boiler are continuously monitored by a CEMS.

The No. 1 and No. 2 recovery boilers are direct contact evaporator recovery boilers that fire BLS, natural gas, No. 2 fuel oil, and No. 6 fuel oil. Each boiler is equipped with two induced draft fans and an electrostatic precipitator (ESP) to control emission of PM. TRS emissions are reduced by a two-stage heavy black liquor oxidation system. Each stack is equipped with a continuous emissions monitoring system (CEMS) to continuously monitor TRS and a continuous opacity monitoring system (COMS) to continuously measure opacity. High-Volume Low-Concentration (HVLC) NCGs from the No. 1 Brown Stock Washer System (BSWS) are collected and destroyed in either of the recovery boilers.

On October 20, 2020, WestRock submitted a Four-Factor Analysis for the Panama City Mill (see Appendix B-3).

Table 7-36 shows the most recent SO_2 emissions from each of these units, excluding de minimis units emitting less than five tons per year. The original projected emissions are significantly higher than recent actual emissions because projections were based on the 2011 base year emissions. 2017 emissions better reflect how the facility has generally operated since 2012. The cost-effectiveness analyses were, therefore, based on 2017 emissions. Please note that the Panama City Mill suspended operations in 2022. The Panama City Mill still has a valid operating permit and is authorized to operate if Westrock elects to restart the mill. It is unclear at this time whether any of these units will operate in the future.

Table 7-36. SO_2 emissions (tpy) from units at WestRock Panama City Mill

Year	Total	No. 1 RB – EU001	No. 3 CB – EU015	No. 4 CB – EU016	No. 2 RB – EU019
2011	2,378.9	592.7	37.9	1,167.0	581.3
2012	908.8	63.3	36.7	711.2	97.6
2013	1,032.0	73.5	132.9	759.6	66
2014	1,461.1	108.2	602.8	666.1	84
2015	983.2	129.3	264.2	517.3	72.4
2016	1,004.7	108.7	198.5	621.8	75.7
2017	1,010.5	166.9	198.8	570.5	74.3
2018	660.6	110.3	172.4	297.3	80.6
2019	457.8	79.5	151.9	125.9	100.5
2020	1,114.5	168.6	176.9	672.6	96.4
2021	1,009.0	177.1	182.6	547.5	101.8
Projected 2028	2,577.9	562.4	1.1	1,458.8	555.6

7.8.4.1 Nos. 3 and 4 Combination Boilers (EU015 and EU016)

WestRock Panama City identified replacing the No. 6 fuel oil (for both combination boilers) with ULSD, increasing caustic to the existing wet scrubbers, and installation of a spray dry absorber system as available controls for the Nos. 3 and 4 Combination Boilers.

7.8.4.1.1 Estimated Costs of Compliance

Low-Sulfur Fuels – The cost to replace No. 6 fuel oil firing in both combination boilers with ULSD was evaluated using Panama City 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 combination boilers 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.

Increasing Caustic to Wet Scrubber – Panama City 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. WestRock 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 Panama City 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.

Spray Dry Absorber (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 and Panama City Mill-specific cost data. These equations are also included in the update to the OAQPS Control Cost Manual, Section 5 ("SO_2 and Acid Gas Controls"). The initial cost effectiveness values were as follows:

- No. 3 Combination Boiler:
  - Replacing No. 6 fuel oil with ULSD - $84,520/ton of SO_2 removed;
  - Increasing caustic to the existing wet scrubber - $16,364/ton of SO_2 removed;
  - Installing an SDA - $14,267/ton of SO_2 removed.

- No. 4 Combination Boiler:
  - Replacing No. 6 fuel oil with ULSD - $50,097/ton of SO_2 removed;
  - Increasing caustic to the existing wet scrubber - $6,816/ton of SO_2 removed;
  - Installing an SDA - $12,966/ton of SO_2 removed.

The Department noted some parts of Westrock's analysis which were not justified adequately or were inconsistent with EPA's Cost Control Manual. In its control equipment calculations, WestRock used a 4.75% interest rate (the current bank prime interest rate), used a fifteen- or twenty-year lifetime for equipment, and included property taxes without justification. These issues led to inflated cost effectiveness values. Even with the corrections to certain values, Department did, however, determine that replacing No. 6 fuel oil with ULDS, increasing caustic to the wet scrubber, or installing SDA are not cost effective.

7.8.4.1.2 Time Necessary for Compliance

Fuel usage changes and addition of caustic to the scrubber would typically take up to twelve months to complete. A new SDA system would take approximately two to four years to secure funding, install and verify that the SDA was functionally optimally.

7.8.4.1.3 Energy and Non-Air Quality Impacts of Compliance

Typical energy and non-air quality impacts of compliance include caustic and sulfuric acid costs, additional electrical costs associated with scrubber operation, additional fresh water for scrubber needs and wastewater disposal.

7.8.4.1.4 Remaining Useful Life

The Nos. 3 and 4 Combination Boilers are assumed to have a remaining useful life of twenty years or more. For increasing caustic to the wet scrubber or installing an SDA system, the Westrock used the remaining useful life of the control, which was estimated to be 15 years for the wet scrubber and 20 years for an SDA system.

7.8.4.1.5 Summary of Findings for Nos. 3 and 4 Combination Boilers

The primary factor that the Department used to determine whether a control or measure is necessary for reasonable progress was the cost of compliance. The Department then further considered the other three factors (time necessary for compliance, energy, and non-air quality impacts, and remaining useful life). In some cases, the other factors are already considered in the costs, such as remaining useful life through annualizing the costs of compliance, or energy and non-air quality impacts being considered in costs such as increased water and electricity usage. The Department did not identify any cost-effective emission reductions through application of new control technology. The Department has determined that the existing measures at the Nos. 3 and 4 Combination Boilers ***are necessary*** for reasonable progress and emissions limits and associated supporting conditions are required to be adopted into the SIP. The Department proposes that the following permit conditions from Permit No. 0050009-047-AC, issued on June 7, 2023, to WestRock Panama City Mill be incorporated into Florida's SIP:

- Reducing coal usage to 125 tons per day and limiting the sulfur content of the coal to 0.75% for the No. 4 Combination Boiler.
- Prohibiting the purchasing of new No. 6 fuel oil in the Nos. 3 and 4 Combination Boilers. No. 6 fuel oil may, however, be used until the fuel storage on-site is exhausted. Once the fuel supply is exhausted, No. 6 fuel oil will no longer be authorized to be fired in the Nos. 3 and 4 Combination Boilers.
- Limiting the maximum concentration of sulfur in the No. 2 fuel oil fired in the boilers to 0.75% by weight.

These permit conditions represent reasonable progress for SO_2 reduction. These requirements will be included as part of Florida's Regional Haze SIP.

7.8.4.2.1 Nos. 1 and 2 Recovery Boilers (EU001 and EU019)

The recovery boilers are direct contact evaporator recovery boilers that fire BLS, natural gas, No. 2 fuel oil, and No. 6 fuel oil. Each recovery boiler has a maximum design BLS firing rate of 123,700 lb/hour based on 3,000 lb BLS per air dried unbleached pulp (lb/ADUBP). Each boiler is equipped with two induced draft fans and an electrostatic precipitator (ESP) to control emission of PM. TRS emissions are reduced by a two-stage heavy black liquor oxidation system. Each stack is equipped with a CEMS to continuously monitor TRS and a continuous opacity monitoring system (COMS) to continuously measure opacity. High-Volume Low-Concentration (HVLC) non-condensable gases (NCG) from the No. 1 Brown Stock Washer System (BSWS) are collected and destroyed in either of the recovery boilers. The No. 1 Recovery Boiler began operation in 1970 and the No. 2 Recovery Boiler in 1971.

WestRock identified using low-sulfur startup fuels (replacing startup and load-bearing burners with burners designed to fire natural gas and ULSD) and installation of a wet scrubber as available controls for the Nos. 1 and 2 Recovery Boilers.

7.8.4.2.2 Estimated Costs of Compliance

Low-Sulfur Fuels – The costs to eliminate No. 6 fuel oil firing in Nos. 1 and 2 Recovery Boilers were evaluated using Panama City 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 both Recovery Boilers 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.

Installing a 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 (BE&K Report). WestRock used cost estimates of 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 each 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.

The Department reviewed the cost effectiveness values, and the Department agrees that replacing No. 6 fuel oil with gas ULSD and installing a wet scrubber are not cost effective. Although the Department identified some issues with Westrock's cost effectiveness calculations, such as using a 4.75% interest rate, the weight of evidence demonstrates that installing these controls would still not be cost effective with a revised analysis. The final cost effectiveness values for these controls were:

- No. 1 Recovery Boiler
    - Replacing No. 6 fuel oil with gas - \$34,323/ton of SO_2 removed;
    - Replacing No. 6 fuel oil with ULSD - \$154,848/ton of SO_2 removed;
    - Installing a wet scrubber - \$39,961/ton of SO_2 removed.
- No. 2 Recovery Boiler
    - Replacing No. 6 fuel oil with gas - \$12,217/ton of SO_2 removed;
    - Replacing No. 6 fuel oil with ULSD - \$43,143/ton of SO_2 removed;
    - Installing a wet scrubber - \$89,221/ton of SO_2 removed.

Revised calculations for control cost options are not included, however, because the updated costs remain an order of magnitude above a reasonable cost-effectiveness threshold. The Department has determined that increasing caustic to the wet scrubber or installing SDA are not cost effective.

7.8.4.2.3 Time Necessary for Compliance

WestRock would need a minimum of four years to install a wet scrubber or complete changes needed to implement switching to natural gas or ULSD startup fuels. This would include securing funding, the design, permitting, procurement, installation, and shakedown of the emission control.

7.8.4.2.4 Energy and Non-Air Quality Impacts of Compliance

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.

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.

7.8.4.2.5 Remaining Useful Life

The Nos. 1 and 2 Recovery Boilers are assumed to have a remaining useful life of twenty years or more. For installing a wet scrubber, the Westrock used the remaining useful life of the control, which was estimated to be fifteen years.

7.8.4.2.6 Summary of Findings for Nos. 1 and 2 Recovery Boilers

The primary factor that the Department used to determine whether a control or measure is necessary for reasonable progress was the cost of compliance. The Department then further considered the other three factors (time necessary for compliance, energy and non-air quality impacts, and remaining useful life). In some cases, the other factors are already considered in the costs, such as remaining useful life through annualizing the costs of compliance, or energy and non-air quality impacts being considered in costs such as increased water and electricity usage. The Department did not identify any cost-effective emission reductions through application of new control technology.

The Department has determined that the existing measures at the Nos. 1 and 2 Recovery Boilers ***are necessary*** for reasonable progress and emissions limits and associated supporting conditions are required to be adopted into the SIP. The Department proposes that the following permit conditions from Permit No. 0050009-047-AC, issued on June 7, 2023, to WestRock Panama City Mill be incorporated into Florida's SIP:

- Prohibiting the purchase new of No. 6 fuel oil in the Nos. 1 and 2 Recovery Boilers, however, No. 6 fuel oil may be used until the fuel storage on-site is exhausted. Once the fuel supply is exhausted, No. 6 fuel oil will no longer be authorized to be fired in the Nos. 1 and 2 Recovery Boilers.

This permit conditions represent reasonable progress for SO_2 reduction. Florida proposes that this requirement (as reflected in Permit No. No. 0050009-047-AC, attached to this submittal as Appendix A-3) be included as components of Florida's Regional Haze SIP.

10.4 State and Federal Land Manager Consultation

EPA's Regional Haze Rule requires states to provide opportunity for consultation with Federal Land Managers early in the SIP development process (40 CFR 51.308(i)(2)):

> The State must provide the Federal Land Manager with an opportunity for consultation, in person at a point early enough in the State's policy analyses of its long-term strategy emission reduction obligation so that information and recommendations provided by the Federal Land Manager can meaningfully inform the State's decisions on the long-term strategy. The opportunity for consultation will be deemed to have been early enough if the consultation has taken place at least 120 days prior to holding any public hearing or other public comment opportunity on an implementation plan (or plan revision) for regional haze required by this subpart. The opportunity for consultation on an implementation plan (or plan revision) or on a progress report must be provided no less than 60 days prior to said public hearing or public comment opportunity. This consultation must include the opportunity for the affected Federal Land Managers to discuss their:
>
> (i) Assessment of impairment of visibility in any mandatory Class I Federal area; and
> (ii) Recommendations on the development and implementation of strategies to address visibility impairment.

10.4.1 Federal Land Manager 60-day Comment Period

On June 8, 2023, the Department sent consultation letters to the U.S. Fish and Wildlife Service (FWS), the U.S. Forest Service (FS), and the U.S. National Park Service (NPS) Federal Land Managers together with a preliminary copy of the draft proposed Amendments to Florida's Regional Haze Plan for the Second Implementation Period for a 60-day comment period (copies of the consultation letters are provided in Florida's SIP Submittal Number 2023-02 (Supplement to Florida Regional Haze Plan).

Continuing Consultation

40 CFR 51.308(i)(4) requires that each state's Regional Haze SIP include procedures for continuing consultation between the state and FLMs on the implementation of the visibility protection program. Florida commits to ongoing consultation with the FLMs. Florida will follow the consultation requirements in 40 CFR 51.308(i)(3) on any future plan revisions or progress reports, and Florida will engage with the FLMs upon request on any matters related to regional haze affected by Florida sources.

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