Georgia-Pacific

Georgia-Pacific Savannah River LLC

Savannah River Mill

Utility Footprint Project
Prevention of Significant Deterioration Application

Permit No. 2621-103-0007-05-0 As Amended

October 2024

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1. EXECUTIVE SUMMARY

Georgia-Pacific Savannah River LLC (GP or SRM) owns and operates a recycle deinking and bleaching paper mill in Rincon (Effingham County) Georgia, which is a major air emissions source under the Title V Major Source Operating Permit program. The facility operates under Permit 2621-103-0007-V-05 issued by Georgia's Environmental Protection Division (EPD). A timely permit renewal application was submitted on January 30, 2023. The facility is categorized under the Standard Industrial Classification (SIC) code 2621 (Primary) for Paper (except newsprint) mills. The facility is also categorized under the North American Industrial Classification System (NAICS) code 322120 for Paper Mills.

SRM is located in Effingham County, which has been designated by the United States Environmental Protection Agency (U.S. EPA) as in attainment or unclassified for all criteria pollutants. SRM has solid fossil fuel-fired boilers with heat inputs greater than 250 MMBtu/hr, therefore the Prevention of Significant Deterioration (PSD) threshold of 100 tpy applies. SRM has the potential to emit (PTE) more than 100 tpy for at least one criteria pollutant and is a major PSD source.

GP is proposing to implement changes to our utilities to improve operational flexibility, energy costs, and efficiency at the Mill. Specifically, a new 285 MMBtu/hr natural gas-fired boiler will be added, which will be designated as Boiler No. 7 (BO07). Boiler No. 3 (BO01), which is currently permitted to burn petroleum coke, coal, No. 2 fuel oil, wood, tire-derived fuel (TDF), peat, and wastewater treatment residuals (WWTR), will add burners to also fire natural gas and larger amounts of WWTR. No. 2. fuel oil will no longer be burned. Boiler No. 5 (BO03), which is currently permitted to burn petroleum coke, coal, No. 2 fuel oil, wood, tire-derived fuel (TDF), peat and wastewater treatment residuals (WWTR), will be converted to a natural gas and WWTR-fired boiler only. Combustion Turbine No. 2/Waste Heat Boiler No. 2 (CT02/WHB2) which has not operated since 2016 will be permanently decommissioned.

The estimated emission increases from the combined boiler changes exceed the PSD significant emission rates (SER) for carbon monoxide (CO) and greenhouse gases (GHG, as carbon dioxide equivalents, CO_2e). Therefore, PSD review is required for CO and GHG for the project. GP submits this complete application to authorize the construction of Boiler No. 7 and modifications to Boiler Nos. 3 and 5 and is organized into the following sections:

- Section 2 – Facility and Project Description
- Section 3 – Emission Calculations
- Section 4 – Regulatory Applicability
- Section 5 – Best Available Control Technology (BACT) Analysis
- Section 6 – Air Quality Analysis
- Appendix A – Area Map, Plot Plan, and Process Flow Diagrams
- Appendix B – Emission Calculations
- Appendix C – Permit Application Forms
- Appendix D – Proposed Redline Permit

2. FACILITY AND PROJECT DESCRIPTION

2.1. FACILITY LOCATION

The facility is located in Rincon, Georgia (Effingham County) at 437 Old Augusta Road South. Effingham County has been designated by the US EPA as in attainment or unclassifiable for all criteria pollutants.

2.2. PROCESS DESCRIPTION

The Savannah River Mill includes the following manufacturing processes.

2.2.1. Pulp and Bleaching

Pulp is manufactured from various grades of wastepaper. The pulp processing area pulps, deinks, cleans, and bleaches wastepaper to a specific level of brightness determined by product and customer specifications. The breakdown of wastepaper occurs in the agitation process inside High Consistency Batch or Continuous Drum Pulpers when combined with water. During the pulping stage, the wastepaper breaks down into a slurry (referred to as stock or pulp). The stock is then passed to a Screening System that removes plastic, latex, sand, clay, metal and other contaminants. After the removal of the larger contaminants, coatings, ash and inks are removed from the stock by washing and deinking. These cleaning/screening processes help prevent these contaminants from being included in the final tissue, towel and napkin products. The stock may then be bleached using sodium borohydride, sodium hydrosulfite, and hydrogen peroxide. The final stage of bleaching is washing the stock to remove residual chemicals. This stock is pumped to storage tanks for use on the Paper Machines.

The mill is also capable of using purchased virgin pulp to meet various paper quality and customer specifications.

2.2.2. Paper Machines

Pulp stock is processed through one of five paper machines to produce commercial and retail grades of tissue, towel, and napkins. Various chemical additives are used when processing the pulp stock to give the finished product different properties required for each product. Examples include the use of wet strength resin in paper towels to make the product strong when wet, or release agents that help prevent the product from sticking to the Yankee dryer roll as it is processed on the paper machine. Chemical cleaning agents are used on the paper machine clothing to remove the build-up of contaminants (e.g. stickies) that form over time from the use of secondary fiber.

Each of the paper machines has a steam-heated Yankee dryer section to reduce the moisture content of the product before it is removed from the paper machine on the associated wind-up reel. Each paper machine also has a hood system that contains two gas-fired burners that supply heat to assist in drying the paper sheet. Paper Machine 17 has an after-dryer that uses steam to complete the final drying step for the finished paper product.

2.2.3. Converting

The finished paper rolls from the paper machines are sent to the converting area where the paper is converted to tissue, towel and napkin products. This area of the mill also uses purchased core stock to form the core material used for toilet paper and paper towel rolls. The finished paper products are packaged and prepared for off-site shipment via truck.

2.2.4. Utilities

The facility operates a number of combustion units to provide steam and electrical power to the production operations. Currently, there are two primary power boilers, two combustion turbines with waste heat boilers, and two leased natural gas boilers.

Each of the two circulating fluidized bed power boilers has a heat input rating of 422 MMBtu/hr and is equipped with a baghouse to control particulate matter emissions and a limestone injection system to control sulfur dioxide emissions. Steam from the two power boilers feeds a common header, which serves two steam turbine generators that are each rated at 45 MW of electrical power. The power boilers are permitted to fire a number of different fuels including: petroleum coke, bituminous coal, peat, no. 2 fuel oil, natural gas, wood, WWTR, and TDF.

The facility maintains several different outdoor storage piles for coal, petroleum coke, and limestone that are fed as fuels or chemical reduction agents (limestone) to the boilers. These materials are delivered to the mill by railcar or by truck and are transported to the storage piles with the use of mechanical conveyors. The coal and petroleum coke are processed through a granulator to obtain the proper size for firing before these materials are sent to storage silos. The coal, petroleum coke, and limestone are then fed to the boilers from the storage silos. The bottom and fly ash from the boilers is collected in storage silos and sent to the mill's onsite landfill or used for beneficial reuse as approved by the appropriate regulatory agencies. Sand is used in the power boilers as a bed material and is stored in an onsite bin.

Additional steam and electrical power are provided to the mill via a combustion turbine equipped with a waste heat boiler. The turbine may also generate power that can be sold to the local utility grid. The power sold is limited to less than one-third of our potential output capacity per permit condition 3.2.1. Combustion Turbine No. 1 can generate 15 MW of power. The waste heat boiler burner is rated at 85.9 MMBtu/hr. The combustion turbine and waste heat boiler burn natural gas. The waste heat boiler cannot be operated independently of the turbine. The Savannah River Mill rents two (2) natural gas boilers, each rated at less than 100 MMBtu/hr, for use during maintenance and/or unplanned power boiler or combustion turbine shutdowns or if it is beneficial to the mill based on fuel pricing/availability.

2.2.5. Ancillary Operations

In addition to main process operations, there are other ancillary operations at the mill with the potential to generate air emissions. The mill operates a wastewater treatment plant to process the wastewater from the pulp processing and the paper machines areas. The wastewater treatment residuals (WWTR) and boiler ash may be landfilled on site, beneficially reused as approved by the appropriate regulatory agencies, or burned in the boilers as approved by appropriate regulatory agencies (WWTR only). Portions of the gases generated from the breakdown of organic matter in the closed portions of the landfill are collected and combusted in a flare.

The mill grinds wooden pallets for use as a boiler fuel and paper cores for recycling back into the pulping process. A number of raw materials necessary to our processes are stored in tanks. The mill also has a number of reciprocating internal combustion (RICE) engines onsite, including engines designated for emergency and temporary use.

In addition to the main production facility, a separate division of Georgia-Pacific owns a warehouse across the street from the Savannah River Mill. The Rincon Warehouse stores some of the final products produced at the mill, as well as products from other locations. With the exception of an emergency fire pump engine and small diesel tanks, there are no regulated sources of emissions at the warehouse.

2.3. PROJECT DESCRIPTION

SRM is proposing the following to modify its steam production capability and flexibility to improve energy efficiency and reliability. The proposed project includes the following:

- Construct and operate a new 285 MMBtu/hr natural gas-fired boiler designated as Boiler No. 7 (BO07) with low oxides of nitrogen (NO_X) burners.

- Modify existing Boiler No. 3 (BO01): Boiler No. 3 is currently a circulating fluidized bed boiler with a heat input rating of 422 MMBtu/hr, authorized to fire coal, petroleum coke, peat, wood, no. 2 fuel oil, natural gas, TDF, and WWTR. Modifications to this boiler include adding screw feeders and associated sludge handling equipment to deliver WWTR to the lower furnace bed, replacing in-duct fuel oil burner with a gas burner, and adding natural gas bed burners and load burners in the lower furnace. After modification, Boiler No. 3 will fire a mix of WWTR and natural gas and/or the originally permitted fuels with the exception of fuel oil. Fuel oil will no longer be fired. The boiler will have a maximum heat input rate of 422 MMBtu/hr when firing the existing fuel mix, 392.6 MMBtu/hr when firing gas and WWTR combined, and 397.7 MMBtu/hr when firing natural gas alone. Emissions will be controlled by ammonia injection for oxides of nitrogen (NO_X), a secondary air system for CO control, and the existing baghouse for particulate matter (PM) control.

- Modify existing Boiler No. 5 (BO03). Boiler No. 5 is currently a circulating fluidized bed boiler with a heat input rating of 422 MMBtu/hr, authorized to fire coal, petroleum coke, peat, wood, no. 2 fuel oil, natural gas, TDF and WWTR. Modifications to this boiler include adding screw feeders and associated sludge handling equipment to deliver WWTR to the lower furnace bed, replacing in-duct fuel oil burner with a gas burner, and adding natural gas bed burners and load burners in the lower furnace. After modification, Boiler No. 5 will fire WWTR and natural gas only. The boiler will have maximum steaming rate of 320,000 pounds per hour, with a maximum heat input rate of 392.4 MMBtu/hr when firing WWTR and natural gas and 393.2 MMBtu/hr when firing natural gas alone. Emissions will be controlled by ammonia injection for oxides of nitrogen (NO_X), a secondary air system for CO control and the existing baghouse for particulate matter (PM) control.

- Permanently decommission Combustion Turbine No. 2/Waste Heat Boiler No. 2 (CT02/WHB2) that has not operated since 2016.

In addition to the boiler changes, the following changes will also be made:

- Existing solid fuel silos will be removed from Boiler 5 and five storage bins will be added to store WWTR (FS09), and the existing limestone silos will be repurposed for sand storage (LM03 to SAND) for Boiler 5. The WWTR conveyors to the boilers are completely enclosed.
- A steam dryer will be installed to remove moisture from the WWTR fuel. A scrubber will be installed at the outlet of the dryer to remove solids. The outlet of the dryer will exhaust into the combustion chamber of either Boiler 3 or Boiler 5. Therefore, the dryer and scrubber are not considered emission sources.
- Add an aqueous ammonia tank and associated piping to supply for NO_X control.

The modifications to Boiler Nos. 3 and 5 are expected to begin construction in April 2025 and construction of Boiler No. 7 is expected in 2026.

3. EMISSION CALCULATION METHODOLOGY

3.1. SUMMARY

To determine the appropriate permitting path for the project, it is necessary to calculate the emission increases expected to occur as a direct result of the proposed project and compare those increases to each pollutant's PSD significant emission rate (SER). Under the federal PSD permitting program, which the Georgia Environmental Protection Division (EPD) has adopted by reference with exceptions noted and incorporated in the rules, emission increases are calculated differently for new emission units and existing emission units. For new emission units, emission increases resulting from a project are defined as the difference between the potential-to-emit (PTE) of the unit following completion of the project and the baseline actual emissions before the project ("baseline actual-to-potential" emissions test). The PSD regulations state that baseline actual emissions for a new emission unit are equal to zero.

For existing emissions units, the emissions increase resulting from a proposed project may be calculated using either the "baseline actual-to-potential" emissions test described above or the "baseline actual-to-projected actual" emissions applicability test. The latter test allows an applicant to calculate a projected actual emission rate, which is the maximum annual emission rate that an existing emissions unit is projected to emit in any one of the five years (or ten years in certain circumstances) following the completion of a project.[1] For projects involving both new and existing emission units, a hybrid methodology that includes both the "baseline actual-to-potential" and the "baseline actual-to-projected actual" emissions increase tests can be used. GP has chosen the hybrid method and is using the "baseline actual-to-potential" test for Boiler No. 7 and the "baseline actual-to-projected actual" test for existing Boiler Nos. 3 and 5.

3.2. NEW SOURCE EMISSIONS

"Potential to Emit emissions" (PTE) are defined by Chapter 391-3-1-.02(7)(a)2(ii)(II)IV. of the Georgia Rules as,

> *[T]he maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable.*

PTE emissions for the new natural gas boiler were based on vendor guarantees for NO_X, PM_{10}, $PM_{2.5}$, and CO, EPA's mandatory reporting rule (MRR) for greenhouse gases, and AP-42 for the remainder of the pollutants. All emissions were based on maximum heat input rating and 8,760 hours of operation. Detailed calculations are provided in Appendix B.

[1] The ten year period applies if the project involves increasing the unit's design capacity or PTE and full utilization of the unit would result in a significant emissions increase for a regulated pollutant.

3.3. Projected Actual Emissions

Projected actual emissions are defined by Chapter 391-3-1-.02(7)(a)2(ii)(I), as

"*the maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a regulated NSR pollutant in any one of the 5 years (12-month period) following the date the unit resumes regular operation after the project, or in any one of the 10 years following that date, if the project involves increasing the emissions unit's design capacity or its potential to emit that regulated NSR pollutant and full utilization of the unit would result in a significant emissions increase or a significant net emissions increase at the major stationary source.*"[2]

Per Chapter 391-3-1-.02(7)(a)2(ii)(II)I, in determining PAE, the owner or operator of a source shall consider all relevant information, including but not limited to, historical operational data, the company's own representations, the company's expected business activity and the company's highest projections of business activity for the five or ten year period after implementation of the project, the company's filings with the State or Federal regulatory authorities, and compliance plans under the approved State Implementation Plan.

In developing the projected actual emissions, EPD's PSD rule [391-3-1-.02(7)(a)2(ii)(II)III] specifies that the projected actual emission rate "*may exclude, in calculating any increase in emissions that results from the particular project, that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions… and that is also unrelated to the particular project, including any increased utilization due to product demand growth…*". GP did not exclude any "could have accommodated" emissions for this project.

Specific details on projected actual emissions are provided in the following sections and detailed calculations are provided in Appendix B.

3.3.1. Boiler No. 3

Future emissions from Boiler No. 3 after the proposed modifications are based on the following:

- Boiler MACT limits for carbon monoxide (CO) for all fuels. Depending on fuel use, the No. 3 Boiler may be regulated as a fluidized bed unit designed to burn coal/solid fossil fuel or designed to burn biomass/bio-based solids. For the PSD calculations, the higher of the two limits was used as a conservative calculation.
- Vendor guarantees for NO_X, for all fuels with ammonia injection as needed
- WWTR factors based on vendor estimate for sulfur dioxide (SO_2). PM based on test data (average plus one standard deviation) for existing solid fuels. Remaining pollutants based on test data for similar source
- Test data (average plus one standard deviation) for PM and SO_2 from existing fuels
- EPA mandatory reporting rule (MRR) for greenhouse gas emissions

[2] The 5-year projection applies to sources that do not modify the unit's existing design capacity or their PTE.

- NCASI emission factors for wood firing
- AP-42 factors for all other fuels and pollutants.

Projected emissions are based on the factors above and the assuming 60% of the year the boiler is operated at a maximum firing rate for WWTR and natural gas firing and 40% of the year at a maximum firing rate (422 MMBtu/hr) and historical fuel mix for existing fuels.

3.3.2. Boiler No. 5

Future emissions from Boiler No. 5 after the proposed modifications are based on the following:

- Boiler MACT limits for carbon monoxide (CO), all fuels
- PM based on test data (average plus one standard deviation) for existing solid fuels.
- Vendor guarantees for NO_X, all fuels with ammonia injection as needed
- WWTR factors based on vendor estimate for sulfur dioxide (SO_2). Remaining pollutants based on test data for similar source.
- EPA mandatory reporting rule (MRR) for greenhouse gas emissions
- AP-42 factors for natural gas for other pollutants.

Projected emissions are calculated from the factors above and the worst-case emissions from the maximum heat input for WWTR and gas firing scenarios.

3.3.3. Ancillary Sources

Existing solid fuel silos will be removed from Boiler 5 and five storage bins added to store WWTR (FS09) and the existing limestone silos will be repurposed for sand storage (LM03 to SAND) for Boiler 5. For simplicity, the potential emissions were used for these sources. In addition, the granulator, storage piles, existing fuel silos and ash silos for Boiler No. 3 are included with projected actual emissions.

3.4. BASELINE ACTUAL EMISSIONS (BAE)

Baseline Actual Emissions are defined by Chapter 391-3-1-.02(7)(a)2(i)(II) as "*the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 10-year period immediately preceding either the date the owner or operator begins actual construction of the project, or the date a complete permit application is received by the Department for a permit…*". As this application is being submitted in October 2024, the baseline period is November 2014 through the present. Baseline emissions were calculated for Boiler Nos. 3 and 5, fuel silos and lime silos. Baseline emissions were based on CEMS, stack test data, and published emission factors. Detailed calculations are provided in Appendix B. Table 3-1shows the baseline period for each pollutant.

Table 3-1. Baseline Period by Pollutant

		Baseline Period	
Pollutant		**Start Month**	**End Month**
CO		Jan-2016	Dec-2017
NO_X		Dec-2021	Nov-2023
PM		Jan-2017	Dec-2018
PM_{10}		Jan-2017	Dec-2018
$PM_{2.5}$		Jan-2017	Dec-2018
SO_2		Nov-2017	Oct-2019
VOC		Mar-2015	Feb-2017
SAM		May-2015	Apr-2017
Lead		Nov-2014	Oct-2016
Total CO_2e		May-2018	Apr-2020

3.5. PROJECT EMISSION INCREASES

Under Step 1 of the PSD analysis, the emission increases for the project are calculated by summing the individual emission increases and decreases, as well as the associated emission increases from existing affected units. There are no affected sources other than the utility sources. The proposed changes will ensure future reliability of the mill but will not cause production to increase. Therefore, only utility sources are included in the emissions calculations.

These total project emission increases were then compared to the PSD SERs. Table 3-2 provides a summary of the project emissions increases. As shown in Table 3-2, the Step 1 emissions analysis demonstrates that the project emissions of all PSD-regulated pollutants are below the respective SERs with the exception of CO and GHG.

Table 3-2. Emissions Increase Summary

		CO	NO_X	PM	PM_{10}	$PM_{2.5}$	SO_2	VOC	SAM	Lead	Total CO_2e
New Units											
Boiler No. 7	PTE	46.19	44.94	2.37	6.24	6.24	0.73	6.69		6.08E-04	146,173
WWTR Silo	PTE			0.03	0.02	0.002					
Modified Units											
Boiler No. 5	PAE	484.82	172.22	17.22	26.87	26.87	295.71	12.42	3.16	0.00	259,182
	BAE	43.51	69.03	15.76	35.40	30.08	888.95	4.72	8.70	0.01	301,158
	Change	441.31	103.19	1.46	(8.54)	(3.21)	(593.24)	7.71	(5.53)	(0.004)	(41,976)
Boiler No. 3	PAE	503.48	178.45	17.84	35.48	32.98	876.68	11.73	8.45	0.00	313,753
	BAE	26.12	301.57	8.84	30.67	27.68	1255.49	6.63	10.42	0.01	290,601
	Change	477.37	(123.12)	9.00	4.81	5.29	0.00	5.10	0.00	0.00	23,151
Solid Fuel Silos	PAE			0.04	0.02	0.00					
	BAE			0.11	0.05	0.01					
	Change			(0.07)	(0.03)	(0.01)					
Storage Pile Loading	PAE			0.12	0.06	0.01					
	BAE			0.11	0.05	0.01					
	Change			0.0047	0.0022	0.0003					
Lime/Sand Silos	PAE			0.77	0.77	0.77					
	BAE			0.69	0.69	0.69					
	Change			0.08	0.08	0.08					
Ash Silo	PAE			0.18	0.09	0.01					
Granulator	PAE			0.08	0.03	0.03					
Project Increase		964.86	25.01	13.1	2.7	8.4	(592.51)	19.50	(5.53)	(0.004)	127,348
PSD SER		100	40	25	15	10	40	40	7	0.6	75,000
Triggers PSD?		Yes	No	No	No	No	No	No	No	No	Yes

Note that as a conservative measure, emissions decreases were only taken credit for the removal of certain fuels (PM species, SO_2, SAM, lead, and CO_2e for Boiler No. 5), added controls (ammonia injection for Boiler Nos. 3 and 5), and removal of sources (Solid fuel silos). Emissions decreases were set to zero for changes due to projected fuel mix for Boiler No. 3.

PSD permitting is required if both a significant emissions increase ("Step 1") and a significant net emissions increase ("Step 2") occurs. As the only projects involving CO and GHG emissions during the contemporaneous period show emissions increases, PSD for CO and GHG applies. Contemporaneous project CO emissions are included in the air quality analysis in Section 5.

3.6. AIR TOXIC EMISSIONS

Emissions of hazardous air pollutants (HAP) from Boiler No. 7 and modified Boiler Nos. 3 and 5 equal 93 tpy total HAP. HAP emissions from the existing Boiler Nos. 3 and 5 are 102 tpy. The utility project will result in a potential decrease of 9 tons of HAP.

Individual HAP were compared for the new and previous operating scenario (Boiler Nos. 3, 5 and 7 as compared to previous Boiler Nos. 3 and 5 fuels). All individual HAP were lower for the future operating scenario with the exception of hexane, mercury, and polychlorinated biphenyls (PCB). The total hexane emissions from the entire facility post-project are below the minimum emission rate for required air toxic analyses (25,309 pound per yr as compared to 170,331 pound/yr). Greater than 90% of hexane emissions are emitted from point sources. Total mercury emissions are 73.8 lb/year as compared to 73 lb/yr and are addressed in Section 6. PCB are not included in the toxic air assessment guidelines and emissions are very low (1.19 e-4 tpy). The data used to determine PCB emissions is from 1999 testing at a similar GP facility firing wastewater treatment residuals (WWTR). Site specific WWTR PCB analysis from Savannah were non-detect. Based on this information, the Division agreed that a PCB assessment is not required.[3] Detailed HAP calculations are provided in Appendix B.

[3] Email correspondence from Ms. Heather Brown (GA EPD) to Ms. Mary Hoffmann (GP), February 18, 2022.

4. REGULATORY REVIEW

This section summarizes all federally-enforceable and state-enforceable air regulations that are potentially applicable to the project.

4.1. FEDERAL AIR QUALITY REGULATIONS

The federal regulations potentially applicable to the proposed project are PSD regulations in 40 CFR 52.21; New Source Performance Standards (NSPS) in 40 CFR 60; National Emission Standards for Hazardous Air Pollutants (NESHAP) in 40 CFR 61 and 63; Compliance Assurance Monitoring (CAM) (40 CFR Part 64); and Title V Operating Permit regulations in 40 CFR 70. A discussion of these regulations is provided in the following subsections. These requirements are codified in the Georgia Rules for Air Quality Control, specifically Rules 391-3-1-.02(7), (8), (9), and 391-3-1-.03(10), respectively. A discussion of these regulations is provided in the following subsections.

4.1.1. Prevention of Significant Deterioration (PSD) Applicability

Implementation of the PSD regulations has been delegated in full to the State of Georgia. These air quality regulations are contained in Georgia Rules for Air Quality Control Rule 391-3-1-02(7). The PSD regulations apply to major modifications at major stationary sources, which are those sources belonging to any one of the 28 source categories listed in the regulations that have the potential to emit more than 100 tons per year of any New Source Review (NSR) regulated pollutant, or any other stationary source which has the potential to emit more than 250 tons per year of any NSR regulated pollutant. SRM has fossil fuel boilers with heat inputs greater than 250 MMBtu/hr heat input, therefore the 100 tpy threshold applies. SRM has the potential to emit more than 100 tpy of several pollutants and is a major PSD source.

Under the PSD regulations, a “major modification” is defined as “any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any regulated NSR pollutant.” Physical changes or changes in the method of operation at PSD major stationary sources must be evaluated to determine if PSD review is required. The proposed new boiler and boiler modifications are physical changes and therefore the PSD applicability analysis was performed for the proposed project. The emissions calculation methodology used to determine PSD applicability was described in Section 3. The emission factors and throughputs used to estimate emissions are presented in Appendix B. Based on the emission calculations described in Section 3 of this application, the net emissions increases associated with the project are below the application PSD SER for all pollutants except CO and GHG. Therefore, the proposed project is subject to PSD for CO and GHG only. Sections 5 and 6 of this permit application address the Best Available Control Technology (BACT) analysis and CO modeling.

EPD has adopted a slightly different version of EPA’s “reasonable possibility” rules outlined under 40 CFR 52.21(r)(6). EPD’s rules state that for projects at an existing emissions unit at a major stationary source that are required to obtain a construction permit, and where the owner or operator elects to use the "baseline actual-to-projected actual" applicability test in paragraphs (b)(41)(ii)(a) through (c) of 40 CFR 52.21, then an applicant must comply with the provisions specified under paragraph 391-3-1-.02(7)(b)15.(i). These provisions require monitoring of emissions and recordkeeping for projects that require a state construction permit and use the "baseline actual-to-projected actual" applicability test. The proposed boiler modifications for Boiler Nos. 3 and 5 are subject to these recordkeeping requirements. As such GP will be required to keep records of these emissions and all information required under 391-3-1-.02(7)(b)15.(i)(I) for a total of 10 years.

4.1.2. Title V Operating Permit Applicability and Updates

SRM currently operates under Title V Permit No. 2621-103-0007-V-05 and its amendments. GP requests that a revised Title V permit be issued under Georgia Air Regulations as a major modification to reflect the changes to Boiler No. 5 and Boiler No. 3 and incorporate Boiler No. 7. A summary of proposed changes is detailed below.

- CT2/WHB2 (Removal also requested in Title V renewal application)
    - Remove all references to CT2, and WHB2.
- Boiler No. 3 (BO01)
    - Update NSPS Subpart Db conditions as discussed in Section 4.1.3.4
    - Update NESHAP Subpart DDDDD conditions as discussed in Section 4.1.4.2
    - Update fuels fired
- Boiler No. 4 (BO02) (Removal also requested in Title V renewal application)
    - Boiler No. 4 (BO02) has been permanently decommissioned. Please update permit to remove all references to this unit to include FS04-FS07, FD01-FD04 and LM02.
- Boiler No. 5 (BO03)
    - Remove limestone feed system as the control device
    - Remove FS08 and FS10
    - Update NSPS Subpart Db conditions as discussed in Section 4.1.3.4
    - Update NESHAP Subpart DDDDD conditions as discussed in Section 4.1.4.2
    - Update fuels fired
- Limestone Silo No. 3 (LM03) – Change to "Sand Silo"(SAND)
- Fuel Storage – Change to WWTR Storage (FS09)
- Boiler No. 7 (BO07)– add unit and associated conditions

4.1.3. New Source Performance Standards (NSPS) – 40 CFR 60

NSPS apply to any stationary source for which standards are promulgated and at which any equipment defined as an "affected facility" in the standard is constructed, reconstructed, or modified after the effective date of the applicable standard. NSPS requirements are promulgated under 40 CFR 60 pursuant to Section 111 of the Clean Air Act. Potentially applicable NSPS are discussed in the following sections.

4.1.3.1. NSPS Subpart A – General Provisions

All sources subject to an NSPS standard are also subject to the general provisions of NSPS Subpart A, unless specifically excluded by the source-specific NSPS. Subpart A requires initial notification and performance testing, recordkeeping, monitoring, provides reference methods, and mandates general control device requirements for all other subparts as applicable.

4.1.3.2. NSPS Subpart D – Large Steam Generating Units

NSPS Subpart D, Standards of Performance for Fossil Fuel Fired Steam Generators, regulates fossil fuel fired steam generating units for which construction or modification commenced after August 17, 1971. This subpart applies to steam generating units having a maximum rated heat input capacity in excess of 250 MMBtu/hr.

Boiler No. 3 has a heat input capacity greater than 250 MMBtu/hr, was constructed after the applicability date of August 17, 1971, and is currently subject to NSPS Subpart D. Boiler Nos. 5 and 7 have a maximum rated heat input capacity over 250 MMBtu/hr but were constructed after the NSPS Subpart Db applicability date of June 19, 1986, so they are not subject to NSPS Subpart D.[4]

4.1.3.3. NSPS Subpart Da – Electric Utility Steam Generating Units

NSPS Subpart Da, Standards of Performance for Electric Utility Steam Generating Units, provides standards of performance for electric utility steam generating units with fossil fuel-fired capacities greater than 250 MMBtu/hr for which construction, modification or reconstruction commenced after September 18, 1978. The definition of "electric utility steam generating unit" requires that the unit be constructed for the purpose of supplying more than one-third of its potential electric output capacity <u>and</u> more than 25 MW net electrical output to the grid. The Mill does sell small quantities of electricity to the grid. However, the facility is limited to selling less than one-third of its power output to the grid per permit condition 3.2.1. Therefore, this subpart does not apply to the Mill's boilers.

4.1.3.4. NSPS Subpart Db – Industrial-Commercial-Institutional Steam Generating Units

NSPS Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units, provides standards of performance for steam generating units with capacities greater than 100 MMBtu/hr for which construction, modification, or reconstruction commenced after June 19, 1984. Revisions to NSPS Subpart Db were promulgated to establish more limits for units that are constructed, reconstructed, or modified after July 9, 1997 and February 28, 2005.

[4] 40 CFR 60.40b(j)

The proposed Boiler No. 3 modifications do not constitute a modification as defined in 40 CFR 60.14 since the project will not result in any increases in the maximum hourly emission rates of any pollutants regulated by Subpart Db. The existing NSPS and PSD avoidance limits will remain the same and therefore there is no change to maximum hourly emissions. Per 40 CFR 60.40b(b)(2), coal-fired affected facilities having a heat input capacity greater than 73 MW (250 MMBtu/hr) and meeting the applicability requirements under subpart D (Standards of performance for fossil-fuel-fired steam generators; § 60.40) are subject to the PM and NO_X standards under this subpart and to the sulfur dioxide (SO_2) standards under subpart D (§ 60.43).

Boiler No. 5 is currently subject to Subpart Db and was originally constructed in 1995. The proposed Boiler No. 5 modifications do not constitute a modification as defined in 40 CFR 60.14 since the project will not result in any increases in the maximum hourly emission rates of any pollutants regulated by Subpart Db. The existing NSPS and PSD avoidance limits will remain the same and therefore there is no change to maximum hourly emissions.

The proposed changes to each Boiler Nos. 3 and 5 cost approximately $23 million each. The cost of new comparable WWTR and gas fired boiler is approximately $78 million. Therefore, the proposed project does not meet the definition of reconstruction as the costs are less than 50% of that for a comparable new unit. As the units are not being reconstructed or modified, Boiler No. 3 remains subject to NSPS Subpart D and Boiler Nos. 3 and 5 are subject to the earlier version of the emission limits in NSPS Subpart Db.[5]

Specifically for Boiler No. 5, NO_X will be limited to 0.3 lb/MMBtu 30-day rolling average per 40 CFR 60.44b(d) as the unit fires natural gas and "other solid fuel". When natural gas alone is fired, the unit will be subject to the 0.1 lb/MMBtu limit for low-heat release natural gas fired boilers per 40 CFR 60.44b(a)(1)(i). Boiler No. 5 will continue to operate the existing continuous emissions monitoring system (CEMS) for compliance with this requirement. Described limits are lower than the previous 0.4 lb/MMBtu PSD avoidance limit. Boiler No. 3 will retain the existing limits in the current permit as it will continue to fire coal and petroleum coke.

There are no specific emission limits for PM or SO_2 for natural gas or natural gas and unspecified solid fuels in NSPS Db. The PM emission limit of 0.051 lb/MMBtu, opacity limit of no greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity, SO_2 lb/MMBtu pro-rated 30 day rolling limit, and minimum 90% sulfur reduction limit will no longer apply to Boiler 5. The PM and SO_2 limits for Boiler No. 3 will remain the same as existing.

[5] As Boiler No. 3 was constructed after June 19, 1984 but before June 18, 1986, it is subject to both NSPS Subpart D and Db.

Boiler No. 7 has a fossil fuel firing capacity greater than 100 MMBtu/hr and will be constructed after the applicability date and is therefore subject to NSPS Subpart Db. Boiler No. 7 will not be subject to any opacity, PM, or SO_2 emission limits under NSPS Subpart Db because it will only combust natural gas. The boiler will be subject to a NO_X emission limit of 0.10 lb/MMBtu under 40 CFR 60.44b(l)(2) as a 30-day rolling average. A CEMS or PEMS is required by 40 CFR 60.48b(b)(1) to be installed, calibrated, and maintained to demonstrate compliance with the applicable NO_X emission limit.

4.1.3.1. NSPS Subpart Dc – Small Industrial-Commercial-Institutional Steam Generating Units

Boiler Nos. 3, 5, and 7 have a heat input greater than 100 MMBtu/hr and are therefore not subject to this rule.

4.1.4. National Emission Standards for Hazardous Air Pollutants – 40 CFR 61

Part 61 NESHAP Subpart E – National Emission Standard for Mercury – applies to facilities that "incinerate or dry wastewater treatment plant sludge." The rule does not define "incinerate" or "incinerator", or distinguish that term from units that burn/combust wastewater treatment residuals (WWTR) for energy recovery. Boiler Nos. 3 and 5 are not designed or operated as an "incinerator". Moreover, EPA has determined that WWTR are a non-waste "fuel" under the Non-Hazardous Secondary Materials rule, so burning this material would not constitute the burning of solid waste such as would make the boilers subject to the Commercial and Solid Waste Incinerator (CISWI) rule. Still, according to previous EPA determinations under Subpart E, which pre-date the NHSM rule and its associated non-waste "fuel" determination for wastewater treatment residuals, the rule could be said to apply to the combustion of paper mill WWTR as a fuel in a boiler for energy recovery, and so GP considered its potential applicability in an earlier permit application to burn WWTR in Boilers 3 and 5 (BO01, BO03). Subpart E requirements were incorporated into permit Amendment 2621-103-0007-V-05-1 allowing WWTR burning in both units issued December 27, 2018 and will continue to apply with the proposed project.

The rule and Condition 3.3.28 states that emissions from covered units shall not exceed 7.1 lb of mercury per 24-hour period. Compliance with this limit may be shown via stack testing per 40 CFR 61.53(d) or sludge sampling per 40 CFR 61.54. Per Condition 4.2.7, sampling following EPA Method 105 was conducted in January 2019 and results submitted to the Division on February 7, 2019. The sampling resulted in emissions estimates of 0.08 lb/day. Per 40 CFR 61.55(a) and Condition 6.2.25, no additional sampling is required as the emissions are below 3.5 lb/day.

4.1.5. National Emission Standards for Hazardous Air Pollutants (NESHAP) – 40 CFR 63

NESHAPs, federal regulations found in Title 40 Parts 61 and 63 of the CFR, are emission standards for HAPs that apply to major sources of HAPs (facilities that exceed the major source thresholds of 10 tpy of a single HAP and 25 tpy of any combination of HAPs) or specifically designated area sources under Part 63. The Part 63 NESHAPs apply to sources in specifically regulated industrial source classifications (Clean Air Act Section 112(d)) or on a case-by-case basis (Clean Air Act Sections 112(g) and 112(j)) where EPA has failed to promulgate a 112(d) standard. SRM is a major source of HAP. Potentially applicable NESHAP are discussed in the following sections.

4.1.5.1. 40 CFR Part 63 Subpart A – General Provisions

All affected sources subject to a source-specific subpart under 40 CFR Part 63 are subject to the general provisions of Subpart A unless specifically excluded by the source-specific NESHAP. Subpart A requires initial notification and performance testing, recordkeeping, monitoring, provides reference methods, and mandates general control device requirements for all other subparts as applicable. Because various other Part 63 subparts are applicable to the proposed project, the provisions of Subpart A also apply to the proposed project.

4.1.5.2. 40 CFR Part 63 Subpart DDDDD – Boiler MACT

Boiler Nos. 3 and 5 are currently subject to Subpart DDDDD as existing fluidized bed units designed to burn coal/solid fossil fuel.

As described previously, the proposed changes to Boiler Nos. 3 and 5 cost approximately $23 million each. The cost of new comparable WWTR and gas fired boiler is approximately $78 million each. Therefore, the proposed project does not meet the definition of reconstruction as the costs are less than 50% of that for a comparable new unit. As the units are not reconstructed, Boiler Nos. 3 and 5 will continue to be subject to Subpart DDDDD as existing units.

40 CFR 63.7575 provides the following boiler classifications:

> *Unit designed to burn biomass/bio-based solid subcategory includes any boiler or process heater that burns at least 10 percent biomass or bio-based solids on an annual heat input basis in combination with solid fossil fuels, liquid fuels, or gaseous fuels.*
>
> *Unit designed to burn coal/solid fossil fuel subcategory includes any boiler or process heater that burns any coal or other solid fossil fuel alone or at least 10 percent coal or other solid fossil fuel on an annual heat input basis in combination with liquid fuels, gaseous fuels, or less than 10 percent biomass and bio-based solids on an annual heat input basis.*

WWTR is classified as biomass under Boiler MACT regulations. Under current operating plans, Boiler No. 3 may fire more than 10 percent biomass and would therefore be subject to limits for fluidized bed biomass boilers. This value will be verified on an annual basis. If annual heat input is less than 10% biomass, coal/solid fossil fuel limits will apply. Boiler No. 5 will fire more than 10 percent biomass (WWTR) and will be subject to the emissions limits for fluidized bed biomass boilers.

Specifically, per Table 2 to Subpart DDDDD, existing units designed to burn solid fuel are limited to 2.0E-02 lb/MMBtu for HCl and 5.4E-06 lb/MMBtu for Mercury. Per Table 2 existing units designed to burn coal/solid fossil fuel are limited to 0.039 lb/MMBtu filterable PM or 5.3e-5 lb/MMBtu for total select metals (TSM). Fluidized bed units designed to burn biomass/bio-based solids are limited to 7.4-03 lb/MMBtu of filterable particulate matter or 6.4E-05 lb/MMBtu for TSM. CO is limited to 230 ppm and 310 ppm, respectively for fluidized bed units designed to burn coal/solid fossil and designed to burn biomass/biobased solid. The CO limits are by volume on a dry basis corrected to 3 percent oxygen on a 30-day rolling average with CEMs.

Boiler Nos. 3 and 5 will continue to operate the existing continuous emissions monitoring system (CEMS) for compliance with the CO limit. Stack testing and resulting applicable operating limits will be utilized to demonstrate compliance with the emission limits per Tables 4, 5, 7, and 8. Boiler Nos. 3 and 5 will continue to operate a continuous oxygen trim system that maintains an optimum air to fuel ratio. Tune-ups and Definition 1 of start-up will be conducted per Table 3 Work Practice Standards. Boiler Nos. 3 and 5 will continue to comply with the alternate TSM limit.

Boiler No. 7 will be a new unit in the "designed to burn gas 1" subcategory. No emission limits are designated for this subcategory. Boiler No. 7 is expected to operate a continuous oxygen trim system that maintains an optimum air to fuel ratio and will meet the tune-up requirements in Table 3 Work Practice Standards.

4.1.6. Compliance Assurance Monitoring – 40 CFR 64

EPA's Compliance Assurance Monitoring (CAM) requirements are implemented through Title V operating permits and apply to emissions units that use a control device to achieve compliance with an emissions limit and whose pre-controlled emissions are greater than the major source threshold. Per 40 CFR 64.1, a "control device" is "equipment other than inherent process equipment". "Inherent process equipment" is defined as "equipment that is necessary for the proper or safe functioning of the process, or material recovery equipment that the owner or operator documents is installed and operated primarily for purposes other than compliance with air pollution regulations." Emission units may be exempt from CAM requirements if the emission limits they are meeting are NSPS or NESHAP proposed after November 15, 1990 (40 CFR 64.2(b)(1)(i)) or if a part 70 permit specifies a continuous compliance determination method (40 CFR 64.2(b)(1)(vi)).

Boiler Nos. 3 and 5 have emission limits with controls for PM, NO_X, and HCl. The uncontrolled emissions of HCl and Hg are below the major source thresholds. The NO_X emissions are currently required by the Title V permit to be monitored by a CEMS. As there is already a continuous monitoring requirement, CAM is not required or necessary. PM emissions from the baghouse have an existing CAM plan that may continue to apply after the proposed modifications. Please note that GP requested removal of the PM CAM plan in the Title V Renewal draft permit comments as these units are subject to the Boiler MACT standard and demonstrate compliance with the PM alternative Total Selected Metals (TSM) emission limit and daily opacity average limit of 10% upon the compliance date of January 31, 2016.

Boiler No. 7 will use Low NO_X Burners to meet emission limits for NSPS Subpart Db. These limits are for regulations proposed after 1990 and include a continuous monitoring requirement. Therefore, CAM does not apply.

4.2. GEORGIA AIR QUALITY REGULATIONS

Georgia has promulgated air pollution control requirements under Georgia Rules for Air Quality Control (GRAQC) Chapter 391-3-1. Most of these regulations are part of the Georgia state implementation plan (SIP) for compliance with the Clean Air Act and most SIP regulations are federally enforceable. Generally applicable requirements, such as those pertaining to requirements to obtain air quality permits and malfunction reporting, are not discussed because these requirements are widely recognized as being applicable to significant sources of air pollution. A brief discussion of both applicable and key non-applicable requirements is included in this section.

4.2.1. Fuel-Burning Equipment

GRAQC 391-3-1-.02(2)(d), *Fuel-Burning Equipment,* regulates emissions of PM, opacity, and NO_X from fuel-burning equipment. Boiler Nos. 3, 5, and 7 are subject to this regulation. PM is limited to 0.1 lb/MMBtu for Boiler Nos. 3, 5, and 7 as the units have a heat input greater than 250 MMBtu/hr. Opacity is limited to 20% except for one six-minute period per hour of not more than 27%. NO_X is limited to 0.2 lb/MMBtu for natural gas.

4.2.2. VOC Emissions from Major Sources - GRAQC 391-3-1-.02(2)(tt)

This regulation limits VOC emissions for certain counties in Georgia, as outlined in 391-3-1-.02(2)(tt)3. SRM is located in Effingham County, and therefore, this rule does not apply.

4.2.3. NOx Emissions from Major Sources - GRAQC 391-3-1-.02(2)(yy)

This regulation limits NO_x emissions for certain counties in Georgia, as outlined in 391-3-1-.02(2)(yy)2. SRM is located in Effingham County, and therefore, this rule does not apply.

4.2.4. NOx Emissions from Fuel-Burning Equipment - GRAQC 391-3-1-.02(2)(lll)

GRAQC 391-3-1-.02(2)(lll) sets a limit for the emissions of NOx for certain fuel-burning equipment installed or modified on or after May 1, 1999. Per GRAQC 391-3-1-.02(2)(lll)6.(iii)(I), the requirements of this regulation do not apply to fuel-burning equipment in Effingham County and therefore, this rule does not apply.

4.2.5. NOx Emissions from Small Fuel-Burning Equipment - GRAQC 391-3-1-.02(2)(rrr)

This regulation sets forth NO_x emissions limits and work practices for small fuel-burning equipment in certain counties in Georgia, as outlined in 391-3-1-.02(2)(rrr)4.(ii). SRM is located in Effingham County which is not listed in the definition of affected unit for this rule and therefore, this rule does not apply to the facility.

4.2.6. Prevention of Significant Deterioration of Air Quality - GRAQC 391-3-1-.02(7)

See Section 4.1.1 above for discussion of PSD applicability.

4.2.7. New Source Performance Standards - GRAQC 391-3-1-.02(8)

See Section 4.1.3 above for discussion of NSPS applicability.

4.2.8. Emission Standards for Hazardous Air Pollutants - GRAQC 391-3-1-.02(9)

See Section 4.1.4 above for discussion of NESHAP applicability.

5. BEST AVAILABLE CONTROL TECHNOLOGY (BACT) ASSESSMENT

5.1. BACT OVERVIEW

The Georgia regulations require that applicants for a PSD preconstruction permit conduct a BACT analysis for all regulated pollutants emitted in significant quantities from new or modified major stationary sources to demonstrate compliance with Federal PSD regulations, which are incorporated by reference in Georgia Rule 391-3-1-.02(7). The federal regulations define BACT:

> *"an emissions limitation (including a visible emissions standard) based on the maximum degree of reduction for each regulated NSR pollutant that would be emitted from any proposed major stationary source or major modification that which the [Georgia EPD Director], on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60 and 61. If the [Georgia EPD Director] determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results."*

The USEPA and Georgia EPD recommend that a "top down" approach be used to conduct the BACT analysis. This process begins with the identification of the alternative control technologies available for the source category based upon a review of:

- Those technologies required by previous BACT determinations made by the USEPA or state agencies; and
- Those technologies applied in practice to the same category or a similar source category by means of technology transfer.

The available control technologies are then evaluated to determine whether they are technically feasible for the given application. Those control technologies found to be technically infeasible are eliminated from further consideration, while the remaining control technologies are ranked by their performance levels, from the highest to the lowest performance level. The technically feasible control technologies are then evaluated based on the associated economic, energy and environmental impacts. If an alternative technology, starting with the highest performance level, is eliminated based on any of these criteria, the control technology with the next highest performance level is evaluated until a control technology qualifies as BACT.

Historically, the cost effectiveness of alternative control technologies in reducing air pollutant emissions is the principal criterion used to assess the economic feasibility of a particular emissions control alternative in their determinations of BACT. All evaluated control technologies must be capable of meeting the NSPS for the pollutant in question, i.e., NSPS is the BACT-floor.

According to USEPA guidance[6], potentially applicable BACT candidates can be categorized in three ways:

- Inherently lower-emitting processes or practices;
- Add-on controls; and
- Combinations of inherently lower-emitting processes and add-on controls.

Consideration of lower-emitting processes through a change in raw materials is generally only considered for industrial processes that use chemicals, such as solvents, where substitution with a lower emitting chemical may be technically feasible. In this instance, consideration of any alternate fuels as lower-emitting processes is inappropriate for two reasons. Natural gas (the supplemental fuel that will be used in Boilers 3 and 5 and the only fuel to be used in Boiler 7) is the lowest emitting fuel for most NSR pollutants. Since the primary purpose of the modifications to Boilers 3 and 5 is to convert the Boiler 5 primary fuels from petroleum coke and coal to wastewater treatment plant residuals (WWTR) and allow Boiler 3 to burn more WWTR, consideration of any other fuel besides WWTR would constitute redefinition of Boilers 3 and 5. Historically, EPA has recognized that a BACT option which fundamentally redefines the source may be excluded from consideration as an available alternative in Step 1 of the BACT assessment process[7].

In summary, the EPA and GA EPD's "top-down" BACT process consists of five steps as outlined below:

- Step 1 - Identify all available control options with potential for application to the specific emission unit for the regulated pollutant under evaluation;
- Step 2 - Eliminate technically infeasible options;
- Step 3 - Rank remaining control technologies by control effectiveness;
- Step 4 - Evaluate most effective controls and document results to determine if energy, environmental, and economic impacts are reasonable; if top option is not selected as BACT, evaluate next most effective control option; and
- Step 5 - Select BACT, which will be the most effective option not rejected based on energy, environmental, and economic impacts.

[6] USEPA "NSR Workshop Manual," Section B.IV.A, October 1990.
[7] USEPA "NSR Workshop Manual," Section B.V.A.3, October 1990.

The "top-down" approach was used in this analysis to evaluate available air emission controls for CO and GHG emissions from Boilers 3, 5 and 7.

5.2. BACT FOR CARBON MONOXIDE

5.2.1. Formation

CO emissions are generated during fuel combustion due to incomplete conversion of carbon-containing compounds in the fuel to CO_2 and water. CO emission rates are principally influenced by equipment operating conditions. Higher CO emissions may be the result of lower than optimal combustion temperature, insufficient combustion residence time, and low fuel firing rates.

5.2.2. Step 1 - Available CO Control Alternatives

Available control technologies to reduce CO emissions from fuel combustion sources include an oxidation catalyst and good combustion practices; each of these alternatives are discussed in the following sections.

Oxidation Catalyst

An oxidation catalyst is a post-combustion technology that removes CO from the exhaust gas stream after it is formed in the boiler combustion zone. In the presence of a catalyst, CO will react with oxygen present in the boiler exhaust, converting it to carbon dioxide. No supplementary reactant is used in conjunction with an oxidation catalyst.

Oxidation catalyst systems seek to remove pollutants from the combustion exhaust gas rather than limiting pollutant formation at the source. Oxidation of CO to CO_2 utilizes the excess oxygen present in the exhaust; the activation energy required for the oxidation reaction to proceed is lowered in the presence of the catalyst. Technical factors relating to this technology include the catalyst reactor design, optimum operating temperature, back pressure loss to the system, catalyst life, and potential collateral increases in emissions of particulate matter and sulfuric acid mist.

CO catalytic oxidation systems operate in a relatively narrow temperature range (600 - 800°F, depending on the specific catalyst formulation). At lower temperatures, CO conversion efficiency falls off rapidly. At higher temperatures, catalyst sintering may occur, thus causing permanent damage to the catalyst. For this reason, the CO catalyst is placed at a location in the boiler that is selected to ensure that the proper operating temperature is maintained, considering the temperature variations that are expected to occur across the unit's operating load range.

Catalyst life may vary from the manufacturer's typical 3-year guarantee to a 5- to 6-year predicted life. Periodic testing of catalyst material is necessary to predict annual catalyst life for a given installation to minimize CO emissions.

Combustion Controls/Good Combustion Practices

As noted above, CO is formed during the combustion process due to incomplete combustion of the carbon present in the fuel. The formation of CO is limited by designing and operating the combustion system to maximize oxidation of the fuel carbon to CO_2. Proper burner design and optimization of a boiler's combustion air feed systems to achieve good combustion efficiency will minimize the generation of CO emissions from boilers.

The modifications planned for Boilers 3 and 5 will include secondary combustion air systems to be installed in conjunction with new gas-fired load burners on each boiler. The secondary air systems will promote good fuel-air mixing, complete fuel combustion and reduce CO emissions. In-duct gas burners will also be included on each boiler to provide additional flexibility to keep each unit's fluidized bed temperature sufficiently high to promote CO burnout during low-load operating conditions.

Boiler 7 will be equipped with a natural gas burner that will be designed to promote combustion efficiency (and thereby decrease CO emissions) while at the same time decreasing nitrogen oxide formation. Such burners employ burner operating features such as fuel or air staging and internal exhaust gas recirculation within the burner flame; collectively such features to promote combustion efficiency are referred to as combustion controls.

5.2.3.Step 2 – Technical Feasibility Assessment of CO Control Alternatives

Boilers 3 and 5

It is not feasible to conduct a search of the RBLC listings for boilers with precisely the same fuel mix as will be utilized in Boilers 3 and 5, as the Clearinghouse does not have a specific process code for classifying boilers burning wastewater treatment plant residuals and natural gas. Therefore, a search of the RBLC for boilers with similar configurations and fuel types that have been permitted in the past 10 years was performed. This search encompassed boilers categorized using Process Codes 11.19 (fluidized bed boilers burning solid fuels), 11.12 (wood, wood waste and other biomass-fired boilers), and 21.5 (sewage sludge-fired boilers or incinerators). This search identified a total of 51 listings of solid- and mixed-fuel fired combustion units with BACT determinations for CO; sixteen of these units are described as fluidized bed boilers, eighteen are mixed-fuel fired boilers where the firing type is undefined, eleven are stoker units or hybrid suspension/stokers, four are pulverized coal units modified to burn biomass, and two are sludge incinerators. The CO emissions technology that is employed by the boiler is identified in 39 of these listings. Six of the listings describes the use of an oxidation catalyst or catalytic reactor as the CO control alternative, and the other 30 listings describe good combustion, staged combustion, or boiler design as the CO control alternative. These RBLC search results are summarized in Table 5-1.

The single mixed-fuel boiler unit listing in the RBLC that has been permitted in the past 10 years with a BACT limit on CO emission listed as employing an oxidation catalyst system (Sun Bio Material Company in Arkadelphia, AR) has not been constructed[8] and plans to construct the paper mill where the boiler would have been located have been terminated[9].

For an oxidation catalyst system to be utilized on a solid fuel-fired boiler, the catalyst grid would need to be installed downstream of the boiler's particulate matter control device to avoid plugging the catalyst

[8] Email communication dated January 18, 2022 from Thomas Rheaume, PE, Office of Air Quality, Arkansas Division of Environmental Quality.

[9] "$1.5 billion Sun Paper Project Near Arkadelphia Officially Terminated," https://talkbusiness.net/2020/03/1-5-billion-sun-paper-project-near-arkadelphia-officially-terminated/, retrieved January 14, 2022.

with solid material. As noted above, the catalyst needs to be installed in a location where the boiler exhaust gas temperature is within its acceptable operating range.

Consequently, the particulate matter control system needs to be capable of operating at or above the required operating temperature of the catalyst grid (600°F or higher). The fabric filter systems that are currently utilized on Boilers 3 and 5 are not capable of operating in this range, and therefore would need to be replaced by hot-side electrostatic precipitators (ESPs) in order for catalytic oxidation to be technically feasible on these specific boilers. In addition, to make room for the ESP and catalyst grid to be installed within an appropriate temperature range, a portion of each boiler's economizer would need to be removed. As explained further below, the removal of the economizer portion would cause a decrease in the operating efficiency of each boiler because feedwater would be introduced to each boiler at a lower temperature.

Therefore, while oxidation catalyst systems and combustion controls are considered to be technically feasible alternatives for control of CO emissions from Boilers 3 and 5, substantial additional modifications would need to be made to each boiler in order to accommodate this alternative.

Table 5-1: RACT/BACT/LAER Clearinghouse Search Results – CO Emission Controls for Mixed Fuel-Fired Combustion Units

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	BOILER TYPE	FUELS	THROUGHPUT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
AR-0161	SUN BIO MATERIAL COMPANY	AR	9/23/2019	Power Boiler	Bubbling Fluidized Bed Boiler	Biomass	1200 MMBtu/H	Oxidation Catalyst	0.075	LB/MMBTU
FL-0362	HIGHLANDS ENVIROFUELS	FL	9/13/2017	Cogeneration Biomass Boiler	Hybrid suspension/stoker	Bagasse	458 MMBtu/hr	Oxidation catalyst	0.3	LB/MMBTU
AK-0084	DONLIN GOLD PROJECT	AK	6/30/2017	Incinerator (Sewage Sludge)	Sludge Incinerator	Sewage Sludge	0.06 ton/day	Good Combustion Practices		
KS-0034	ABENGOA BIOENERGY BIOMASS OF KANSAS (ABBK)	KS	5/27/2014	biomass to energy cogeneration bioler	Not listed	different types of biomass	500 MMBtu/hr	Oxidation catalyst	0.23	LB/MMBTU
CA-1225	SIERRA PACIFIC INDUSTRIES-ANDERSON DIVISION	CA	4/25/2014	STOKER BOILER (NORMAL OPERATION)	Stoker	BIOMASS	468 MMBTU/H	Good combustion practices	0.23	LB/MMBTU
VT-0039	NORTH SPRINGFIELD SUSTAINABLE ENERGY PROJECT	VT	4/19/2013	Wood Fired Boiler	Bubbling Fluidized Bed Boiler	wood	464 MMBTU/H	Bubbling fluidized bed boiler design	0.075	LB/MMBTU
VA-0316	ALTAVISTA POWER STATION	VA	5/23/2012	BIOMASS-FIRED, SPREADER STOKER BOILERS, (2)	Spreader Stoker	Woody Biomass	394 MMBTU/H	Good combustion practices (GCP); enhanced over-fire air	0.3	LB/MMBTU
VA-0317	HOPEWELL POWER STATION	VA	5/23/2012	BIOMASS-FIRED, SPREADER STOKER BOILERS, (2)	Spreader Stoker	Woody Biomass	394 mmBTU/H	Good combustion practices (GCP); enhanced over-fire air	0.3	LB/MMBTU
VA-0318	SOUTHAMPTON POWER STATION	VA	5/23/2012	BIOMASS-FIRED, SPREADER STOKER BOILERS, (2)	Spreader Stoker	Woody Biomass	394 MMBTU/H	Good combustion practices (GCP); enhanced over-fire air	0.3	LB/MMBTU
CA-1193	RIO BRAVO JASMIN COGENERATION	CA	5/15/2012	CIRCULATING FLUIDIZED BED COMBUSTION BOILER (NORMAL OPERATION)	Fluidized Bed Boiler	COAL, PET COKE, BIOMASS	389 MMBTU/H		0.27	LB/MMBTU
CA-1194	RIO BRAVO POSO COGENERATION	CA	5/15/2012	CIRCULATING FLUIDIZED BED BOILER (NORMAL OPERATION)	Fluidized Bed Boiler	COAL, PET COKE, BIOMASS	389 MMBTU/H		0.27	LB/MMBTU
WI-0259	MANITOWOC PUBLIC UTILITIES	WI	4/16/2012	B09 - Circulating Fluidized Bed Boiler	Fluidized Bed Boiler	coal, petroleum coke, paper pellets, and renewable biomass fuels	650 MMBtu per hour		0.15	LB/MMBTU
WI-0259	MANITOWOC PUBLIC UTILITIES	WI	4/16/2012	B08 - Circulating Fluidized Bed Boiler	Fluidized Bed Boiler	coal, petroleum coke, paper pellets, and renewable biomass fuels	270 MMBtu per hour		0.36	LB/MMBTU
VT-0037	BEAVER WOOD ENERGY FAIR HAVEN	VT	2/10/2012	Main Boiler	Not listed	wood	482 MMBTU/H	Good combustion control and a Multi Pollutant Catalytic Reactor	0.075	LB/MMBTU
*PA-0280	DELAWARE CNTY REG WA/DELCORA WESTERN REG	PA	8/24/2011	SEWAGE SLUDGE INCINERATOR 1 & 2	Sludge Incinerator	sewage sludge, natural gas, No. 2 oil				
TX-0599	LAS BRISAS ENERGY CENTER	TX	4/19/2011	CFB BOILER	Fluidized Bed Boiler	PET COKE, NATURAL GAS OR PROPANE	3080 MMBTU/H EACH	GOOD COMBUSTION PRACTICE	0.1	LB/MMBTU
OH-0338	DP & L, KILLEN GENERATING STATION	OH	12/29/2010	Utility Boiler, dry bottom, wall-fired	Dry bottom PC, modified to fire	Coal, biomass	5928 MMBtu/H	Good combustion practices	0.15	LB/MMBTU
CT-0162	PLAINFIELD RENEWABLE ENERGY, LLC	CT	12/29/2010	Fluidized Bed Gasification	Fluidized Bed	Wood	523.1 MMBtu/hr	Good Combustion	0.105	LB/MMBTU
OH-0338	DP & L, KILLEN GENERATING STATION	OH	12/29/2010	Utility Boiler, dry bottom, wall-fired	Dry bottom PC, modified to fire	Coal and briquetted wood, grass or other clean cellulosic biomass	5928 MMBtu/H	Good combustion practices	0.15	LB/MMBTU
GA-0141	WARREN COUNTY BIOMASS ENERGY FACILITY	GA	12/17/2010	Boiler, Biomass Wood	Bubbling Fluidized Bed Boiler	Biomass wood	100 MW	Good design and operating practices.	0.08	LB/MMBTU
GA-0140	MITCHELL STEAM-GENERATING PLANT (PLANT MITCHELL)	GA	12/3/2010	Boiler, Wood-Fired	Stoker	Wood, Biomass	96 MW	Good Combustion Practices	0.45	LB/MMBTU
ME-0037	VERSO BUCKSPORT LLC	ME	11/29/2010	Biomass Boiler 8	Not listed	Biomass, oil, natural gas	814 MMBTU/H		0.3	LB/MMBTU
SC-0117	SPRINGS GLOBAL US, INC. - GRACE COMPLEX	SC	11/6/2010	UTILITY- AND LARGE INDUSTRIAL-SIZE BOILERS/FURNACES	Not listed	WOOD BIOMASS	260 MMBTU/H	OVERFIRE AIR AND GOOD COMBUSTION PRACTICES	0.45	LB/MMBTU
OH-0343	SMART PAPERS-HAMILTON MILL	OH	11/1/2010	Pulverized Dry-Bottom Boiler	Dry bottom PC, modified to fire	Coal, sludge, wood, biomass	420 MMBtu/H	Use of over-fire air with good combustion practices	0.15	LB/MMBTU
OH-0343	SMART PAPERS-HAMILTON MILL	OH	11/1/2010	Pulverized Dry-Bottom Boiler	Dry bottom PC, modified to burn	Coal, paper mill sludge, clean wood, biomass, or fuel pellets	420 MMBtu/H	Use of over-fire air with good combustion practices	0.15	LB/MMBTU

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	BOILER TYPE	FUELS	THROUGHPUT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
CA-1203	SIERRA PACIFIC INDUSTRIES-LOYALTON	CA	8/30/2010	RILEY SPREADER STOKER BOILER - Transient Period (see notes)	Spreader Stoker	WOOD	335.7 MMBTU/H	RILEY STOKER BOILER SHALL BE OPERATED WITH HIGH	2.30	LB/MMBTU
CA-1203	SIERRA PACIFIC INDUSTRIES-LOYALTON	CA	8/30/2010	RILEY SPREADER STOKER BOILER	Spreader Stoker	WOOD	335.7 MMBTU/H	RILEY STOKER BOILER SHALL BE OPERATED WITH HIGH PRESSURE	1.64	LB/MMBTU
NH-0018	BURGESS BIOPOWER	NH	7/26/2010	EU01 BOILER #1	Bubbling Fluidized Bed Boiler	Wood chips	1013 MMBTU/H	BFB BOILER DESIGN AND FGR	0.15	LB/MMBTU
CA-1210	MT. POSO COGENERATION COMPANY	CA	7/21/2010	CIRCULATING FLUIDIZED BED BOILER	Fluidized Bed Boiler	Coal, Coke, Biomass, and TDF	650 MMBTU/H		0.077	LB/MMBTU
CT-0156	MONTVILLE POWER LLC	CT	4/6/2010	42 MW Biomass utility boiler	Not listed	Clean wood	600 MMBTU/H	Oxidation Catalyst	0.1	LB/MMBTU
TX-0553	LINDALE RENEWABLE ENERGY	TX	1/8/2010	Wood fired boiler	Stoker	biomass	73 T/H	Good combustion practices	0.31	LB/MMBTU
TX-0555	LUFKIN GENERATING PLANT	TX	10/26/2009	Wood-fired Boiler	Stoking grate	wood	693 MMBtu/H	Good combustion practices	0.075	LB/MMBTU
GA-0132	YELLOW PINE ENERGY COMPANY, LLC	GA	12/3/2008	BUBBLING FLUIDIZED BOILER	Fluidized Bed	BIOMASS	1529 BTU/H HEAT		0.149	LB/MMBTU
LA-0223	BIG CAJUN I POWER PLANT	LA	1/8/2008	CFB BOILER	Fluidized Bed Boiler	PETROLEUM COKE, COAL, BIOMASS, BAGASSE, AND NON-CHEMICALLY TREATED WOOD PRODUCTS	2330 MMBTU/H	CIRCULATING FLUIDIZED BED TECHNOLOGY AND GOOD	0.1	LB/MMBTU
MN-0074	KODA ENERGY	MN	8/23/2007	BIOMASS BOILER 4	Not listed	Biomass		GOOD COMBUSTION PRACTICE	0.43	LB/MMBTU
WA-0335	SIMPSON TACOMA KRAFT COMPANY, LLC	WA	5/22/2007	UTILITY AND LARGE INDUSTRIAL SIZED BOILERS/FURNACES	Not listed	WOOD WASTE (INCLUDING RECYCLED CARDBOARD), WASTEWATER TREATMENT SLUDGE,	595 MMBTU/H	OVERFIRE AIR SYSTEM INSTALLED IN 2006 TO IMPROVE COMBUSTION	0.35	LB/MMBTU
ND-0022	NORTHERN SUN	ND	5/1/2006	WOOD/HULL FIRED BOILER	Not listed	Biomass (nut hulls), railroad ties, clean wood		GOOD COMBUSTION PRACTICES	0.63	LB/MMBTU
OH-0307	SOUTH POINT BIOMASS GENERATION	OH	4/4/2006	WOOD FIRED BOILERS (7)	Not listed	WOOD	318 MMBTU/H	OXIDATION CATALYST	0.1	LB/MMBTU
LA-0202	RODEMACHER BROWNFIELD UNIT 3	LA	2/23/2006	CFB BOILERS UNITS 3-1; 3-2	Fluidized Bed Boiler	PET COKE/COAL, WOOD BIOMASS	3006 MMBTU/H	CFB TECHNOLOGY WITH GOOD COMBUSTION PRACTICES	0.1	LB/MMBTU
WA-0337	BOISE WHITE PAPER LLC	WA	2/1/2006	UTILITY-AND LARGE INDUSTRIAL-SIZE BOILERS/FURNACES (>250 MILLION BTU/H)	Not listed	WOOD/BARK, NATURAL GAS	343 MMBTU/H	OVERFIRE AIR SYSTEM ADDED TO IMPROVE THE BOILER'S COMBUSTION	0.34	LB/MMBTU
WA-0327	SKAGIT COUNTY LUMBER MILL	WA	1/25/2006	WOOD-FIRED COGENERATION UNIT	Not listed	BARK & WASTE WOOD	430 mmBtu/H		0.35	LB/MMBTU
WA-0329	DARRINGTON ENERGY COGENERATION POWER	WA	2/11/2005	WOOD WASTE-FIRED BOILER	Not listed	WOOD WASTE	403 MMBtTU/H	GOOD COMBUSTION PRACTICES	0.35	LB/MMBTU
LA-0188	BOGALUSA MILL	LA	11/23/2004	NO. 12 HOGGED FUEL BOILER	Not listed	BARK, OCC REJECTS	787.5 MMBTU/H	EXISTING OVERFIRE AIR SYSTEM AND GOOD COMBUSTION PRACTICES	0.6	LB/MMBTU
NH-0013	SCHILLER STATION	NH	10/25/2004	BOILER, WOOD FIRED CFB, UNIT #5	Fluidized Bed Boiler	BIOMASS, COAL	720 MMBTU/h	GOOD COMBUSTION PRACTICES WITH THE FLUIDIZED BED DESIGN	0.1	LB/MMBTU
GA-0114	INLAND PAPERBOARD AND PACKAGING, INC. - ROME	GA	10/13/2004	BOILER, SOLID FUEL	Fluidized Bed Boiler	BARK	856 MMBTU/H	STAGED COMBUSTION AND GOOD COMBUSTION PRACTICES	0.26	LB/MMBTU
FL-0257	CLEWISTON SUGAR MILL AND REFINERY	FL	11/18/2003	EXTERNAL COMBUSTION, MULTIPLE FUELS	Not listed	BAGASSE	936 MMBTU/H	GOOD COMBUSTION AND OPERATING PRACTICES	0.38	LB/MMBTU
LA-0178	DERIDDER PAPER MILL	LA	11/14/2003	WOOD-FIRED BOILER	Not listed	BARK	454.29 MMBTU/H	GOOD EQUIPMENT DESIGN AND PROPER COMBUSTION TECHNIQUES	0.33	LB/MMBTU
MS-0075	GEORGIA PACIFIC CORPORATION, MONTICELLO	MS	7/9/2003	COMBINATION BOILER	Not listed	SCRAP WOOD, SLUDGE, TDF	917.4 MMBTU/H		1.38	LB/MMBTU
MS-0075	GEORGIA PACIFIC CORPORATION, MONTICELLO	MS	7/9/2003	COMBINATION BOILER	Not listed	SCRAP WOOD	917.4 MMBTU/H		1.38	LB/MMBTU
MN-0057	FIBROMINN BIOMASS POWER PLANT	MN	10/23/2002	BOILER, MULTIFUEL	Not listed	Turkey manure and other biomass	792 mmbtu/h	GOOD COMBUSTION PRACTICES	0.24	LB/MMBTU
WA-0298	ABERDEEN DIVISION	WA	10/17/2002	HOG FUEL BOILER	Spreader Stoker	WASTE WOOD	310 MMBTU/H	GOOD COMBUSTION	0.35	LB/MMBTU

Boiler 7

A search of EPA's RBLC was performed to identify natural gas-fired boilers with a heat input rates between 250 and 500 MMBtu/hr permitted in the past 10 years with BACT determinations for CO. The RBLC search found a total of 21 listings meeting these criteria with emission limitations for CO; 20 of these listings describe the CO emissions control technology that is employed. The RBLC search results for natural gas-fired boilers are summarized in Table 5-2.

Of the 21 natural gas-fired boiler unit listings in the RBLC with heat input rates in the range proposed for Boiler 7 (285 MMBtu/hr) permitted in the past 10 years that describe the CO emissions control technology employed, two listings describe the use of an oxidation catalyst system as BACT. The RBLC search results found that combustion controls alone (including combustor design or good combustion practices) were concluded to be representative of BACT for a total of 16 of the 21 natural gas-fired RBLC boiler entries where the emission control technology was identified.

Accordingly, an oxidation catalyst system and combustion controls are considered to be technically feasible CO emissions control alternatives for the proposed natural gas-fired boiler.

Table 5-2: RACT/BACT/LAER Clearinghouse Search Results – CO Emission Controls for Natural Gas-Fired Boilers

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT		CONTROL METHOD DESCRIPTION	EMISSION LIMIT	
*LA-0394	GEISMAR PLANT	LA	12/12/2023	01-22 - AO-5 Boiler	350	MM BTU/hr	Use of good operating practices	0.037	LB/MMBTU
TX-0936	BILL GREEHEY REFINERY EAST PLANT	TX	3/29/2022	BOILER	334	MMBTU/HR	Gaseous fuel and good combustion practices	0.037	LB/MMBTU
TX-0888	ORANGE POLYETHYLENE PLANT	TX	4/23/2020	BOILERS	250	MMBTU	Good combustion practice and proper design.	0.037	LB/MMBTU
KS-0041	HOLLYFRONTIER EL DORADO REFINERY	KS	10/30/2019	New Boiler	360.2	MMBTU/H	Ultra Low NOx Burners	0.035	LB/MMBTU
MI-0440	MICHIGAN STATE UNIVERSITY	MI	5/22/2019	EUSTMBOILER	300	MMBTU/H	Good combustion control practices.	0.05	LB/MMBTU
*TN-0163	HOLSTON ARMY AMMUNITION PLANT	TN	10/8/2018	Four Boilers, Natural Gas & No. 2 Oil-Fired	327	MMBtu/hr, each boiler	Oxidation catalyst & good combustion practices	0.035	LB/MMBTU
LA-0346	GULF COAST METHANOL COMPLEX	LA	1/4/2018	Inline Boilers (4)	258	mm btu/hr	Catalytic oxidation	0.008	LB/MMBTU
*LA-0312	ST. JAMES METHANOL PLANT	LA	6/30/2017	B1-13 - Boiler 1 (EQT0003)	350	MM BTU/hr	Good Combustion Practices	0.038	LB/MMBTU
*LA-0312	ST. JAMES METHANOL PLANT	LA	6/30/2017	B2-13 - Boiler 2 (EQT0004)	350	MM BTU/hr	Good Combustion Practices	0.038	LB/MMBTU
OH-0368	PALLAS NITROGEN LLC	OH	4/19/2017	Package Boilers (2 identical, B003 and B004)	265	MMBTU/H	good combustion control (i.e., high temperatures, sufficient excess air,	0.015	LB/MMBTU
LA-0323	MONSANTO LULING PLANT	LA	1/9/2017	No. 9 Boiler - Natural Gas Fired	325	MMBTU/h	Good combustion practices and Boiler MACT	0.045	LB/MMBTU
LA-0323	MONSANTO LULING PLANT	LA	1/9/2017	No. 10 Boiler - Natural Gas Fired	325	MMBTU/h	Good combustion practices and Boiler MACT	0.045	LB/MMBTU
IN-0234	GRAIN PROCESSING CORPORATION	IN	12/8/2015	BOILER 1	271	MMBTU/H	GOOD COMBUSTION PRACTICES	0.0365	LB/MMBTU
IN-0234	GRAIN PROCESSING CORPORATION	IN	12/8/2015	BOILER 2	271	MMBTU/H	GOOD COMBUSTION	0.0365	LB/MMBTU
IA-0109	CITY OF AMES STEAM ELECTRIC PLANT	IA	7/28/2015	Boiler 7	476	mmBtu/hr	Good combustion practices	0.2	LB/MMBTU
TX-0704	UTILITY PLANT	TX	12/2/2014	(2) boilers	450	MMBTU/H	good combustion practices	0.037	LB/MMBTU
TX-0704	UTILITY PLANT	TX	12/2/2014	boiler	250	MMBTU/H	good combustion practices	0.037	LB/MMBTU
WI-0272	PACKAGING CORPORATION OF AMERICA-TOMAHAWK	WI	7/15/2014	B12 Boiler	425	mmBTU/hr	Use of a CEMS to make the limitation more stringent	0.037	LB/MMBTU
ND-0032	SPIRITWOOD NITROGEN PLANT	ND	6/20/2014	Package boiler	280	MMBTU/H	good combustion practices	0.06	LB/MMBTU
OK-0162	ENID NITROGEN PLANT	OK	5/29/2014	Boiler	450	MMBTUH	Natural Gas Fuel, Good Combustion Practices	0.037	LB/MMBTU
ID-0021	MAGNIDA	ID	4/21/2014	PACKAGE BOILER	275	MMBtu/hr (HHV)	not listed	0.015	LB/MMBTU

5.2.4.Step 3 - Ranking of CO Control Alternatives by Control Effectiveness

Although the single mixed fuel-fired boiler found in the RBLC search that lists the use of an oxidation catalyst system as the control alternative for CO (Sun Bio Material Company) was never built, the engineering consultant for this project has concluded that it is technically feasible to retrofit this alternative on either Boiler 3 or Boiler 5. Consequently, the use of an oxidation catalyst system is considered to be the most stringent alternative for control of CO emissions from these units. Combustion control systems, including the secondary air system and in-duct burner that will be added as part of the boiler modifications, are next-most stringent alternative for control of CO emissions from this boiler.

Based on the results of the of the RBLC search, the use of an oxidation catalyst system is the most stringent alternative for control of CO emissions from any of the three boilers that are the subject of this application. The lowest emission limit among the six oxidation catalyst-equipped solid fuel boilers found in the RBLC search is 0.075 lb/MMBtu, and the lowest emission limit among the two oxidation catalyst-equipped small natural gas-fired boilers is 0.008 lb/MMBtu.

Combustion control systems are the next-most stringent alternative for control of CO from the boilers. The average emission limit for solid fuel boilers employing combustion controls found in the RBLC search is 0.26 lb/MMBtu, while a typical emission limit for natural gas-fired boilers equipped with combustion controls is 50 ppm @3% O_2 or 0.037 lb/MMBtu.

5.2.5.Step 4 - Evaluation of Technically Feasible CO Control Alternatives for Economic, Energy and Environmental Impacts

Analyses were conducted to evaluate the energy, environmental and economic aspects of employing oxidation catalyst systems to control CO emissions from Boilers 3, 5 and 7. The findings of these analyses are presented below.

- **Energy Penalty –** Use of an oxidation catalyst system to control CO emissions would impose an adverse energy penalty on either boiler primarily due to the additional combustion air fan energy to overcome the pressure drop imposed by the catalyst grid.

  As noted in Section 5.3.3, use of oxidation catalyst systems on Boilers 3 and 5 would necessarily require replacement of each unit's existing ambient temperature fabric filter particulate matter control system with a hot-side ESP. Therefore, in addition to the energy penalty associated with the catalyst grid, the energy requirements associated with the electrical power needed to operate the ESP would be imposed if an oxidation catalyst system was to be utilized on either Boiler 3 or Boiler 5. The project's engineering consultant estimates that the net increase in electrical requirements for this alternative on either boiler would be a total of 209 kw per boiler, or 1,830,840 kwhr/yr per boiler . Furthermore, removal of one of each boiler's air preheaters to accommodate the hot-side ESP and catalyst grid would reduce the steam generation efficiency of each unit by requiring that the feedwater be introduced to the boiler at a lower temperature. This would translate into an energy penalty amounting to an estimated additional $100,000/yr per boiler.

  According to the project's engineering consultant, the additional 2.5 inches w.c. of pressure drop imposed by the catalyst grid in Boiler 7 would require an additional 45 kw of combustion air fan power. Based on an annual operating schedule of 8,760 hours/yr, this amounts to an energy penalty of 394,000 kwhr/yr.

- **Environmental Impact** – The use of oxidation catalyst systems on Boilers 3, 5 or 7 would have relatively minor environmental impacts, consisting primarily of the impacts associated with preparation of the metal catalyst materials and disposing of spent catalyst materials following the end of their useful life.

- **Economic Impact** – Cost effectiveness assessments were carried out for the use of oxidation catalyst systems to control CO emissions from Boilers 3, 5 and 7. These analyses were conducted using the cost assessment methodology presented in the US EPA's Control Cost Manual[10] and vendor-supplied data. The results of these assessments are presented in Table 5-3. Note that although the vendor-supplied costs only guaranteed control of 50%, a conservative value of 80% was used based on published data. Additional site-specific studies would be required from the vendor to guarantee 80% reduction in CO.

As shown in Table 5-3, the cost per ton of CO reduction is approximately $12,000, $13,000, and $18,000 for Boiler Nos. 3, 5, and 7 respectively.

The Georgia EPD maintains a database of PSD permit applications that have been processed by the Division dating back to 2002. This database contains information on the twenty-two PSD permit applications that have been submitted to the Division for review in the past five years; six of these applications are for new sources or modifications of existing sources that triggered PSD review for CO. One of these applications is for a wood-fired boiler for Yellow Pine Energy Company, LLC in Fort Gaines, however a final permit for that facility has not been issued. No BACT review was required for CO for the paper machine expansion at Packaging Corporation of America's paper mill in Valdosta because the project's CO emissions increases occurred at affected but unmodified boilers.

The remaining four emission units subject to PSD for CO listed in the EPD database include:

- A wood-fired thermal oil heater for West Fraser's lumber mill replacement in Dudley,
- A new cement kiln/calciner for US Cement LLC in Perry,
- The addition of fuel oil as an approved fuel for the simple cycle combustion turbines at the Washington County Power Plant in Sandersville, and
- Various small natural gas-fired combustion units at the Hyundai Motor Group's new automobile assembly plant in Ellabell.

In each of these instances, BACT was concluded to be good combustion practices or proper design and operation of the emission unit. EPD concluded that add-on CO controls were not BACT on the basis of unreasonable economic impacts for two of these units. For US Cement, add-on CO controls were rejected as BACT at an estimated cost effectiveness of over $6,000 per ton controlled, and for the Washington County facility add-on CO controls were rejected as BACT at an estimated cost effectiveness of over $28,000 per ton controlled.

[10] EPA Control Cost Manual (7th Edition) – Section 1 (Introduction), Chapter 2 (Cost Estimation: Concepts and Methodology), EPA Office of Air Quality Planning and Standards, November 2017.

Oxidation catalyst systems to control CO emissions from Boiler Nos. 3, 5 and 7 are estimated to have annualized cost impacts that are similar to or higher than what EPD has previously concluded to be economically infeasible. Accordingly, oxidation catalyst systems are not concluded to be cost effective for CO control.

Table 5-3 Annualized Cost and Cost Effectiveness of Oxidation Catalyst Systems

	Boiler No. 3	Boiler No. 5	Boiler No. 7	Note
TOTAL INSTALLED CAPITAL COST (TIC)	$37,340,000	$37,340,000	$3,454,545	(1)
ANNUALIZED OPERATING COST				
Capital Recovery				(2)
30 year equipment life, 8% interest	$3,316,820	$3,316,820	$306,860	
Additional Electricity Cost				(3)
45 kw @ $0.04686/kwhr			$18,470	
209 kw @ $0.04686/kwhr	$85,790	$85,790		
Additional Energy Costs				
Boiler energy efficiency loss	$100,000	$100,000		(4)
Mantainance: Catalyst Replacement				(5)
$1,000,000 @5 year life	$200,000	$200,000	$200,000	
Indirect Annualized Costs				(6)
Taxes (1% of TIC)	$373,400	$373,400	$34,545	
Insurance (1% of TIC)	$373,400	$373,400	$34,545	
Administration (2% of TIC)	$746,800	$746,800	$69,091	
TOTAL ANNUAL OPERATING COST	$5,196,210	$5,196,210	$663,512	
Baseline annual CO emissions rate (tons/yr)	550	485	46	
Control effectiveness	80%	80%	80%	(7)
Annual emission reduction (tons/yr)	440	388	37	
Cost effectiveness ($/ton removed)	$11,812	$13,398	$17,956	

(1) Cost quotes provided by engineering consultant. Boiler Nos. 3 and 5, provided on September 12, 2024.
Boiler No. 7 cost quote provided for 99 MMBtu/boiler March 2023 for $1,200,000
Ratioed to current size as $3,454,545.45
Difference between May 2024 (latest available) and March 2023 CEPCI is negligible
with ratio of 800.2 to 799.1, so original cost value is used
(2) Prime rate is currently 8.00%
(3) Energy costs per Mill electricity costs, August 2024
Additional energy requirements per engineerng consultant estimates, February 2022
(4) Energy penalty due to dropping a section of the economizer to allow for Boiler Nos. 3 and 5 to accommodate
a hot side ESP, boiler engineering, February 2022
(5) ESI estimate, February 2022, $1,000,000 and a five year life.
(6) EPA Control Cost Manual, November 2017, Chapter 2.
(7) Engineering consultant provided costs for 50% control. As a conservative measure, 80% is used

The next-most stringent alternative for control of CO emissions (good combustion practices) is proposed as BACT for CO control from Boiler Nos. 3, 5 and 7. Consequently, an analysis of the energy, environmental and economic impacts that are associated with this alternative on each of the boilers is not required to be conducted.

5.2.6.Step 5 - CO BACT Conclusions

The use of oxidation catalyst systems to control CO emissions from Boiler 3, Boiler 5 and Boiler 7 is technically feasible on each unit, however utilizing these alternatives would require expenditure of significant capital and annual costs. At over $11,500/ton controlled for each boiler, this alternative is not cost-effective.

Accordingly, the next most stringent alternative (combustion controls) is considered representative of BACT for control of CO emissions from these units. The proposed emission limit for Boilers 3 and 5 is 310 ppmvd @3% O_2 and the proposed emission limit for Boiler 7 is 0.037 lb/MMBtu, or an emission level of 50 ppmvd @ 3% O_2.

5.3.BACT FOR CARBON DIOXIDE

5.3.1.Formation

GHG emissions that result from fuel combustion in any of the three boiler units (Boiler 3, Boiler 5, or Boiler 7) include carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). CO_2 is a necessary product of combustion from fuels containing carbon. For example, the theoretical combustion equation for methane, the primary component of natural gas, is:

$$CH_4 + 2\ O_2 \rightarrow CO_2 + 2\ H_2O$$

Consequently, CO_2 emissions are an essential and intended product of the chemical reaction between the fuel and the oxygen in which it burns and are not a byproduct caused by impurities in the fuel or by incomplete combustion. Since the control alternatives for CO_2 are the same for each boiler unit, this BACT review has been prepared for the units in general rather than for each individual unit.

As described previously, however, Boilers 3 and 5 are to be modified to burn wastewater treatment plant residuals. Because this material is produced by the microorganisms that populate the mill's wastewater treatment plant, it is a biogenic fuel rather than a fossil fuel. Boilers 3 and 5 are being modified to accept up to 41% wastewater treatment plant residuals on a heat input basis; when wastewater treatment plant residuals are fired at this level, 55% of each boilers' CO_2 emissions will be from the combustion of biogenic fuel.

5.3.2.Step 1 – Available CO_2 Control Alternatives

A search of EPA's RACT/BACT/LAER Clearinghouse was conducted to identify potential control options for CO_2 emissions from the proposed boiler units. In addition, relevant new and proposed federal emission standards, EPA guidance documents, and recently issued new source review permits for similar sources were reviewed.

The RBLC search results for CO_2 emissions from mixed fuel and natural-gas fired boilers are summarized in Tables 5-4 and 5-5, respectively. Based on the RBLC search results, no add-on control options for CO_2 emissions were identified. Many facilities listed some variation of the use of good combustion practices and low-GHG (clean) fuels as BACT for CO_2 emissions.

In addition to the technologies identified in the RBLC search, this analysis considers carbon capture and sequestration (CCS) as a potential control option from the proposed boiler units based on EPA guidance, a recent EPA rulemaking, and because this option has been identified as a possible alternative for CO_2 control for several recently submitted PSD projects in Georgia.

In November 2010, EPA released guidance for permit writers and permit applications to address BACT for GHGs in a document entitled "*PSD and Title V Permitting Guidance for Greenhouse Gases*"[11]; the document was subsequently issued with minor revisions in March 2011. In this document, the Agency stated that:

> "For the purposes of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is "available" for facilities emitting CO_2 in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing). For these types of facilities, CCS should be listed in Step 1 of a top-down BACT analysis for GHGs. This does not necessarily mean CCS should be selected as BACT for such sources. Many other case-specific factors, such as the technical feasibility and cost of CCS technology for the specific application, size of the facility, proposed location of the source, and availability and access to transportation and storage opportunities, should be assessed at later steps of a top-down BACT analysis. However, for these types of facilities and particularly for new facilities, CCS is an option that merits initial consideration…"

EPA reiterated and expanded on this guidance in a subsequent document "*Guidance for Determining Best Available Control Technology for Reducing Carbon Dioxide Emissions from Bioenergy Production*"[12]. Accordingly, CCS is included in this BACT review as a candidate CO_2 control alternative, although none of the industrial boilers that are the subject of this application are the types of facilities for which CCS is described by EPA in these guidance documents as an "available" pollution control technology.

Other CO_2 control technologies such as the use of alternative fuels (e.g., low-GHG hydrogen) were not considered as CO_2 control alternatives as none of the boilers that are the subject of this application have the capability to utilize fuels apart from those either already permitted or addressed by this project.

[11] "PSD and Title V Permitting Guidance for Greenhouse Gases," EPA-457-B-11-001 (March 2011).
[12] "Guidance for Determining Best Available Control Technology for Reducing Carbon Dioxide Emissions from Bioenergy Production," US EPA Office of Air and Radiation (March 2011)

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Table 5-4: RACT/BACT/LAER Clearinghouse Search Results – CO_2 Emission Controls for Mixed Fuel-Fired Boilers

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	BOILER TYPE	FUELS	THROUGHPUT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT
AR-0161	SUN BIO MATERIAL COMPANY	AR	9/23/2019	Power Boiler	Bubbling Fluidized Bed Boiler	Biomass	1200 MMBTU/H	Good Combustion Practices	211 LB/MMBtu
FL-0362	HIGHLANDS ENVIROFUELS	FL	9/13/2017	Cogeneration Biomass Boiler	Hybrid suspension/stoker	Bagasse	458 MMBtu/hr		0.42 lb/lb steam
AK-0084	DONLIN GOLD PROJECT	AK	6/30/2017	Incinerator (Sewage Sludge)	Sludge Incinerator	Sewage Sludge	0.06 ton/day	Good Combustion Practices	3934 ton/yr
FL-0359	CLEWISTON MILL	FL	11/29/2016	Boiler No. 9	Hybrid suspension grate	Bagasse	1077 MMBtu/hr	Use of low-emitting fuels and boiler efficiency	0.49 lb/lb steam
KS-0034	ABENGOA BIOENERGY BIOMASS OF KANSAS (ABBK)	KS	5/27/2014	biomass to energy cogeneration bioler	Not listed	different types of biomass	500 MMBtu/hr	Restriction of fuels to biomass, energy efficiency, cogeneration,	0.35 lb/lb steam
CA-1225	SIERRA PACIFIC INDUSTRIES-ANDERSON DIVISION	CA	4/25/2014	STOKER BOILER (NORMAL OPERATION)	Stoker	BIOMASS	468 MMBTU/H		0.36 lb/lb steam
VT-0039	NORTH SPRINGFIELD SUSTAINABLE ENERGY PROJECT	VT	4/19/2013	Wood Fired Boiler	Bubbling Fluidized Bed Boiler	wood	464 MMBTU/H	Energy efficient design and the use of a thermal district heat loop.	2668 lb/Mwhr
VT-0037	BEAVER WOOD ENERGY FAIR HAVEN	VT	2/10/2012	Main Boiler	Not listed	wood	482 MMBTU/H	Implementing energy efficiency and good operating and maintenance	2993 lb/Mwhr
CT-0156	MONTVILLE POWER LLC	CT	4/6/2010	42 MW Biomass utility boiler	Not listed	Clean wood	600 MMBTU/H		225 LB/MMBtu

Table 5-5: RACT/BACT/LAER Clearinghouse Search Results – CO_2 Emission Controls for Natural Gas-Fired Boilers

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT
AL-0271	GEORGIA PACIFIC BREWTON LLC	AL	6/11/2014	No.4 Power Boiler	425 MMBTU/H		117.1 LB/MMBTU
*IN-0228	JET CORR, INC	IN	3/27/2014	NATURAL GAS FIRED BOILER E028	350 MMBTU/H		
KY-0111	PHOENIX PAPER WICKLIFFE LLC	KY	12/18/2019	#1 Power Boiler	325 mmBtu/h	i. Use of natural gas only; ii. Good combustion practices; and iii. Follow manufacturer's procedures for start-up and shutdown	116.1 LB/MMBTU
KY-0111	PHOENIX PAPER WICKLIFFE LLC	KY	12/18/2019	#2 Power Boiler	325 mmBtu/h	i. Use of natural gas only; ii. Good combustion practices; and iii. Follow manufacturer's procedures for start-up and shutdown	116.1 LB/MMBTU
*LA-0312	ST. JAMES METHANOL PLANT	LA	6/30/2017	B1-13 - Boiler 1 (EQT0003)	350 MM BTU/hr	Energy Efficiency Measures:	117.1 LB/MMBTU
*LA-0312	ST. JAMES METHANOL PLANT	LA	6/30/2017	B2-13 - Boiler 2 (EQT0004)	350 MM BTU/hr	Energy efficiency measures	117.1 LB/MMBTU
LA-0323	MONSANTO LULING PLANT	LA	1/9/2017	No. 9 Boiler - Natural Gas Fired	325 MMBTU/h	Good combustion practices and energy efficient operation	0.167 LB/LB
LA-0323	MONSANTO LULING PLANT	LA	1/9/2017	No. 10 Boiler - Natural Gas Fired	325 MMBTU/h	Good combustion practices and energy efficient operation	0.167 LB/LB
*LA-0394	GEISMAR PLANT	LA	12/12/2023	01-22 - AO-5 Boiler	350 MM BTU/hr	Use of low carbon fuels, good combustion practices, good operating and maintenance practices, and energy efficient design	117.1 LB/MMBTU
MI-0440	MICHIGAN STATE UNIVERSITY	MI	5/22/2019	EUSTMBOILER	300 MMBTU/H	Utilize low-carbon fuels and implement energy efficiency measures and preventative maintenance pursuant to manufacturer recommendations.	163.6 LB/MMBTU
ND-0032	SPIRITWOOD NITROGEN PLANT	ND	6/20/2014	Package boiler	280 MMBTU/H	good combustion practices	117.0 LB/MMBTU
NE-0065	CARGILL, INCORPORATED	NE	12/28/2018	Boiler L	299 MMBtu/hr	Good Combustion Practices	117.1 LB/MMBTU
OH-0368	PALLAS NITROGEN LLC	OH	4/19/2017	Package Boilers (2 identical, B003 and B004)	265 MMBTU/H	thermal efficiency of 80%, based on HHV in addition to good design, good combustion practices, and energy efficient operation.	118.3 LB/MMBTU
OK-0162	ENID NITROGEN PLANT	OK	5/29/2014	Boiler	450 MMBTUH	Efficient Design, Air Preheaters	117 LB/MMBTU
*TN-0163	HOLSTON ARMY AMMUNITION PLANT	TN	10/8/2018	Four Boilers, Natural Gas & No. 2 Oil-Fired	327 MMBtu/hr, each boiler	Design, operate, & maintain the source to minimize radiation heat loss; install & maintain adequate insulation; design & operate the boiler to minimize heat loss from the stack, minimize excess air/air infiltration, maintain boiler feedwater & heat transfer surfaces, properly tune burners	236.7 LB/MMBTU
TX-0888	ORANGE POLYETHYLENE PLANT	TX	4/23/2020	BOILERS	250 MMBTU	Good combustion practice and proper design.	
WI-0267	GREEN BAY PACKAGING, INC. - MILL DIVISION	WI	9/6/2018	Two Natural Gas-Fired Boilers (Boilers B34 and B35)	285 mmBtu/hr	Good combustion practices, only fire natural gas, equip boilers with low NOx burners and flue gas recirculation	160 LB CO2e /klb steam
WI-0272	PACKAGING CORPORATION OF AMERICA-TOMAHAWK	WI	7/15/2014	B12 Boiler	425 mmBTU/hr	- The use of natural gas as the fuel; - The use of low NOx burners; - A 65.0% thermal efficiency during the first 11 months of operation to account for startup and shutdown evaluations as well as possible reduced operations during this time; - A 65.0% thermal efficiency during any month with a capacity factor of 25% or less; - A 72.5% thermal efficiency on a 12 month rolling average basis, beginning with the 12th month of operation following boiler startup;	178.75 LB/1000 Btu

Good Combustion, Operating and Maintenance Practices

Good combustion, operating, and maintenance practices are also inherent to the operation of each boiler. Over the operating life of the units, the boilers will inevitably experience performance degradation and efficiency loss over time, and accordingly each unit will be maintained under a routine maintenance program.

Use of Low-GHG Fuels

As demonstrated by the RBLC search results, the use of low-GHG fuels is a demonstrated alternative for control of CO_2 emissions from combustion sources. In addition, EPA has established the use of low-GHG (i.e., clean) fuels as the best system of emission reduction (BSER) for certain combustion units in NSPS Subparts TTTT and TTTTa. Boilers 3, 5 and 7 will all burn natural gas, and Boilers 3 and 5 will also burn wastewater treatment plant sludge which is biogenic and has a similar carbon content to biomass. Accordingly, the use of low-GHG fuels is inherent to the operation of each boiler, and this is a technically feasible alternative for control of CO_2 emissions for this application.

Carbon Capture and Sequestration

Carbon capture and storage (CCS) is a set of technologies that can reduce CO_2 emissions from power plants and some industrial sources. It is an integrated three-step process that involves processes and equipment to separate and capture CO_2 from the exhaust stream, compress and transport the CO_2 to a suitable storage location, and pump the CO_2 deep underground into suitable rock formations.

In a recent federal rulemaking (40 CFR 60 Subpart TTTTa), EPA deemed CCS to be a technically feasible add-on control option for certain types of combustion units. Although this alternative has not been demonstrated on an industrial boiler, as described above, CCS is nonetheless evaluated as a potential control option in this BACT analysis.

In summary, the following potential control options for CO_2 emissions from the proposed boiler units were considered as part of this BACT analysis:

- Good combustion, operating, and maintenance practices;
- Use of low-GHG fuels; and
- Carbon capture and sequestration (CCS).

The technical feasibility of each of these control options is discussed in the following section.

5.3.3. Step 2 – Technical Feasibility Assessment of CO_2 Control Alternatives

Good Combustion, Operating and Maintenance Practices and Use of Low-GHG Fuels

Good combustion, operating, and maintenance practices are all inherent to the operation of Boilers 3, 5 and 7 and are technically feasible. Boiler 7 will be fired exclusively with natural gas, which is the lowest carbon intensity fossil fuel. Boilers 3 and 5 will also be fired with natural gas, in combination with up to 41% wastewater treatment plant residuals. Accordingly, the use of low-GHG fuels is also a technically feasible alternative for Boilers 3 and 5.

Carbon Capture and Sequestration

CCS is an integrated suite of technologies with the potential to work together to capture (separate and purify) CO_2 from stationary source emissions, compress and transport it to a suitable location, and then pump it into deep underground geologic formations for permanent storage. Geologic storage refers specifically to the process by which CO_2 is pumped underground into rocks such that it is permanently trapped and cannot enter the atmosphere. In some parts of the country, CO_2 is being transported and pumped into oil fields and utilized for enhanced oil recovery (EOR).

For CCS to be technically feasible, each individual step in the process (capture, compression, transportation, and storage) must be technically feasible. The integrated suite of components must also be technically feasible in the sense that components have been demonstrated to work together without interfering with the essential operation of the combustion sources that are to be controlled. Accordingly, potential barriers to the successful integration of these components must be considered in determining whether CCS is technically feasible.

As noted previously, CCS has never been utilized to control CO_2 emissions from industrial boilers; the following paragraphs describe some of the integration challenges and rough order of magnitude costs associated with applying this alternative on combustion sources in general and industrial boilers in particular.

CO_2 Capture – Any emission control technology utilized on a combustion source must be carefully integrated into the combustion process, since any additional heating, cooling compression or other energy-consuming aspects of the control system will impact the net output of the combustion process. The temperature of the flue gas discharged from industrial boilers is generally maintained as low as possible to maximize boiler efficiency and minimize stack heat losses. Some CO_2 capture technologies (such as magnesium oxide absorption), however, operate at higher temperatures than typical boiler flue gas, and for these capture alternatives the flue gas needs to be heated before it is introduced into the CO_2 absorber. Flue gas heating may be accomplished by utilizing a portion of the boiler's steam supply, but this decreases a boiler's combustion efficiency. Other capture technologies (such as amine absorption, ammonia absorption, membrane separation or the Rectisol process) operate at temperatures that are lower than typical boiler flue gas; for these alternatives flue gas cooling is required, which also impacts the net efficiency of a boiler system. The US DOE estimates that available technologies for post-combustion CO_2 capture impose a net efficiency penalty of at least 10%.[13]

Industrial boilers also typically operate near ambient pressure, which has significant implications for CO_2 capture technologies (such as membrane separation) that operate at higher pressure or that rely on differences in partial pressure as the driving force for separating CO_2 from the boiler flue gas.

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[13] U.S. Department of Energy, National Energy Technology Laboratory, "Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity Final Report," DOE/NETL-2010/1397, Rev. 2 (November 2010).

CO_2 capture technologies may also increase plant water use significantly, primarily because current technologies generally use large quantities of cooling water. Finally, capture technologies must be able to produce high-purity CO_2 containing low concentrations of other gases and contaminants; since CCS has not been applied to industrial boilers, particularly boilers utilizing wastewater treatment plant sludge as fuel, further research is needed to determine whether the requisite CO_2 purity can be achieved on this source type.

With respect to costs, a recent report by the Congressional Budget Office[14] estimated the cost of CO_2 capture (in 2019 dollars) at between $50 - $100/metric ton for power generation. Adjusting for inflation and assuming that the capture system costs on industrial boilers would be on the same order of magnitude as for power generation sources, the cost to capture 90% of the annual potential CO_2 emissions from Boilers 3, 5 and 7 is between $44 million and $88 million per year, or between $59 and $119 per ton.

CO_2 Compression – The most significant challenge associated with CO_2 compression is the energy requirement needed to bring the captured CO_2 to pipeline conditions (typically a liquid compressed to at least 1,600 psi). The estimated minimum theoretical parasitical energy loss associated with CO_2 compression is 61 kWh/MT of CO_2 compressed.15 Based on CCS theoretically being capable of 90% capture, compression of the potential captured CO2 emissions from Boilers 3, 5, and 7 would require a minimum energy impact of over 40.8. million kWhr/yr. The overall effect of this energy penalty on the net efficiency of the boilers is not directly quantifiable since the boilers produce steam and not electricity, but at a typical compressor efficiency of 70% this compression energy requirement represents over 2% of the potential annual heat input to the three boilers or the equivalent of $1.9 million dollars per year in energy costs.

CO_2 Transportation and Sequestration – There are no CO_2 sequestration sites in the immediate vicinity of the Savannah River Mill, and so a pipeline would need to be constructed to transport the captured and compressed CO_2 to a suitable location.

Per the database maintained by the National Energy Technology Laboratory (NETL) the closest sequestration location to the mill that has been investigated through the Southeast Regional Carbon Sequestration Partnership (SECARB) process is the Black Warrior Basin test site northeast of Tuscaloosa, AL which is approximately 375 direct miles from the mill. This site, however, only consists of a test well and the site was used to conduct initial studies to understand the potential for CO_2 storage and enhanced coalbed methane (CBM) recovery from mature CBM reservoirs; it is not a commercially operating sequestration site. The closest commercial CO_2 pipeline to the mill is the Free State Pipeline owned by Denbury Onshore, LLC between West Yellow Creek, MS and the Jackson Dome CO_2 reservoir. In the West Yellow Creek oil field, compressed CO_2 is used to enhance oil recovery from aging oil wells. This location, however, is a considerable distance from the mill; approximately 450 direct miles away.

[14] "Carbon Capture and Storage," December 2023
https://www.cbo.gov/system/files/2023-12/59345-carbon-capture-storage.pdf
[15] Herzog, Howard et al, "Advanced Post-Combustion CO2 Capture," April 2009
https://sequestration.mit.edu/pdf/Advanced_Post_Combustion_CO2_Capture.pdf

In 2019, the NETL estimated the transportation and storage cost for a 100-km (62 mile) CO_2 pipeline at between \$10 and \$22/metric ton of CO_2[16] Adjusting for inflation, these figures suggest that a very significant cost would be incurred to transport the captured CO_2 emissions from Boilers 3, 5, and 7 and store it at the nearest commercial sequestration site. Using the NETL figures, the minimum transportation and storage cost is between \$64 million and \$141 million per year, or between \$86 and \$190 per ton of CO_2 captured.

In summary, CCS has not been demonstrated in practice on this source type. Furthermore, no research and development has been carried out to address specifically the implementation issues associated with CCS on industrial boilers, and thus there is no available information to determine if it can reasonably be installed and operated on this source type. Moreover, there is no existing CO_2 sequestration site in the vicinity of the mill, and significant expenditure would be needed to transport and store the captured CO_2 to the nearest commercial sequestration site. Based on publicly available figures, the minimum total cost to implement a CCS system on the boilers which are the subject of this application is between \$149 and \$313 per ton of CO_2 captured.

Therefore, per the distinction described by EPA in Chapter B, Section IV.B of the draft New Source Review Workshop Manual,[17] CCS is not an “applicable” control option for this application and thus not technically feasible. Moreover, as described above the application of CCS to the three boilers that are the subject of this application would be prohibitively expensive.

5.3.4.Step 3 - Ranking of CO_2 Control Alternatives by Control Effectiveness

If CCS were to be technically feasible in this application, this alternative would be concluded to be the most stringent alternative for control of CO_2. The use of good combustion and operating practices and low-GHG fuels would be the next-most stringent alternatives.

5.3.5.Step 4 - Evaluation of Technically Feasible CO_2 Control Alternatives for Economic, Energy and Environmental Impacts

The Georgia EPD database of PSD permit applications contains information on twenty-two PSD permit applications that have been submitted to the Division for review in the past five years; six of these applications are for new sources or modifications of existing sources that triggered PSD review for GHGs. No BACT review was required for CO_2 for one of these applications (the paper machine expansion at Packaging Corporation of America’s paper mill in Valdosta) because the project’s CO_2 emissions increases occurred at affected but unmodified boilers.

The remaining five emission units subject to PSD for GHGs listed in the EPD database include:

- A wood-fired thermal oil heater for West Fraser’s lumber mill replacement in Dudley,
- A new cement kiln/calciner for US Cement LLC in Perry,

[16] “Carbon Dioxide Transport and Storage Costs in NETL Studies,” August 2019 https://www.netl.doe.gov/projects/files/QGESSCarbonDioxideTransportandStorageCostsinNETLStudies_081919.pdf
[17] USEPA “NSR Workshop Manual,” Section B.IV.B, October 1990.

- Combustion turbine modifications for Oglethorpe Power's Thomas A. Smith Energy Center in Dalton,
- The addition of fuel oil as an approved fuel for the simple cycle combustion turbines at the Washington County Power Plant in Sandersville, and
- Various small natural gas-fired combustion units at the Hyundai Motor Group's new automobile assembly plant in Ellabell.

In each of these instances, BACT was concluded to be either good combustion and/or the firing of low GHG fuels (biomass for West Fraser, pipeline quality natural gas for Hyundai).

Carbon Capture and Sequestration

CCS is not technically feasible for the boilers that are the subject of this application, and as described above this control option is considered unrepresentative of BACT based on the unreasonable estimated cost that would be associated with implementing it.

Use of Clean or Low-GHG Fuels and Good Combustion, Operating, and Maintenance Practices

There are no source-specific energy, economic, or environmental impacts that would make good combustion, operating, and maintenance practices or Low-GHG (clean) fuels inappropriate for BACT for CO_2 emissions from the boilers that are the subject of this application.

5.3.6.Step 5 - CO_2 BACT Conclusions

The use of good combustion, operating and maintenance practices coupled with Low GHG (clean) fuels is concluded to be representative of BACT for control of CO_2. The only other alternative (CCS) is technically infeasible and economically prohibitive and is not a viable BACT alternative. The proposed emission limits are 226.33 lb CO_2e/MMBtu for Boiler No. 3, based on the worst-case fuel – pet coke, 209.34 lb CO_2e/MMBtu for Boiler No. 5 firing WWTR, and 117.10 lb CO_2e/MMBtu for Boilers Nos. 3 and 5 firing natural gas. These emission limits utilize the default GHG emission factors in 40 CFR Part 98 and the current global warming potentials for CO_2, CH_4 and N_2O, and are based on the worst-case fuel firing configuration for each respective boiler.

5.4.BACT FOR METHANE (CH_4)

For any of the three boiler units, the contribution of CH_4 to total CO_2e emissions will be essentially negligible and therefore a detailed BACT review for this GHG constituent may not be warranted. Nonetheless, the following top-down analysis is provided for CH_4 emissions from the three boiler units. Since the control alternatives for CH_4 are the same for each unit, this BACT review has been prepared for the units in general rather than for each individual unit.

5.4.1.Formation

Emissions of CH_4 may occur due to incomplete combustion of the hydrocarbons that make up each boiler fuel.

5.4.2. Step 1 - Available CH_4 Control Alternatives

The RBLC contains no listings of boiler units with controls for CH_4 emissions. Nonetheless, as discussed above CH_4 emissions occur due to incomplete fuel combustion. Accordingly, good combustion practices are an available control option to reduce CH_4 emissions from the proposed boiler units.

Catalyst providers do not offer products specifically to control CH4 emissions from combustion units due to the very low concentration of this constituent typically present in combustion unit exhaust streams (5 ppm or less). Additionally, the reaction rate for hydrocarbons over an oxidation catalyst is a strong function of the number of carbon atoms per molecule, making post-combustion oxidation of CH4 particularly difficult. Therefore, good combustion practices are the only available control option for CH4 emissions from the proposed boiler units.

5.4.3. Step 2 – Technical Feasibility Assessment of CH_4 Control Alternatives

Good combustion practices are the only available control option for CH_4 emissions from the proposed boiler units and are technically feasible.

5.4.4. Step 3 - Ranking of CH_4 Control Alternatives

No ranking of control options is required, as good combustion practices are the only available and technically feasible control option for CH_4 emissions from the proposed boiler units.

5.4.5. Step 4 - Evaluation of Technically Feasible CH_4 Control Alternatives

The top control option – good combustion practices – is proposed for emissions of CH_4 from the proposed boiler units. Therefore, no further evaluation of the CH_4 control options is required.

5.4.6. Step 5 - CH_4 BACT Conclusions

Good combustion practices are concluded to be representative of BACT for control of CH_4 emissions from the proposed boiler units. A separate numerical limit for CH_4 emissions is unnecessary because CH_4 emissions are included in the proposed GHG limits expressed in CO_2e concluded to be representative of BACT for CO_2 above. Emissions will be calculated based on the emission factor from 40 CFR Part 98 Subpart C and the GWP of 28 (per 40 CFR 98 Subpart A, May 14, 2024 update).

5.5. BACT for Nitrous Oxide (N2O)

As with CH_4, the contribution of N_2O to total CO_2e emissions from any of the three boiler units will also be essentially negligible and therefore a detailed BACT review for this GHG constituent may not be warranted. Nonetheless, the following top-down analysis is provided for N_2O emissions from the three boiler units. Since the emission control alternatives for N_2O are the same for each unit, this BACT review has been prepared for the units in general rather than for each individual unit.

5.5.1. Formation

There are five (5) primary pathways of nitrogen oxide (NOx) production in combustion sources: thermal NO_x formation, prompt NOx formation, NOx from N_2O intermediate reactions, fuel NOx formation, and

NO_X formed through reburning. These pathways primarily produce the two principal constituents of NOx (nitrogen oxide – NO, and nitrogen dioxide – NO_2) but nitrous oxide (N_2O) is a third constituent that is formed primarily in combustion sources via the thermal NO_x pathway. Most of the N_2O that is formed is readily destroyed during the fuel combustion process, and so this GHG constituent is typically emitted in very small quantities.

5.5.2.Step 1 - Available N_2O Control Alternatives

The RBLC contains no listings of boiler units with controls for N_2O emissions. Nonetheless, good combustion practices are an available control option to reduce N_2O emissions from the three boiler units. As discussed above, N_2O formation is limited during complete combustion, since most oxides of nitrogen will tend to oxidize completely to NO_2, which is not a greenhouse gas.

Additionally, N_2O catalysts have been used in nitric/adipic acid plant applications to minimize N_2O emissions. Through this technology, tail gas from the nitric acid production process is routed to a reactor vessel with an N_2O catalyst followed by ammonia injection and a NO_X catalyst.

5.5.3.Step 2 – Technical Feasibility Assessment of N_2O Control Alternatives

Catalyst providers do not offer products to control N_2O emissions from any of the combustion units addressed by this application due to the very low N_2O concentrations expected to be present in each boilers' exhaust stream (typically less than 0.5 ppm).

Since N_2O catalysts are not available for this application, good combustion practices are the only available control option and are technically feasible.

5.5.4.Step 3 - Ranking of N_2O Control Alternatives

No ranking of control options is required, as good combustion practices are the only available and technically feasible control option for N_2O emissions from these boiler units.

5.5.5.Step 4 - Evaluation of N_2O Control Alternatives

The top control option – good combustion practices – is being proposed for emissions of N_2O from the proposed boiler units. Therefore, no further evaluation of the N_2O control options is required.

5.5.6.Step 5 - N_2O BACT Conclusion

Good combustion practices are concluded to be representative of BACT for control of N_2O emissions from the proposed boiler units. A separate numerical limit for N_2O emissions is unnecessary because N_2O emissions are included in the proposed GHG limits expressed in CO_2e concluded to be representative of BACT for CO_2 above. Emissions will be calculated based on the emission factor from 40 CFR Part 98 Subpart C and the GWP of 265 (per 40 CFR 98 Subpart A, May 14, 2024 update).

6. AIR QUALITY ANALYSIS

6.1. INTRODUCTION

An emissions analysis for the proposed Project detailed in Section 3.4 results in carbon monoxide (CO) emissions above the applicable Prevention of Significant Deterioration (PSD) significant emission rate (SER), requiring air dispersion modeling to demonstrate compliance with the National Ambient Air Quality Standards (NAAQS). There are no Class I or Class II PSD increments for CO. In addition, an air toxics assessment is conducted for mercury according to the current EPD's Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions ("Guideline" hereinafter).

The dispersion modeling analyses conducted adheres to the *Revision to the Guideline on Air Quality Models*[18] (GAQM) published on January 17, 2017 and EPD's *PSD Permit Application Guidance Document*[19], dated February 2017 ("EPD PSD Guidance Document"). The following sections present the source data modeled, the procedures used for assessing ambient air impacts from the SRM emission sources, the standards to which the predicted impacts were compared, and the results of the analyses. For reference, Figure 6-1 shows the location of the Savannah River Mill and Figure 6-**2** shows a near-field aerial view of the mill.

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[18] US EPA "*Revision to the Guideline on Air Quality Models*", January 17, 2017

[19] EPD "*PSD Permit Application Guidance Document"*, revised February 2017. [https://epd.georgia.gov/air-protection-branch-technical-guidance-0/air-quality-modeling]

Figure 6-1 Location of the Savannah River Mill

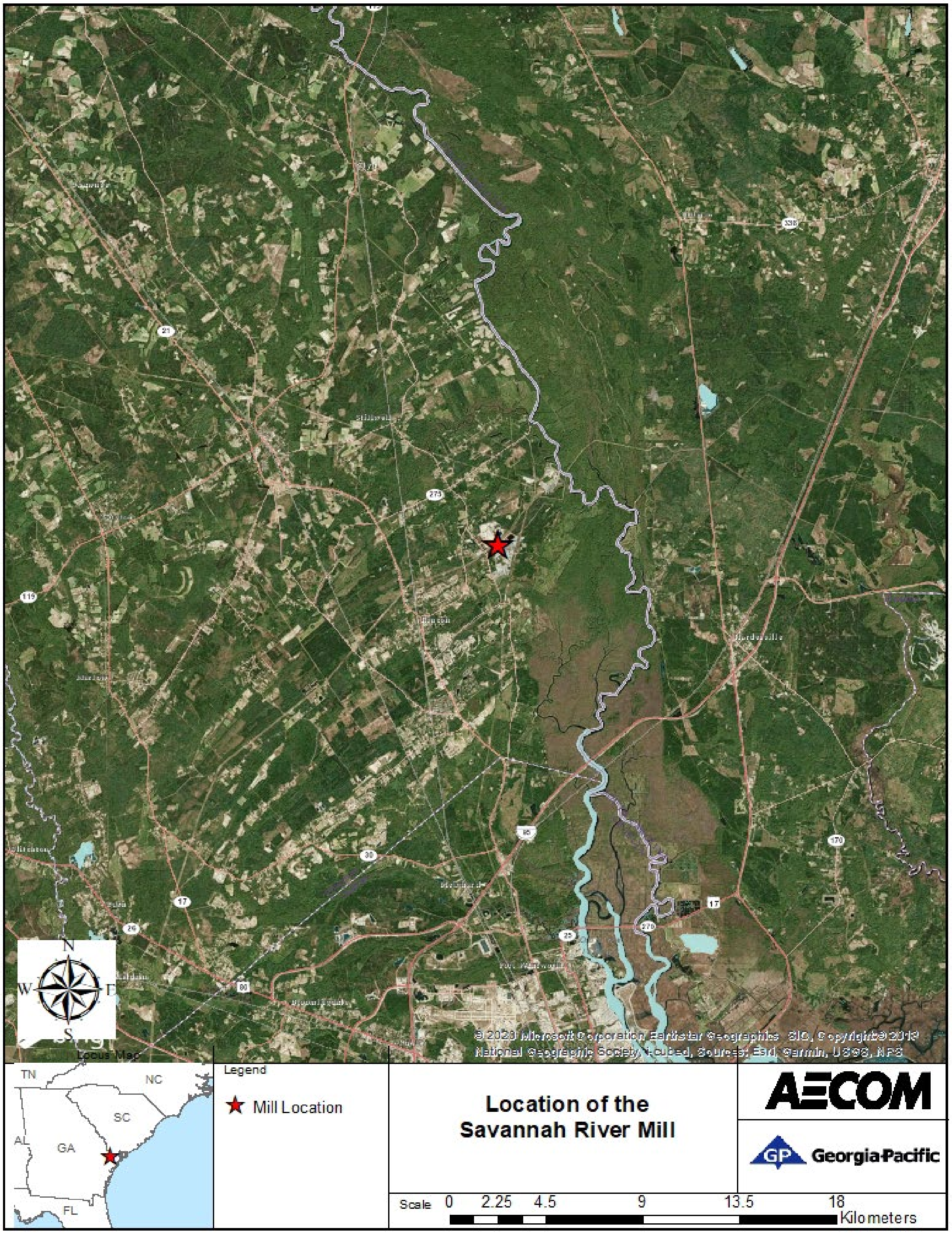
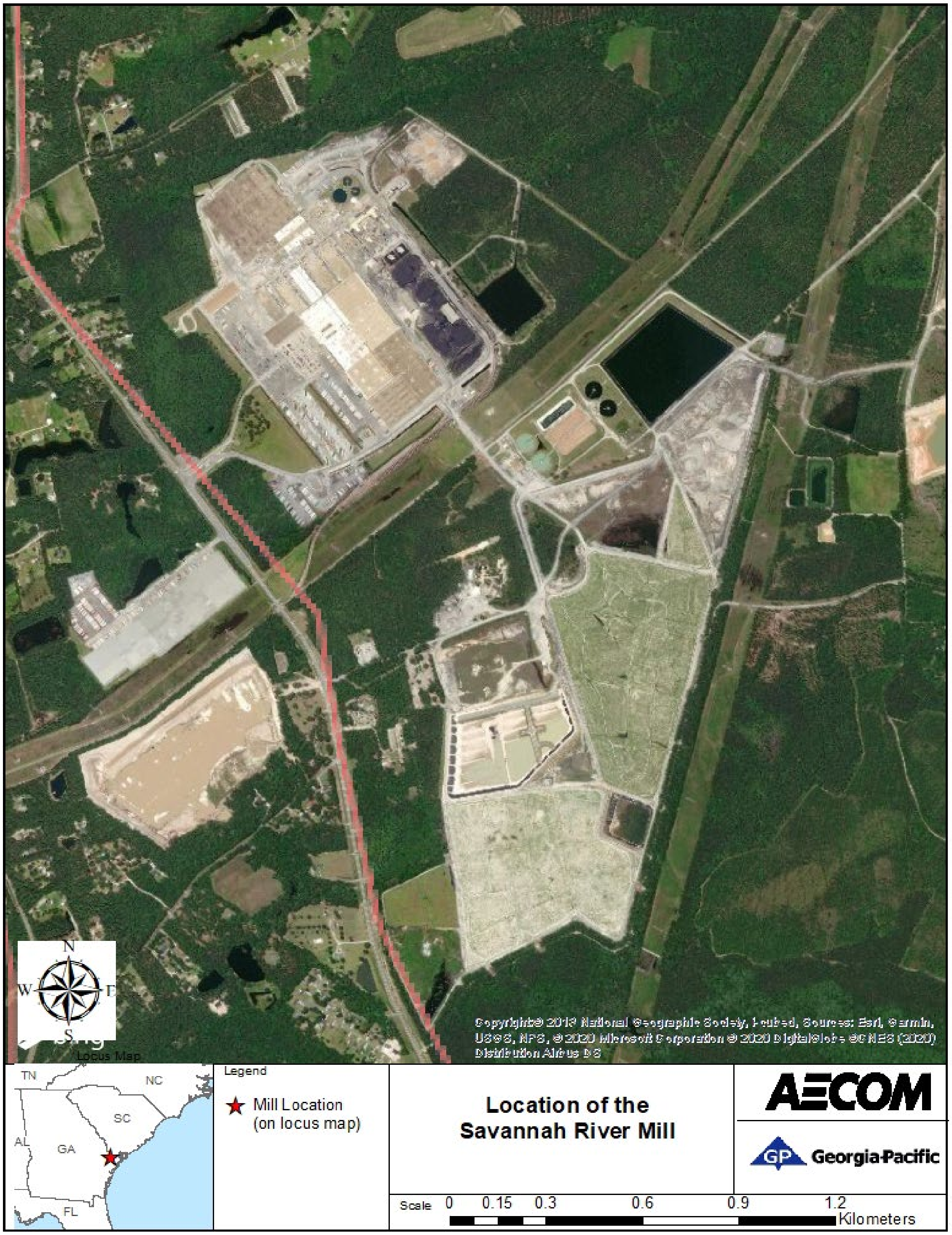


Figure 6-2 Aerial Photograph of the Savannah River Mill



6.2. Applicable Regulations

6.2.1. Federal Air Quality Standards

The Clean Air Act of 1970 required the US EPA to establish ambient concentration thresholds for certain compounds based upon the identifiable effects that the compounds may have on the public health and welfare. Subsequently, the US EPA promulgated regulations that set NAAQS for six criteria compounds: sulfur dioxide (SO_2), carbon dioxide (CO), nitrogen dioxide (NO_2), particulate matter (PM[20], PM_{10} and $PM_{2.5}$), lead (Pb), and ozone (O_3). Two classes of ambient air quality standards have been established: (1) primary standards defining levels of air quality that the US EPA has judged as necessary to protect public health; and, (2) secondary standards defining levels for protecting soils, vegetation, wildlife, and other aspects of public welfare.

Table 6-1 lists the CO NAAQS applicable to this Project.

Table 6-1 National Ambient Air Quality Standards

Pollutant	Averaging Period	Primary Standard ($\mu g/m^3$)	Secondary Standard[2] ($\mu g/m^3$)
CO	1-hour[1]	40,000	--
	8-hours[1]	10,000	--

1. Not to be exceeded more than once per year.
2. No secondary standards for CO.

Source: 40 CFR 50

Also, pursuant to the 1970 Clean Air Act, states were required to delineate air quality control regions (AQCRs) and to adopt State Implementation Plans (SIPs) to provide for attainment of the NAAQS as expeditiously as practical, within certain time limits. The 1977 Clean Air Act Amendments, in Section 107, required US EPA and states to identify, by category, those AQCRs (or portions thereof) meeting and not meeting the NAAQS. Areas meeting the NAAQS are termed attainment areas, and areas not meeting the NAAQS are termed non-attainment areas. Areas that have insufficient data to make a determination of attainment/non-attainment status are unclassified or are not designated but are treated as being attainment areas for permitting purposes. The designation of an area is made on a pollutant-by-pollutant basis.

SRM is located in Effingham County. Per 40 CFR §81.310 and US EPA information available at the US EPA Green Book Nonattainment website, Effingham County is unclassifiable/attainment for CO.

[20] PM is a non-criteria indicator for which there are currently no ambient air quality standards.

6.2.2. Prevention of Significant Deterioration - Applicability and Requirements

SRM is proposing to install a new boiler and modify two existing boilers with associated equipment, resulting in a net increase of CO emissions greater than its applicable PSD SER. No other pollutant potentially subject to air dispersion modeling has an emissions increase above its applicable PSD SER. Thus, a PSD air quality analysis is being conducted for CO only. The net increase of greenhouse gas (GHG) emissions is also greater than applicable PSD SER but GHG emissions are not subject to air dispersion modeling demonstrations and are thus not discussed further within this section.

The PSD regulations require that an owner or operator undergoing a major modification perform the following air quality analyses for those pollutants subject to PSD review:

- Analysis of existing air quality in the vicinity of the source;
- Assessment of air quality impacts resulting from pollutant emissions from the source relative to any applicable PSD Increments (there are none for CO) and NAAQS;
- PSD increment consumption, visibility, and air quality related values (AQRVs) impact analyses at PSD Class I areas (generally within 300 kilometers of the facility where the project is slated to take place) [not applicable for this project since these requirements do not apply to CO emissions];
- A Class II visibility analysis [not applicable for this project since this requirement does not apply to CO emissions];
- Assessment of the effects of emitted pollutants on soils and vegetation in the source's impact areas; and
- Assessment of impacts associated with indirect economic growth.

The PSD regulations limit the amount that ambient air quality concentrations can be increased above existing ambient levels in attainment areas. These allowable increases in concentrations called PSD increments have only been established for SO_2, PM_{10}, $PM_{2.5}$, and NO_2. Since there is no PSD increment for CO, this specific analysis is not required for the proposed Project.

US EPA has defined concentrations called significant impact levels (SILs) that are used to determine whether a major new source or modification will "significantly" impact a PSD Class II area. US EPA has proposed SILs for PSD Class I areas (July 23, 1996 Federal Register, Section IV.C.4), but these have not yet been finalized.

The applicable Class II SILs for CO are presented in **Table 6-2**. There are no Class I SILs for CO.

Table 6-2 PSD Increments and Significant Impact Levels

Pollutant	Averaging Period	PSD Increment ($\mu g/m^3$)		SIL ($\mu g/m^3$)	
		Class I	Class II	Class I	Class II
CO	1-hour	--	--	--	2,000
	8- hour	--	--	--	500

If predicted Project impacts for CO are below the SILs, no additional analysis will be necessary since, by definition, the Project cannot cause or contribute to a NAAQS violation. If modeling indicates that the CO SIL(s) are exceeded, then a cumulative impact assessment would be required to demonstrate compliance with the NAAQS.

As detailed in Section 6.4, modeled concentrations are below both the 1- hour and 8- hour CO Class II SILs and a cumulative impact assessment is not required.

6.3. DISPERSION MODELING ANALYSIS

6.3.1. Model Selection

Dispersion models compute downwind pollutant concentrations by simulating the evolution of a plume over time and space given inputs including the quantity of emissions and the initial dispersion conditions (e.g., velocity and temperature) of the stack exhaust to the atmosphere. The modeling analysis was performed using US EPA's preferred dispersion model, AERMOD (Version 21112) along with the regulatory default options. GP followed guidance provided in the final version of GAQM published on January 17, 2017[21], EPD's PSD Guidance Document, and correspondence with EPD.

6.3.2. Building Downwash

US EPA modeling guidelines require the evaluation of the potential for physical structures to affect the dispersion of emissions from stack emission points. The exhaust from stacks that are located within specified distances of buildings, and whose physical heights are below specified levels, may be subject to "aerodynamic building downwash" under certain meteorological conditions. If this is the case, a model capable of simulating this effect must be employed.

The analysis used to evaluate the potential for building downwash is referred to as a physical "Good Engineering Practice" ("GEP") stack height analysis. Stacks with heights below physical GEP are considered to be subject to building downwash. In the absence of influencing structures, a "default" GEP stack height is creditable up to 65 meters (213 feet) per the Guideline for Determination of Good Engineering Practice Stack Height (US EPA, 1985). Any portion of a stack above the maximum of the physical or default GEP height cannot be used in the dispersion modeling analysis for purposes of comparison to US EPA's ambient impact criteria.

A GEP stack height analysis was performed for all point sources included in the modeling in accordance with US EPA's guidelines (US EPA, 1985). Per the guidelines, the physical GEP height ("H_{GEP}") is determined from the dimensions of all buildings that are within the region of influence using the following equation:

$$H_{GEP} = H + 1.5L$$

where:

H = height of the structure within 5L of the stack which maximizes H_{GEP}, and
L = lesser dimension (height or projected width) of the structure.

[21] US EPA "*Revision to the Guideline on Air Quality Models*", January 17, 2017

For a squat structure (i.e., height less than projected width), the formula reduces to:

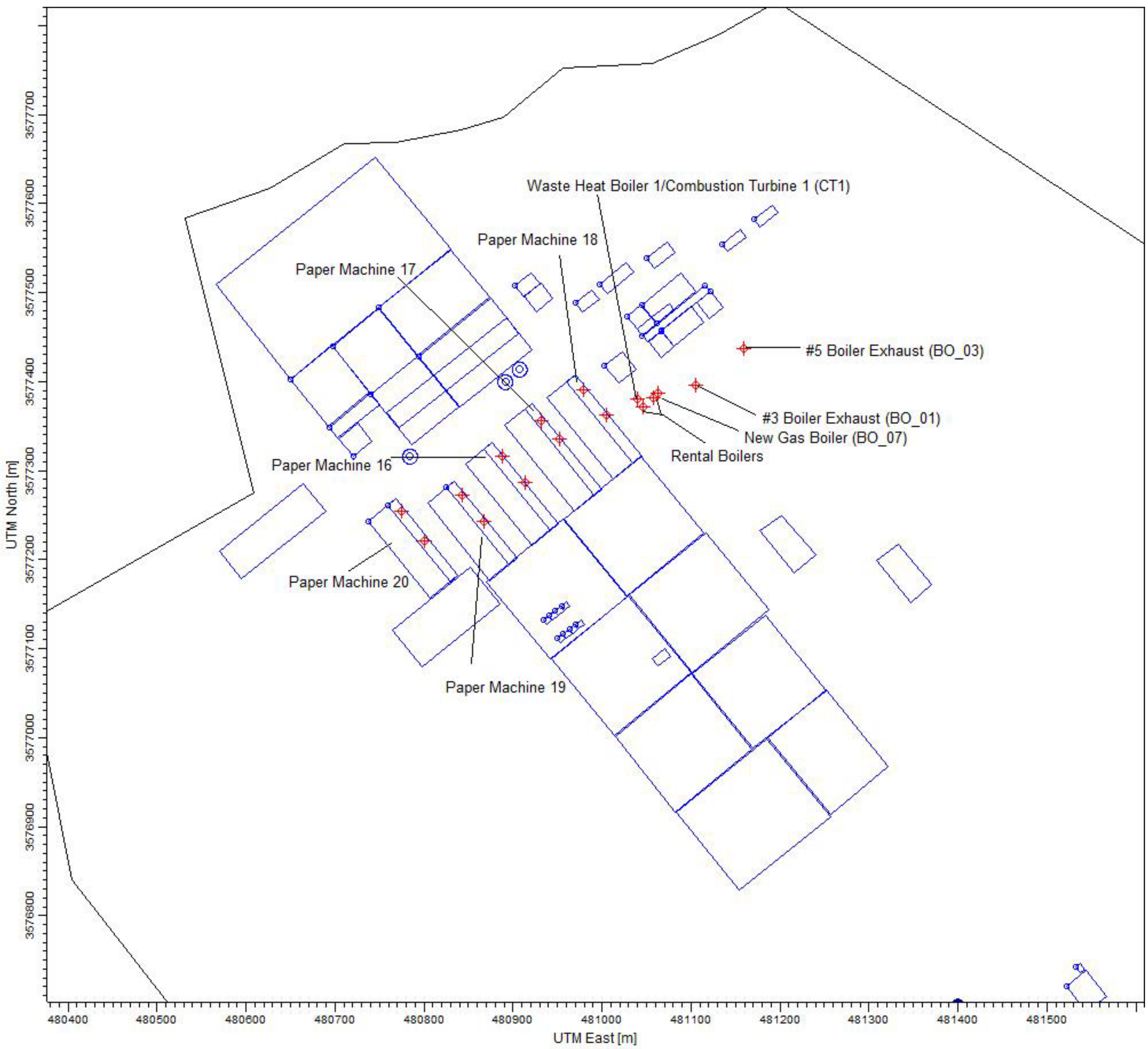
$$H_{GEP} = 2.5H$$

Building coordinates and stack locations were developed using site plan drawings, aerial photographs and GIS software. Building heights were determined from site elevation drawings and information gathered during site inspection of the facility buildings.

Wind direction-specific building dimensions for input to AERMOD were developed with the PRIME version of US EPA's Building Profile Input Program (BPIP-PRIME Version 04274).

Figure 6-3 presents the SRM layout of primary buildings and point sources included in the BPIP analysis. Full BPIP input and output files (which includes all the relevant stack locations and building heights) are provided in the modeling archive. The modeling archive will be transferred electronically to EPD.

Figure 6-3 Stack and Buildings used for BPIP Analysis



6.3.3. Dispersion Environment

The dispersion environment was determined through inspection of aerial photographs of the three-kilometer (3-km) area surrounding SRM and a review of land use characterizations (taken from USGS National Land Cover Data (NLCD) 2016 land cover data) within that area. Aerial photographs show that the area surrounding SRM is predominantly rural and this is verified using the NLCD 2016 land cover characterizations that show only 4 percent of land cover within 3-km of SRM is classified as medium or high intensity developed land. Therefore, the default dispersion environment was used in the modeling analyses and the urban source option was not utilized.

6.3.4.Meteorological Data

As prescribed by the EPD for modeling applications in Effingham County[22], the modeling analysis was conducted using 5-years of surface meteorological data (2018-2022) from Savannah International Airport (KSAV), GA and concurrent upper air data from Charleston International Airport, SC. The EPD pre-processed meteorological dataset using the ADJ_U* option was download from the EPD website.

KSAV is located approximately 13 miles south of SRM. Although KSAV is the EPD recommended meteorological station for modeling in Effingham County, the EPD modeling guidelines require a demonstration to show that the meteorological data from the airport is representative of the area surrounding SRM. Visual inspection of aerial photographs depicting the area immediately surrounding KSAV and SRM show similar land use in that both are located within the river valley and are surrounded by a mix of forested land, low-intensity residential areas, commercial/industrial areas and wetland/river.

The EPD guidelines, consistent with US EPA's AERMOD Implementation Guide (AIG)[23], specifies that the determination of representativeness of meteorological data should include a comparison of surface characteristics; specifically, the surface roughness, albedo, and the Bowen ratio between the monitoring site and the project site. Therefore, a comparison of the surface characteristics in the area surrounding KSAV and SRM was conducted using a US EPA developed tool called AERSURFACE.

The most recent version of AERSURFACE (20060) uses digital land cover data from the USGS NLCD 2016 archives and is commonly applied to derive surface land use characteristics for input to AERMET. As such, this tool was utilized to compare the surface characteristics between KSAV and SRM. Specifically, AERSURFACE was applied with a 1-km radius (AERSURFACE default) for the surface roughness determination for each location to determine an annual average set of surface characteristics. The 1-km radius around KSAV was partitioned into four site-specific sectors, as provided by EPD. Sectors 1 and 3 were classified as non-airport land use and Sectors 2 and 4 were classified as airport land use. For this analysis, the 1-km radius around SRM assumed the same sectors used for KSAV and were classified as non-airport land use.

Table 6-3 presents the AERSURFACE results for albedo, Bowen ratio and surface roughness. The AERSURFACE results show that the albedo, Bowen ratio and surface roughness are generally similar between KSAV and SRM, with the exception of the surface roughness. The surface roughness was expected to be lower at KSAV and likely would lead to more conservative modeled concentrations relative to higher surface roughness. That is, the lower surface roughness should result in higher modeled concentrations in AERMOD due to reduced mechanical mixing associated with lower surface roughness. For this reason, the surface characteristics used to

[22] https://epd.georgia.gov/air-protection-branch-technical-guidance-0/air-quality-modeling/georgia-aermet-meteorological-data

[23] US EPA, "*AERMOD Implementation Guide*", August 2019.

process the meteorological data at KSAV are representative of the surface characteristics at the SRM, making the meteorological data from KSAV acceptable for use in dispersion modeling at the SRM.

Table 6-3 Seasonal Average Land Use Characteristics

Season	Wind Sector* (AP/NONAP)	Airport (KSAV)			Facility (SRM)			Airport (KSAV) - Facility (SRM)			[Airport(KSAV) - Facility (SRM)]/Airport (KSAV)		
		Albedo	Bowen Ratio	Surface Roughness	Albedo	Bowen Ratio	Surface Roughness	Δ (Albedo)	Δ (Bowen Ratio)	Δ (Surface Roughness)	% (Albedo)	% (Bowen Ratio)	% (Surface Roughness)
Winter	1 (NONAP)	0.16	0.59	0.157	0.15	0.41	0.129	0.01	0.18	0.028	6.3%	30.5%	17.8%
Winter	2 (AP)	0.16	0.59	0.029	0.15	0.41	0.149	0.01	0.18	-0.120	6.3%	30.5%	-413.8%
Winter	3 (NONAP)	0.16	0.59	0.145	0.15	0.41	0.129	0.01	0.18	0.016	6.3%	30.5%	11.0%
Winter	4 (AP)	0.16	0.59	0.020	0.15	0.41	0.054	0.01	0.18	-0.034	6.3%	30.5%	-170.0%
Winter	Average	0.16	0.59	0.088	0.15	0.41	0.115	0.01	0.18	-0.028	6.3%	30.5%	-31.3%
Spring	1 (NONAP)	0.15	0.49	0.181	0.14	0.35	0.161	0.01	0.14	0.020	6.7%	28.6%	11.0%
Spring	2 (AP)	0.15	0.49	0.035	0.14	0.35	0.219	0.01	0.14	-0.184	6.7%	28.6%	-525.7%
Spring	3 (NONAP)	0.15	0.49	0.169	0.14	0.35	0.178	0.01	0.14	-0.009	6.7%	28.6%	-5.3%
Spring	4 (AP)	0.15	0.49	0.026	0.14	0.35	0.089	0.01	0.14	-0.063	6.7%	28.6%	-242.3%
Spring	Average	0.15	0.49	0.103	0.14	0.35	0.162	0.01	0.14	-0.059	6.7%	28.6%	-57.4%
Summer	1 (NONAP)	0.15	0.47	0.201	0.14	0.31	0.265	0.01	0.16	-0.064	6.7%	34.0%	-31.8%
Summer	2 (AP)	0.15	0.47	0.040	0.14	0.31	0.291	0.01	0.16	-0.251	6.7%	34.0%	-627.5%
Summer	3 (NONAP)	0.15	0.47	0.189	0.14	0.31	0.229	0.01	0.16	-0.040	6.7%	34.0%	-21.2%
Summer	4 (AP)	0.15	0.47	0.032	0.14	0.31	0.122	0.01	0.16	-0.090	6.7%	34.0%	-281.3%
Summer	Average	0.15	0.47	0.116	0.14	0.31	0.227	0.01	0.16	-0.111	6.7%	34.0%	-96.3%
Fall	1 (NONAP)	0.15	0.59	0.181	0.14	0.41	0.263	0.01	0.18	-0.082	6.7%	30.5%	-45.3%
Fall	2 (AP)	0.15	0.59	0.035	0.14	0.41	0.285	0.01	0.18	-0.250	6.7%	30.5%	-714.3%
Fall	3 (NONAP)	0.15	0.59	0.169	0.14	0.41	0.224	0.01	0.18	-0.055	6.7%	30.5%	-32.5%
Fall	4 (AP)	0.15	0.59	0.026	0.14	0.41	0.120	0.01	0.18	-0.094	6.7%	30.5%	-361.5%
Fall	Average	0.15	0.59	0.103	0.14	0.41	0.223	0.01	0.18	-0.120	6.7%	30.5%	-117.0%

* AP (airport) or NONAP (non-airport) in the Wind Sector is for the Airport (KSAV) only. NONAP was applied for all sectors for SRM.

6.3.5.Receptors and Terrain

A Cartesian receptor grid extending approximately 20 kilometers (km) from the facility centroid was used in the modeling. The grid receptors consist of the following spacing:

- 50 m intervals along the facility fence line;
- Facility centroid to 3 km spaced at 100-m intervals;
- 3 km to 5 km spaced at 500-m intervals;
- 5 km to 10 km spaced at 1,000-m intervals; and
- 10 km to 20 km spaced at 2,000- m intervals.

Far-field and near-field views of the receptor grid and ambient air boundary are shown in Figures 6-4 and 6-5, respectively. All model concentrations that were 90 percent of a standard or greater were resolved to 100-m grid spacing.

Figure 6-6 shows the ambient air boundary comprising effective barriers that restricts access by the general public. Effective barriers include physical obstacles (e.g., security fencing), active and passive deterrents (e.g., security patrols and surveillance), and natural barriers (e.g., dense vegetation, low lying water areas, ditches, creeks, and ponds) that collectively prevent reasonable access by unauthorized persons on mill property.

Terrain elevations from the National Elevation Dataset (NED) acquired from United State Geological Survey (USGS)[24] were processed with AERMAP (version 18081) to develop the receptor terrain elevations and critical hill heights. All receptor locations are represented in the Universal Transverse Mercator projection (UTM), Zone 17, North American Datum 1983.

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[24] http://www.mrlc.gov/viewerjs

Figure 6-4 Far-Field View of the Cartesian Receptor Grid

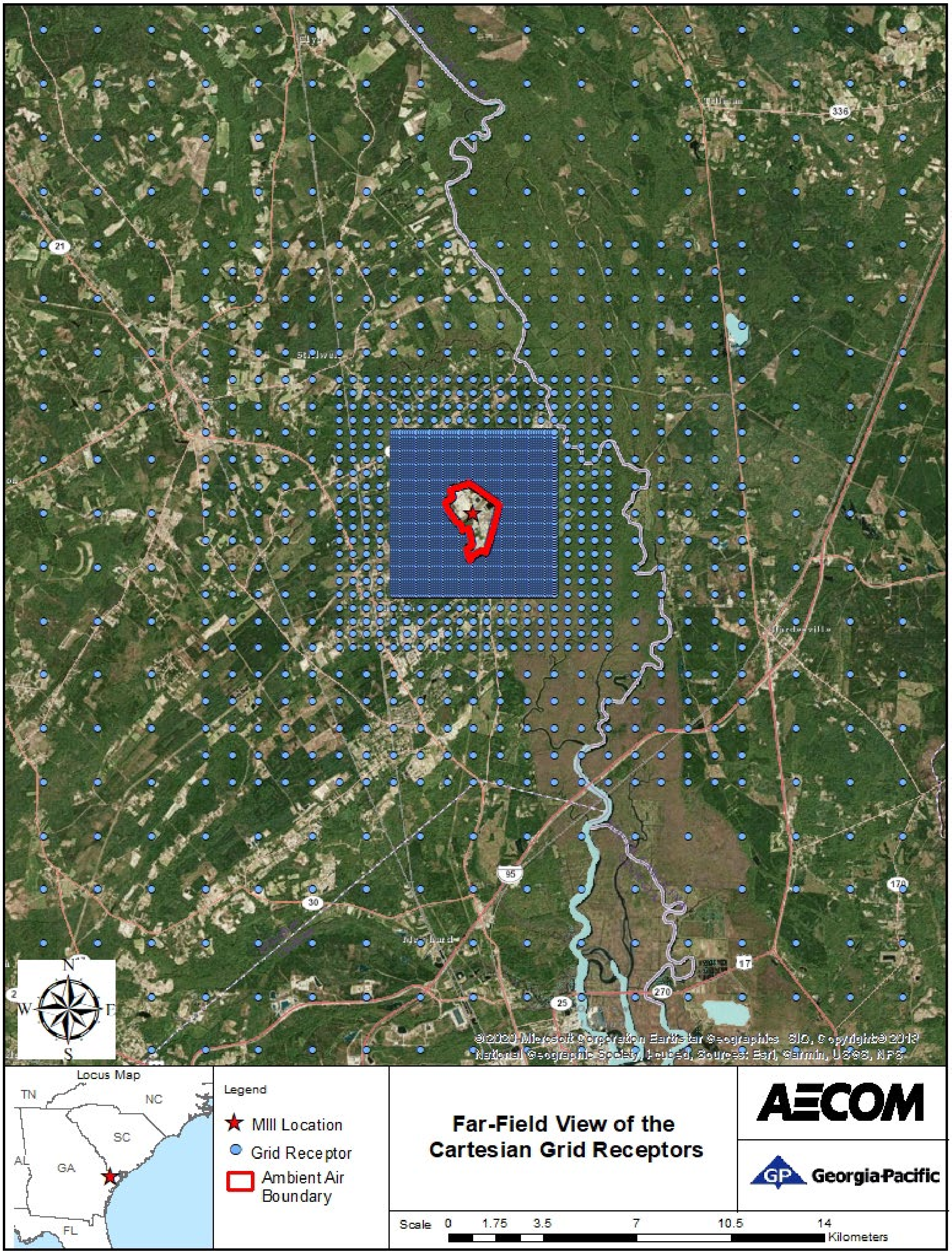


Figure 6-5 Near-Field View of the Cartesian Receptor Grid

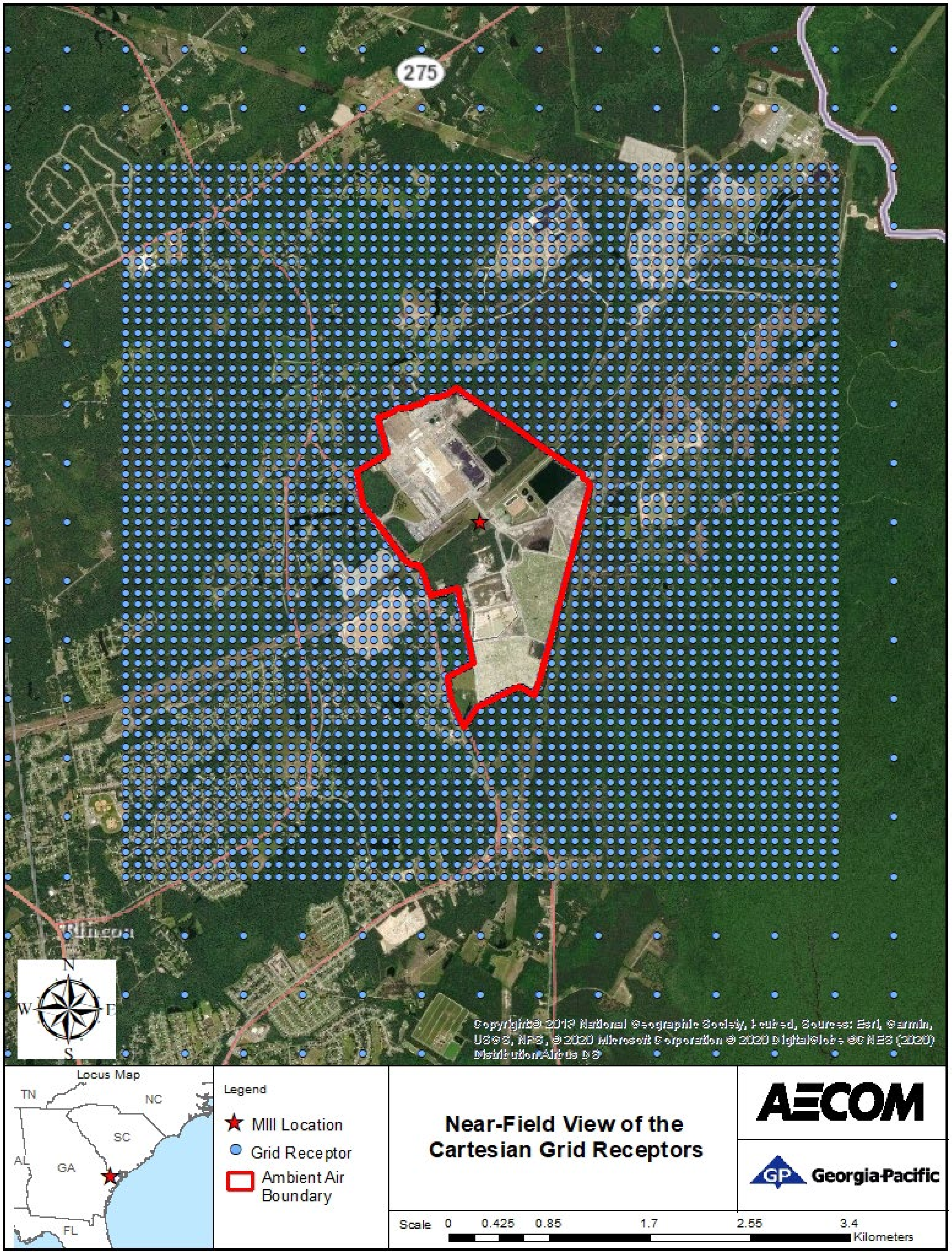
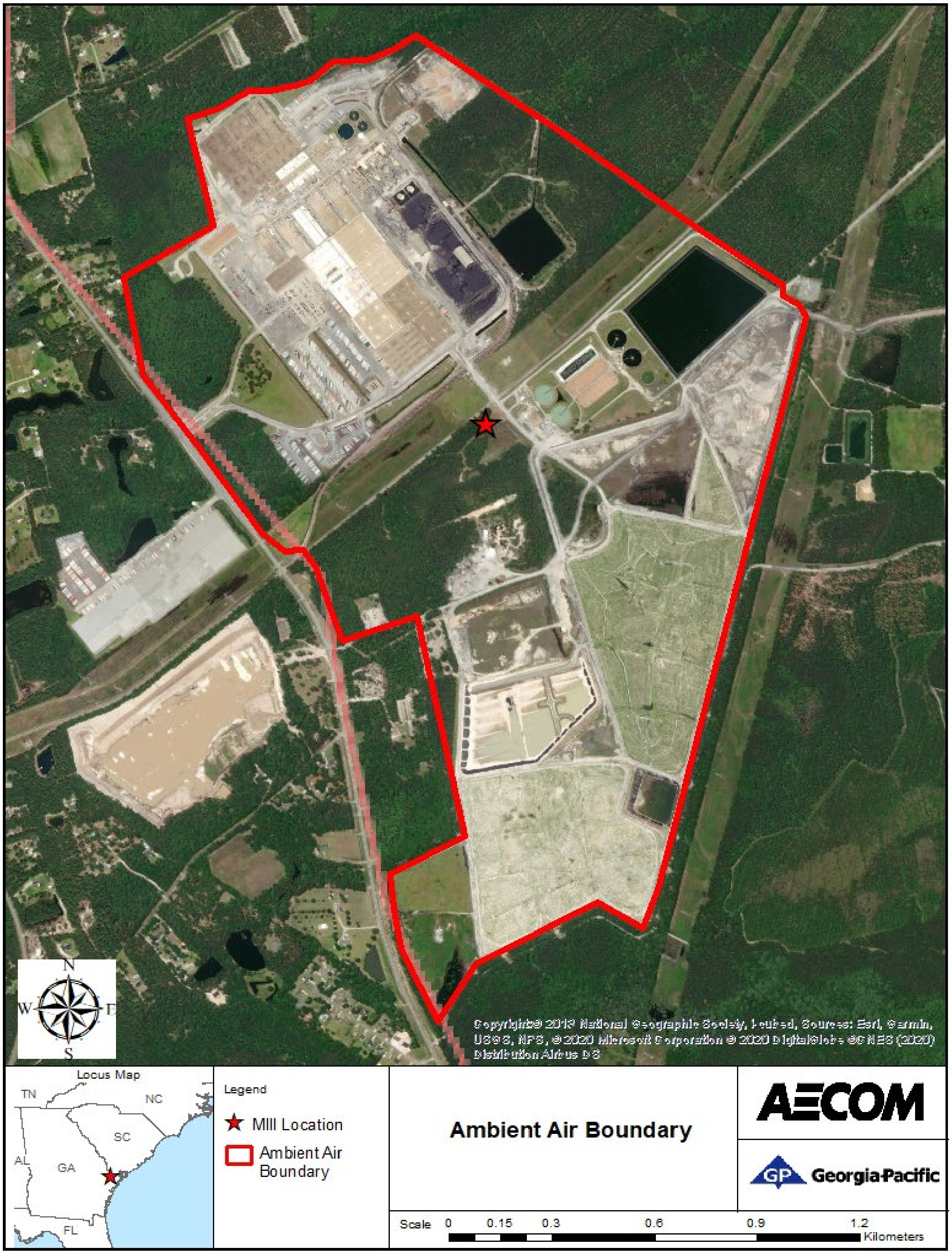


Figure 6-6 Ambient Air Boundary



6.3.6.Source Data

For SIL modeling, only sources with net emissions increases are required to be modeled. The project related sources include the new natural gas-fired boiler (Boiler No. 7), the modified existing Boiler No. 5 (BO003) and the modified existing Boiler No. 3 (BO001). In addition, contemporaneous projects between 2018 and 2024 impact the Waste Heat Boiler No. 1 (WHB1), Combustion Turbine No. 1 (CT01) (where emissions are emitted from the combined stack with WHB1), the Rental Gas Boilers (RGB01 and RGB02), and existing Paper Machines 16-20 (PM01-PM05) as affected or modified sources.

To be conservative, only the maximum potential CO hourly emission rates (worst-case emissions) from the new Boiler No. 7, the modified Boiler No. 5, the modified Boiler No. 3, the combined WHB1 and CT01, the Rental Gas Boilers and the Paper Machines were modeled for comparison to the 1- hour and 8-hour CO SILs. Based on the different fuel options for Boiler No. 5 and Boiler No. 3, four (4) different potential emission rates for Boiler No. 5 and five (5) different potential emission rates for Boiler No. 3, were examined to determine the worst-case scenario. The worst-case scenario emission rates are also protective of other operating scenarios, such as start-up or shut-down operations.

Given the multiple fuel scenarios for Boiler No. 5 and Boiler No. 3, to simplify the modeling, a conservative screening approach was used. The aforementioned Paper Machine sources, the combined CT01/WHB1 source, Rental Boilers, new Boiler No. 7, modified Boiler No. 5 and modified Boiler No. 3 maximum emission rate scenarios were individually modeled. The maximum modeled concentrations resulting from each of the Boiler No. 5 and Boiler No. 3 scenarios, respectively, were summed with the maximum modeled concentrations for the other sources irrespective of time and space. This combined maximum concentration was then evaluated relative to the 1-hour and 8-hour CO SILs. This is a conservative approach since the highest impacts for each source and maximum fuel scenario likely do not occur at the same receptor or during the same time period.

The stack parameters and CO emission rates for the modeled sources are presented in the following sub-sections. The GA EPD modeling spreadsheet with these emissions and source parameters will be provided to GA EPD via electronic transfer.

6.3.6.1. Project Emissions

Details of the project emissions are included in Appendix B. Emissions per source are included in Table 6-4 below.

6.3.6.2. Source Parameters

In the dispersion modeling, the project-related CO emission points at SRM are represented as point sources. Detailed source-by-source stack parameters are included in Table 6-4 below. Physical and exhaust parameters (stack height and diameter, exit temperature and velocity) were developed from design data, mill records and visual inspection. Most of the CO emission points at SRM have vertical and unobstructed stacks. However, there are a couple of stacks/vents that are horizontal or capped releases. Horizontal sources were modeled using the POINTHOR source types described in Section 3.2.2.3 of the User's Guide for the AMS/EPA Regulatory Model (AERMOD) and capped sources were modeled as POINTCAP. To implement these source types in the model, the source type is changed from POINT to POINTHOR or POINTCAP in the LOCATION card and the actual source parameters are used as if the source were a vertical release.

Table 6-4 Stack Parameters and CO Emissions

Source	Model ID	Stack Orientation	CO Emissions (lb/hr)	Stack Height (m)	Stack Temperature (K)	Stack Velocity (m/s)	Stack Diameter (m)
New Gas Boiler (Boiler 7)	BO_07	Vertical	10.55	12.192	455.372	15.596	1.829
Modified Boiler 3 – Scenario #1	BO_01C1	Vertical	107.89	117.350	391.533	7.619	3.688
Modified Boiler 3 – Scenario #2	BO_01C2	Vertical	102.25	117.350	396.100	6.417	3.688
Modified Boiler 3 – Scenario #3	BO_01C3	Vertical	106.69	117.350	403.756	7.008	3.688
Modified Boiler 3 – Scenario #4	BO_01C4	Vertical	107.04	117.350	424.222	7.585	3.688
Modified Boiler 3 – Scenario #5	BO_01C5	Vertical	125.54	117.350	390.783	8.303	3.688
Modified Boiler 5 – Scenario #1	BO_03C1	Vertical	101.67	117.350	387.617	13.759	2.432
Modified Boiler 5 – Scenario #2	BO_03C2	Vertical	105.12	117.350	397.017	15.206	2.432
Modified Boiler 5 – Scenario #3	BO_03C3	Vertical	110.06	117.350	404.850	16.661	2.432
Modified Boiler 5 – Scenario #4	BO_03C4	Vertical	110.69	117.350	425.411	18.080	2.432
Waste Heat Boiler Common Stk #1 (WH01 and CT-01 Emissions)	CT1	Vertical	25.07	50.290	533.150	27.000	3.660
Rental Natural Gas Boiler #1	RGB01	Capped	3.46	8.230	472.039	11.369	1.302
Rental Natural Gas Boiler #2	RGB02	Capped	3.46	8.230	472.039	11.369	1.302
Paper Machine 16 – Yankee Wet End Exhaust	EP45	Horizontal	2.62	30.264	362.039	18.586	2.134

Source	Model ID	Stack Orientation	CO Emissions (lb/hr)	Stack Height (m)	Stack Temperature (K)	Stack Velocity (m/s)	Stack Diameter (m)
Paper Machine 16 – Yankee Dry End Exhaust	EP56	Horizontal	2.62	30.264	366.483	18.586	2.134
Paper Machine 17 – Yankee Wet End Exhaust	EP66	Horizontal	6.44	30.264	520.928	23.948	1.880
Paper Machine 17 – Yankee Dry End Exhaust	EP67	Horizontal	6.44	30.264	520.928	23.948	1.880
Paper Machine 18 – Yankee Wet End Exhaust	EP03	Vertical	4.60	32.980	362.039	21.120	2.134
Paper Machine 18 – Yankee Dry End Exhaust	EP14	Vertical	4.60	32.980	363.150	21.120	2.134
Paper Machine 19 – Yankee Wet End Exhaust	EP24	Vertical	2.05	32.980	377.594	21.120	2.134
Paper Machine 19 – Yankee Dry End Exhaust	EP37	Vertical	2.05	32.980	387.594	21.120	2.134
Paper Machine 20 – Yankee Wet End Exhaust	EP28	Vertical	2.46	29.578	404.261	18.979	1.295
Paper Machine 20 – Yankee Dry End Exhaust	EP30	Vertical	2.46	29.578	405.372	18.256	1.321

6.4. EVALUATION OF MODEL RESULTS.

6.4.1. Significant Impact Level Modeling

Dispersion modeling using AERMOD with the meteorological data discussed in Section 6.3.4 and the source data described in Section 6.3.6 was conducted to determine the maximum concentrations for 1-hour and 8-hour CO [SIL modeling]. The SIL modeling results in Table 6-5 show that the maximum concentrations are below the SILs for both the 1-hour and 8-hour averaging periods. No further modeling is thus required.

Table 6-5 SIL Modeling Results

Pollutant	Averaging Period	SIL ($\mu g/m^3$)	Maximum Concentration[1] ($\mu g/m^3$)
CO	1-hour	2,000	322.26
	8-hour	500	160.57
1. Concentration represents maximum H1H concentration between the five modified Boiler 5 scenarios and four modified Boiler 3 scenarios.			

6.5. CLASS I AREA REVIEW

6.5.1. Class I Area Air Quality Related Values

PSD Class I areas are areas of special national or regional value from a natural, scenic, recreational, or historical perspective. The PSD program provides special protection for such areas. According to 40 CFR §52.21(p), sources located within 300 km of a Class I area may need to demonstrate that the PSD Class I increments would not be exceeded, nor would certain air quality-related values be adversely affected. However, the demonstration is not required for CO emissions since PSD increments have not been established for CO. A notification was submitted to the US Fish and Wildlife Service though to inform them of the project since it is located withing 105 km of the Wolf Island National Wildlife Refuge.

6.5.2. Class I PSD Increments

There are no Class I PSD Increments for CO and thus no Class I PSD Increment analysis will be required.

6.6. AIR QUALITY REVIEW

According to 40 CFR §52.21(m), an analysis of ambient air quality in the vicinity of the proposed source for each compound subject to PSD review should be conducted.

Air quality data are obtained from a pre-construction monitoring program or, under certain conditions, from existing monitoring data. Existing air quality may be used in lieu of pre-constructing monitoring if:

- The data are representative of the proposed facility's impact areas;
- The data are of similar quality as would be obtained if the applicant monitored according to the PSD requirements; and
- The data are current; that is, the data have been collected during the two-year period preceding the permit application, provided the data are still representative of current conditions.

As noted in 40 CFR §52.21(i)(5), EPD may exempt the source from the PSD program's ambient air quality monitoring analysis requirements contained in 40 CFR §52.21(m) on a compound-by-compound basis if the net emissions increase of compounds subject to PSD review will cause air quality impacts to be less than the significant monitoring concentrations (SMCs). **Table 6-6** presents the SMCs for CO.

Table 6-6 Significant Monitoring Concentrations

Pollutant	Averaging Period	Significant Monitoring Concentration ($\mu g/m^3$)
CO	8-hour	575

The SIL modeling results will show that the 8-hour CO modeled concentration (160.57 $\mu g/m^3$) is below the SMC.

6.7. ADDITIONAL IMPACTS

Per 40 CFR §52.21(o), following is an analysis of a project's effect on visibility, soils and vegetation and general commercial, residential industrial or other growth in the vicinity of the project.

6.7.1. Growth Analysis

The growth analysis evaluates the impact associated with the project on the general commercial, residential, and industrial growth within the project vicinity. The PSD program requires an assessment of the secondary impacts from applicable projects. Negligible growth is expected to be associated with this project as the facility is replacing existing steam generating sources. Therefore, no analysis of secondary impacts from associated growth was needed for this project.

6.7.2. Soils and Vegetation

An analysis of the Project's potential impact on soils and vegetation in the vicinity of the facility was performed in accordance with the procedures recommended in US EPA's A Screening Procedure for Impacts of Air Pollution Sources on Plants, Soils and Animals (EPA-450/2-81-

078). The highest modeled impacts from the Project obtained in the SIL analysis was evaluated for compliance relative to the screening concentration listed in **Table 6-7.**

Table 6-7 Significant Monitoring Concentrations

Pollutant	NAAQS[1] ($\mu g/m^3$)	USEPA's 1980 Screening Concentration[2] ($\mu g/m^3$)
CO	None	1,800,000 (weekly)

1. Vegetation sensitivity – No corresponding weekly NAAQS exists and screening concentration unlikely to be reached under ambient conditions
2. Source: "A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals". USEPA 450/2-81-078, December 1980.

The SIL modeling results will show that the 8-hour CO modeled concentration (160.57 µg/m3) is below the screening concentration.

6.7.3. Class II Visibility

Per the EPD PSD modeling guidelines, a Class II visibility analysis should be completed for airports, state parks, and state historic sites located within the project's largest calculated SIA as determined by the PSD modeling evaluation for Class II visibility-affecting pollutants. Since CO is not a visibility-affecting pollutant, a Class II visibility assessment is not required for this project.

6.8. AIR TOXICS ANALYSIS

As outlined in the current EPD's Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions ("Guideline" hereinafter), an analysis of toxic air pollutants (TAP) to determine compliance with applicable Allowable Ambient Concentrations (AACs) is required for:

- All new facilities that require a State Implementation Plan (SIP) Permit.
- All existing facilities that are adding new equipment that require a SIP permit and emit a toxic air pollutant listed in the Guideline's Appendix A.
- All existing facilities that are modifying existing equipment that increases the emission of toxic air pollutant listed in the Guideline's Appendix A.
- All existing facilities that are modifying existing equipment or making process changes that result in emission of toxic air pollutant listed in the Guideline's Appendix A not previously emitted from the facility.
- In some cases, a demonstration may be required for sources that have never demonstrated compliance with the AAC.
- Case-by-case as determined by the Division.

For any facility that meets one of the criteria noted above, the general procedure for determining a TAPs impact is:

- For a pollutant that has a facility-wide emission rate below the Minimum Emissions Rate (MER) established in the table in the Guidelines' Appendix A, assuming the source of the emissions are mainly point sources, no further analysis is required.
- For pollutant that has a facility-wide emission rate above the MER, further analysis [often dispersion modeling] is required.

As this is an existing facility where a new source and modified sources are being proposed, calculations of total HAP emissions [of which TAPs are equivalent to, in general] from the new Boiler No. 7 and modified Boiler Nos. 3 and 5, are 93 tpy post proposed project. HAP emissions from the existing Boiler Nos. 3 and 5 are 102 tpy. Thus, the utility project will result in a potential decrease of 9 tons of HAPs.

As noted in Section 3.5, individual HAPs were compared between the proposed and existing operating scenarios (i.e. proposed Boiler Nos. 3, 5 and 7 operations as compared to existing Boiler Nos. 3 and 5 fuels). All individual HAPs were lower for the future proposed operating scenarios with the exception of hexane, Hg , and polychlorinated biphenyls (PCB).

PCBs are not included in the toxic air assessment guidelines and facility emissions are very low (1.19E-4 tpy). The data used to determine PCB emissions was from 1999 testing at a similar GP facility firing wastewater treatment residuals (WWTR). Site specific WWTR PCB analysis from SRM were non-detect. Based on this information, EPD has previously agreed that a PCB assessment is not required. Thus, no further analysis of PCB emissions is required.

The total hexane emissions from the entire facility post-project are below the MER (facility emissions of 25,309 lb/yr as compared to the MER of 170,331 lb/yr) and thus no further analysis is required. Greater than 90% of hexane emissions are emitted from unobstructed point sources, allowing for the use of the MER screening process in accordance with EPD's Guideline.

The total Hg emissions are 73.8 lb/yr as compared to the MER of 73 lb/yr, thus requiring dispersion modeling to demonstrate compliance with the Hg AACs. The dispersion modeling and results are described below.

Detailed HAP emission calculations are provided in Appendix B.

6.8.1.Dispersion Modeling Analysis - Process

As with the CO modeling analysis, the AERMOD dispersion model was used to determine the maximum short-term and annual modeled concentrations of Hg for comparison to the applicable AACs. AERMOD was applied with the same source data, receptor grid, meteorological data, building downwash file, and model options as used in the CO air quality analysis described in Section 6.3, with the addition of the flare source (FP12). Also, for the modified Boilers No. 3 and No.5, the worst-case stack parameters between the different fuel options (lowest stack temperature, lowest stack velocity) was conservatively used in lieu of modeling each scenario as was conducted for the CO SIL modeling. Table 6-8 provides Hg emissions modeled for each source and Table 6-9 provides the stack parameters for the flare and the modified Boilers No.3 and No. 5. Note the source parameters for the other Hg sources are the same as provided in Table 6-4.

Table 6-8 Hg Emissions

Source	Model ID	Hg Emissions (lb/hr)
New Gas Boiler (Boiler 7)	BO_07	1.54E-03
Modified Boiler 3	BO_01	2.28E-03
Modified Boiler 5	BO_03	2.12E-03
Waste Heat Boiler Common Stk #1 (WH01 and CT-01 Emissions)	CT1	7.54E-04
Rental Natural Gas Boiler #1	RGB01	2.37E-05
Rental Natural Gas Boiler #2	RGB02	2.37E-05
Flare	FP12	6.86E-06
Paper Machine 16 – Yankee Wet End Exhaust	EP45	1.82E-04
Paper Machine 16 – Yankee Dry End Exhaust	EP56	1.82E-04
Paper Machine 17 – Yankee Wet End Exhaust	EP66	2.00E-04
Paper Machine 17 – Yankee Dry End Exhaust	EP67	2.00E-04
Paper Machine 18 – Yankee Wet End Exhaust	EP03	1.43E-04
Paper Machine 18 – Yankee Dry End Exhaust	EP14	1.43E-04
Paper Machine 19 – Yankee Wet End Exhaust	EP24	1.43E-04
Paper Machine 19 – Yankee Dry End Exhaust	EP37	1.43E-04
Paper Machine 20 – Yankee Wet End Exhaust	EP28	1.71E-04
Paper Machine 20 – Yankee Dry End Exhaust	EP30	1.71E-04

Table 6-9 Hg Stack Parameters (that differ from Table 6-4)

Source	Model ID	Stack Orientation	Stack Height (m)	Stack Temperature (K)	Stack Velocity (m/s)	Stack Diameter (m)
Modified Boiler 3 –	BO_01	Vertical	117.350	390.783	6.417	3.688
Modified Boiler 5	BO_03	Vertical	117.350	387.617	13.759	2.432
Flare	FP12	Vertical	10.360	1033.150	57.910	0.250

6.8.2. Dispersion Modeling Analysis - Results

Table 6-10 summarizes the results of the dispersion modeling for short-term averages and annual averages and compares the maximum modeled concentration per averaging period to the applicable AAC. As specified in the Guideline, 15-minute average concentrations were determined using a 1.32 scaling factor for 1-hour average model results.

As shown in Table 6-10, the dispersion modeling demonstrates that facility-wide emissions of Hg does not result in an exceedance of an AAC.

Table 6-1010 Summary of Maximum AERMOD Dispersion Modeling Results vs AACs

Pollutant	Averaging Period	Rank	Maximum AERMOD Concentration ($\mu g/m^3$)	Maximum AERMOD Concentration - 15- min Adjustment ($\mu g/m^3$)	AAC ($\mu g/m^3$)	% of Criteria
Hg	1-hr	H1H	0.0125	0.0164	10	0.16%
	Annual	H1H	0.0004	--	0.3	0.14%

APPENDIX A

AREA MAP, PLOT PLAN AND PROCESS FLOW DIAGRAMS

APPENDIX B

EMISSION CALCULATIONS

APPENDIX C

FORMS

APPENDIX D

REDLINE PERMIT