Prevention of Significant Air Quality Deterioration Review

Preliminary Determination

February 2025

Facility Name: Georgia-Pacific Savannah River LLC
City: Rincon
County: Effingham
AIRS Number: 04-13-10300007
Application Number: 873390
Date Application Received: October 14, 2024

Review Conducted by:
State of Georgia - Department of Natural Resources
Environmental Protection Division - Air Protection Branch
Stationary Source Permitting Program

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SUMMARY

The Environmental Protection Division (EPD) has reviewed the Prevention of Significant Deterioration ("PSD") application submitted by Georgia-Pacific Savannah River LLC (hereafter "SRM") for a permit to construct and operate a project that modifies steam production capability to improve energy efficiency and reliability (Utility Footprint Project). The proposed project will include a new 285 MMBtu/hr natural gas-fired boiler, 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, TDF, peat, and 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.

<u>Summary of PSD/New Source Review Applicability</u>
The addition of a boiler and modification of the existing boilers due to this project will result in an emissions increase in filterable total suspended particulate matter ("filterable TSP"), particulate matter with an aerodynamic diameter of less than or equal to 10 micrometers ("PM_{10}"), particulate matter with an aerodynamic diameter of less than or equal to 2.5 micrometers ("$PM_{2.5}$"), carbon monoxide ("CO"), nitrogen oxides ("NO_X"), volatile organic compounds ("VOC"), and total greenhouse gases ("Total GHG").

A PSD New Source Review ("NSR") analysis was performed for the facility for all pollutants to determine if the site is a major stationary source for any NSR pollutant and identify pollutants that would exceed the significant emission rate levels.

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 ("PTE") more than 100 tons per year of any 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 tons per year ("tpy") of several pollutants and is a major PSD source. Therefore, the project is subject to review under Georgia Rule for Air Quality Control ("Georgia Rule") 391-3-1-.02(7), which is the state regulatory citation equivalent to the Federal PSD regulation in 40 CFR 52.21. Pursuant to these regulations, modifications at major stationary sources must demonstrate that they will not significantly deteriorate the air quality in the region. Additionally, the potential emissions CO and Total GHG were determined to be above the PSD significant level thresholds.

SRM is located in Effingham County, which is classified as "attainment" or "unclassifiable" for SO_2, $PM_{2.5}$ and PM_{10}, NO_X, CO, and ozone (VOC).

The EPD review of the data submitted by SRM related to the proposed modification indicates that the proposed modifications conform to all applicable federal new source performance standards ("NSPS"), national emission standards for hazardous air pollutants ("NESHAP"), and Georgia Rules for Air Quality Control. It is also the preliminary determination of the EPD that the proposed facility provides for the application of Best Available Control Technology ("BACT") for the control of CO and Total GHG as required by 40 CFR 52.21(j).

EPD has determined through approved modeling techniques that the estimated emissions will not cause or contribute to a violation of any ambient air standard or allowable PSD increment in the area surrounding the facility or in Class I areas located within 200 km of the facility. It has further been determined that the proposal will not cause impairment of visibility or detrimental effects on soils or vegetation. Any air quality impacts produced by project-related growth should be inconsequential.

This Preliminary Determination concludes that an Air Quality Permit should be issued to Georgia-Pacific Savannah River LLC for the modifications necessary to complete the Utility Footprint Project. Various conditions have been incorporated into the current Title V operating permit to ensure and confirm compliance with all applicable air quality regulations. A copy of the draft permit amendment is included in Appendix A. This Preliminary Determination also acts as a narrative for the Title V Permit.

1.0 INTRODUCTION – FACILITY INFORMATION AND EMISSIONS DATA

On October 14, 2024, Georgia-Pacific Savannah River LLC) submitted an application for an air quality permit to construct and operate new equipment and modifications for the Utility Footprint Project. The facility is located at 437 Old Augusta Road South in Rincon, Effingham County.

Table 1-1: Title V Major Source Status

Pollutant	Is the Pollutant Emitted?	If emitted, what is the facility's Title V status for the Pollutant?		
		Major Source Status	Major Source Requesting SM Status	Non-Major Source Status
PM	✓	✓		
PM_{10}	✓	✓		
$PM_{2.5}$	✓	✓		
SO_2	✓	✓		
VOC	✓	✓		
NO_x	✓	✓		
CO	✓	✓		
TRS	✓			✓
H_2S	✓			✓
Individual HAP	✓	✓		
Total HAPs	✓	✓		
Total GHGs	✓	✓		

Table 1-2 below lists all current Title V permits, all amendments, 502(b)(10) changes, and off-permit changes, issued to the facility, based on a review of the "Permit" file(s) on the facility found in the Air Branch office.

Table 1-2: List of Current Permits, Amendments, and Off-Permit Changes

Permit Number and/or Off-Permit Change	Date of Issuance/ Effectiveness	Purpose of Issuance
2621-103-0007-V-06-0	TBD	Renewal permit.

Based on the proposed project description and data provided in the permit application, the estimated incremental increases of regulated pollutants from the facility are listed in Table 1-3 below:

Table 1-3: Emissions Increases from the Project

Pollutant	Baseline Years	Total Emissions Increase (tpy)	PSD Significant Emission Rate (tpy)	Subject to PSD Review
PM	Jan-2017 to Dec-2018	13.1	25	No
PM_{10}	Jan-2017 to Dec-2018	2.70	15	No
$PM_{2.5}$	Jan-2017 to Dec-2018	8.45	10	No
VOC	Mar-2015 to Feb-2017	20.2	40	No
NO_X	Dec-2021 to Nov-2023	25.0	40	No
CO	Jan-2016 to Dec-2017	964.9	100	Yes
SO_2	Nov-2017 to Oct-2019	-592.5	40	No
TRS	--	--	10	No
Pb	Nov-2014 to Oct-2016	-0.002	0.6	No
Fluorides	--	--	3	No
H_2S	--	--	10	No
SAM	May-2015 to Apr-2017	-5.53	7	No
Total CO_2e*	May-2018 to Apr-2020	127,348	75,000	Yes

*Greenhouse gases as Total CO_2e.

The definition of baseline actual emissions is the average emission rate, in tons per year, at which the emission unit actually emitted the pollutant during any consecutive 24-month period selected by the facility within the 10-year period immediately preceding the date a complete permit application was received by EPD. The total emission increases were calculated by subtracting the past actual emissions (based upon the annual average emissions from the selected 24-month time period) from the future projected actual emissions of the modified boilers, associated emission increases from non-modified equipment, and potential emissions from the new boiler and WWTR silo. Table 1-4 details this emissions summary. The emissions calculations for Tables 1-3 and 1-4 can be found in detail in the facility's PSD application (see Appendix B of Application No. 873390). These calculations have been reviewed and approved by the Division.

Table 1-4: Net Change in Emissions Due to the Major PSD Modification

Pollutant	Increase from Modified Equipment*		New Boiler and WWTR Silo	Associated Units Increase (tpy)	Total Emissions Increase (tpy)
	Past Actual	Future Actual			
PM	25.5	36.3	2.40	0	13.1
PM_{10}	66.9	63.3	6.26	0	2.70
$PM_{2.5}$	58.5	60.7	6.24	0	8.45
VOC	10.7	24.2	6.69	0	20.2
NO_X	370.6	350.7	44.9	0	25.0
CO	69.6	988.3	46.2	0	964.9
SO_2	888.9	295.7	0.73	0	-592.5
TRS	--	--	--	0	--
Pb	0.0042	0.0012	6.08E-4	0	-0.002
Fluorides	--	--	--	0	--
H_2S	--	--	--	0	--
SAM	8.70	3.16	--	0	-5.53
Total CO_2e	591,759	572,935	146,173	0	127,348

*Modified equipment is Boiler No. 3, Boiler No. 5, and various solids handling equipment.

Based on the information presented in Tables 1-3 and 1-4 above, SRM's proposed modification, as specified per Georgia Air Quality Application No. 873390, is classified as a major modification under PSD because the emission increases of CO and Total CO_2e.

Through its new source review procedure, EPD has evaluated SRM's proposal for compliance with State and Federal requirements. The findings of EPD have been assembled in this Preliminary Determination.

2.0 PROCESS DESCRIPTION

According to Application No. 873390, SRM has proposed to construct and operate a project that modifies steam production capability to improve energy efficiency and reliability (Utility Footprint Project).

2.1 Overall Facility Description

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 catch 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.

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.

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.

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, a combustion turbine with waste heat boiler, 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 combustion turbine 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 mill rents two 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.

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 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 boiler fuel and paper cores for recycling back into the pulping process. A number of raw materials necessary to the 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 SRM. The 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.

2.2 Modification Description

Georgia-Pacific Savannah River LLC (SRM) is modifying its steam production capability and flexibility to improve energy efficiency and reliability. The project includes the following:

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

- 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, permitted to fire coal, petroleum coke, peat, wood, no. 2 fuel oil, natural gas, tire derived fuel (TDF), and wastewater treatment residuals (WWTR). Modifications to this boiler include adding screw feeders and associated WWTR handling equipment to deliver WWTR to the lower furnace bed, replacing the 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 a new ammonia injection system for NO_X, a new secondary air system for CO, the existing limestone injection system for SO_2, and the existing baghouse for PM.

- 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, permitted 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 WWTR handling equipment to deliver WWTR to the lower furnace bed, replacing the 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 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 a new ammonia injection system for NO_X, a new secondary air system for CO, and the existing baghouse for PM.

- Permanently decommission Combustion Turbine No. 2/Waste Heat Boiler No. 2 (CT02/WHB2) that has not operated since 2016. The equipment was removed from the permit in the most recent renewal permit.

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

- The existing solid fuel silos will be removed from Boiler No. 5. The existing limestone silo will be repurposed for sand storage (LM03 to SAND) for Boiler No. 5. A total of five metering bins will be added to store feed WWTR (FS09) to both Boiler Nos. 3 and 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 No. 3 or Boiler No. 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 SRM permit application and supporting documentation are included in Appendix A of this Preliminary Determination and can be found online at https://epd.georgia.gov/psd112gnaa-nsrpcp-permits-database.

3.0 REVIEW OF APPLICABLE RULES AND REGULATIONS

3.1 State Rules

Georgia Rule for Air Quality Control (Georgia Rule) 391-3-1-.03(1) requires that any person prior to beginning the construction or modification of any facility which may result in an increase in air pollution shall obtain a permit for the construction or modification of such facility from the Director upon a determination by the Director that the facility can reasonably be expected to comply with all the provisions of the Act and the rules and regulations promulgated thereunder. Georgia Rule 391-3-1-.03(8)(b) continues that no permit to construct a new stationary source or modify an existing stationary source shall be issued unless such proposed source meets all the requirements for review and for obtaining a permit prescribed in Title I, Part C of the Federal Act [i.e., Prevention of Significant Deterioration of Air Quality (PSD)], and Section 391-3-1-.02(7) of the Georgia Rules (i.e., PSD).

Georgia Rule 391-3-1-.03(1) - Construction Permit requires that any person prior to beginning the construction or modification of any facility which may result in an increase in air pollution shall obtain a permit for the construction or modification of such facility from the Director upon a determination by the Director that the facility can reasonably be expected to comply with all the provisions of the Act and the rules and regulations promulgated there under.

Georgia Rule 391-3-1-.03(8)(b) continues that no permit to construct a new stationary source or modify an existing stationary source shall be issued unless such proposed source meets all the requirements for review and for obtaining a permit prescribed in Title I, Part C of the Federal Act [i.e., Prevention of Significant Deterioration of Air Quality], and Section 391-3-1-.02(7) of the Georgia Rules (i.e., PSD).

Georgia Rule 391-3-1-.02(2)(b) - Visible Emissions limits the opacity of visible emissions from any air contaminant source which is subject to some other emission limitation under section (2). The opacity of visible emissions from regulated sources may not exceed 40 percent under this general visible emission standard. This limitation applies to direct sources of emissions such as stationary structures, equipment, machinery, stacks, flues, pipes, exhausts, vents, tubes, chimneys, or similar structures with the capability of emitting particulates. This limit is subsumed by more stringent regulations for all three boilers. The material handling operations that support Boiler Nos. 3 and 5 are designed and equipped to comply with the provisions.

Georgia Rule 391-3-1-.02(2)(e) - Particulate Emission from Manufacturing Processes establishes an allowable rate of particulate emissions for Manufacturing Processes. For process weight rates up to 30 tons per hour and for rates above 30 tons per hour the allowable emission rates are established by the following equations. The material handling operations that support Boiler Nos. 3 and 5 are designed and equipped to minimize PM emissions.

$E = 4.1P^{0.67}$ for process input weight rate up to 30 tons per hour
$E = 55P^{0.11} – 40$ for process input weight rate above 30 tons per hour

Where: E = the allowable emission rate in pounds per hour
P = process weight rate in tons per hour.

Georgia Rule 391-3-1-.02(2)(d) – Fuel-Burning Equipment establishes limits for PM, opacity, and NO_X for fuel-burning equipment. The boilers will all have construction dates after January 1, 1972, and have a heat input capacity of greater than 250 MMBtu/hr. The boilers are each subject to a PM limit of 0.10 lb/MMBtu, an opacity limit to less than 20% opacity (6-minute average), except for one 6-minute period per hour of not more than 27% opacity, and prorated NO_X limits depending on if coal, oil, and/or natural gas are fired. PM and NO_X emission limits may be subsumed by limits under 40 CFR 60 Subpart Db and 40 CFR 63 Subpart DDDDD.

Georgia Rule 391-3-1-.02(2)(g) – Sulfur Dioxide establishes limits for SO_2 emissions and fuel sulfur content for boilers constructed dates after January 1, 1972. All three boilers are larger than 100 MMBtu/hr, therefore Georgia Rule (g) limits the sulfur content of fuel burned in the boilers to 3%. However, higher fuel sulfur contents are permitted if the source uses sulfur dioxide removal. Boiler No. 3 is also subject to a limit of 1.2 lb/MMBtu SO_2 based on the heat input from solid fossil fuel. Boiler Nos. 5 and 7 will comply by burning natural gas/WWTR and natural gas only, respectively.

Georgia Rule 391-3-1-.02(2)(n) – Fugitive Dust requires the facility to take all reasonable precautions to prevent dust from becoming airborne for any operation, process, handling, transportation, or storage facility which may result in fugitive dust. This regulation also establishes allowable opacity and work practice standards to minimize fugitive dust.

3.2 Federal Rule – Prevention of Significant Deterioration

The regulations for PSD in 40 CFR 52.21 require that any new major source or modification of an existing major source be reviewed to determine the potential emissions of all pollutants subject to regulations under the Clean Air Act. The PSD review requirements apply to any new or modified source which belongs to one of 28 specific source categories having potential emissions of 100 tons per year or more of any regulated pollutant, or to all other sources having potential emissions of 250 tons per year or more of any regulated pollutant. They also apply to any modification of a major stationary source which results in a significant net emission increase of any regulated pollutant.

Georgia has adopted a regulatory program for PSD permits, which the United States Environmental Protection Agency ("EPA") has approved as part of Georgia's SIP. This regulatory program is codified in the Georgia Rules at 391-3-1-.02(7). This means that Georgia EPD issues PSD permits for new major sources pursuant to the requirements of Georgia's regulations. It also means that Georgia EPD considers, but is not legally bound to accept, EPA comments or guidance. A commonly used source of EPA guidance on PSD permitting is EPA's Draft October 1990 New Source Review Workshop Manual for Prevention of Significant Deterioration and Nonattainment Area Permitting ("NSR Workshop Manual"). The NSR Workshop Manual is a comprehensive guidance document on the entire PSD permitting process.

The PSD regulations require that any major stationary source or major modification subject to the regulations meet the following requirements:

- Application of BACT for each regulated pollutant that would be emitted in significant amounts;
- Analysis of the ambient air impact;
- Analysis of the impact on soils, vegetation, and visibility;
- Analysis of the impact on Class I areas; and
- Public notification of the proposed plant in a newspaper of general circulation.

The following is a discussion of the applicable federal rules and regulations pertaining to the equipment that is the subject of this preliminary determination, which is then followed by the top-down BACT analysis.

3.3 Federal Rule – New Source Performance Standards

40 CFR 60 Subpart A – General Provisions
The provisions of this regulation apply to the owner or operator of any stationary sources which contain an affected facility, the construction or modification of which is commenced after the date of publication in the part of any standard applicable to that facility.

40 CFR 60 Subpart D – Standards of Performance for Fossil-Fuel-Fired Steam Generators
The provisions of this regulation apply to 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 for fossil fuel or fossil fuel fired with wood residue. 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 Subpart D. The subpart limits SO_2 emissions to 1.2 lb/MMBtu. Boiler No. 3 must comply with 40 CFR 60 Subpart Db for PM and NO_X emissions. Boiler Nos. 5 and 7 have a maximum rated heat input capacity over 250 MMBtu/hr but were constructed after the Subpart Db applicability date of June 19, 1986, so they are not subject to Subpart D.

40 CFR 60 Subpart Da – Standards of Performance for Electric Utility Steam Generating Units
40 CFR 60 Subpart Da applies to 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 and more than 25 MW net electrical output to the grid. SRM sells 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 modification.

40 CFR 60 Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

40 CFR 60 Subpart Db 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 Subpart Db were promulgated to establish more limits for units that are constructed, reconstructed, or modified after July 9, 1997, and February 28, 2005.

Boiler No. 3 was originally constructed in 1987 and is currently subject to Subpart Db. The proposed Boiler No. 3 modifications do not constitute a modification as defined in 40 CFR 60.14 because the project will not result in any increases in the maximum hourly emission rates of any pollutants regulated by Subpart Db. The existing Subpart Db and PSD avoidance limits will remain the same. The proposed changes to Boiler No. 3 cost approximately $23 million. The cost of a new comparable 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.

For Boiler No. 3, per 40 CFR 60.40b(b)(2), coal-fired affected facilities having a heat input capacity greater than 250 MMBtu/hr and meeting the applicability requirements under 40 CFR 60 Subpart D are subject to the PM and NO_X standards under Subpart Db and to the SO_2 standards under Subpart D. Following the project, the limit for PM will continue to be 0.051 lb/MMBtu and the limit for NO_X will continue to be prorated between 0.2 lb/MMBtu and 0.6 lb/MMBtu depending on the amounts of gas and coal being burned. The modified boiler will also continue to be subject to an 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 under the subpart.

Boiler No. 5 originally constructed in 1995 and is currently subpart to Subpart Db. 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 PSD avoidance limits will remain the same and limits under NO_X Subpart Db will be reduced due to the change in fuel mix. The proposed changes to Boiler No. 5 cost approximately $23 million. The cost of a new comparable 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.

Specifically for post-project 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). Both limits are lower than the existing 0.4 lb/MMBtu PSD avoidance limit. There are no specific emission limits for PM or SO_2 for natural gas or natural gas and WWTR in Subpart 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 No. 5.

40 CFR 60 Subpart Db will apply to Boiler No. 7 because it has a heat input capacity greater than 100 MMBtu/hr and will be constructed after the applicability date. The boiler will burn only natural gas; therefore, it will not be subject to limits for opacity, PM, or SO_2. The boiler is subject to a NO_X limit of 0.10 lb/MMBtu as it applies to a natural gas boiler with a low heat release rate under 40 CFR 60.44b(l)(2) on a 30-day rolling average.

40 CFR 60 Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units
40 CFR 60 Subpart Dc applies to boilers for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr. The SRM boilers all have heat inputs greater than 100 MMBtu/hr; therefore, the rule does not apply.

3.4 National Emissions Standards For Hazardous Air Pollutants

The facility has the potential to emit more than 25 tpy of total HAP and more than 10 tpy of individual HAP. Therefore, the facility is classified as a major source of HAP.

40 CFR 61 Subpart A – General Provisions
The provisions of this regulation apply to the owner or operator of any stationary sources which contains an effected facility, the construction or modification of which is commenced after the date of publication in the part of any standard applicable to that facility.

40 CFR 61 Subpart E – National Emission Standard for Mercury
40 CFR 61 Subpart E applies to facilities that "incinerate or dry wastewater treatment plant sludge." Neither Boiler No. 3 or 5 are designed or operated as an "incinerator", however, according to previous US EPA determinations under Subpart E, the rule can be said to apply to the combustion of paper mill WWTR as a fuel in a boiler for energy recovery. The rule limits mercury emissions to 7.1 lb of mercury per 24-hour period. The regulation allows compliance with this limit to be shown via stack testing per 40 CFR 61.53(d) or sludge sampling per 40 CFR 61.54. SRM conducted sampling in January 2019. The sampling estimated emissions of 0.08 lb/day. Per 40 CFR 61.55(a), no additional sampling is required as the emissions are below 3.5 lb/day. Boiler Nos. 3 and 5 will continue to be subject to the subpart post-project.

40 CFR 63 Subpart A – General Provisions
The provisions of this regulation apply to the owner or operator of any stationary sources which contains an affected facility, the construction or modification of which is commenced after the date of publication in the part of any standard applicable to that facility.

40 CFR 63 Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters
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 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 Subpart DDDDD specifies limits and monitoring requirements based on the type of boiler and the permitted fuels. The subpart classifies WWTR as biomass; therefore, following the project, the existing boilers will be classified as follows:

- Boiler No. 3 may be one of two classifications, depending on fuel mix. The regulation specifies what actions the facility must take if boiler classification changes:

    - 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.

    OR

    - 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.

- Boiler No. 5:

    - 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.

It should be noted that Subpart DDDDD was amended in 2022 to include changes to several numeric emission limits for new and existing boilers. The effective date for the new limits is October 6, 2025. Because this modification will be permitted prior to October 6, 2025, the permit amendment includes limits for the modified boiler configurations before and on/after October 6, 2025. 40 CFR 63 Subpart DDDDD includes limits for hydrogen chloride (HCl), mercury (Hg), carbon monoxide (CO), and either particulate matter (PM) or total selected metals (TSM).

The following are the limits for Boiler No. 3 post-modification.

- Before October 6, 2025:
  - Biomass subcategory:
    - 0.022 lb/MMBtu HCl.
    - 5.7×10^{-6} lb/MMBtu Hg.
    - 470 ppm CO by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or 310 ppm CO by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average if using CEMS.
    - 0.11 lb/MMBtu filterable PM or 1.2×10^{-3} lb/MMBtu TSM.
  - Coal/solid fossil subcategory:
    - 0.022 lb/MMBtu HCl.
    - 5.7×10^{-6} lb/MMBtu Hg.
    - 130 ppm CO by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or 230 CO ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average if using CEMS.
    - 0.04 lb/MMBtu filterable PM or 5.3×10^{-5} lb/MMBtu TSM.
- On and after October 6, 2025:
  - Biomass subcategory:
    - 0.020 lb/MMBtu HCl.
    - 5.4×10^{-6} lb/MMBtu Hg.
    - 210 ppm CO by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or 310 ppm CO by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average if using CEMS.
    - $7.4 \mathrm{X} 10^{-3}$ lb/MMBtu filterable PM or 6.4×10^{-5} lb/MMBtu TSM.
  - Coal/solid fossil subcategory:
    - 0.020 lb/MMBtu HCl.
    - 5.4×10^{-6} lb/MMBtu Hg.
    - 130 ppm CO by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or 230 CO ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average if using CEMS.
    - 0.039 lb/MMBtu filterable PM or 5.3×10^{-5} lb/MMBtu TSM.

The following are the limits for Boiler No. 5 post-modification.

- Before October 6, 2025:
  - 0.022 lb/MMBtu HCl.
  - 5.7×10^{-6} lb/MMBtu Hg.
  - 470 ppm CO by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or 310 ppm CO by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average if using CEMS.
  - 0.11 lb/MMBtu filterable PM or 1.2×10^{-3} lb/MMBtu TSM.

- On and after October 6, 2025:

  - 0.020 lb/MMBtu HCl.
  - 5.4×10^{-6} lb/MMBtu Hg.
  - 210 ppm CO by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or 310 ppm CO by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average if using CEMS.
  - $7.4X10^{-3}$ lb/MMBtu filterable PM or 6.4×10^{-5} lb/MMBtu TSM.

Boiler Nos. 3 and 5 will continue to operate the existing CO CEMS and have elected to comply with the alternate TSM limit. The facility will comply with the startup and shutdown requirements in Table 3 of the subpart. Stack testing and resulting applicable operating limits will be utilized to demonstrate compliance with the emission limits per Tables 4, 5, 7, and 8 of the subpart. Boiler Nos. 3 and 5 will continue to operate a continuous oxygen trim system that maintains an optimum air to fuel ratio. Tune-ups will be conducted once every 5 years as specified by the regulations.

Boiler No. 7 will be a new unit in the “designed to burn gas 1” subcategory. There are no emission limits that apply to the “designed to burn gas 1” subcategory. Boiler No. 7 will operate a continuous oxygen trim system that maintains an optimum air-to-fuel ratio and will meet the 5-year tune-up requirements required by the subpart.

3.5 State and Federal – Startup and Shutdown and Excess Emissions

Excess emission provisions for startup, shutdown, and malfunction are provided in Georgia Rule 391-3-1-.02(2)(a)7. Excess emissions from the boilers associated with the proposed project would most likely results from a malfunction of the associated control equipment. The facility cannot anticipate or predict malfunctions. However, the facility is required to minimize emissions during periods of startup, shutdown, and malfunction.

40 CFR 60 and 40 CFR 63 rules each contain their own provisions for periods of startup and shutdown.

3.6 Federal Rule – 40 CFR 64 – Compliance Assurance Monitoring

Under 40 CFR 64, the *Compliance Assurance Monitoring* Regulations (CAM), facilities are required to prepare and submit monitoring plans for certain emission units with the Title V application. The CAM Plans provide an on-going and reasonable assurance of compliance with emission limits. Under the general applicability criteria, this regulation applies to units that use a control device to achieve compliance with an emission limit and whose pre-controlled emissions levels exceed the major source thresholds under the Title V permitting program. Although other units may potentially be subject to CAM upon renewal of the Title V operating permit, such units are not being modified under the proposed project and need not be considered for CAM applicability at this time.

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)).

Modified Boiler No. 3 will maintain the existing controls for PM and SO_2, and ammonia injection will be added to control of NO_X emissions. The boiler will continue to be subject to CAM for SO_2 emissions using the CEMS as the compliance indicator. The boiler is not subject to CAM for NO_X because the existing CEMS is the compliance method for the Title V permit. The boiler will not be subject to CAM for PM because limits under 40 CFR 63 Subpart DDDDD were proposed after November 15, 1990.

Modified Boiler No. 5 will maintain the existing controls for PM and ammonia injection will be added to control of NO_X emissions. The boiler will no longer continue to be equipped with SO_2 controls; therefore, CAM does not apply for that pollutant. The boiler is not subject to CAM for NO_X because the existing CEMS is the compliance method for the Title V permit. The boiler will not be subject to CAM for PM because limits under 40 CFR 63 Subpart DDDDD were proposed after November 15, 1990.

Boiler No. 7 will not be equipped with a control device; therefore, CAM does not apply.

4.0 CONTROL TECHNOLOGY REVIEW

The proposed project will result in emissions that are significant enough to trigger PSD review for the following pollutants: CO and Total GHG (CO_2e).

Definition of BACT

The PSD regulation requires that Best Available Control Technology (BACT) be applied to all regulated air pollutants emitted in significant amounts. Section 169 of the Clean Air Act defines BACT as “an emission limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Act, which would be emitted from any proposed major stationary source or major modification which the Administrator (in this case, EPD), 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 and available methods, systems, and techniques.”

In no case can the application of BACT result in emissions of any pollutant which would exceed emissions allowed any applicable standards under 40 CFR Parts 60, 61, or 63. In addition, if EPD determines that there is no economically reasonable or technologically feasible way to measure the emissions, and hence to impose and enforceable emissions standard, it may require the source to use a design, equipment, work practice or operations standard or combination thereof, to reduce emissions of the pollutant to the maximum extent practicable.

The BACT limits contained in the permit as outlined below apply at all times, including startup and shutdown.

This review was conducted generally using the top-down analysis and five-step process recommended by EPA in their *Draft New Source Review Workshop Manual* dated October 1990. The five steps of a top-down BACT review procedure identified by EPA per BACT guidelines are listed below:

Step 1: Identify all available control technologies;
Step 2: Eliminate technically infeasible options;
Step 3: Rank the remaining control technologies by control effectiveness;
Step 4: Evaluate the most effective controls and documentation of results; and
Step 5: Selection of BACT.

4.1 CARBON MONOXIDE – CO

Applicant’s Proposal

Boiler Nos. 3, 5, and 7 are subject to PSD review and have carbon monoxide (CO) emissions requiring a BACT evaluation. There are no CO emissions from any other source involved with the project.

Formation

CO emissions are generated during fuel combustion due to incomplete conversion of carbon-containing compounds in the fuel to carbon dioxide (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.

Step 1 – Available CO Control Technologies

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 CO_2. 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 Boiler Nos. 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 No. 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 NO_X 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.

Step 2 – Eliminate Technically Infeasible Options

Boiler Nos. 3 and 5

It is not feasible to conduct a search of the EPA's RACT/BACT/LAER (RBLC) listings for boilers with precisely the same fuel mix as will be utilized in Boiler Nos. 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 describe 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 of the application.

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 and plans to construct the paper mill where the boiler would have been located have been terminated.

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 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 Boiler Nos. 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. 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 Boiler Nos. 3 and 5, substantial additional modifications would need to be made to each boiler in order to accommodate this alternative.

<u>Boiler No. 7</u>
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 application.

Of the 21 natural gas-fired boiler unit listings in the RBLC with heat input rates in the range proposed for Boiler No. 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.

<u>Step 3 – Rank Remaining Feasible Control Technologies</u>

<u>Boiler Nos. 3 and 5</u>
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 No. 3 or 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 the next most stringent alternative for control of CO emissions.

The lowest emission limit among the six oxidation catalyst-equipped solid fuel boilers found in the RBLC search is 0.075 lb/MMBtu. The average emission limit for solid fuel boilers employing combustion controls found in the RBLC search is 0.26 lb/MMBtu.

1. Oxidation Catalyst System
2. Combustion Controls/Good Combustion Practices

Boiler No. 7

Based on the results of the RBLC search, the use of an oxidation catalyst system is the most stringent alternative for control of CO emissions from Boiler No. 7. The lowest emission limit among the two oxidation catalyst-equipped small natural gas-fired boilers is 0.008 lb/MMBtu. A typical emission limit for natural gas-fired boilers equipped with combustion controls is 50 ppm @3% O_2 or 0.037 lb/MMBtu.

1. Oxidation Catalyst System
2. Combustion Controls/Good Combustion Practices

Step 4 – Evaluate Remaining Control Technologies

The applicant conducted analyses to evaluate the energy, environmental and economic aspects of employing oxidation catalyst systems to control CO emissions from Boiler Nos. 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 modified boiler primarily due to the additional combustion air fan energy to overcome the pressure drop imposed by the catalyst grid.

  As previously noted, use of oxidation catalyst systems on Boiler Nos. 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 No. 3 or 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 water column (w.c.) of pressure drop imposed by the catalyst grid in Boiler No. 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 Boiler No. 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 Boiler Nos. 3, 5, and 7. These analyses were conducted using the cost assessment methodology presented in the US EPA's Control Cost Manual and vendor-supplied data. The results of these assessments are presented in Table 5-3 of the application. 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 of the application, 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.

  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.

  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.

Step 5 – Selection of BACT

The use of oxidation catalyst systems to control CO emissions from Boiler Nos. 3, 5 and 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 (good combustion practices/combustion controls) is considered representative of BACT for control of CO emissions from these units. The proposed emission limit for Boiler No. 3 and Boiler No. 5 is 310 ppmvd @3% O_2 and the proposed emission limit for Boiler No. 7 is 0.037 lb/MMBtu, or an emission level of 50 ppmvd @ 3% O_2.

EPD Review of BACT for CO Emissions from Boiler Nos. 3, 5, and 7

The Division agrees with the facility that oxidation catalyst systems are technically feasible for each boiler. For Boiler Nos. 3 and 5, the Division also agrees there are significant economic, energy, and efficiency issues associated with the use of such a system on the existing boilers. These impacts include the replacement of the baghouses with ESPs, the additional energy that would be required to operate ESPs, removal of boiler sections to accommodate the system, and cost effectiveness values more than $11,500 per ton of CO removed for each boiler. Based on a review of the RBLC, the EPD also confirmed that the other listed control technology is combustion controls/good combustion practices. The proposed limits of 310 ppmvd at 3% oxygen is in line with recent RBLC entries in terms of lb CO per MMBtu heat input for boilers burning biomass and/or coal (approximately 0.29 lb/MMBtu). It should also be noted that 310 ppmvd at 3% oxygen is also the 40 CFR 63 Subpart DDDDD limit for circulating fluidized bed boilers burning biomass. Modified Boiler No. 3 may be classified as a biomass boiler based on fuel mix and modified Boiler No. 5 will be classified as a biomass boiler.

The Division agrees with the facility that an oxidation catalyst system is technically feasible for Boiler No. 7. The Division also agrees there are significant economic issues, as the cost effectiveness value is approximately $18,000 per ton of CO removed. Based on a review of the RBLC, the EPD also confirmed that the other listed control technology is combustion controls/good combustion practices. The vendor guarantee proposed limit of 50 ppmvd at 3% oxygen is in line with recent RBLC entries in terms of lb CO per MMBtu heat input for natural gas fired boilers (approximately 0.037 lb/MMBtu).

Table 4-1: BACT Summary for CO from Boiler Nos. 3, 5, and 7

Unit	Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
Boiler No. 3 (BO01)	CO	Combustion Controls/Good Combustion Practices	310 ppmvd @ 3% O_2	30-day rolling	CEMS
Boiler No. 5 (BO03)	CO	Combustion Controls/Good Combustion Practices	310 ppmvd @ 3% O_2	30-day rolling	CEMS
Boiler No. 7 (BO07)	CO	Combustion Controls/Good Combustion Practices	50 ppmvd @ 3% O_2 (0.037 lb/MMBtu)	30-day rolling	CEMS

4.2 GREEN HOUSE GASES (GHG) – Total CO_2e

Boiler No. 3, Boiler No. 5, and Boiler No. 7 are subject to PSD review and have Total CO_2e emissions requiring a BACT evaluation. There are no Total CO_2e emissions from any other source involved with the project. The applicant conducted an analysis for Total CO_2e by conducting a review of each component, including carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O).

4.2.1 Carbon Dioxide – CO_2

Applicant's Proposal

Formation
GHG emissions that result from fuel combustion in any of the three boilers include CO_2, CH_4, and 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, this BACT review has been prepared for the units in general rather than for each individual unit.

As described previously, Boiler Nos. 3 and 5 will be modified to burn WWTR. 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. Boiler Nos. 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 boiler's CO_2 emissions will be from the combustion of biogenic fuel.

Step 1 – Available CO_2 Control Technologies
A search of RBLC database 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 of the application, 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*"; 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*". Accordingly, CCS is included in this BACT review as a 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.

<u>Good Combustion, Operating and Maintenance Practices</u>

Good combustion, operating, and maintenance practices are 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 (Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units) and TTTTa (Standards of Performance for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units). All three boilers will burn natural gas, and Boiler Nos. 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 (CCS)

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).

Step 2 – Eliminate Technically Infeasible Options

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 Boiler Nos. 3, 5 and 7 and are technically feasible. Boiler No. 7 will be fired exclusively with natural gas, which is the lowest carbon intensity fossil fuel. Boiler Nos. 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 Boiler Nos. 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 boiler 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%.

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.

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 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 Boiler Nos. 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 parasitic energy loss associated with CO_2 compression is 61 kWh/MT of CO_2 compressed. Based on CCS theoretically being capable of 90% capture, compression of the potential captured CO_2 emissions from Boiler Nos. 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, 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.

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. Adjusting for inflation, these figures suggest that a very significant cost would be incurred to transport the captured CO_2 emissions from Boiler Nos. 3, 5, and 7 and store them 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. No research and development has been carried out to address specifically the implementation issues associated with CCS on industrial boilers, and 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, CCS is not an "applicable" control option for this application and thus not technically feasible. As described above, the application of CCS to the three boilers that are the subject of this application would be prohibitively expensive.

Step 3 – Rank Remaining Feasible Control Technologies

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.

Step 4 – Evaluate Remaining Control Technologies

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,
- 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.

Step 5 – Selection of BACT

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 226.31 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 No. 7 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.

EPD Review of BACT for CO_2 Emissions from Boiler Nos. 3, 5, and 7

Based on a review of the RBLC database and information discussed by the applicant, the Division agrees with the facility that CCS is technically infeasible for the Utility Footprint Project. Furthermore, the Division agrees that good combustion, operating, and maintenance practices / low GHG fuels (biomass/natural gas) are technically feasible and have been applied as BACT for similar sources emitting GHG. The applicant has established limits for each boiler based on the emission factors in the 40 CFR 98 – Mandatory Greenhouse Gas Reporting regulation. The Division confirmed this methodology is in line with similar sources in the RBLC database. The proposed numerical limits include CO_2, CH_4, and N_2O.

Table 4-2: BACT Summary for CO_2 from Boiler Nos. 3, 5, and 7

Unit	Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
Boiler No. 3 (BO01)	CO_2	Good Combustion, Operating, and Maintenance Practices / Low GHG Fuels	226.31 lb/MMBtu*	N/A	40 CFR Part 98 Emission Factors
Boiler No. 5 (BO03)	CO_2	Good Combustion, Operating, and Maintenance Practices / Low GHG Fuels	209.34 lb/MMBtu*	N/A	40 CFR Part 98 Emission Factors
Boiler No. 7 (BO07)	CO_2	Good Combustion, Operating, and Maintenance Practices / Low GHG Fuels	117.10 lb/MMBtu*	N/A	40 CFR Part 98 Emission Factors

*Limit includes CO_2, CH_4, and N_2O

4.2.2 Methane – CH_4

Applicant's Proposal

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.

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

Step 1 – Available CH_4 Control Technologies
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 boilers.

Catalyst providers do not offer products specifically to control CH_4 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 CH_4 particularly difficult. Therefore, good combustion practices are the only available control option for CH_4 emissions from the boilers.

Step 2 – Eliminate Technically Infeasible Options
Good combustion practices are the only available control option for CH_4 emissions from the boilers and are technically feasible.

Step 3 – Rank Remaining Feasible Control Technologies
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 boilers.

Step 4 – Evaluate Remaining Control Technologies
The top control option – good combustion practices – is proposed for emissions of CH_4 from the boilers. Therefore, no further evaluation of the CH_4 control options is required.

Step 5 – Selection of BACT
Good combustion practices are concluded to be representative of BACT for control of CH_4 emissions from the boilers. 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.

EPD Review of BACT for CH_4 Emissions from Boiler Nos. 3, 5, and 7
The Division agrees with the applicant's findings regarding CH_4 emissions from the boilers. See Table 4-2 of the preliminary determination for the Total CO_2e numerical limits.

Table 4-3: BACT Summary for CH_4 from Boiler Nos. 3, 5, and 7

Unit	Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
Boiler No. 3 (BO01)	CH_4	Good Combustion Practices	Included in CO_2e Limit	N/A	40 CFR Part 98 Emission Factors
Boiler No. 5 (BO03)	CH_4	Good Combustion Practices	Included in CO_2e Limit	N/A	40 CFR Part 98 Emission Factors
Boiler No. 7 (BO07)	CH_4	Good Combustion Practices	Included in CO_2e Limit	N/A	40 CFR Part 98 Emission Factors

4.2.3 Nitrous Oxide – N_2O

Applicant's Proposal

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.

Formation

There are five (5) primary pathways of nitrogen oxide (NO_X) production in combustion sources: thermal NO_X formation, prompt NO_X formation, NO_X from N_2O intermediate reactions, fuel NO_X formation, and NO_X formed through reburning. These pathways primarily produce the two principal constituents of NO_X (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.

Step 1 – Available CH_4 Control Technologies

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 boilers. 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.

Step 2 – Eliminate Technically Infeasible Options

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 boiler's 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.

Step 3 – Rank Remaining Feasible Control Technologies

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 boilers.

Step 4 – Evaluate Remaining Control Technologies

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

Step 5 – Selection of BACT

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.

EPD Review of BACT for CH_4 Emissions from Boiler Nos. 3, 5, and 7

The Division agrees with the applicant's findings regarding N_2O emissions from the boilers. See Table 4-2 of the preliminary determination for the Total CO_2e numerical limits.

Table 4-4: BACT Summary for N_2O from Boiler Nos. 3, 5, and 7

Unit	Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
Boiler No. 3 (BO01)	N_2O	Good Combustion Practices	Included in CO_2e Limit	N/A	40 CFR Part 98 Emission Factors
Boiler No. 5 (BO03)	N_2O	Good Combustion Practices	Included in CO_2e Limit	N/A	40 CFR Part 98 Emission Factors
Boiler No. 7 (BO07)	N_2O	Good Combustion Practices	Included in CO_2e Limit	N/A	40 CFR Part 98 Emission Factors

5.0 TESTING AND MONITORING REQUIREMENTS

In order to demonstrate initial and ongoing compliance with BACT limits as well as federal and state emissions standards, the draft permit contains requirements for emissions testing of equipment and ongoing monitoring of pollution control equipment parameters. These requirements will be discussed below according to the associated compliance requirement.

CO BACT Limits

Boiler Nos. 3, 5, and 7 are all subject to BACT limits for CO. No stack testing will be required because the boilers will use CO CEMS for demonstrating continuous compliance.

Total CO_2e BACT Limits

Boiler Nos. 3, 5, and 7 are all subject to BACT limits for Total CO_2e. No stack testing is required as the facility is using emission factors from 40 CFR 98 – Mandatory Greenhouse Gas Reporting (May 14, 2024 Version). Compliance will be demonstrated by burning only permitted fuels. The permit requires the facility to monitor fuel usage daily.

New PSD Avoidance Limits

Boiler No. 7 is subject to PSD avoidance limits for NO_X and $PM_{10}/PM_{2.5}$, which are based on vendor guarantees for the new boiler. The boiler will be equipped with a NO_X CEMS for demonstration continuous compliance and the permit requires a stack test to demonstrate compliance with the $PM_{10}/PM_{2.5}$ limit.

Existing PSD Limits

Boiler Nos. 3 and 5 are subject to existing BACT limits for SO_2 and NO_X. Those limits will remain in effect and the Permittee uses CEMS/stack flow monitors to demonstrate continuous compliance.

40 CFR 63 Subpart DDDDD

Boiler No. 3 is required to conduct initial and periodic stack testing for Hg, HCl, and TSM. The facility must use the testing to establish operating limits, including sorbent injection rate (if not using an SO_2 CEMS for HCl or an HCl CEMS), opacity (COMS), and operating load. The facility must also develop a site-specific monitoring plan. The facility will comply with the CO limit with a CEMS. The facility must also conduct a tune-up every 5 years.

Boiler No. 5 is required to conduct initial and periodic stack testing for Hg, HCl, and TSM. The facility must use the testing to establish operating limits, including sorbent injection rate (if not using an SO_2 CEMS for HCl or an HCl CEMS), opacity (COMS) and operating load. The facility must also develop a site-specific monitoring plan. The facility will comply with the CO limit with a CEMS. The facility must also conduct a tune-up every 5 years.

Boiler No. 7 is required to undergo a tune-up every up every 5 years.

40 CFR 61 Subpart E

No testing is required for burning WWTR in Boiler Nos. 3 and 5. The facility has conducted sampling that shows the Hg content of the WWTR is well below limits and no further action is necessary.

40 CFR 60 Subpart Db

Boiler No. 3 will be subject to an initial stack test and periodic testing for PM. The facility must monitor the baghouse pressure drop and implement a Preventative Maintenance Program for the baghouse. Boiler No. 3 will demonstrate compliance with the opacity limits with a COMS. Boiler Nos. 3, 5, and 7 will conduct a 30-day initial NO_X test and continue to continuously monitor emissions with CEMS.

40 CFR 60 Subpart D and Georgia Rule (g)

Boiler No. 3 will continue to use a CEMS to demonstrate compliance with the SO_2 limit.

Georgia Rule (d)

Boiler Nos. 3 and 5 will be subject to an initial stack test and periodic testing for PM. The facility must monitor the baghouse pressure drop and implement a Preventative Maintenance Program for the baghouse. Boiler No. 3 will demonstrate compliance with the opacity limits with a COMS. Boiler No. 7 is not subject to PM or opacity testing/monitoring because it will burn only natural gas.

Georgia Rules (b), (e), (n)

The Permittee operates baghouses for fuel and material silos and conducts visible emission checks for fuel and material silos. The facility will use good operating practices to minimize emissions from the WWTR fuel bins.

CAM

Modified Boiler No. 3 will maintain the existing controls for PM and SO_2, and ammonia injection will be added to control of NO_X emissions. The boiler will continue to be subject to CAM for SO_2 emissions using the CEMS as the compliance indicator. The boiler is not subject to CAM for NO_X because the existing CEMS is the compliance method for the Title V permit. The boiler will not be subject to CAM for PM because limits under 40 CFR 63 Subpart DDDDD were proposed after November 15, 1990.

Modified Boiler No. 5 will maintain the existing controls for PM and ammonia injection will be added to control of NO_X emissions. The boiler will no longer continue to be equipped with SO_2 controls; therefore, CAM does not apply for that pollutant. The boiler is not subject to CAM for NO_X because the existing CEMS is the compliance method for the Title V permit. The boiler will not be subject to CAM for PM because limits under 40 CFR 63 Subpart DDDDD were proposed after November 15, 1990.

Boiler No. 7 will not be equipped with a control device; therefore, CAM does not apply.

6.0 AMBIENT AIR QUALITY REVIEW

An air quality analysis is required to determine the ambient impacts associated with the construction and operation of the proposed modifications. The main purpose of the air quality analysis is to demonstrate that emissions emitted from the proposed modifications, in conjunction with other applicable emissions from existing sources (including secondary emissions from growth associated with the new project), will not cause or contribute to a violation of any applicable National Ambient Air Quality Standard (NAAQS) or PSD increment in a Class I or Class II area. NAAQS exist for NO_2, CO, $PM_{2.5}$, PM_{10}, SO_2, Ozone (O_3), and lead. PSD increments exist for SO_2, NO_2, and PM_{10}.

The proposed project at SRM triggers PSD review for CO. An air quality analysis was conducted to demonstrate the facility’s compliance with the NAAQS and PSD Increment standards for CO. An additional analysis was conducted to demonstrate compliance with the Georgia air toxics program. This section of the application discusses the air quality analysis requirements, methodologies, and results. Supporting documentation may be found in the Air Quality Dispersion Report of the application and in the additional information packages.

The facility utilized AERMOD and 5-year meteorological data to model proposed emissions of each pollutant subject to PSD review.

Modeling Requirements

The air quality modeling analysis was conducted in accordance with Appendix W of Title 40 of the Code of Federal Regulations (CFR) §51, *Guideline on Air Quality Models*, and Georgia EPD’s *Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions (Revised)*.

The proposed project will cause net emission increases of CO that are greater than the applicable PSD Significant Emission Rates. Therefore, air dispersion modeling analyses are required to demonstrate compliance with the NAAQS and PSD Increment. GHG has no PSD increment or NAAQS and therefore are not modeled.

Significance Analysis: Ambient Monitoring Requirements and Source Inventories

Initially, a Significance Analysis is conducted to determine if the CO emissions increases at SRM would significantly impact the area surrounding the facility. Maximum ground-level concentrations are compared to the pollutant-specific U.S. EPA-established Significant Impact Level (SIL). The SIL for the pollutants of concern are summarized in Table 6-1.

If a significant impact (i.e., an ambient impact above the SIL) does not result, no further modeling analyses would be conducted for that pollutant for NAAQS or PSD Increment. If a significant impact does result, further refined modeling would be completed to demonstrate that the proposed project would not cause or contribute to a violation of the NAAQS or consume more than the available Class II Increment.

Under current U.S. EPA policies, the maximum impacts due to the emissions increases from a project are also assessed against monitoring *de minimis* levels to determine whether pre-construction monitoring should be considered. These monitoring *de minimis* levels are also listed in Table 6-1. If either the predicted modeled impact from an emission increase or the existing ambient concentration is less than the monitoring *de minimis* concentration, the permitting agency has the discretionary authority to exempt an applicant from pre-construction ambient monitoring. This evaluation is required for CO.

If any off-site pollutant impacts calculated in the Significance Analysis exceed the SIL, a Significant Impact Area (SIA) would be determined. The SIA encompasses a circle centered on the facility with a radius extending out to (1) the farthest location where the emissions increase of a pollutant from the project causes a significant ambient impact, or (2) a distance of 50 km, whichever is less. All sources within a distance of 50 km of the edge of a SIA are assumed to potentially contribute to ground-level concentrations within the SIA and would be evaluated for possible inclusion in the NAAQS and PSD Increment analyses.

Table 6-1: Summary of Modeling Significance Levels

Pollutant	Averaging Period	PSD Significant Impact Level (ug/m^3)	PSD Monitoring Deminimis Concentration (ug/m^3)
CO	8-Hour	500	575
	1-Hour	2000	--

<u>NAAQS Analysis</u>

The primary NAAQS are the maximum concentration ceilings, measured in terms of total concentration of pollutant in the atmosphere, which define the "levels of air quality which the U.S. EPA judges are necessary, with an adequate margin of safety, to protect the public health." Secondary NAAQS define the levels that "protect the public welfare from any known or anticipated adverse effects of a pollutant." The primary and secondary NAAQS are listed in Table 6-2 below.

Table 6-2: Summary of National Ambient Air Quality Standards

Pollutant	Averaging Period	NAAQS	
		Primary / Secondary (ug/m^3)	Primary / Secondary (ppm)
CO	8-Hour	10,000 / None	9 / None
	1-Hour	40,000 / None	35 / None

If the maximum pollutant impact calculated in the Significance Analysis exceeds the SIL at an off-property receptor, a NAAQS analysis is required. The NAAQS analysis would include the potential emissions from all emission units at SRM, except for units that are generally exempt from permitting requirements and are normally operated only in emergency situations. The emissions modeled for this analysis would reflect the results of the BACT analysis for the modified emission unit. Facility emissions would then be combined with the allowable emissions of sources included in the regional source inventory. The resulting impacts, added to appropriate background concentrations, would be assessed against the applicable NAAQS to demonstrate compliance. For an annual average NAAQS analysis, the highest modeled concentration among five consecutive years of meteorological data would be assessed, while the highest second-high impact would be assessed for the short-term averaging periods.

PSD Increment Analysis

The PSD Increments were established to "prevent deterioration" of air quality in certain areas of the country where air quality was better than the NAAQS. To achieve this goal, U.S. EPA established PSD Increments for certain pollutants. The sum of the PSD Increment concentration and a baseline concentration defines a "reduced" ambient standard, either lower than or equal to the NAAQS that must be met in an attainment area. Significant deterioration is said to have occurred if the change in emissions occurring since the baseline date results in an off-property impact greater than the PSD Increment (i.e., the increased emissions "consume" more that the available PSD Increment).

U.S. EPA has established PSD Increments for NO_X, SO_2, $PM_{2.5}$, and PM_{10}; no increments have been established for CO.

Modeling Methodology

Details on the dispersion model, including meteorological data, source data, and receptors can be found in EPD's PSD Dispersion Modeling and Air Toxics Assessment Review in Appendix A of this Preliminary Determination and in Part 6 – Air Quality Analysis of the of the permit application.

Modeling Results

Table 6-3 shows that the proposed project will not cause ambient impacts of CO above the appropriate SIL. Because the emission increases from the proposed project resulted in ambient impacts less than the SIL for CO, no further PSD analyses were conducted.

Table 6-3: Class II Significant Impact Levels Modeling

Pollutant	Averaging Period	Max Modeled Conc. (μg/m^3)	SIL (μg/m^3)	Receptor UTM Zone: 17	
				Easting (m)	Northing (m)
CO	1-hour	183.97674	2,000	481,445.55	3,577,663.40
	8-hour	99.85962	500	481,279.60	3,577,773.47

Ambient Monitoring Requirements

The impacts for CO quantified in Table 6-3 of the Class I Significance Analysis are compared to the Monitoring *de minimis* concentrations, shown in Table 6-1, to determine if ambient monitoring requirements need to be considered as part of this permit action. Because all maximum modeled impacts are below the corresponding deminimis concentrations, no pre-construction monitoring is required for CO.

Class I Area Analysis

Federal Class I areas are regions of special national or regional value from a natural, scenic, recreational, or historic perspective. Class I areas are afforded the highest degree of protection among the types of areas classified under the PSD regulations. U.S. EPA has established policies and procedures that generally restrict consideration of impacts of a PSD source on Class I Increments to facilities that are located near a federal Class I area. Historically, a distance of 100 km has been used to define “near”, but more recently, a distance of 200 kilometers has been used for all facilities that do not combust coal. 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 within 105 km of the Wolf Island National Wildlife Refuge.

7.0 ADDITIONAL IMPACT ANALYSES

PSD requires an analysis of impairment to visibility, soils, and vegetation that will occur as a result of a modification to the facility and an analysis of the air quality impact projected for the area as a result of the general commercial, residential, and other growth associated with the proposed project.

Soils and Vegetation

To address the potential soil and vegetation impacts, SRM adopted the NAAQS analysis presented above because EPA set the secondary NAAQS standards for such analysis to protect public welfare, including protection against damage to crops and vegetation. The Soils and Vegetation analyses have been reviewed and based on the results of the contribution of SRM to the NAAQS secondary standards, there are no adverse effects on Soils and Vegetation due to increased ozone levels attributed to this project.

Growth

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.

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.

Georgia Toxic Air Pollutant Modeling Analysis

Georgia EPD regulates the emissions of toxic air pollutant ("TAP") emissions through a program covered by the provisions of Georgia Rules for Air Quality Control, 391-3-1-.02(2)(a)3(ii). A TAP is defined as any substance that may have an adverse effect on public health, excluding any specific substance that is covered by a State or Federal ambient air quality standard. Procedures governing the Georgia EPD's review of TAP emissions as part of air permit reviews are contained in the agency's "Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions (Revised)."

For projects with quantifiable increases in TAP emissions, an air dispersion modeling analysis is generally performed to demonstrate that off-property impacts are less than the established Acceptable Ambient Concentration ("AAC") values. The TAP evaluated are restricted to those that may increase due to the proposed project. Thus, the TAP analysis would generally be an assessment of off-property impacts due to facility-wide emissions of any TAP emitted by a facility.

SRM calculated HAP emissions (of which TAPs are equivalent to, in general) pre- and post-project. Potential HAP emissions from the new Boiler No. 7 and modified Boiler Nos. 3 and 5 are 93 tpy. Potential 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. The TAPS were also compared on an individual pollutant basis. All individual HAPs were lower for the future proposed operating scenarios with the exception of hexane, mercury (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 Georgia-Pacific facility firing WWTR. Site specific WWTR PCB analysis from SRM were non-detect. Based on this information, GA EPD 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 summarized below. The results pass the modeling assessment.

Table 7-1: TAP MGLC Assessment

TAP	**Averaging Period**	**AAC ($\mu g/m^3$)**	**Max Modeled Conc. ($\mu g/m^3$)**	**Receptor UTM Zone: 17**	
				Easting (m)	**Northing (m)**
Mercury	15-min	10	0.016434	481,000.00	3,577,900.00
	Annual	0.3	0.00041	481,056.84	3,577,757.36

8.0 EXPLANATION OF DRAFT PERMIT CONDITIONS

The permit requirements for this proposed modification are included in draft Permit Amendment No. 2621-103-0003-V-06-1.

The draft permit uses a "delete and replace" structure. In general, pre-modification conditions have been designated as null and void as applicable by Condition 7.14.1 and post-modification conditions as designated as becoming effective once each modified/new boiler is complete. The modified and new boiler sections are also listed separately. This may result in repeating certain conditions; however, this is intended. This allows for easier reading and compliance with individual boiler requirements as the project is completed.

Section 1.0: Facility Description

The project is for the installation and operation of 285 MMBtu/hr natural gas fired Boiler No. 7 (Source Code BO07), modification of existing Boiler No. 3 (Source Code BO01) to burn additional WWTR and natural gas with existing permitted fuels, modification of existing Boiler No. 5 (Source Code BO03) to burn only WWTR and natural gas, and miscellaneous support changes including silos, a new WWTR steam dryer, and ammonia tank.

Section 2.0: Requirements Pertaining to the Entire Facility

No conditions in Section 2.0 are being added, deleted or modified as part of this permitting action.

Section 3.0: Requirements for Emission Units

Existing Conditions 3.2.3 through 3.25 limit SO_2 and NO_X emissions from Boiler Nos. 3 and 5 based on a previous PSD analysis. There are no changes to the conditions as part of this permitting action.

Conditions 3.2.15 and 3.2.16 have been added to the permit. The conditions specify the BACT limits for CO emissions and Total CO_2e emissions from Boiler No. 3.

Conditions 3.2.17 and 3.2.18 have been added to the permit. The conditions specify the BACT limits for CO and Total CO_2e emissions from Boiler No. 5.

Conditions 3.2.19 and 3.2.20 have been added to the permit. The conditions specify the BACT limits for CO emissions and Total CO_2e emissions from Boiler No. 7.

Condition 3.2.21 has been added to the permit. The condition is a PSD avoidance limit for NO_X emissions from new Boiler No. 7. The limit is based on the vendor guarantee used to calculate potential emissions from the boiler.

Condition 3.2.23 has been added to the permit. The condition is a PSD avoidance limit for PM_{10}/$PM_{2.5}$ emissions from new Boiler No. 7. The limit is based on the vendor guarantee used to calculate potential emissions from the boiler.

Existing Conditions 3.3.1 and 3.3.3 through 3.3.5 are the general applicability statements for Boiler Nos. 3 and 5 for 40 CFR 63 Subparts A and DDDDD, 40 CFR 60 Subparts A, D, and Db, and 40 CFR 61 Subpart E. There are no changes to the conditions as part of this permitting action.

Existing Conditions 3.3.6 through 3.3.16 are emission limits that apply to Boiler Nos. 3 and 5 prior to modification as part of the Utility Footprint Project. The conditions will become null and void after the boilers are modified as listed in new Condition 7.14.1 of the permit.

Conditions 3.3.28 through 3.3.30 have been added to the permit. The conditions are the 40 CFR 63 Subpart DDDDD limits for HCl, Hg, CO and PM/TSM for Boiler No. 3 as modified, but operating before the new emission limits that take effect on October 6, 2025, per the regulation. Two sets of limits have been included for CO and PM/TSM because the facility may operate the unit as either a fluidized bed unit designed to burn coal/solid fossil fuel, or a fluidized bed unit designed to burn biomass/bio-based solid under 40 CFR 63 Subpart DDDDD. The applicable HCl and Hg limits are the same for both operating scenarios.

Conditions 3.3.31 through 3.3.33 have been added to the permit. The conditions are the 40 CFR 63 Subpart DDDDD limits for HCl, Hg, CO and PM/TSM for Boiler No. 3 as modified, but operating after the new emission limits that take effect on October 6, 2025, per the regulation. Two sets of limits have been included for CO and PM/TSM because the facility may operate the unit as either a fluidized bed unit designed to burn coal/solid fossil fuel, or a fluidized bed unit designed to burn biomass/bio-based solid under 40 CFR 63 Subpart DDDDD. The applicable HCl and Hg limits are the same for both operating scenarios.

Condition 3.3.34 has been added to the permit. The condition requires the facility to comply with the startup and shutdown requirements under 40 CFR Subpart DDDDD for modified Boiler No. 3.

Condition 3.3.35 has been added to the permit. The condition requires the facility to establish opacity levels under 40 CFR 63 Subpart DDDDD for modified Boiler No. 3 if the facility elects to demonstrate compliance with TSM limits.

Condition 3.3.36 has been added to the permit. The condition lists the compliance options for modified Boiler No. 3 for the HCl limit under 40 CFR 63 Subpart DDDDD. The facility may use sorbent injection rate or the existing SO_2 CEMs to demonstrate compliance.

Condition 3.3.37 has been added to the permit. The condition specifies the SO_2 limit for modified Boiler No. 3 under 40 CFR 60 Subpart D while burning solid fossil fuel or solid fossil fuel and wood residue.

Conditions 3.3.38 through 3.3.40 have been added to the permit. The conditions specify the PM, opacity, and NO_X limits for modified Boiler No. 3 under 40 CFR 60 Subpart Db.

Condition 3.3.41 has been added to the permit. The condition specifies the Hg limit for modified Boiler No. 3 while burning WWTR under 40 CFR 61 Subpart E.

Condition 3.3.42 has been added to the permit. The condition is the 40 CFR 63 Subpart DDDDD limits for HCl, Hg, CO and PM/TSM for Boiler No. 5 as modified, but operating before the new emission limits that take effect on October 6, 2025, per the regulation. The unit is classified as a fluidized bed unit designed to burn biomass/bio-based solid under 40 CFR 63 Subpart DDDDD.

Condition 3.3.43 has been added to the permit. The condition is the 40 CFR 63 Subpart DDDDD limits for HCl, Hg, CO and PM/TSM for Boiler No. 5 as modified, but operating after the new emission limits that take effect on October 6, 2025, per the regulation. The unit is classified as a fluidized bed unit designed to burn biomass/bio-based solid under 40 CFR 63 Subpart DDDDD.

Condition 3.3.44 has been added to the permit. The condition requires the facility to comply with the startup and shutdown requirements under 40 CFR Subpart DDDDD for modified Boiler No. 5.

Condition 3.3.45 has been added to the permit. The condition requires the facility to establish opacity levels under 40 CFR 63 Subpart DDDDD for modified Boiler No. 5.

Condition 3.3.46 has been added to the permit. The condition specifies the NO_X limits for modified Boiler No. 5 under 40 CFR 60 Subpart Db.

Condition 3.3.47 has been added to the permit. The condition specifies the Hg limit for modified Boiler No. 5 while burning WWTR under 40 CFR 61 Subpart E.

Conditions 3.3.48 and 3.3.49 have been added to the permit. The conditions are the general applicability statements for 40 CFR 63 Subparts A and DDDDD and 40 CFR 60 Subparts A and Db as they apply to new Boiler No. 7.

Condition 3.3.50 has been added to the permit. The condition specifies the NO_X limits for new Boiler No. 7 under 40 CFR 63 Subpart DDDDD.

Existing Conditions 3.4.3 and 3.3.4 specify the fuels that can be burned in Boiler Nos. 3 and 5 prior to modification as part of the Utility Footprint Project. The conditions will become null and void after the boilers are modified as listed in new Condition 7.14.1 of the permit.

Existing Condition 3.4.5 specifies the amount of TDF that can be burned in Boiler Nos. 3 and 5 prior to modification as part of the Utility Footprint Project. The condition will become null and void after the boilers are modified as listed in new Condition 7.14.1 of the permit as Boiler No. 5 will no longer burn TDF.

Conditions 3.4.11 and 3.4.12 have been added to the permit. The conditions specify the types of fuels and the amount of TDF that can be burned in Boiler No. 3 after modification.

Condition 3.4.13 has been added to the permit. The condition specifies for PM and opacity limits under Georgia Rule (d) for modified Boiler No. 5.

Condition 3.4.14 has been added to the permit. The condition specifies the fuel types that can be burned in Boiler No. 5 after modification.

Condition 3.4.15 has been added to the permit. The condition specifies for PM and opacity limits under Georgia Rule (d) for new Boiler No. 7.

Condition 3.4.16 has been added to the permit. The condition specifies the fuel types that can be burned in new Boiler No. 7.

Section 4.0: Requirements for Testing

New Condition 4.1.5 has been added to include test methods for $PM_{10}/PM_{2.5}$.

Existing Conditions 4.2.1 through 4.2.4 are testing conditions that apply to Boiler Nos. 3 and 5 prior to modification as part of the Utility Footprint Project. The conditions will become null and void after the boilers are modified as listed in new Condition 7.14.1 of the permit.

Condition 4.2.8 has been added to the permit. The condition specifies the general periodic PM testing that must be conducted for the modified boilers.

Condition 4.2.9 has been added to the permit. The condition specifies the performance testing/operating limit provisions under 40 CFR 63 Subpart DDDDD as they apply to modified Boiler Nos. 3 and 5.

Condition 4.2.10 has been added to the permit. The condition specifies the tune-up requirements under 40 CFR 63 Subpart DDDDD as they apply to modified Boiler Nos. 3 and 5.

Condition 4.2.11 has been added to the permit. The condition requires the facility to conduct an initial PM test for modified Boiler No. 3 to demonstrate compliance with Georgia Rule (d) and 40 CFR 60 Subpart Db.

Condition 4.2.12 has been added to the permit. The condition requires the facility to conduct an initial NO_X test for modified Boiler No. 3 to demonstrate compliance with Georgia Rule (d) and 40 CFR 60 Subpart Db.

Condition 4.2.13 has been added to the permit. The condition requires the facility to conduct an initial PM test for modified Boiler No. 5 to demonstrate compliance with Georgia Rule (d).

Condition 4.2.14 has been added to the permit. The condition requires the facility to conduct an initial NO_X test for modified Boiler No. 5 to demonstrate compliance with Georgia Rule (d) and 40 CFR 60 Subpart Db.

Condition 4.2.15 has been added to the permit. The condition requires the facility to conduct an initial PM test for new Boiler No. 7 to demonstrate compliance with Georgia Rule (d).

Condition 4.2.16 has been added to the permit. The condition requires the facility to conduct a $PM_{10}/PM_{2.5}$ performance test for new Boiler No. 7 to demonstrate compliance with the limit under PSD Avoidance.

Condition 4.2.17 has been added to the permit. The condition requires the facility to conduct an initial NO_X test for new Boiler No. 7 to demonstrate compliance with Georgia Rule (d) and 40 CFR 60 Subpart Db.

Condition 4.2.18 has been added to the permit. The condition requires the facility to conduct the initial new Boiler No. 7 tune-up as required by 40 CFR 63 Subpart DDDDD.

Section 5.0: Requirements for Monitoring

Existing Conditions 5.2.1.a and 5.2.1.b are the continuous monitoring requirements for NO_X, SO_2, and opacity that apply to Boiler Nos. 3 and 5 prior to modification as part of the Utility Footprint Project. The conditions will become null and void after the boilers are modified as listed in new Condition 7.14.1 of the permit.

Existing Condition 5.2.2.a is the continuous stack flow monitoring requirements for Boiler Nos. 3 and 5 prior to modification as part of the Utility Footprint Project. The condition will become null and void after the boilers are modified as listed in new Condition 7.14.1 of the permit.

Existing Conditions 5.2.3.a and 5.2.3.b require the Permittee to monitor fuel usage and pressure drop for the baghouses on Boiler Nos. 3 and 5. There are no changes to the conditions because of the Utility Footprint Project. The modified boilers will continue to be subject to these monitoring requirements.

Existing Condition 5.2.4 specifies the calculations the Permittee should use to demonstrate compliance with the pound per hour SO_2 emission limits for Boiler Nos. 3 and 5. The condition will become null and void after the boilers are modified as listed in new Condition 7.14.1 of the permit.

Existing Conditions 5.2.5 and 5.2.6 refer to monitoring requirements for Boiler Nos. 3 and 5 as specified in 40 CFR 63 Subpart DDDDD. The conditions will become null and void after the boilers are modified as listed in new Condition 7.14.1 of the permit.

Existing Condition 5.2.7 refers to accuracy and calibration requirements for CEMS at the facility. The condition will become null and void after the boilers are modified as listed in new Condition 7.14.1 of the permit.

Existing Conditions 5.2.8 through 5.2.10 specify the data and monitoring requirements for the SO_2 CEMS on Boiler No. 5 under the provisions of 40 CFR 60 Subpart Db. The conditions will become null and void after the boiler is modified as listed in new Condition 7.14.1 of the permit.

Existing Conditions 5.2.11 and 5.2.12 specify the data and monitoring requirements for the NO_X CEMS on Boiler Nos. 3 and 5 under the provisions of 40 CFR 52.21 and 40 CFR 60 Subpart Db. The conditions will become null and void after the boiler is modified as listed in new Condition 7.14.1 of the permit.

Existing Condition 5.2.13 defines a steam generating unit-operating day for the purposes of 40 CFR 60 Subpart Db. The condition will become null and void after the boiler is modified as listed in new Condition 7.14.1 of the permit.

Existing Condition 5.2.14 requires the Permittee to implement a preventative maintenance program for the baghouses, including those on Boiler Nos. 3 and 5. There are no changes to the condition because of the Utility Footprint Project. The modified boilers will continue to be subject to these requirements.

Existing Condition 5.2.15 has been modified to remove reference to the fuel silos for Boiler No. 5 and the limestone silo for Boiler No. 5.

Existing Condition 5.2.16 specifies the equipment and pollutants at the facility that are subject to CAM. The condition will become null and void after the boiler is modified as listed in new Condition 7.14.1 of the permit.

Existing Condition 5.2.18 specifies the CAM requirements for SO_2 emissions for Boiler Nos. 3 and 5. The condition will become null and void after the boiler is modified as listed in new Condition 7.14.1 of the permit.

Condition 5.2.20 has been added to the permit. The condition specifies the CEMS accuracy and calibration requirements for the facility under 40 CFR Part 60.

Conditions 5.2.21.a through 5.2.21.c have been added to the permit. The conditions specify the facility must continuously monitor NO_X, SO_2, opacity, and CO for modified Boiler Nos. 3 and 5 following the Utility Footprint Project. The CEMS are used to comply with the provisions of 40 CFR 52.21, 40 CFR 60 Subpart Db, and Georgia Rules (d) and (g).

Condition 5.2.22.a has been added to the permit. The condition specifies the stack flow monitoring requirements for modified Boiler Nos. 3 and 5, which are used to comply with the existing 40 CFR 52.21 limits for SO_2.

Condition 5.2.23 has been added to the permit. The condition specifies how the facility should use the SO_2 CEMs and the stack flow monitors to demonstrate compliance with the existing 40 CFR 52.21 limits.

Conditions 5.2.24 through 5.2.27 have been added to the permit. The conditions specify the monitoring and data requirements for the NO_X CEMS for modified Boiler Nos. 3 and 5. The monitoring is used to demonstrate compliance with the existing 40 CFR 52.21 limits and 40 CFR 60 Subpart Db.

Condition 5.2.28 has been added to the permit. The condition requires the facility to comply with the site-specific monitoring plan provisions of 40 CFR 63 Subpart DDDDD for modified Boiler Nos. 3 and 5.

Conditions 5.2.29 through 5.2.33 have been added to the permit. The conditions require the facility to monitor applicable operating parameters and operate continuous monitoring systems for modified Boiler Nos. 3 and 5 under 40 CFR 63 Subpart DDDDD.

Condition 5.2.34 has been added to the permit for new Boiler No. 7. The condition requires the facility to operate continuous monitoring systems to demonstrate compliance with the NO_X limit under 40 CFR 60 Subpart Db and for the CO BACT limit.

Condition 5.2.35 has been added to the permit for new Boiler No. 7. The condition requires the facility to record the type and quantity of fuel burned daily to demonstrate compliance with 40 CFR 60 Subpart Db.

Conditions 5.2.36 through 5.2.38 have been added to the permit for new Boiler No. 7. The conditions specify the monitoring and data requirements for the NO_X CEMS under 40 CFR 60 Subpart Db.

Conditions 5.2.39 and 5.2.40 have been added to the permit. The conditions reflect the CAM requirements for Boiler Nos. 3 and 5 as modified.

Section 6.0: Other Recordkeeping and Reporting Requirements

Existing Condition 6.1.7.a.i through 6.1.7.a.iii are the excess emission reporting requirements for SO_2 from Boiler No. 3 and for NO_X and opacity for Boiler Nos. 3 and 5 prior to modification as part of the Utility Footprint Project. The conditions will become null and void after the boilers are modified as listed in new Condition 7.14.1 of the permit.

Existing Conditions 6.1.7.b.iii through 6.1.7.b.vi are the exceedance reporting requirements for SO_2 emissions under 40 CFR 52.21 and 40 CFR 60 Subpart Db for Boiler Nos. 3 and 5 prior to modification as part of the Utility Footprint Project. The conditions will become null and void after the boilers are modified as listed in new Condition 7.14.1 of the permit.

Existing Condition 6.1.7.b.vii is the exceedance reporting requirements for NO_X emissions under 40 CFR 52.21 for Boiler Nos. 3 and 5 prior to modification as part of the Utility Footprint Project. The condition will become null and void after the boilers are modified as listed in new Condition 7.14.1 of the permit.

Existing Condition 6.1.7.b.viii is the exceedance reporting requirements for the amount of TDF burned in Boiler Nos. 3 and 5 prior to modification as part of the Utility Footprint Project. The condition will become null and void after the boilers are modified as listed in new Condition 7.14.1 of the permit.

Condition 6.1.7.b.x has been modified. The condition lists the exceedance requirements for any time an unpermitted fuel is burned in a unit. The condition has been updated to include the rental boilers for completeness purposes.

Existing Conditions 6.1.7.c.i and 6.1.7.c.ii are the pressure drop and preventative maintenance excursion reporting requirements for the baghouses on Boiler Nos. 3 and 5 prior to modification as part of the Utility Footprint Project. The conditions will become null and void after the boilers are modified as listed in new Condition 7.14.1 of the permit.

Condition 6.1.7.d.i has been modified. The condition refers to reporting requirements for units that burn fuel oil. The condition has been modified to remove reference to Boiler Nos. 3 and 5 and Waste Heat Boiler 1.

Existing Condition 6.1.7.d.ii refers to steam generating records under 40 CFR 60 Subpart Db for Boiler Nos. 3 and 5 prior to modification as part of the Utility Footprint Project. The condition will become null and void after the boilers are modified as listed in new Condition 7.14.1 of the permit.

Condition 6.1.8.a.i has been added to the permit. The condition is the excess emission reporting requirement for SO_2 under 40 CFR 60 Subpart D and Georgia Rule (g) for modified Boiler No. 3.

Condition 6.1.8.a.ii has been added to the permit. The condition is the excess emission reporting requirement for NO_X under 40 CFR 60 Subpart Db for modified Boiler No. 3.

Condition 6.1.8.a.iii has been added to the permit. The condition is the excess emission reporting requirement for opacity under 40 CFR 60 Subpart Db and Georgia Rule (d) for modified Boiler No. 3.

Condition 6.1.8.a.iv has been added to the permit. The condition is the excess emission reporting requirement for CO under 40 CFR 60 Subpart DDDDD for modified Boiler No. 3.

Conditions 6.1.8.b.i through 6.1.8.b.iii have been added to the permit. The conditions are the exceedance reporting requirements for SO_2, NO_X, and CO emissions under 40 CFR 52.21 for modified Boiler No. 3.

Condition 6.1.8.b.iv has been added to the permit. The condition is the exceedance reporting requirement for the daily amount of TDF burned in modified Boiler No. 3.

Condition 6.1.8.c.i has been added to the permit. The condition is the excursion reporting requirement for pressure drop across the baghouse on modified Boiler No. 3.

Condition 6.1.8.c.ii has been added to the permit. The condition is the excursion reporting requirement for preventative maintenance checks for the baghouse on modified Boiler No. 3.

Conditions 6.1.8.c.iii through 6.1.8.c.vi have been added to the permit. The conditions are the excursion reporting requirement for parameters related to 40 CFR 63 Subpart DDDDD as they apply to modified Boiler No. 3.

Condition 6.1.8.d.i has been added to the permit. The condition requires the facility to submit steam generating unit operating records under 40 CFR 60 Subpart Db for modified Boiler No. 3.

Condition 6.1.9.a.i has been added to the permit. The condition is the excess emission reporting requirement for NO_X under 40 CFR 60 Subpart Db for modified Boiler No. 5.

Condition 6.1.9.a.ii has been added to the permit. The condition is the excess emission reporting requirement for opacity under Georgia Rule (d) for modified Boiler No. 5.

Condition 6.1.9.a.iii has been added to the permit. The condition is the excess emission reporting requirement for CO under 40 CFR 60 Subpart DDDDD for modified Boiler No. 5.

Conditions 6.1.9.b.i through 6.1.8.9.iii have been added to the permit. The conditions are the exceedance reporting requirements for SO_2, NO_X, and CO emissions under 40 CFR 52.21 for modified Boiler No. 5.

Condition 6.1.9.c.i has been added to the permit. The condition is the excursion reporting requirement for pressure drop across the baghouse on modified Boiler No. 5.

Condition 6.1.9.c.ii has been added to the permit. The condition is the excursion reporting requirement for preventative maintenance checks for the baghouse on modified Boiler No. 5.

Conditions 6.1.9.c.iii through 6.1.8.c.v have been added to the permit. The conditions are the excursion reporting requirement for parameters related to 40 CFR 63 Subpart DDDDD as they apply to modified Boiler No. 5.

Condition 6.1.9.d.i has been added to the permit. The condition requires the facility to submit steam generating unit operating records under 40 CFR 60 Subpart Db for modified Boiler No. 5.

Condition 6.1.10.a.i has been added to the permit. The condition is the excess emission reporting requirement for NO_X under 40 CFR 60 Subpart Db for new Boiler No. 7.

Condition 6.1.10.b.i has been added to the permit. The condition is the exceedance reporting requirements for the CO BACT limit for new Boiler No. 7.

Condition 6.1.10.b.ii has been added to the permit. The condition is the exceedance reporting requirements for the NO_X PSD avoidance limit for new Boiler No. 7.

Condition 6.1.10.b.iii has been added to the permit. The condition is the exceedance reporting requirements for the permitted fuel for Boiler No. 7.

Condition 6.1.10.d.i has been added to the permit. The condition requires the facility to submit steam generating unit operating records under 40 CFR 60 Subpart Db for new Boiler No. 7.

Existing Condition 6.2.3 refers to the general reporting requirements under 40 CFR 63 Subpart DDDDD for Boiler Nos. 3 and 5 prior to modification as part of the Utility Footprint Project. The condition will become null and void after the boilers are modified as listed in new Condition 7.14.1 of the permit.

Existing Condition 6.2.7 refers to SO_2 steam generating unit records for Boiler No. 5 under 40 CFR 60 Subpart Db prior to modification as part of the Utility Footprint Project. The condition will become null and void after the boiler is modified as listed in new Condition 7.14.1 of the permit.

Existing Condition 6.2.8 refers to NO_X steam generating unit records for Boiler Nos. 3 and 5 under 40 CFR 60 Subpart Db prior to modification as part of the Utility Footprint Project. The condition will become null and void after the boilers are modified as listed in new Condition 7.14.1 of the permit.

Existing Condition 6.2.9 refers to fuel usage records for Boiler Nos. 3 and 5 required to be kept under 40 CFR 60 Subpart Db prior to modification as part of the Utility Footprint Project. The condition will become null and void after the boilers are modified as listed in new Condition 7.14.1 of the permit.

Existing Condition 6.2.10 refers to TDF combustion records for Boiler Nos. 3 and 5 required to demonstrate compliance with the usage limit prior to modification as part of the Utility Footprint Project. The condition will become null and void after the boilers are modified as listed in new Condition 7.14.1 of the permit.

Condition 6.2.27 has been added to the permit. The condition requires the facility to submit startup notifications as required by 40 CFR 60 Subpart Db for modified Boiler Nos. 3 and 5.

Condition 6.2.28 has been added to the permit. The condition requires the facility to maintain records and amounts of fuel burned in modified Boiler Nos. 3 and 5 as required by 40 CFR 60 Subpart Db. The facility is also required to calculate the annual capacity factor for each fuel.

Condition 6.2.29 has been added to the permit. The conditions require the facility to maintain daily NO_X records for modified Boiler Nos. 3 and 5. This is a requirement of 40 CFR 60 Subpart Db.

Condition 6.2.30 has been added to the permit. The condition requires the facility to submit notification prior to performance testing conducted in accordance with 40 CFR 63 Subpart DDDDD.

Condition 6.2.31 has been added to the permit. The condition requires the facility to submit notifications of compliance status for modified Boiler Nos. 3 and 5 as required by 40 CFR 63 Subpart DDDDD.

Conditions 6.2.32 and 6.2.33 have been added to the permit. The conditions require the facility to submit periodic reports and maintain records for modified Boiler Nos. 3 and 5 as required by 40 CFR 63 Subpart DDDDD.

Condition 6.2.34 has been added to the permit. The condition specifies how and for how long records must be maintained for modified Boiler Nos. 3 and 5 as required by 40 CFR 63 Subpart DDDDD.

Conditions 6.2.35 and 6.2.36 have been added to the permit. The conditions specify what the Permittee must do if Boiler No. 3 undergoes a fuel switch after modification. These are provisions under 40 CFR 63 Subpart DDDDD and apply because the facility can be classified as a solid fossil fuel boiler or a biomass boiler under the subpart depending on fuel mix.

Condition 6.2.37 has been added to the permit. The condition requires the facility to maintain TDF usages records to demonstrate compliance with the limit in Part 3.4 of the permit.

Condition 6.2.38 has been added to the permit. The condition requires the facility to submit an update to the existing Preventative Maintenance Program for the baghouse on modified Boiler No. 3.

Condition 6.2.39 has been added to the permit. The condition requires the facility to submit the pressure drop range that represents normal operation of the baghouse on modified Boiler No. 3.

Condition 6.2.40 has been added to the permit. The condition requires the facility to submit an update to the existing Preventative Maintenance Program for the baghouse on modified Boiler No. 5.

Condition 6.2.41 has been added to the permit. The condition requires the facility to submit the pressure drop range that represents normal operation of the baghouse on modified Boiler No. 5.

Condition 6.2.42 has been added to the permit. The condition requires the facility to submit startup notifications as required by 40 CFR 60 Subpart Db for new Boiler No. 7.

Condition 6.2.43 has been added to the permit. The condition requires the facility to maintain records and amounts of fuel burned in new Boiler No. 7 as required by 40 CFR 60 Subpart Db. The facility is also required to calculate the annual capacity factor for each fuel.

Condition 6.2.44 has been added to the permit. The conditions require the facility to maintain daily NO_X records for new Boiler No. 7. This is a requirement of 40 CFR 60 Subpart Db.

Conditions 6.2.45 and 6.2.46 have been added to the permit. The conditions require the Permittee to submit startup notifications and notifications of compliance status for new Boiler No. 7 as required by 40 CFR 63 Subpart DDDDD.

Conditions 6.2.47 and 6.2.48 have been added to the permit. The conditions require the facility to submit periodic reports and maintain records for new Boiler No. 7 as required by 40 CFR 63 Subpart DDDDD.

Condition 6.2.49 has been added to the permit. The condition specifies how and for how long records must be maintained for new Boiler No. 7 as required by 40 CFR 63 Subpart DDDDD.

Conditions 6.2.50 through 6.2.53 have been added to the permit. The language is 40 CFR 52.21 record keeping and reporting requirements that apply because the facility used the baseline to projected actual calculation analysis for Boiler Nos. 3 and 5.

<u>Section 7.0: Other Specific Requirements</u>

Condition 7.14.1 has been added to the permit. The condition specifies the conditions relating to Boiler Nos. 3, 5, and 7 that will experience no changes, become null and void, or become effective because of the Utility Footprint Project.

APPENDIX A

EPD'S PSD Dispersion Modeling and Air Toxics Assessment Review

DMU Modeling Review Report – PSD

General Information

Application #	873390
AIRS #	103-00007
Applicant	Georgia-Pacific Savannah River LLC
Application Receipt Date	10/14/2024
Modeling Review Request Date	N/A
Assigned SSPP PM1	Wendy Troemel
Assigned Permit Engineer	Heather Brown
Date of Review Report Submission	11/20/2024
Assigned DMU Modeler	Ryan Gallagher
Approved by DMU PM1	11/20/2024
List of Reviewed Pollutants	CO

Review Summary

Are the modeled concentrations of all pollutants below SIL for Class I and Class II areas?	☒ Yes	☐ No

Modeling Results

Table 1. Class II Significant Impact Levels Modeling

Pollutant	Averaging Period	Max Modeled Conc. (μg/m^3)	SIL (μg/m^3)	Receptor UTM Zone: 17	
				Easting (m)	Northing (m)
CO	1-hour	183.97674	2,000	481,445.55	3,577,663.40
	8-hour	99.85962	500	481,279.60	3,577,773.47

DMU Modeling Review Report – TAP

General Information

Application#	873390
AIRS #	103-00007
Applicant	Georgia-Pacific Savannah River LLC
Application Receipt Date	10/14/2024
Modeling Review Request Date	N/A
Assigned SSPP PM1	Wendy Troemel
Assigned Permit Engineer	Heather Brown
Date of Review Report Submission	11/20/2024
Assigned DMU Modeler	Zach D'Aquino
Approved by DMU PM1	11/20/2024
List of Reviewed Pollutants	TAPs: mercury

Review Summary

MGLCs of All TAPs below AACs?	☒ Yes	☐ No

Modeling Results

Table 1. TAP MGLC Assessment

TAP	Averaging Period	AAC (μg/m^3)	Max Modeled Conc. (μg/m^3)	Receptor UTM Zone: 17	
				Easting (m)	Northing (m)
Mercury	15-min	10	0.016434	481,000.00	3,577,900.00
	Annual	0.3	0.00041	481,056.84	3,577,757.36