Environmental Assessment

OglethorpePower

Oglethorpe Power Corporation (An Electric Membership Corporation)

Chattahoochee Energy Facility Combustion Turbine Upgrades Project

11/3/2020

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prepared for

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Chattahoochee Energy Facility Combustion Turbine Upgrades Project
Franklin, Georgia

11/3/2020

prepared by

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LIST OF ABBREVIATIONS

Abbreviation	**Term/Phrase/Name**
AAC	Acceptable Air Concentration
BACT	Best Available Control Technology
Burns & McDonnell	Burns & McDonnell Engineering Company, Inc.
CCCT	Combined-cycle combustion turbine
CEQ	Council on Environmental Quality
CFR	Code of Federal Regulations
CO	Carbon monoxide
CO_2e	Carbon dioxide equivalents
EMC	Electric membership corporation
EPA	U.S. Environmental Protection Agency
EPD	Environmental Protection Division
Facility	Chattahoochee Energy Facility
FEMA	Federal Emergency Management Agency
FONSI	Finding of No Significant Impact
FWS	U.S. Fish and Wildlife Service
GDNR	Georgia Department of Natural Resources
GHG	Greenhouse gases
H_2SO_4	Sulfuric acid
IPaC	Information for Planning & Consultation System
LLTD	Low Load Turndown
LVWW	Low-volume wastewater
MER	Minimum Emission Rate
MW	Megawatts
NAAQS	National Ambient Air Quality Standards
NEPA	National Environmental Policy Act
NO_2	Nitrogen dioxide
NO_X	Nitrogen oxides

Abbreviation	Term/Phrase/Name
NPDES	National Pollutant Discharge Elimination System
NSA	Noise Sensitive Area
NSPS	New Source Performance Standards
NSR	New Source Review
NWI	National Wetlands Inventory
O_2	Oxygen
Oglethorpe	Oglethorpe Power Corporation
$PM_{2.5}$	Particulate matter less than 2.5 microns in diameter
PM_{10}	Particulate matter less than 10 microns in diameter
ppm	Parts per million
Program	RUS Electric Loan Program
Project	The Combustion Turbine Upgrades Project
PSD	Prevention of Significant Deterioration
RE Act	Rural Electrification Act
RUS	Rural Utilities Service
SER	Significant Emission Rate
SO_2	Sulfur dioxide
TAP	Toxic air pollutants
TIA	Toxic Impact Assessment
TPU1	Thermal Performance Upgrade Step 1
tpy	Tons per year
USC	United States Code
USDA	U.S. Department of Agriculture
VOC	Volatile organic compounds

1.0 INTRODUCTION

Oglethorpe Power Corporation (Oglethorpe) is seeking financing assistance from the Rural Utilities Service (RUS) to make software and hardware upgrades at its existing Chattahoochee Energy Facility (Facility), a 502 megawatt (MW) gas-fired combined-cycle power generating facility, on Liberty Church Road in Heard County at coordinates 33.4070°N; 85.0387°W near Franklin, Georgia. The Facility's Combustion Turbine Upgrades Project (Project) would increase the current generation capacity of the Facility to approximately 525 MW. This projected capacity increase is based on 59-degree Fahrenheit conditions and will vary slightly under differing ambient temperatures. The Project will help reduce the overall cost per MW of power generated, and allow the Facility's gas turbines to continue to operate at reduced power during times of low demand with less frequent shutdowns and subsequent restarts once demand increases. This Environmental Assessment (EA) describes the alternatives evaluated, the affected environment, potential environmental consequences, cumulative effects, mitigation measures, and agency scoping for the Project.

The RUS action is the decision to provide financing assistance for the Project. Under the Rural Electrification Act (RE Act), as amended, the Secretary of Agriculture is authorized and empowered to make loans to nonprofit cooperatives and others for rural electrification "for the purpose of financing the construction and operation of generating plants, electric transmission and distribution lines, or systems for the furnishing and improving of electric service to persons in rural areas" (7 U.S. Code [USC] § 904). A primary function or mission of RUS is to carry out this electric loan program (7 USC § 6942).

Oglethorpe, which is headquartered in Tucker, Georgia, is a generation cooperative operating on a not-for-profit basis that generates electricity for 38 of Georgia's electric membership cooperatives (EMCs). Oglethorpe's objective is to provide reliable energy to its EMC members to meet their existing and expanding power supply needs. The Facility, on Liberty Church Road in Heard County near the city of Franklin, Georgia, is an approximately 13-acre natural gas generation block owned and operated by Oglethorpe (see **Figure 1-1**). The Facility is co-located on 5,200 acres with the Plant Wansley coal-fired power plant operated by Georgia Power (a subsidiary of Southern Company) and three other natural gas generation blocks owned and operated by other entities. Surrounding lands include the Chattahoochee River, streams, planted pine, woodland, agricultural, and forested wetlands. The Chattahoochee River is located approximately 2,500 feet southeast of the Facility. The Facility was constructed by Oglethorpe and commenced commercial operations in 2003.

Oglethorpe intends to finance this Project under the RUS Electric Loan Program (the Program). As a result, the Project represents a Federal action that must be reviewed under the National Environmental Policy Act (NEPA) of 1969. The responsible agency will be the RUS. This EA has been prepared in compliance with RUS policies and Procedures, 7 Code of Federal Regulations (CFR) Part 1970 and the Council on Environmental Quality (CEQ) Regulations for implementation of NEPA 40 CFR Parts 1500-1508. As part of its broad environmental review process, RUS must also take into account the effect of the Project on historic properties in accordance with Section 106 of the National Historic Preservation Act and its implementing regulation, “Protection of Historic Properties” (36 CFR Part 800). RUS has made a finding that this project has “No Potential to Effect” historic properties or cultural resources because it does not involve ground disturbing activities and all activities are undertaken within the existing facility, as indicated in the memo provided in Appendix A. Pursuant to 36 CFR § 800.2(d)(3), there is no Section 106 requirement for public comment once RUS determines “No Potential To Effect.”

1.1 Project Description

The proposed Project would involve the implementation of two upgrades for the Chattahoochee Energy Facility’s two combustion turbines: the Thermal Performance Upgrade Step 1 (TPU1) and the Low Load Turndown (LLTD) upgrade. The TPU1 would improve plant output and heat rate and extend the maintenance interval of the units by installing enhanced hardware in the gas turbines, replacing certain auxiliary hardware components, and adding site-specific control logic optimizations. New turbine hardware would include combustion chamber components with optimized cooling air reduction, impingement cooled tile holders, the latest ceramic heat shields, metallic heat shields, and burner swirlers with reduced swirl angle. Auxiliary hardware replacements would include the pilot gas flow meter, an advanced combustion dynamic monitoring system, heat resistant ignition cables, blow-off valve actuators, and additional pressure and acceleration measurement instrumentation. These changes would increase the existing capacity of the Facility by approximately 23 MW to a total capacity of approximately 525 MW, with slight variations from ambient temperatures, and lower the cost to Oglethorpe’s 38 EMC members.

The LLTD upgrades would allow the gas turbines to operate at steady-state minimum loads of approximately 67 MW, with variations for ambient temperatures, while continuing to maintain emissions concentrations of nitrogen oxides (NO_X) and carbon monoxide (CO) in compliance with the Facility’s permitted emission limits. Currently, the Facility shuts down periodically during low demand and then restarts when demand increases. The LLTD upgrades would involve installation of new gas turbine components and software controls to replace selected equipment and connected accessories to allow sustained operations at lower operating loads during periods of low demand. These changes would include compressor inlet guide vane extended range sensor, ring modification and linearization unit replacement, and the addition of a gas turbine exhaust metallic heat shield, along with site-specific control logic optimizations. This upgrade would allow the Facility to continue to operate with less frequent shutdowns during low demand periods, thereby reducing maintenance and fuel costs associated with cycling through unit shutdowns and startups. Neither the TPU1 nor the LLTD upgrades would increase the expected lifespan of the Facility.

This Project would result in increases in maximum heat input and maximum projected annual air emissions. A small increase in water usage and water discharges is also expected. It is anticipated the Project may result in an increase in maximum short-term emissions, and Oglethorpe is permitting the Project as a modification under the federal New Source Performance Standards (NSPS) regulations. As such, the combustion turbines and associated duct burners would be subject to the NSPS in 40 CFR 60 Subpart KKKK, Standards of Performance for Stationary Combustion Turbines, after completion of the Project. The Facility’s Title V permit includes more stringent NO_X emission limits than the limits under Subpart KKKK. Therefore, the Facility will use its existing air pollution control devices and emissions monitoring systems to comply with Subpart KKKK. No installation of new devices or equipment is required.

Implementation of the Project is not expected to increase the noise from the Facility above historical levels, nor would it require changes in the infrastructure for gas supply, electrical transmission, or water usage/discharge. The Project would involve software and mechanical upgrades to existing equipment within the current Facility structures. Oglethorpe has consulted with Georgia Transmission Corporation and confirmed that the introduction of the additional power to the integrated transmission system would not cause system impacts and that no infrastructure upgrades would be necessary to support the Project. No new ground-disturbing activities or new facilities, equipment, or buildings would be constructed within or outside the current Facility footprint. As a result, the Project would not impact biological resources, soils and geological resources, cultural resources, socioeconomic resources, hazardous materials, or wetlands.

1.2 Purpose and Need

1.2.1 Oglethorpe Power Purpose and Need

Oglethorpe is responsible for providing reliable, efficient, and low-cost power to the 38 EMC members of the not-for-profit generation cooperative who provide power to over 4 million Georgians. Oglethorpe continues to evaluate methods for increasing the reliability and efficiency of their power generation while continuing to lower costs to their members.

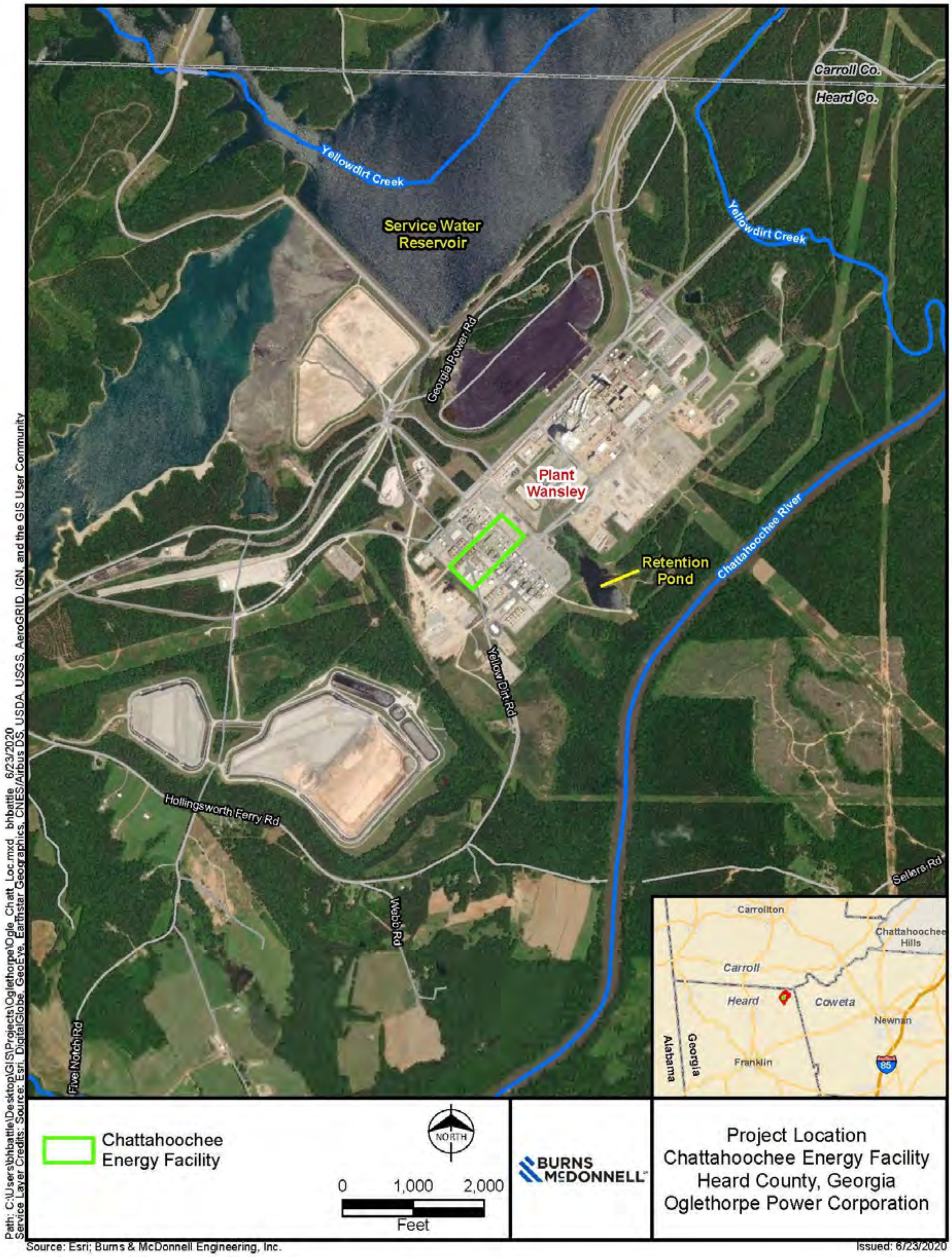
The proposed Project would increase capacity at the existing Facility and allow Oglethorpe to meet system demand with the Facility operating rather than starting other less efficient units, purchasing power from others, or constructing new generation. The Project would lower maintenance costs, reduce start-up costs because the Facility would have to shut down less often, and improve the Facility's overall operating efficiency.

The additional capacity at lower costs would meet the need of providing more efficient and less expensive power to its members and the Georgians they serve.

1.2.2 RUS Potential Funding Action

Utilities can seek financial assistance for capital projects that meet the U.S. Department of Agriculture (USDA) Rural Development objectives. The Rural Electrification Act of 1936 allows for the Secretary of Agriculture, through RUS, to approve loans, loan guarantees, grants, and other project financing to electric utilities and projects that serve rural communities. Oglethorpe may seek financial assistance for the Project from this Program to increase capacity and lower maintenance costs to its 38 EMC members. RUS' reviews of financial assistance applications include information ranging from purpose and need of the Project, engineering feasibility of the Project, cost, alternatives considered, to environmental impacts, and other applicable topics. RUS uses these reviews and analyses to determine whether to provide financing assistance to a project, which is a federal action for RUS. RUS' financial decision for the Project is based on funds available in the agency's budget. Therefore, publication of the EA and execution of environmental findings does not constitute an approval of funds for the Project but is required before financing is provided, should funds be available.

Figure 1-1: Project Location Map



2.0 ALTERNATIVES EVALUATED

In accordance with NEPA and RUS policies, Oglethorpe considered alternatives to the Project to determine if an alternative would be environmentally preferable, reasonable, and/or technically and economically feasible to the proposed action. As the proposed action does not require any new ground disturbances or construction of new facilities, site alternatives are not further discussed. Oglethorpe evaluated the no action alternative and compared it to the proposed action using three criteria:

1. Would the no action alternative meet the objectives of the proposed action?
2. Would the no action alternative offer a significant environmental advantage over the proposed action?
3. Would the no action alternative be technically and economically feasible, reasonable, and practical?

2.1 Proposed Action

The proposed action includes hardware and software upgrades to the combined-cycle Facility to improve the performance, heat rate, and capacity of the turbines, and allow them to continue to operate during periods of low demand to reduce the frequency of shutdowns. Oglethorpe has consulted with Georgia Transmission Corporation, confirming the existing grid infrastructure will accept increased power output from the Facility. The proposed upgrades will allow Oglethorpe to provide generation at a lower price per MW of power generated.

The mechanical upgrades would be performed during one of the routine major outages at the Facility that occur after a certain number of operating hours or approximately every 8 years. During a major outage, the Facility is shut down for a longer period of time and a larger number of contractors and personnel are brought to the Facility to perform maintenance, and upgrades if applicable. The contractors performing the major outage would also perform the mechanical upgrades for the Project, and a permanent increase in personnel at the Facility is not proposed. One or two one-time shipments of mechanical equipment may also be required to install these mechanical upgrades, but no significant increases in traffic or equipment is proposed.

2.2 Other Alternatives Evaluated

This EA does not look at alternative sites for increased capacity, as a new site would require the construction of a large amount of infrastructure (transmission, water intake, etc.) that currently exists at the Facility site. Increasing capacity at other existing facilities could also potentially require significant infrastructure upgrades resulting in more environmental impacts associated with the upgrades. Additionally, the Chattahoochee Energy Facility is Oglethorpe’s least expensive generation source and therefore the most operated units. As such, performing these upgrades at this site will result in more use of the additional capacity than if upgrades were available and were installed at other sites.

2.3 No Action Alternative

Under the no action alternative, the software and mechanical upgrades associated with Project would not be implemented, and the Facility would continue to operate in its current state. Therefore, the capacity would not increase and the price per MW of power generated would not decrease as a result of efficiency improvements from the Project. Oglethorpe may need to start other units or purchase power from others to meet the system demands. Additionally, the Facility would not be able to remain online through periods of low demand resulting in more shutdowns and startups, and, in turn, increased wear and tear on the equipment. For these reasons, the no action alternative is not preferable to or does not provide a significant environmental advantage over the proposed action, and it is not recommended.

3.0 AFFECTED ENVIRONMENT AND ENVIRONMENTAL CONSEQUENCES

The Project would occur within the boundaries and buildings of the current Facility and would involve software and mechanical upgrades to existing computer and generation equipment. It would not impact biological resources, soils and geological resources, cultural resources, socioeconomic resources, hazardous materials, wetlands, infrastructure for water usage or discharge, noise emissions above historical levels, or gas supply infrastructure. The following discusses a variety of natural and social resources and the potential project-related consequences to each.

3.1 Aesthetics

As shown in the aerial imagery on **Figure 1-1**, the Project would occur inside of the existing Facility. The surrounding land use is considered industrial and includes adjacent natural gas generating units as well as the Plant Wansley coal-fired power plant. Since there would be no changes to the current or future aesthetics within or surrounding the Facility, no impact on the aesthetic environment would occur as a result of the Project. No environmental consequences would occur, and no mitigation is proposed.

3.2 Air Quality

The current air quality of the area surrounding the Facility along with the anticipated impacts on air quality as a result of the Project are discussed in the following sub-sections.

Ambient air quality is protected by federal and state regulations. The U.S. Environmental Protection Agency (EPA) established National Ambient Air Quality Standards (NAAQS) to protect human health and welfare. Primary standards protect human health, including the health of defined sensitive populations, such as asthmatics, children, and the elderly. NAAQS have been developed for sulfur dioxide (SO_2), particulate matter (PM) with a diameter of 10 microns or less (PM_{10}), PM with a diameter of 2.5 microns or less ($PM_{2.5}$), nitrogen dioxide (NO_2), carbon monoxide (CO), ozone, and lead, and include levels for short-term (acute) and long-term (chronic) exposures as applicable. Ozone is not a pollutant emitted directly into the air. It is formed from a chemical reaction involving nitrogen oxides NO_X and volatile organic compounds (VOC) in the presence of sunlight. Consequently, emissions of NO_X and VOCs are regulated by the EPA as “precursors” to the formation of ground-level ozone. VOC means any compound of carbon (excluding CO, carbon dioxide [CO_2], carbonic acid, metallic carbides or carbonates, and ammonium carbonate) which participates in atmospheric photochemical reactions (40 CFR 51.100s). The current NAAQS are listed on the EPA’s website (EPA, 2020a).

3.2.1 Affected Environment

New Source Review (NSR) is a pre-construction permitting program designed to protect air quality when air pollutant emissions are increased either through the modification of existing sources or through the construction of a new source of air pollution. In areas with good air quality, NSR ensures that the new emissions do not significantly degrade the air quality. This is achieved through the implementation of the Prevention of Significant Deterioration (PSD) permitting program or state minor permit programs. In areas with poor air quality, Nonattainment NSR ensures that the new emissions do not inhibit progress toward cleaner air. In addition, NSR ensures that any new or modified large industrial source uses the Best Available Control Technology (BACT) to reduce its air emissions. Air permitting of stationary sources has been delegated to each state and/or local permitting authority. The Facility is considered a PSD major source because it has potential emissions of multiple regulated pollutants exceeding the major source threshold of 100 tons per year (tpy) for a listed source (fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input). Additionally, the Facility is considered a major source of NO_X emissions under the Georgia Nonattainment NSR permitting program because it has potential emissions of NO_X exceeding 100 tpy, contains electric generating units, and is located in an area (Heard County) contributing to the ambient air level of ozone in the metropolitan Atlanta ozone nonattainment area (Georgia Air Quality Control Rule 391-3-1-.03(8)(c)(15)). Therefore, a NSR-emissions increase analysis is required to determine whether PSD permitting and/or Nonattainment NSR permitting applies to the Project.

3.2.2 Environmental Consequences

The Project would result in increases in maximum heat input and maximum projected annual emissions from the combined cycle combustion turbines (CCCTs). It is anticipated the Project may also result in an increase in maximum short-term emissions. Annual emissions increases from the Project were evaluated using the actual-to-projected applicability test defined in the federal PSD regulations. Specifically, emissions increases were calculated as the difference between maximum projected actual and baseline actual emissions, excluding the portion of emissions following the project that the unit could have accommodated prior to the Project and that are unrelated to the Project. The federal PSD regulations define “projected actual emissions” as the maximum annual rate at which an existing unit is projected to emit a regulated NSR pollutant in any of the 10 years following the date the unit resumes regular operation after the project (40 CFR 52.21(b)(41)(i)). As such, the emissions increase estimates for the Project are conservatively high, because they are based on the future *maximum* projection of actual emissions, not the future *expected* or most likely actual emissions.

The resulting analysis calculates maximum increases for each pollutant at levels lower than their respective PSD Significant Emission Rates (SER), and it has therefore been determined that PSD permitting will not be required for the Project. Oglethorpe has prepared and submitted to the Georgia Environmental Protection Division (EPD) a Title V Significant Modification with Construction Application for the Project (**Appendix B**). Further, the Project emissions increase for NO_X is less than the Nonattainment NSR SER, and, as a result, the Nonattainment NSR permitting is also not required for the Project. Note that the applicable SER for NO_X is the same under both the PSD and the Nonattainment NSR permitting programs (40 tpy).

A comparison of the emissions increase from the Project for each pollutant to its SER is provided in Table 3.2-1, below.

Table 3.2-1: PSD Permitting Determination

Pollutant	CCCT Baseline Actual Emissions (tpy)	CCCT Projected Actual Emissions (tpy)	CCCT Emissions that Could Have Been Accommodated (tpy)	CCCT Demand Growth Exclusion (tpy)	CCCT Project Emissions Increase[(a)] (tpy)	Cooling Tower Associated Emissions Increase[(b)] (tpy)	Total Project Emissions Increase (tpy)	NSR SER (tpy)	NSR Permitting Required?
NO_X	100.2	153.1	116.4	16.2	36.7	--	36.7	40	No
CO	19.0	67.6	30.0	11.0	37.6	--	37.6	100	No
PM	69.7	90.6	81.1	11.4	9.5	0.31	9.8	25	No
PM_{10}	69.7	90.6	81.1	11.4	9.5	0.27	9.8	15	No
$PM_{2.5}$	69.7	90.6	81.1	11.4	9.5	0.0015	9.5	10	No
VOC	11.6	15.1	13.5	1.9	1.6	--	1.6	40	No
SO_2	7.0	9.1	8.1	1.1	0.95	--	0.95	40	No
H_2SO_4	0.80	1.0	0.93	0.13	0.11	--	0.11	7	No
CO_2e	1,382,762	1,796,567	1,608,206	225,444	188,361	--	188,361	75,000	No[(c)]

(a) CCCT Project Emissions Increase (tpy) = CCCT Projected Actual Emissions (tpy) - CCCT Demand Growth Exclusion (tpy) - CCCT Baseline Actual Emissions (tpy)
(b) The cooling tower will have an associated emissions increase due to increases in drift loss following the Project. There are no modifications to the cooling tower occurring as part of this Project.
(c) PSD permitting for CO_2e is only required if 1) the emissions increase exceeds the SER of 75,000 tpy AND 2) the project triggers PSD anyway for at least one other PSD-regulated pollutant.

Source: Title V Significant Modification with Construction Application (Appendix B)

Since the Project does not require PSD or Nonattainment NSR permitting, Oglethorpe is not required to evaluate BACT for its CCCTs or perform an ambient air quality analysis. However, because the Project may result in an increase in maximum short-term emissions, Oglethorpe is permitting the Project as a modification under the federal New Source Performance Standards (NSPS) regulations. Both CCCTs would be subject to the NSPS in 40 CFR 60 Subpart KKKK, Standards of Performance for Stationary Combustion Turbines, following the completion of the Project. The NO_X emission limits under Subpart KKKK (15 ppm at 15% oxygen [O_2] when operating at or above 75% of peak load; 96 ppm at 15% O_2

when operating below 75% of peak load) would be subsumed by the more stringent existing NO_X emission limit under the Facility's Title V permit (3.0 ppm at 15% O_2). The Facility will use its existing air pollution control devices and emissions monitoring systems to comply with Subpart KKKK. No installation of new devices or equipment is required.

Oglethorpe has submitted an application to the Georgia EPD seeking a combined Title V operating permit modification and state construction permit, which will authorize the construction and operation of the proposed Project and incorporate the requirements of 40 CFR 60 Subpart KKKK into the Facility's permit. The application, provided in **Appendix B**, outlines the methodology used to evaluate the Project emissions increase, details the requirements of 40 CFR 60 Subpart KKKK, and includes a Toxic Impact Assessment (TIA) in accordance with state guidelines. In the TIA, the potential emissions of individual toxic air pollutants (TAPs) from the Facility's operations are compared to each TAP's Minimum Emission Rate (MER) in Appendix A to the TIA guidelines. For each TAP with potential emissions exceeding the MER, screening modeling (SCREEN3) is then used to demonstrate that the ambient impact from the Facility's operations is well below the TAP's Acceptable Ambient Concentration (AAC) in Appendix A in the TIA guidelines.

3.2.3 Mitigation

The Project will not require a NSR permit. No new ground-disturbing activities are proposed for the Project, and there will be no emissions associated with earth-moving for construction. Therefore, no mitigation is proposed in connection with the Project. However, the Facility will continue to utilize its existing air emission control measures, including dry low NO_X combustors on the turbines and low NO_X duct burners, selective catalytic reduction (SCR) for NO_X emissions control, catalytic oxidation for CO and VOC emissions control, and the use of low-sulfur fuel (natural gas), , in accordance with the Facility's existing air permits.

3.3 Floodplains

The Project would occur within the existing footprint of the Facility, which is not located within a floodplain as indicated on FEMA Firmette Flood Map 1314900C70D, effective 4/19/2017 (**Appendix D**). No floodplains would be affected by the Project. Since the Project is not located within a floodplain and no impact on floodplains would occur as a result of the Project, no floodplain mitigation is proposed.

3.4 Geology, Soils, and Farmland

The Project would occur within the existing footprint of the Facility, and there would be no ground-disturbing impacts or new facilities, equipment, or buildings constructed within or outside the current

Facility footprint. Additionally, no hazardous materials or petroleum products would be used for the Project. All Project activities would occur within existing building and any spills would be contained and cleaned up immediately, preventing exposure of any potentially hazardous substances to soils. No impacts would occur to geology, soils, or farmland as a result of the Project, and no mitigation is proposed.

3.5 Historic and Cultural Resources

No impacts beyond the existing Facility footprint are proposed. Though this project reaches an Environmental Assessment level of review, the RUS Federal Preservation Officer, has reviewed the project scope and has determined that the Project would meet the criteria for “No Potential to Effect” historic properties or cultural resources (**Appendix A**) because there is no ground disturbance involved and activities take place entirely within the inside of the facility. Therefore, no impacts on important cultural, archeological, or paleontological resources that are listed or eligible for listing in the National Register of Historic Places would occur as a result of the Project, and no mitigation is proposed.

3.6 Human Health and Safety

The Project would occur within the existing footprint of the Facility; and there would be no ground-disturbing impacts within or beyond the existing footprint. The Project will result in an increase in air emissions, and Oglethorpe has submitted an application for a Title V permit modification with construction for the Project to the Georgia EPD. Georgia EPD is the agency responsible for protecting Georgia’s air quality through the regulation of air emissions from industrial and mobile sources. Oglethorpe will obtain an air permit from Georgia EPD prior to commencing the Project and will comply with all applicable air regulations and permit requirements in order to protect public health. As a result, there would be no impacts or environmental consequence to human health and safety as a result of the Project, and no mitigation is proposed.

3.7 Land Use

The Project would not result in the temporary or permanent conversion of existing land use types; therefore, no impacts on land use would occur, and no mitigation is proposed.

3.8 Noise

The Project would not result in increased noise levels above historical levels at noise sensitive areas (NSAs). The nearest NSA (Yellow Dirt Baptist Church at 4058 Hollingsworth Ferry Road in Franklin, Georgia) is approximately 1.2 miles from the Facility; therefore, no noise impacts to NSAs would occur, and no mitigation is proposed.

3.9 Socioeconomics and Environmental Justice

3.9.1 Socioeconomics

Socioeconomics includes population growth trends, racial and ethnic characteristics, employment, income, public services (education facilities, medical facilities, fire protection, police protection), and recreation and open space. The Project includes software and mechanical upgrades to existing equipment during a routine outage and would not result in any changes or impacts to population trends, racial and ethnic characteristics, employment, public services, or recreational spaces.

3.9.2 Environmental Justice

3.9.2.1 Affected Environment

Executive Order 12898, titled Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations and issued in 1994, directs Federal agencies to take the appropriate and necessary steps to identify and address disproportionately high and adverse effects of Federal projects on the health or environment of minority and low-income populations to the greatest extent practicable and permitted by law. For the purpose of this analysis, minority is defined as individuals who identify as a race other than white alone (single race) and/or identify their ethnicity as Hispanic or Latino. Low-income is defined as a household income less than or equal to twice the Federal poverty level.

The area was screened for the presence of minority and low-income populations using the EPA EJSCREEN tool (EPA, 2018). The tool contains demographic indexes, including percent low-income and percent minority, based on the U.S. Census 2013-2017 ACS 5-Year Estimates. The Project is located near seven U.S. Census block groups: 130459108002, 130459109001, 130459109002, 130771701003, 131499701003, 131499702001, and 131499702002, as depicted in **Figure 3-1**. These census block groups span the counties of Heard, Carroll, and Coweta. For this environmental justice analysis, the block group was considered an environmental justice minority area if either (1) the minority population exceeded 50 percent, or (2) the minority population was greater than 10 percentage points of benchmark or reference region. The block group was considered an environmental justice low-income area if its population was greater than 10 percentage points of the benchmark or reference region. For this analysis, the benchmark geographic areas are the counties and state (Georgia) within which each block group is located.

A comparison of the percent minority and low-income for the block groups, Heard County, and State is provided in Table 3.9-1. Table 3.9-2 provides a comparison for the block groups in Carroll County, and Table 3.9-3 provides a comparison for the block group in Coweta County.

Table 3.9-1: Minority and Low-Income Populations near the Project in Carroll County

Geographic Area	Minority population (percent)	Low-income population (percent)
Georgia	46	37
Carroll County	29	41
Carroll County Block Group 130459109001	9	34
Carroll County Block Group 130459109002	4	45
Carroll County Block Group 130459108002	10	32

Source: Environmental Protection Agency, 2020b; U.S. Census Bureau 2013-2017 5-Year Estimates\

Table 3.9-2: Minority and Low-Income Populations near the Project in Heard County

Geographic Area	Minority population (percent)	Low-income population (percent)
Georgia	46	37
Heard County	15	43
Heard County Block Group 131499702002	2	27
Heard County Block Group 131499702001	18	47
Heard County Block Group 131499701003	1	43

Source: Environmental Protection Agency, 2020b; U.S. Census Bureau 2013-2017 5-Year Estimates

Table 3.9-3: Minority and Low-Income Populations near the Project in Coweta County

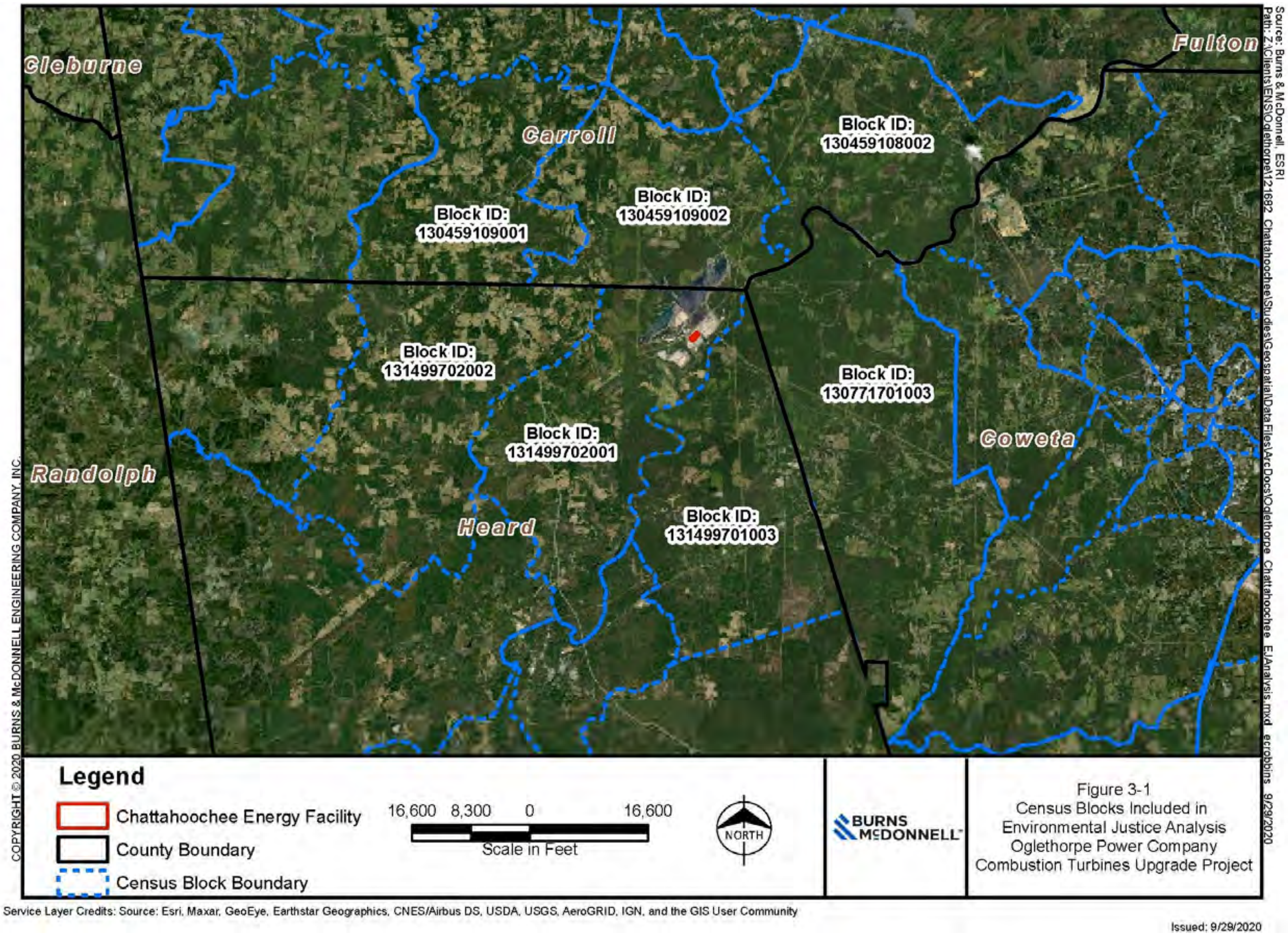
Geographic Area	Minority population (percent)	Low-income population (percent)
Georgia	46	37
Coweta County	28	28
Coweta County Block Group 130771701003	30	32

Source: Environmental Protection Agency, 2020b; U.S. Census Bureau 2013-2017 5-Year Estimates

3.9.2.2 Environmental Consequences

No environmental justice minority or low-income areas were identified near the Project in Carroll County and Coweta County. No environmental justice minority areas were identified in Heard County. The Heard County Block Group 131499702001, as depicted in **Figure 3-1**, is considered an environmental justice low-income area because the low-income population is 10 percentage points greater than the low-income population in Georgia overall. However, the Project would not have disproportionately high and adverse impact on the environmental justice communities in the area because the Project involves only software and mechanical upgrades inside the existing Facility, and there will be no new ground disturbing impacts. Although the Plant Wansley coal-fired power plant is within Census Block Group 131499702001, the Facility is within a small area of the block group and there are few residents in the surrounding area. Due to the lack of residences in this area and the existing small footprint of the Project within the Census Block Group 131499702001, it is anticipated that the Project would have no adverse impacts on environmental justice communities in this area.

Figure 3-1: Census Blocks Included in Environmental Justice Analysis



3.9.3 Utilities

3.9.3.1 Affected Environment

Public utilities include potable water, treated wastewater, sanitary sewer, electricity, gas, and solid waste services. The Project would not result in any changes or impacts to potable water, sanitary sewer, electricity, and solid waste services. There would be changes to the quantity of natural gas received, although no changes to the existing gas supply line infrastructure would be required to support the Project. The air emissions impacts from the increased natural gas consumption were previously outlined in Section 3.2 of this EA. Additionally, there would be an increase in the total treated surface water supplied for the cooling towers.

Georgia Power withdraws surface water from the Chattahoochee River (under State Water Quality Control Permit No. 074-1291-06) to replenish the Service Water Reservoir on Yellowdirt Creek (north of the Wansley coal-fired power plant). Georgia Power then withdraws water from the Service Water Reservoir to supply cooling tower makeup and general service water for on-site operations including the Facility's operations (under State Water Quality Control Permit No. 074-1291-07). After Georgia Power chlorinates the water, it supplies to the Facility but performs no additional water treatment. The Facility receives the water in its raw water storage tank; a portion of the water is demineralized via reverse osmosis and transferred to the demineralized water tank prior to use.

The Facility discharges cooling tower blowdown water into the Wansley Retention Pond. This is a batch process occurring approximately once per week. The Facility monitors the chlorine content of the blowdown water before discharge to ensure it is below the detection limit. The Facility adds sodium bisulfite, as needed, to dechlorinate the water. The Facility also discharges low volume wastewater (LVWW), consisting of water collected from indoor building drains and storm water collected from secondary containment areas, to the Wansley Retention Pond multiple times per day. The collected LVWW is sent through the Facility's oil/water separator, and the pH may be adjusted, as needed, prior to discharge to the Wansley Retention Pond. Georgia Power discharges water from the Wansley Retention Pond to the Chattahoochee River (under NPDES Permit No. GA0026778). Oglethorpe is responsible for ensuring that cooling tower blowdown water meets the applicable limits for "Unit 8" in Georgia Power's NPDES permit before discharging it to the Wansley Retention Pond.

Potable water for use by site personnel (e.g., in kitchens, bathrooms) is purchased from the Heard County Water Authority. There is no on-site water treatment plant for potable uses.

3.9.3.2 Environmental Consequences

The Project would result in increased water usage and discharge quantities. Additional raw water would be drawn from the Service Water Reservoir for treatment and use in the cooling towers, and there would be additional water discharged from the Facility to the Retention Pond and ultimately to the Chattahoochee River. The cooling tower water usage and discharge are modeled to increase in quantity but the quality of the industrial wastewater discharges will not change, and the Facility will continue to operate within the parameters of Georgia Power's existing surface water withdrawal permits (State Water Quality Control Permit Nos. 074-1291-06 and 074-1291-07) and industrial water discharge permit (NPDES Permit No. GA0026778). The Project would not result in an increased potable water usage because there would not be an increase in personnel, and potable water is not used for any of the Facility generation operations.

Table 3.13-1 summarizes the daily cooling tower water usage and discharges in recent years and the modeled usage and discharge levels after Project implementation.

Table 3.9-4: Daily Treated Wastewater Usage and Discharges (thousand gal)

Year	Daily Average Cooling Tower Water Use[1]	Daily Maximum Cooling Tower Water Use	Daily Average Cooling Tower Water Discharge[1]	Daily Maximum Cooling Tower Water Discharge[2]
2015	880	1,765	106	418
2016	966	1,823	102	503
2017	1,134	1,753	169	453
2018	878	1,719	102	419
2019	993	1,707	98	368
Post TPU1	1,074	1,950	135	503

1. Daily average water use and discharge for the cooling tower are based on the actual annual numbers divided by the number of days in the year.
2. The cooling tower blowdown is discharged in a batch process occurring approximately once per week. The maximum quantity of blowdown water that can be discharged in a given day is limited by the discharge system, which would not be modified as part of the TPU1 project. As such, while the project may result in increases in the length of time to complete each discharge batch, it would not increase the maximum amount that can be discharged in a single 24-hour period.
Source: Chattahoochee Energy Facility Discharge Monitoring Reports, Chattahoochee Energy Facility Water Use Calculations

The estimated increase of approximately 243 thousand gallons of daily maximum cooling tower water usage would be within the parameters of Georgia Power's withdrawal permits for Plant Wansley, which allow for 116 million gallons per day (MGD) from the Chattahoochee River to fill the Service Water Reservoir (Permit No. 074-1291-06) and 110.0 MGD from the Service Water Reservoir for use as cooling tower make-up water and general service water (Permit No. 074-1291-07).

3.9.4 Mitigation

Georgia Power's industrial wastewater discharge NPDES permit will likely not require modification because the effluent composition will remain unchanged and the permit does not specify allowable discharge volumes for the Chattahoochee Energy Facility. Additionally, the Project would have increased daily water usage but the amounts would be within the parameters of Georgia Power's existing surface water withdrawal permit. Therefore, there are no mitigation measures for the increased discharges or withdraws.

Georgia Power's industrial wastewater discharge NPDES permit will likely not require modification because the effluent composition will remain unchanged and the permit does not specify allowable discharge volumes for the Chattahoochee Energy Facility. Additionally, the Facility's daily water usage following implementation of the Project will remain within the parameters of Georgia Power's existing permit. Therefore, there are no mitigation measures for the increased discharge or withdrawal amounts.

3.10 Threatened and Endangered Species

Table 3.10-1 provides a list of state and federally protected species with the potential to occur in Carroll and Heard Counties. Protected species information for the specific Project Site was obtained from the U.S. Fish and Wildlife Service (FWS) Information for Planning, & Consultation System (IPaC). Any impacts from the Project would be limited to the existing Facility boundaries. There is no known habitat or previous occurrences documented for federal or state protected species within the Facility footprint, as documented in the IPaC documentation attached in **Appendix D**. Further, there is no designated critical habitat for protected species within the area (FWS, 2020).

Table 3.10-1: Protected Species Potentially occurring in Carroll and Heard Counties

Common Name	Scientific Name	County	Federal Status	State Status
Mammals				
Gray bat	*Myotis grisescens*	Carroll	E	SE
Indiana bat	*Myotis sodalis*	Carroll	E	-
Northern long-eared bat	*Myotis septentrionalis*	Carroll	T	ST
Clams				
Finelined pocketbook	*Lampsilis altilis*	Carroll	T	-
Plants				
Little amphianthus	*Amphianthus pusillus*	Carroll; Heard	E	ST
White-fringless orchid	*Platanthera integrilabia*	Carroll	T	ST
Black-spored quillwort	*Isoetes melanospora*	Carroll; Heard	E	

Source: FWS, 2020
E= federally endangered, T = federally threatened, SE = state endangered, ST = state threatened

There are currently 30 state-protected species of plants and animals with potential to occur in Carroll and Heard Counties (GDNR, 2020). The Facility is located within the Chattahoochee River watershed, which is a state high priority watershed, and several federally protected species have been documented in the river. As the Project would involve only software and mechanical upgrades inside the Facility there will be no new ground disturbing impacts or clearing of vegetation.

As discussed in Section 3.9, the cooling tower water usage and discharge are modeled to increase in quantity once the Project as implemented. However, as demonstrated in Table 3.13-1, there would not be a significant increase in water usage and discharges. the discharges would continue in batches and there would not be a significant change to the discharge volumes. The quality of the industrial wastewater discharges to the Chattahoochee River will also not change. The Facility will continue to operate within the parameters of Georgia Power's existing surface water withdrawal permits (State Water Quality Control Permit Nos. 074-1291-06 and 074-1291-07) and industrial water discharge permit (NPDES Permit No. GA0026778). As a result, adverse impacts to aquatic species are not anticipated. Additionally, no protected species or critical habitat were identified for the Project Site in the IPaC report (**Appendix D**), and further consultation with FWS is not required.

For these reasons, the proposed Project would have no effect on listed threatened or endangered species or their critical habitat. Therefore, in accordance with 1970.657(b) no further consultation with USFWS is required and the Section 7 review is complete. Since no impacts are anticipated, no special mitigation for protected species is proposed.

3.11 Transportation

Since the upgrades for the Project would occur during a routine major outage, there would already be a temporary increase in traffic at the Facility, and impacts from additional personnel and equipment to install the Project equipment would be negligible. No additional full-time employees would be hired for operation of Facility due to the Project, so there are no permanent traffic impacts anticipated. Therefore, no mitigation is proposed.

3.12 Vegetation

The Project would not require clearing of vegetation, as all control and mechanical adjustments would occur within the existing Facility. Therefore, no mitigation is proposed.

3.13 Water Resources and Wetlands

There are no wetlands or waterbodies within the boundaries of the Facility. A National Wetlands Inventory map is included in **Appendix E**. There is one perennial stream and one emergent wetland on the Plant Wansley property, associated with the Retention Pond that acts as the receiving body for the blowdown water from the Facility. The pond discharges into the Chattahoochee River, and the Facility is located in the "Chattahoochee River Lower North 6" watershed which is considered high priority by the Georgia Department of Natural Resources. For the proposed Project, all control and mechanical adjustments would occur within existing Facility structures and would not result in any new impacts to the receiving waters or associated wetland.

There would be no ground-disturbing impacts as a result of the Project. The impacts of the Project on water withdrawn from and discharged to the Chattahoochee River, discussed in section 3.9, will be minimal. Therefore, no impacts on water resources and wetlands are anticipated, and no mitigation is proposed.

3.14 Wildlife

The Plant Wansley property is entirely fenced for security purposes. The existing fence is approximately eight feet high, which deters wildlife from entering the Facility. No changes to the existing Facility footprint or fence line are proposed. Therefore, no impacts on wildlife are anticipated.

4.0 CUMULATIVE EFFECTS

As defined by the CEQ, a cumulative effect is the impact on the environment that results from the incremental impact of the proposed action when added to other past, present, or reasonably foreseeable future actions, regardless of what agency or person undertakes such other actions (CEQ, 1997). Although the individual impact of each separate project may be minor, the additive or synergistic effects of multiple projects could be significant.

In order to understand the contribution of past actions to the cumulative impacts of the proposed action, this analysis relies on current environmental conditions as a proxy for the impacts of past actions. This is because existing conditions reflect the aggregate impact of all prior human actions and natural events that have affected the environment and might contribute to cumulative effects. In this analysis, RUS has generally considered the impacts of past projects within the resource-specific geographic scopes as part of the affected environment (environmental baseline), which was described under the specific resources discussed throughout section 3.0. This cumulative impact analysis includes other actions meeting the following three criteria:

- the action impacts a resource that is also potentially affected by the Facility's TPU1 upgrade and LLTD upgrade Project;
- the action causes the impacts within all or part of the same geographic scope as the Facility's TPU1 upgrade and LLTD upgrade Project; and
- the action causes this impact within all or part of the temporal scope for the potential impacts from the Facility's TPU1 upgrade and LLTD upgrade Project.

Based on the previous findings discussed throughout Section 3.0, the Project would only result in impacts on air quality and water use. Therefore, when combined with other past, present, and reasonably foreseeable future project, the Facility's planned Project could only contribute to cumulative impacts on air quality and water use. For the Project to contribute towards a cumulative impact on air quality and/or water use, the other contributing project(s) must overlap the same geographic and temporal scope as the planned Project.

For air quality, the distance used to establish a geographic scope was derived from the EPA's cumulative modeling of large PSD sources during permitting and follows 40 CFR 51, Appendix W, Section 4.1. This references a 31-mile (50-kilometer) radius of current or proposed sources of operational emissions. Although PSD modeling was not performed for this Project, if there is another ongoing or proposed emission source within the Facility's 31-mile radius, a cumulative impact could occur when the other project(s) is combined with the Project.

Oglethorpe is unaware of any newly proposed or pending power generating facilities within a 31-mile radius. Other proposed or pending non-energy projects identified within the same geographic scope as the proposed Project include:

- General residential, commercial, and manufacturing/industrial development and construction;
- New and existing roadway construction and maintenance;
- Expansion of the Carroll County regional airport; and
- Landfills currently operating under a Title V permit.

4.1 Cumulative Impacts by Resource

4.1.1 Aesthetics

The Project would not result in an impact to current surrounding aesthetics and also would not contribute towards a cumulative impact on aesthetics.

4.1.2 Air Quality

Oglethorpe is not aware of any planned projects for other sources located near the Facility for which the Project would have a cumulative impact on air quality. Any other projects near the Facility would need to evaluate on a case-by-case basis whether cumulative modeling is required under the PSD regulations to demonstrate no violations of the NAAQS or PSD Increment will occur. Should such modeling be required in the future, the other projects and sources would include the Facility's post-Project potential emissions in its cumulative modeling evaluation.

4.1.3 Floodplains

As discussed in Section 3.3 and shown in **Appendix C**, the Project will not be located in a floodplain. The Project would not result in floodplain impacts and would not contribute towards a cumulative impact on floodplains.

4.1.4 Geology, Soils, and Farmland

The Project would not result in geology, soils, or farmland impacts and would not contribute towards a cumulative impact on geology, soils, or farmland.

4.1.5 Historical and Cultural Resources

The Project would not result in a historical or cultural resources impact on existing resources and would not contribute towards a cumulative impact on historical, cultural, or archeological resources.

4.1.6 Human Health and Safety

The Project would not result in adverse impacts to human health and safety and would not contribute towards a cumulative impact on human health and safety.

4.1.7 Land Use

The Project would not result in an impact to current land use types and would not contribute towards a cumulative impact on land use.

4.1.8 Noise

The Project would not result in an increase in noise levels above historical levels and would not contribute towards a cumulative impact on noise levels at NSAs.

4.1.9 Socioeconomics and Environmental Justice

The Project would not result in an adverse impact on the existing socioeconomic conditions of the area or any environmental justice communities and also would not contribute towards an adverse cumulative impact on socioeconomics or environmental justice.

The Project would not result in any adverse impacts to potable water, sanitary sewer, electricity, gas, or solid waste services. The Facility withdraws and discharges to and from the Chattahoochee River under Georgia Power's permits for the Wansley Plant. For the industrial water discharges from the Facility, water composition will remain unchanged and the industrial discharge water permit does not specify allowable discharge volumes. The Project would result in an increase in daily water usage, but the amounts would be within the parameters of Georgia Power's water withdrawal permits. Therefore, there would be no changes to Georgia Power's NPDES discharge permit or withdrawal permits. Further, Oglethorpe is unaware of any other proposed or pending projects that will be withdrawing or discharging water to/from the Chattahoochee River in the vicinity of the Project. Therefore, the proposed Project is unlikely to contribute to an adverse cumulative impact on utilities.

4.1.10 Threatened and Endangered Species

The Project will have no effect on federally or state protected species and water withdrawals and discharges to and from the Chattahoochee River would not significantly change and would continue within the parameters of the permits. Therefore, the Project would not contribute towards a cumulative impact on protected species.

4.1.11 Transportation

The Project would not adversely affect transportation and would not contribute towards a cumulative impact on traffic or transportation when combined with other past, present, or reasonably foreseeable future projects.

4.1.12 Vegetation

The Project would not require clearing of vegetation or any soil disturbance and would not contribute towards an adverse cumulative impact on existing vegetation.

4.1.13 Water Resources and Wetlands

The Project would not affect wetlands or waterbodies and water withdrawals and discharges to and from the Chattahoochee River would not significantly change and would continue within the parameters of the permits. Therefore, the Project would not contribute towards a cumulative impact on water resources and wetlands.

4.1.14 Wildlife

The Project would not result in an impact on wildlife and would not contribute towards a cumulative impact on wildlife.

5.0 SUMMARY OF MITIGATION

No resources would be adversely impacted by the Project, and therefore no mitigation efforts are proposed. The Facility would continue proper operation of air emission controls such as dry low NO_X combustors on the turbines and low NO_X duct burners, SCR, catalytic oxidation, and the use of low-sulfur fuel, as required by the existing air permit.

6.0 PUBLIC INVOLVEMENT

This EA will be made available to the public for a 14-day public review and comment period. Availability of the document for review and comment will be noticed in a local newspaper. Copies of the EA will be made available for public review at RUS, 1400 Independence Avenue, SW, Washington DC 20250-3201; at the headquarters of Oglethorpe at 2100 E Exchange Pl., Tucker, GA 30084; and at the Heard County Public Library at 564 Main Street, Franklin, GA 30217.

All comments from reviewers should be addressed to:

Dennis Rankin
U.S. Dept. of Agriculture, Rural Utilities Service
1400 Independence Avenue, SW, Washington DC 20250-3201
dennis.rankin@usda.gov

Once RUS has reviewed comments, it will issue its environmental decision related to the Project. Should RUS choose to issue a Finding of No Significant Impact (FONSI) for the Project, a newspaper notice will be published informing the public of the RUS finding and the availability of the EA and FONSI. The notice shall be prepared in accordance with RUS guidance.

7.0 LIST OF PREPARERS

The EA for the Project was prepared by RUS in coordination with Oglethorpe Power Corporation, Inc. and Burns & McDonnell. The following is a list of preparers of this document.

RUS

- Lauren Rayburn, Environmental Scientist, Engineering and Environmental Staff
- Kenneth Solano, Engineering Branch Chief, Office of Loan Original and Approval

Oglethorpe

- Don Cheatham, Project Manager
- Dan Neumann, Chattahoochee Energy Facility Operations Manager
- John Miller, Chattahoochee Energy Facility Plant Manager
- Courtney Adcock, Senior Environmental Specialist
- Toni Presnell, Vice President Environmental Affairs

Burns & McDonnell

- Sara Kent, Project Manager
- Steve Thornhill, NEPA Manager
- Jesse A Brown, Senior Environmental Scientist
- Bruce Battle, Staff Environmental Scientist
- Emily Robbins, Staff Environmental Engineer

8.0 REFERENCES

Council on Environmental Quality (CEQ). 1997. Environmental Justice Guidance under the National Environmental Policy Act. Executive Office of the President, Washington, DC.

Georgia Department of Natural Resources (GDNR). 2020. Georgia Biodiversity Portal. Heard County & Carroll County. Accessed on April 13, 2020. Available from https://www.georgiabiodiversity.a2hosted.com/natels/elementmap?area=cnty&group=all_groups

U.S. Code (USC). 2020. Accessed via the internet on May 8, 2020 at: https://uscode.house.gov/

U.S. Environmental Protection Agency (EPA). 2020a. NAAQS Table. Accessed via the internet on May 7, 2020 at: https://www.epa.gov/criteria-air-pollutants/naaqs-table.

U.S. Environmental Protection Agency (EPA). 2020b. *EJSCREEN: Environmental Justice Screening and Mapping Tool*. Retrieved 25 September 2020 from https://www.epa.gov/ejscreen.

U.S. Fish and Wildlife Service (FWS). 2020. List of threatened and endangered species that may occur in your proposed project location, and/or may be affected by your project. Consultation Code: 04EG1000-2020-SLI-1928. Event code: 04EG1000-2020-E-03553. Letter issued on April 12, 2020.

APPENDIX A - MEMO ADDRESSING IMPACTS TO CULTURAL RESOURCES

United States Department of Agriculture

Rural Development

Rural Utilities Service

Water and Environmental Programs

Engineering and Environmental Staff

INTRAOFFICE MEMORANDUM

DATE: September 8, 2020

SUBJECT: GA 109, Oglethorpe Power Corporation
Chattahoochee Energy Facility, Environmental Assessment
No Potential to Effect Historic Properties under Section 106 of the National Historic Preservation Act

TO: ERIKA MARTIN SEIBERT
Federal Preservation Officer
Rural Utilities Service (RUS)

FROM: LAUREN RAYBURN
Physical Scientist (Environmental)
EES, WEP, RUS

The proposed Project would involve the implementation of two upgrades for the Chattahoochee Energy Facility's two combustion turbines: the Thermal Performance Upgrade Step 1 (TPU1) and the Low Load Turndown (LLTD) upgrade. In performing these upgrades, the cooperative has indicated that software and mechanical upgrades to existing equipment within the current Facility structures would be required. The project would not involve new ground disturbance (see **Attachment 1: Project Location Map**).

Because of the lack of ground disturbance or modifications to the appearance of the facility, the proposed undertaking would not result in a change to ground features or visual elements of the landscape. Accordingly, I recommend use of 36 CFR §800.3(a)(1) for this potential undertaking[1].

DECISION BY FEDERAL PRESERVATION OFFICER

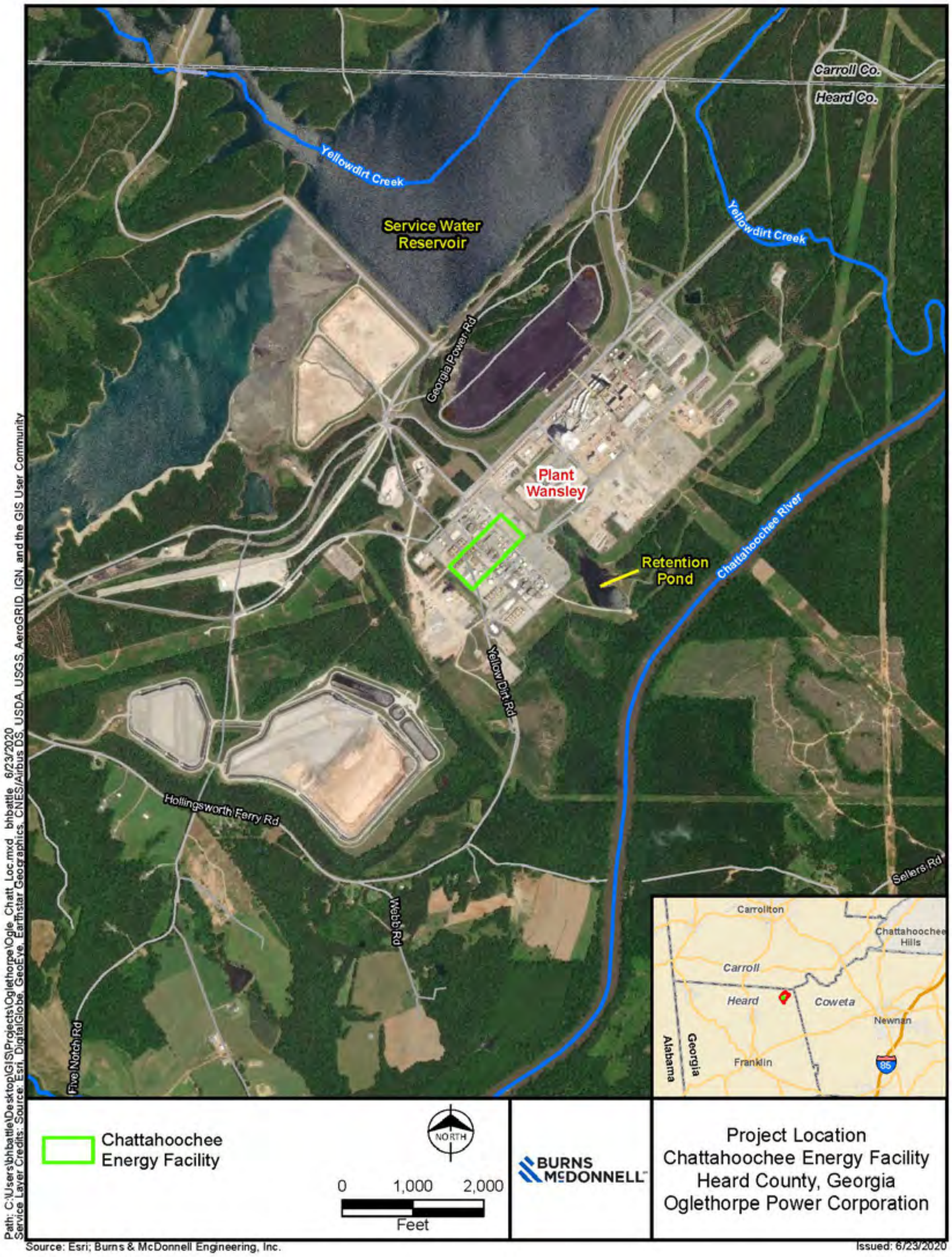
Erika K Martin Seibert Concur

___________ Discuss

9/8/2020 Date

[1] **36 CFR §800.3(a)(1)**: No potential to cause effects. If the undertaking is a type of activity that does not have the potential to cause effects on historic properties, assuming such historic properties were present, the agency official has no further obligations under section 106 or this part.

Attachment 1: Project Location Map



APPENDIX B – TITLE V SIGNIFICANT MODIFICATION WITH CONSTRUCTION APPLICATION

TITLE V SIGNIFICANT MODIFICATION WITH CONSTRUCTION APPLICATION

Oglethorpe Power Corporation > Chattahoochee Energy Facility

TRINITY CONSULTANTS
3495 Piedmont Road
Building 10, Suite 905
Atlanta, GA 30305
(678) 441-9977

June 2020

Project 201101.0056

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1. EXECUTIVE SUMMARY

Oglethorpe Power Corporation (OPC) owns and operates a gas-fired electrical power plant near Franklin, Georgia in Heard County, known as the Chattahoochee Energy Facility (OPC Chattahoochee). OPC Chattahoochee is a major source under both the Title V operating permit program and the Prevention of Significant Deterioration (PSD) construction permitting program. This facility currently operates under Part 70 Operating Permit No. 4911-149-0006-V-05-0, effective January 30, 2018, issued by the Georgia Environmental Protection Division (EPD).

OPC Chattahoochee is a natural gas-fired combined-cycle facility presently capable of producing a nominal power output of 526 megawatts (MW). The facility operates one power block consisting of two combined cycle combustion turbines (CCCTs) and one steam turbine, referred to as a "2-on-1" configuration. Each CCCT includes a Siemens-Westinghouse Model V84.3A2 combustion turbine (CT) exhausting to a heat recovery steam generator (HRSG), which generates steam to power the block's steam turbine. Each HRSG has a duct burner (DB) to provide supplementary firing for additional steam generation as needed.

To minimize the formation of oxides of nitrogen (NO_X), each CT is equipped with dry low NO_X combustors and each duct burner with low NO_X burners. In addition, each CT and associated duct burner stack is equipped with catalytic oxidation to control emissions of carbon monoxide (CO) and volatile organic compounds (VOC) and with a selective catalytic reduction (SCR) system to control NO_X emissions.

OPC Chattahoochee's proposed CT Upgrades Project would increase the current generation capacity of the facility, helping to reduce the overall cost per megawatts (MW) of power generated, and would allow the facility's gas turbines to continue to operate at reduced power during times of low demand with less frequent shutdowns and subsequent restarts once demand increases. The project would result in increases in maximum heat input and maximum projected annual air emissions. This application package contains the necessary state air construction and operating permit submittals for the proposed project. This application is being submitted using the Georgia EPD Online System (GEOS) with application ID No. 486572.

1.1 Proposed Project Description

The proposed CT Upgrades Project would involve the implementation of two upgrades for OPC Chattahoochee's two combustion turbines: the Thermal Performance Upgrade One (TPU1) and the Low Load Turndown (LLTD) upgrade.

The TPU1 would improve the combustion turbines, plant output, and heat rate as well as extend the maintenance interval of the units by installing enhanced hardware in the combustion turbines, replacing certain auxiliary hardware components, and adding site-specific control logic optimizations.

The LLTD upgrade would involve the installation of new combustion turbine components and software controls to replace selected equipment and connected accessories to allow for sustained operations at lower operating loads during periods of low demand.

1.2 Permitting and Regulatory Requirements

OPC is submitting this construction and operating permit application to request authorization to modify and operate the facility's CTs. Since OPC Chattahoochee is a major source under the PSD permitting program, emission increases from the proposed project must be evaluated and compared to the significant emission rates (SERs) for regulated pollutants under the PSD program. OPC has evaluated emissions increases of CO, NO_X, particulate matter (PM), total particulate matter with an aerodynamic diameter of less than 10 microns (PM_{10}), total particulate matter with an aerodynamic diameter of less than 2.5 microns ($PM_{2.5}$), greenhouse gases (GHG) in terms of carbon dioxide equivalents (CO_2e), sulfur dioxide (SO_2), sulfuric acid mist (H_2SO_4), and VOC resulting from the proposed project for comparison to their respective PSD SERs to determine whether PSD permitting is required, as shown in Table 1-1.[1]

Table 1-1. Proposed Project Emissions Increases

Pollutant	Units 8A and 8B				Cooling Tower Associated Emissions Increase (tpy)	Total Project Emissions Increase (tpy)	NSR Significant Emission Rate[2] (tpy)	NSR Triggered?
	Baseline Actual Emissions (tpy)	"Could Have Accommodated" Emissions (tpy)	Projected Actual Emissions (tpy)	Project Emissions Increase[1] (tpy)				
NO_X	100.2	116.4	153.1	36.7	-	36.7	40	No
CO	19.0	30.0	67.6	37.6	-	37.6	100	No
VOC	11.6	13.5	15.1	1.59	-	1.6	40	No
PM	69.7	81.1	90.6	9.5	0.31	9.8	25	No
PM_{10}	69.7	81.1	90.6	9.5	0.27	9.8	15	No
$PM_{2.5}$	69.7	81.1	90.6	9.5	1.5E-03	9.5	10	No
SO_2	7.0	8.1	9.1	0.95	-	0.9	40	No
H_2SO_4	0.80	0.93	1.0	0.11	-	0.1	7	No
CO_2e[3]	1,382,762	1,608,206	1,796,567	188,361	-	188,361	75,000	No

1. Project Emissions Increase = (Projected Actual Emissions - Baseline Actual Emissions) - ("Could Have Accommodated" Emissions - Baseline Actual Emissions)
2. 40 CFR 52.21(b)23(i) and Georgia Air Quality Control Rule 391-3-1-.03(8)(c)15
3. NSR permitting for CO_2e is only required if the project emissions increase exceeds the NSR SER of 75,000 tpy and if NSR permitting is triggered for at least one other regulated pollutant.

Since the combined project emissions increases of all pollutants are below their respective SERs, the proposed project is not required to undergo PSD review. Emission calculations are described in Section 3 of this application, and New Source Review (NSR) applicability is detailed in Section 4.1.

OPC is submitting this construction and operating permit application package in accordance with all federal and state requirements. The proposed project will be subject to federal New Source Performance Standards (NSPS) and the Georgia Rules for Air Quality Control (GRAQC). Applicability of these programs is discussed in Section 4 of this application.

1.3 Application Contents

- Section 2 contains a description of the proposed project;
- Section 3 summarizes emissions calculation methodologies and assesses PSD applicability;
- Section 4 details the regulatory applicability analysis for the proposed project;
- Section 5 contains the toxics impact assessment;
- Appendix A includes an area map and simplified process flow diagram;
- Appendix B includes detailed emission calculations;
- Appendix C contains documentation for the toxics impact analysis; and
- Appendix D contains the EPD SIP construction permit application forms.

[1] AP-42, Chapter 3, Section 1, *Stationary Gas Turbines,* lists the lead (Pb) emission factor for natural gas turbines as ND (no detect); therefore, Pb emissions increases for the proposed project were not evaluated.

2. PROPOSED PROJECT DESCRIPTION

The proposed CT Upgrades Project would involve the implementation of two upgrades for OPC Chattahoochee's two combustion turbines: the TPU1 and the LLTD upgrade.

The TPU1 would improve the combustion turbines, plant output, and heat rate as well as extend the maintenance interval of the units by installing enhanced hardware in the combustion turbines, replacing certain auxiliary hardware components, and adding site-specific control logic optimizations. New turbine hardware would include combustion chamber components with optimized cooling air reduction, impingement cooled tile holders, the latest ceramic heat shields, metallic heat shields, and burner swirlers with reduced swirl angle. Auxiliary hardware replacements would include the pilot gas flow meter, an advanced combustion dynamics monitoring system, heat resistant ignition cables, blow-off valve actuators, and additional pressure and acceleration measurement instrumentation. These changes would increase the capacity of the facility by approximately 23 MW, with variations for ambient temperatures. The increased capacity would decrease the cost of electricity generation.

The LLTD upgrade would involve the installation of new combustion turbine components and software controls to replace selected equipment and connected accessories to allow for sustained operations at lower operating loads during periods of low demand. These changes would include the compressor inlet guide vane extended range sensor, ring modification and linearization unit replacement, and the addition of a combustion turbine exhaust metallic heat shield, along with site-specific control logic optimizations. Currently, the facility shuts down periodically during low demand and then restarts when demand increases. The LLTD upgrades would allow the combustion turbines to operate at steady-state minimum loads of approximately 67 MW, with variations for ambient temperatures, while continuing to maintain emission concentrations of NO_X and CO in compliance with the facility's permitted emission limits. As a result, this upgrade would allow the facility to continue to operate with less frequent shutdowns during low demand periods, thereby reducing maintenance and fuel costs associated with cycling through shutdowns and startups.

3. EMISSIONS CALCULATION METHODOLOGY

This section addresses the methodology used to quantify the emissions from the proposed project and assesses federal NSR permitting applicability. Pollutants with an emissions increase from the proposed project include CO, NO_X, SO_2, VOC, PM, PM_{10}, $PM_{2.5}$, H_2SO_4, GHG in the form of CO_2e, and hazardous air pollutants (HAP). These emissions occur as a result of natural gas combustion in the combustion turbines and duct burners. Detailed emission calculations are presented in Appendix B.

3.1 NSR Permitting Evaluation Methodology

The NSR permitting program generally requires that a source obtain a permit prior to construction of any project at an industrial facility if the proposed project results in increases in air pollution emissions in excess of certain threshold levels. The federal NSR program is comprised of two elements: Nonattainment NSR (NNSR) and PSD. The NNSR program potentially applies to new construction or modifications that result in emission increases of a particular pollutant for which the area the facility is located in is classified as "nonattainment" with the National Ambient Air Quality Standards (NAAQS) for that pollutant. The PSD program applies to project increases of those pollutants for which the area the facility is located in is classified as "attainment" or "unclassifiable" for the NAAQS. OPC Chattahoochee is located in Heard County, which has been designated by the U.S. EPA as "attainment" or "unclassifiable" for all criteria pollutants.[2] Therefore, PSD is the applicable permitting program under the federal NSR program. OPC Chattahoochee is an existing PSD major source, as it has potential emissions of multiple regulated criteria pollutants exceeding the major source threshold of 100 tpy.[3] As a result, new construction or modifications that result in emissions increases for criteria pollutants are potentially subject to PSD permitting requirements.

Additionally, the facility is located in a county specified by the Georgia EPD as subject to GRAQC 391-3-1-.03(8)(c)15, which addresses additional provisions for electrical generating units in the areas contributing to the Atlanta ozone nonattainment area. This state regulation specifies that certain NNSR provisions are potentially applicable when permitting new construction or modifications at any electrical generating unit that is located in a listed contributing county and that has facility-wide potential NO_X emissions exceeding 100 tpy.[4] As OPC Chattahoochee's potential NO_X emissions exceed 100 tpy, the facility is a major source for NO_X emissions under this state regulation. Therefore, applicability of the proposed project to these NNSR permitting provisions must be assessed.

The following sections discuss the methodology used in the project emissions increase evaluation conducted to assess NSR applicability under the PSD and state NNSR program. As the facility is classified as a major source for PSD, if the proposed project meet the definition of a *major modification*, then the full PSD permitting requirements apply. For all PSD-regulated pollutants other than CO_2e, PSD permitting is required if the emissions increase of a specific pollutant exceeds that pollutant's PSD SER. For CO_2e, PSD permitting is only required if the emissions increase exceeds the SER for CO_2e and the project is already undergoing

[2] 40 CFR 81.311

[3] Fossil fuel-fired steam electric plants of more than 250 MMBtu/hr input (which includes combined cycle natural gas plants) are on the "List of 28" named source categories which are subject to a lower major source threshold for criteria pollutants of 100 tpy.

[4] GRAQC 391-3-1-.03(8)(c)15(i)

PSD permitting for at least one other PSD-regulated pollutant.[5] For NO_X, certain NNSR provisions are required if the emissions increase exceeds the applicable NNSR SER of 40 tpy.[6]

3.2 Defining Existing Versus New Emission Units

For purposes of calculating project emissions increases, different calculation methodologies are used for existing and new units; therefore, it is important to clarify whether the sources affected by the proposed project are considered new or existing emission units.

40 CFR 52.21(b)(7)(i) and (ii) define new unit and existing units, and are incorporated by reference in the GRAQC:

> (i) *A new emissions unit is any emissions unit that is (or will be) newly constructed and that has existed for less than 2 years from the date such emissions unit first operated.*
>
> (ii) *An existing emissions unit is any unit that does not meet the requirements in paragraph (b)(7)(i) of this section. A replacement unit, as defined in paragraph (b)(33) of this section, is an existing emissions unit.*

As the emission units at OPC Chattahoochee have operated for more than two years, the proposed project involves physical or operational changes to existing emission units only – specifically, the facility's combustion turbines. There are no new emission units proposed for installation as part of this project.

3.3 Annual Emissions Increase Calculation Methodology

As OPC Chattahoochee is classified as a major source for PSD, if the proposed project meets the definition of a *major modification*, then the full PSD permitting requirements apply. *Major modification* is defined by 40 CFR 52.21(b)(2)(i):

> *"Major Modification" means any physical change in or change in the method of operation of a major stationary source that would result in a significant emission increase … of a regulated NSR pollutant … and a significant net emissions increase of that pollutant …*

Certain exemptions to the major modification definition exist that, if applicable, means a project does not require an emission increase assessment. The proposed project does not qualify for any of the established exemptions.

The project emissions have been analyzed using the current NSR Reform methodology to determine if a significant emissions increase will occur. *Net emissions increase* (NEI) is defined by 40 CFR 52.21(b)(3)(i):

> *"Net Emissions Increase" means, with respect to any regulated NSR pollutant … the amount by which the sum of the following exceeds zero:*

[5] 40 CFR 52.21(b)(49)(iii) as incorporated by reference in the GRAQC

[6] GRAQC 391-3-1-.03(8)(c)15(ii)

(a) The increase in emissions … as calculated pursuant to paragraph (a)(2)(iv) [for existing units, calculated by actual-to-projected actual[7] *or actual-to-potential; for new units, calculated by actual-to-potential]*[8]

(b) Any other increases or decreases in actual emissions…that are contemporaneous with the particular change and are otherwise creditable. Baseline emissions for calculating increases and decreases…shall be determined as provided…

The first step (1) is commonly referred to as the "project emission increases" as it has historically accounted only for emissions related to the proposed project itself. If the emission increases estimated per step (1) exceed the major modification thresholds, then the applicant may move to step (2), commonly referred to as the 5-year netting analysis. The netting analysis includes all projects for which emission increases or decreases (e.g., equipment shutdown) occurred. If the resulting net emission increases exceed the major modification threshold, then NSR permitting is required. OPC has evaluated the project emissions increase for the proposed project (i.e., Step 1) using the methodologies outlined in the following sections. An evaluation of the net emissions increase (i.e., Step 2) was neither required nor conducted for the proposed project.

While the prior quotations only reference three components of the NEI calculation (actual, projected actual, and potential emissions), there are actually five calculated components, with the additional components being (1) a subset of the definition for *projected actual* and (2) additional associated emission unit increases:

- Potential emissions
- Baseline actual emissions
- Projected actual emissions
- "Could have accommodated" emissions exclusion (commonly called the demand growth exclusion)
- Additional associated emission unit increases

3.3.1 Potential Emissions

Potential emissions are defined by 40 CFR 52.21(b)(4) where the potential to emit:

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

[7] 40 CFR 52.21(a)(2)(iv)(c), Actual-to-projected-actual applicability test for projects that only involve existing emissions units, states: A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the projected actual emissions … and the baseline actual emissions … equals or exceeds the significant amount for that pollutant …

[8] 40 CFR 52.21(a)(2)(iv)(d), Actual-to-potential test for projects that only involve construction of new emissions units, states: A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the potential to emit … and the baseline actual emissions … equals or exceeds the significant amount for that pollutant …

While potential emission estimates have not been relied upon for purposes of the PSD project emission increase analysis, potential emissions are detailed for documentation of the facility estimated potential emissions following the project.

3.3.2 Baseline Actual Emissions

Baseline actual emissions are defined in GRAQC 391-3-1-.02(7)(a)2(i)(I):

> *For any existing electric utility steam generating unit, baseline actual emissions means the average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding when the owner or operator begins actual construction of the project. …*

3.3.3 Projected Actual Emissions

Projected actual emissions are defined by GRAQC 391-3-1-.02(7)(a)2(ii)(I):

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

In determining projected actual emissions, following GRAQC 391-3-1-.02(7)(a)2(ii)(II)I, the source:

> *Shall consider all relevant information, including but not limited to, historical operational data, the company's own representations, the company's expected business activity and the company's highest projections of business activity, the company's filings with the State or Federal regulatory authorities, and compliance plans under the approved State Implementation Plan.*

In addition, when calculating projected actual emissions, OPC Chattahoochee can exclude emissions that could have been accommodated prior to the project and that are unrelated to the project, pursuant to GRAQC 391-3-1-.02(7)(a)2(ii)(II)III.

3.3.4 Could Have Accommodated Emissions

An exclusion, per GRAQC 391-3-1-.02(7)(a)2(ii)(II)III, is included in the definition of projected actual emissions and is a value that can be subtracted from the projected actual emissions for existing emission units:

> *May exclude, in calculating any increase in emissions that results from the particular project, [1] that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions under subparagraph (7)(a)2.(i) of this rule and that is also [2] unrelated to the particular project, including any increased*

utilization due to product demand growth (the increase in emissions that may be excluded under this subparagraph shall hereinafter be referred to as "demand growth emissions")... [numbers 1 and 2 added]

3.3.5 Additional Associated Emission Unit Increases

In addition to the emission increases from new or modified units, emission increases from associated emission units that may realize an increase in emissions due to a project must be included in the assessment of the project emissions increases. OPC Chattahoochee anticipates that the modifications to and increased utilization of the combustion turbines would result in an associated increase in drift loss and, therefore, air emissions from the facility's cooling tower. As such, an associated emissions increases are included in this analysis for the cooling towers.

3.4 Baseline Actual Emissions

The most recent 5 year lookback period was utilized for this analysis. Accordingly, a period of May 2016 to April 2018 was selected as the 2 year (consecutive 24-month) baseline period for all pollutants except for CO, for which the period of August 2015 to July 2017 was selected. Baseline actual emissions data utilized for the NSR analysis for each combined cycle combustion unit can be found in Appendix B.

3.5 Projected Actual Emissions

Projected actual emissions for the modified equipment were determined for use in the NSR analysis, based on the highest projected level of actual annual utilization of the modified combustion turbine systems in the ten years following the project (at 30.2 x 10^6 MMBtu/yr total for both CCCTs), and estimated actual emission factors derived from facility operations, as summarized in Table 3-1.

Table 3-1. Criteria Pollutant Projected Actual Emission Factors for CCCT Units

Pollutant	Emission Factor (lb/MMBtu)
VOC[1]	1.00E-03
$PM_{10}/PM_{2.5}$[2]	6.00E-03
SO_2[3]	6.00E-04
NO_X[4]	1.01E-02
CO[4]	4.48E-03
H_2SO_4[5]	6.89E-05
CO_2[6]	118.86
CH_4[7]	2.20E-03
N_2O[7]	2.20E-04
CO_2e[7]	118.98

1. VOC emissions were based on the most recent facility compliance testing data. The total VOC emission factor was calculated as the sum of the 2005 VOC as CH_4 (Method 25A) test results and the 2003 formaldehyde (Method 0011) test results. A 10% safety factor was conservatively applied to the stack test results. The emissions concentrations (ppm @ 15% O_2) were converted to emission factors (lb/MMBtu) using the following equation:

$$lb/MMBtu = (C_{gas,\ VOC\ as\ CH4} * MW_{VOC\ as\ CH4} + C_{gas,\ HCHO} * MW_{HCHO}) * Fd * 2.59E\text{-}9 * 20.9 / (20.9 - \%O_2)$$

where:

$C_{gas,\ VOC\ as\ CH4}$ =	0.596	ppmv, maximum VOC as CH_4 test result for either unit at any load
$MW_{VOC\ as\ CH4}$ =	16.043	lb/lb-mol, molecular weight of CH_4
$C_{gas,\ HCHO}$ =	0.061	ppmv, maximum HCHO test result for either unit at any load
MW_{HCHO} =	30.026	lb/lb-mol, molecular weight of HCHO
Fd =	8,710	dscf/MMBtu, natural gas fuel factor from 40 CFR 60, Method 19, Table 19-2
$\%O_2$ =	15	%, corrected basis for exhaust gas O_2 content

2. PM emissions are based on the average of the 2003 compliance testing results for units 8A (0.0069 lb/MMBtu) and 8B (0.0051 lb/MMBtu). The 2003 testing was inclusive of both the filterable and condensable portions of PM. It was conservatively assumed all PM is less than 2.5 microns in diameter (i.e., $PM_{2.5} = PM_{10} = PM$).

3. SO_2 emissions were estimated using the default SO_2 emission rate for pipeline natural gas from 40 CFR 75, Appendix D, Section 2.3.1.1, consistent with the methodology used to report the facility's SO_2 emissions under the CAMD programs.

4. H_2SO_4 emissions were calculated assuming a 7.5% conversion of SO_2 to H_2SO_4, consistent with the facility's initial November 2000 PSD permit application.

4. The projected actual NO_X and CO emission rates were conservatively based on the maximum of the monthly average emission rates (monthly emissions divided by monthly heat input) during the 24-month baseline period for each pollutant.

5. CO_2 emissions were calculated in accordance with 40 CFR 75, Appendix G, Equation G-4 using the F-factor for natural gas, consistent with the methodology used to report the facility's CO_2 emissions under the CAMD programs and the EPA GHG reporting rule.

6. CH_4 and N_2O emission factors for natural gas combustion are from 40 CFR 98, Subpart C, Table C-2, converted from kg to lb, consistent with the methodology used to report the facility's emissions under the EPA GHG reporting rule.

7. CO_2e was calculated as the sum of the emission factor for each GHG pollutant multiplied by that pollutant's global warming potential (GWP). GWPs were taken from 40 CFR 98, Subpart A, Table A-1:

CO_2:	1
CH_4:	25
N_2O:	298

3.6 Could Have Accommodated Emissions

The "could have accommodated" emissions for this project are based on consideration of the "Georgia Pacific memo" and subsequent correspondence with U.S. EPA, indicating that a maximum 30-day period can be utilized to demonstrate emissions that "could have been accommodated" by a source during the respective baseline period.[9] Additional conservative assumptions were applied to the 30-day maximum period technique as outlined in the referenced Georgia Pacific memo.

Specifically, application of an additional seasonal variation was relied upon for this analysis. The maximum 30-day period from each season was evaluated, and used to evaluate total emissions for the entire seasonal period. Seasonal breakdowns were evaluated as follows;

Spring: March – May
Summer: June – August
Fall: September – November
Winter: December – February

Emissions that were excluded using this methodology are necessarily unrelated to the proposed project as they are based on existing capacity and actual data from the selected baseline period.

Additional data regarding the "could have been accommodated" analysis is included in Appendix B.

3.7 NSR Emissions Increase Summary

Table 3-2 shows the total emissions increase of the proposed project compared to the PSD major modification thresholds.[10] Note that the applicable NO_X SER is the same under both the PSD and NNSR permitting programs (40 tpy). Detailed emission calculations can be found in Appendix B of this application report.

[9] https://www.epa.gov/nsr/response-georgia-pacific-use-demand-growth-exclusion-projected-actual-emissions

[10] AP-42, Chapter 3, Section 1, *Stationary Gas Turbines,* lists the Pb emission factor for natural gas turbines as ND (no detect); therefore, Pb emissions increases for the proposed project were not evaluated.

Table 3-2. Project Emissions Increase

Pollutant	Units 8A and 8B				Cooling Tower Associated Emissions Increase (tpy)	Total Project Emissions Increase (tpy)	NSR Significant Emission Rate[2] (tpy)	NSR Triggered?
	Baseline Actual Emissions (tpy)	"Could Have Accommodated" Emissions (tpy)	Projected Actual Emissions (tpy)	Project Emissions Increase[1] (tpy)				
NO_X	100.2	116.4	153.1	36.7	-	36.7	40	No
CO	19.0	30.0	67.6	37.6	-	37.6	100	No
VOC	11.6	13.5	15.1	1.59	-	1.6	40	No
PM	69.7	81.1	90.6	9.5	0.31	9.8	25	No
PM_{10}	69.7	81.1	90.6	9.5	0.27	9.8	15	No
$PM_{2.5}$	69.7	81.1	90.6	9.5	1.5E-03	9.5	10	No
SO_2	7.0	8.1	9.1	0.95	-	0.9	40	No
H_2SO_4	0.80	0.93	1.0	0.11	-	0.1	7	No
CO_2e[3]	1,382,762	1,608,206	1,796,567	188,361	-	188,361	75,000	No

1. Project Emissions Increase = (Projected Actual Emissions - Baseline Actual Emissions) - ("Could Have Accommodated" Emissions - Baseline Actual Emissions)
2. 40 CFR 52.21(b)23(i) and Georgia Air Quality Control Rule 391-3-1-.03(8)(c)15
3. NSR permitting for CO_2e is only required if the project emissions increase exceeds the NSR SER of 75,000 tpy and if NSR permitting is triggered for at least one other regulated pollutant.

3.8 Potential Emissions Estimate

The following sections discuss the methodology used to calculate the potential emissions for each emission unit at the facility.

3.8.1 Combined Cycle Combustion Turbines

The potential emissions for each CCCT (i.e., combustion turbine with HRSG and duct burner, discharging to a common stack) are determined on a pollutant-by-pollutant basis. Table 3-3 summarizes the criteria pollutant emission factors utilized for estimation of potential emissions from both CCCT units.

Table 3-3. Criteria Pollutant Emission Factors for CCCT Units

Pollutant	Emission Factor (lb/MMBtu)
NO_X[1]	1.11E-02
CO[2]	4.48E-03
VOC[3]	2.59E-03
PM[4]	9.91E-03
Total PM_{10}[4]	9.91E-03
Total $PM_{2.5}$[4]	9.91E-03
SO_2[5]	6.00E-04
H_2SO_4[6]	6.89E-05
CO_2[7]	1.19E+02
CH_4[8]	2.20E-03
N_2O[8]	2.20E-04
CO_2e[9]	1.19E+02

1. Emission factor for NO_X based on 3.0 ppm @ 15% O_2 existing BACT limit. Permit Condition 3.3.4 limits NO_X emissions to 179.6 tpy (total from all CCCTs).

2. Emission factor for CO based on 2.0 ppm @ 15% O_2 existing BACT limit. Permit Condition 3.3.5 limits CO emissions to 86 tpy (total from all CCCTs).

3. VOC emission factor based on 2.0 ppm @ 15% O_2 existing BACT limit.

4. Condition 3.3.6.c limits PM to 0.011 lb/MMBtu, LHV basis. The limit was adjusted to HHV basis using a HHV/LHV ratio of 1.109805, consistent with the ratio used by Siemens in its performance data sheet for TPU1 dated 1/12/2020. It was conservatively assumed all PM is less than 2.5 microns in diameter (i.e., $PM_{2.5}$ = PM_{10} = PM).

5. SO_2 emissions were estimated using the default SO_2 emission rate for pipeline natural gas from 40 CFR 75, Appendix D, Section 2.3.1.1, consistent with the methodology used to report the facility's SO_2 emissions under the CAMD programs.

6. H_2SO_4 emissions were calculated assuming a 7.5% conversion of SO_2 to H_2SO_4, consistent with the facility's initial November 2000 PSD permit application.

7. CO_2 emissions were calculated in accordance with 40 CFR 75, Appendix G, Equation G-4 using the F-factor for natural gas, consistent with the methodology used to report the facility's CO_2 emissions under the CAMD programs and the EPA GHG reporting rule.

8. CH_4 and N_2O emission factors for natural gas combustion are from 40 CFR 98, Subpart C, Table C-2, converted from kg to lb, consistent with the methodology used to report the facility's emissions under the EPA GHG reporting rule.

9. Total GHG emissions in CO_2e is the sum of the product of each GHG and its respective global warming potential (GWP) per 40 CFR Part 98 Subpart A, Table A-1, effective January 1, 2014.

Pollutant	GWP
CO_2	1
CH_4	25
N_2O	298

3.8.2 HAP/TAP Emissions

HAP and toxic air pollutant (TAP) emissions are evaluated from each CCCT using AP-42 based emission factors and vendor based information, as appropriate. Details regarding the estimation of HAP/TAP emissions can be found in Appendix C.

3.8.3 Cooling Tower

Cooling tower emissions, as found in Appendix B, are calculated based on a vendor based drift rate, and facility records of the Total Dissolved Solids (TDS) concentration present in the waters processed at the cooling tower. This data is relied upon using emission estimation methods for cooling towers outlined in *Calculating Realistic PM_{10} Emissions from Cooling Towers* by Joel Reisman and Gordon Frisbie, 2002, to estimate potential emissions from the facility cooling towers.

3.8.4 Insignificant Emissions Sources

The facility has other small insignificant sources of emissions (e.g., fugitive piping leaks, roads, etc.) at the facility which are not quantified within the potential to emit estimates within this application.

4. REGULATORY APPLICABILITY ANALYSIS

The project will be subject to certain federal and state air regulations. This section of the application summarizes the air permitting requirements and key air quality regulations that will potentially apply to OPC Chattahoochee as a result of the proposed project. Applicability to NSR, Title V, NSPS, National Emission Standards for Hazardous Air Pollutants (NESHAP), GRAQC, and other potentially applicable regulations to the proposed project are addressed herein.

4.1 New Source Review Applicability

The NSR permitting program generally requires a source to obtain a permit and undertake other obligations prior to construction of any project at an industrial facility if the proposed project results in an emissions increase in excess of certain pollutant threshold levels. EPD administers its major NSR permitting program through GRAQC Rule 391-3-1-.02(7), *Prevention of Significant Deterioration of Air Quality*, which establishes preconstruction, construction, and operation requirements for new and modified sources.

The federal NSR program is comprised of two elements: NNSR and PSD. The NNSR program potentially applies to new construction or modifications that result in emission increases of a particular pollutant for which the area where the facility is located is classified as "nonattainment" for that pollutant. The PSD program applies to project increases of those pollutants for which the area the facility is located in is classified as "attainment" or "unclassifiable." OPC Chattahoochee is located in Heard County, which has been designated by the U.S. EPA as "attainment" or "unclassifiable" for all criteria pollutants.[11] Therefore, PSD is the applicable permitting program under the federal NSR program. In addition to the federal NSR programs, the facility is located in a county specified by the Georgia EPD as subject to GRAQC 391-3-1-.03(8)(c)(15), which addresses additional provisions for electrical generating units in the areas contributing to the Atlanta ozone nonattainment area. This state regulation specifies that certain NNSR provisions are potentially applicable when permitting new construction or modifications at any electrical generating unit that is located in a listed contributing county and that has facility-wide potential NO_X emissions exceeding 100 tpy.[12]

The PSD program only regulates emissions from "major" stationary sources of regulated air pollutants. A stationary source is considered PSD major if potential emissions of any regulated pollutant exceed the major source thresholds. The PSD major source threshold for OPC Chattahoochee is 100 tpy for all regulated pollutants, except GHG.[13, 14] OPC Chattahoochee is classified as an existing PSD major source since potential emissions of at least one regulated pollutant exceeds 100 tpy. For sources which are PSD major for at least one regulated pollutant, the emissions increases for all regulated pollutants resulting from the proposed project must be compared against the PSD SER to determine if the project is subject to PSD review. For CO_2e, PSD permitting is only required if the emissions increase from the proposed project exceeds the SER for CO_2e and the project is already undergoing PSD permitting for at least one other PSD-regulated pollutant. OPC Chattahoochee is also an existing major source under the state NNSR permitting program for electric generating units in contributing counties, as it has potential NO_X emissions exceeding the major

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[11] 40 CFR 81.311

[12] GRAQC 391-3-1-.03(8)(c)15(i)

[13] Fossil fuel-fired steam electric plants of more than 250 MMBtu/hr input (which includes combined cycle natural gas plants) are on the "List of 28" named source categories which are subject to a lower major source threshold for criteria pollutants of 100 tpy.

[14] 40 CFR 52.21(b)(49)(iii)

source threshold of 100 tpy. Therefore, the NO_X emissions increase for the proposed project must be compared to the NO_X NNSR SER to determine the applicability to certain NNSR provisions.

The emissions increases from the proposed project for each regulated pollutant compared to the respective SERs are shown in Table 4-1. Note that the applicable NO_X SER is the same under both the PSD and NNSR permitting programs (40 tpy).

Table 4-1. Project Emission Increases Compared to PSD and NNSR SERs

Pollutant	Units 8A and 8B				Cooling Tower Associated Emissions Increase (tpy)	Total Project Emissions Increase (tpy)	NSR Significant Emission Rate[2] (tpy)	NSR Triggered?
	Baseline Actual Emissions (tpy)	"Could Have Accommodated" Emissions (tpy)	Projected Actual Emissions (tpy)	Project Emissions Increase[1] (tpy)				
NO_X	100.2	116.4	153.1	36.7	-	36.7	40	No
CO	19.0	30.0	67.6	37.6	-	37.6	100	No
VOC	11.6	13.5	15.1	1.59	-	1.6	40	No
PM	69.7	81.1	90.6	9.5	0.31	9.8	25	No
PM_{10}	69.7	81.1	90.6	9.5	0.27	9.8	15	No
$PM_{2.5}$	69.7	81.1	90.6	9.5	1.5E-03	9.5	10	No
SO_2	7.0	8.1	9.1	0.95	-	0.9	40	No
H_2SO_4	0.80	0.93	1.0	0.11	-	0.1	7	No
CO_2e[3]	1,382,762	1,608,206	1,796,567	188,361	-	188,361	75,000	No

1. Project Emissions Increase = (Projected Actual Emissions - Baseline Actual Emissions) - ("Could Have Accommodated" Emissions - Baseline Actual Emissions)
2. 40 CFR 52.21(b)23(i) and Georgia Air Quality Control Rule 391-3-1-.03(8)(c)15
3. NSR permitting for CO_2e is only required if the project emissions increase exceeds the NSR SER of 75,000 tpy and if NSR permitting is triggered for at least one other regulated pollutant.

As illustrated in Table 4-1, the project emissions increases do not exceed the SERs for any pollutant. Accordingly, neither PSD nor NNSR review is required.

4.2 Title V Operating Permits

40 CFR 70 establishes the federal Title V operating permit program. Georgia has incorporated the provisions of this federal program in its state regulation, Rule 391-3-1-.03(10), *Title V Operating Permits.* This regulation requires that all new and existing Title V major sources of air emissions obtain federally-approved state-administered operating permits. A major source as defined under the Title V program is a facility that has the potential to emit either more than 100 tpy for any criteria pollutant, more than 10 tpy for any single HAP, or more than 25 tpy for combined HAP. Potential emissions from OPC Chattahoochee exceed the major source threshold for several pollutants. Therefore, OPC Chattahoochee is subject to the Title V program and currently operates under the State issued Part 70 Operating Permit No. 4911-149-0006-V-05-0.

The proposed project involves a Title I (NSPS) modification and, therefore, represents a significant modification of the operating permit. As such, the required Title V modification application elements are included in the GEOS submittal with application ID No. 486572.

4.3 New Source Performance Standards

NSPS, promulgated in 40 CFR 60, require new, modified, or reconstructed sources to control emissions to the level achievable by the best demonstrated technology as specified in the applicable provisions. The following is a summary of applicability and non-applicability determinations for NSPS regulations of relevance to the proposed project. Rules that are specific to certain source categories unrelated to the proposed project are not discussed in this regulatory review.

4.3.1 40 CFR 60 Subpart A – General Provisions

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

4.3.2 40 CFR 60 Subpart D – Fossil Fuel-Fired Steam Generators > 250 MMBtu/hr

NSPS Subpart D, *Standards of Performance for Fossil-Fuel-Fired Steam Generators*, applies to fossil fuel-fired steam generating units with heat input capacities greater than 250 MMBtu/hr that have been constructed or modified since August 17, 1971.[15] The rule defines a fossil fuel-fired steam generating unit as:[16]

> *A furnace or boiler used in the process of burning fossil fuel for the purpose of producing steam by heat transfer.*

The combustion turbines and duct burners will not be subject to NSPS Subpart D. The combustion turbines are not classified as steam generating units under this NSPS. The duct burners each have a rated heat input capacity of 95 MMBtu/hr, which is below the applicability threshold of concern for the rule.

4.3.3 40 CFR 60 Subpart Da – Electric Utility Steam Generating Units

NSPS Subpart Da, *Standards of Performance for Electric Utility Steam Generating Units*, provides standards of performance for electric utility steam generating units with heat input capacities greater than 250 MMBtu/hr of fossil fuel (alone or in combination with any other fuel) for which construction, modification, or reconstruction commenced after September 18, 1978.[17] The term "steam generating unit" is defined under this regulation as:[18]

> *For units constructed, reconstructed, or modified after May 3, 2011, steam generating unit means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines…*

The combustion turbines and duct burners will not be subject to NSPS Subpart Da, because:

- ► The combustion turbines are not classified as steam generating units under this regulation;
- ► The duct burners do not have a heat input capacity of greater than 250 MMBtu/hr each; and

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15 40 CFR 60.40

16 40 CFR 60.41

17 40 CFR 60.40Da(a)

18 40 CFR 60.41Da

- Heat recovery steam generators and duct burners that are subject to NSPS Subpart KKKK are not subject to NSPS Subpart Da. Following the proposed modifications, OPC Chattahoochee's combustion turbines and HRSG with duct burners will be NSPS Subpart KKKK affected facilities.[19]

4.3.4 40 CFR 60 Subpart Db – Steam Generating Units > 100 MMBtu/hr

NSPS Subpart Db, *Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units*, provides standards of performance for steam generating units with capacities greater than 100 MMBtu/hr for which construction, modification, or reconstruction commenced after June 19, 1984.[20] The term "steam generating unit" is defined under this regulation as:[21]

> *Steam generating unit means a device that combusts any fuel or byproduct/waste and produces steam or heats water or heats any heat transfer medium. This term includes any municipal-type solid waste incinerator with a heat recovery steam generating unit or any steam generating unit that combusts fuel and is part of a cogeneration system or a combined cycle system. This term does not include process heaters as they are defined in this subpart.*

The combustion turbines and duct burners will not be subject to NSPS Subpart Db, because:

- The combustion turbines are not classified as steam generating units under this regulation;
- The duct burners do not have a heat input capacity of greater than 100 MMBtu/hr each; and
- Heat recovery steam generators and duct burners that are subject to NSPS Subpart KKKK are not subject to NSPS Subpart Db. Following the proposed modifications, OPC Chattahoochee's combustion turbines and HRSG with duct burners will be NSPS Subpart KKKK affected facilities.[22]

4.3.5 40 CFR 60 Subpart Dc – Small Steam Generating Units

NSPS Subpart Dc, *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units*, provides standards of performance for each steam generating unit for which construction, modification, or reconstruction commenced after June 9, 1989.[23] The term "steam generating unit" is defined under this regulation as:[24]

> *Steam generating unit means a device that combusts any fuel and produces steam or heats water or heats any heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart.*

The duct burners at OPC Chattahoochee are currently subject to NSPS Subpart Dc, as they each have a rated heat input capacity of 95 MMBtu/hr and were each constructed after 1989. However, neither the combustion turbines nor the duct burners will be subject to NSPS Subpart Dc after the completion of the proposed project, because:

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[19] 40 CFR 60.40Da(e)

[20] 40 CFR 60.40b(a)

[21] 40 CFR 60.41b

[22] 40 CFR 60.40b(i)

[23] 40 CFR 60.40c(a)

[24] 40 CFR 60.41c

- The combustion turbines do not meet the definition of steam generating units; and
- Heat recovery steam generator and duct burner units that are subject to NSPS Subpart KKKK are not subject to NSPS Subpart Dc. Following the proposed modifications, OPC Chattahoochee's combustion turbines and HRSG with duct burners will be NSPS Subpart KKKK affected facilities.[25]

4.3.6 40 CFR 60 Subpart GG – Stationary Gas Turbines

NSPS Subpart GG, *Standards of Performance for Stationary Gas Turbines*, applies to all stationary gas turbines with a heat input at peak load equal to or greater than 10 MMBtu/hr, based on the lower heating value of the fuel fired, that are constructed, modified, or reconstructed after October 3, 1977.[26]

Presently, the combustion turbines at OPC Chattahoochee are subject to NSPS Subpart GG. However, upon completion of the proposed modifications, the combustion turbine systems will be subject to the more recently promulgated standards for Stationary Combustion Turbines under NSPS Subpart KKKK. Pursuant to 40 CFR 60.4305(b) (NSPS Subpart KKKK), stationary combustion turbines regulated under NSPS Subpart KKKK are exempt from the requirements of NSPS Subpart GG. Therefore, NSPS Subpart GG will no longer apply to the OPC Chattahoochee combustion turbines following the proposed project.

4.3.7 40 CFR 60 Subpart KKKK – Stationary Combustion Turbines

NSPS Subpart KKKK, *Standards of Performance for Stationary Combustion Turbines*, applies to all stationary combustion turbines with a heat input at peak load equal to or greater than 10 MMBtu/hr, based on the lower heating value of the fuel fired, and were constructed, reconstructed, or modified after February 18, 2005.[27] OPC Chattahoochee consists of two natural gas-fired turbines, each of which was constructed prior to 2005 and has a heat input capacity exceeding 10 MMBtu/hr. To determine if the turbines will be subject to NSPS Subpart KKKK following the proposed project, it is necessary to ascertain if a "modification" per the NSPS has occurred. For purposes of NSPS, a modification is defined as:[28]

> *...any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted.*

More specifically, for an existing electric utility steam generating unit:[29]

> *No physical change, or change in the method of operation, at an existing electric utility steam generating unit shall be treated as a modification...provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the 5 years prior to the change.*

The CT Upgrades Project will result in an increase in the hourly heat input capacity for the combustion turbines. OPC has presumed that an increase in the amount of an air pollutant regulated by NSPS Subpart

[25] 40 CFR 60.40c(e)

[26] 40 CFR 60.330

[27] 40 CFR 60.4305(a), (b)

[28] 40 CFR 60.2

[29] 40 CFR 60.14(h)

KKKK could occur on a short-term (hourly) basis. Therefore, once the proposed modifications are complete, the OPC Chattahoochee combustion turbines will be subject to NSPS Subpart KKKK. Pursuant to 40 CFR 60.4305(a), the associated HRSG and duct burners will also be subject to NSPS Subpart KKKK.

Per 40 CFR 60.4305(b), stationary combustion turbines regulated under NSPS Subpart KKKK are exempt from the requirements of NSPS Subpart GG. HRSGs and duct burners regulated under NSPS Subpart KKKK are also exempt from the requirements of NSPS Subparts Da, Db, and Dc.

The following sections detail the applicable requirements as a result of NSPS Subpart KKKK applicability.

4.3.7.1 Emission Limits

Per Table 1 to NSPS Subpart KKKK, a modified combustion turbine is subject to NO_X emission limits depending on the type of fuel combusted and the heat input at peak load. For modified combustion turbines firing natural gas with a rating greater than 850 MMBtu/hr, the NO_X emission standard is 15 ppm at 15% O_2 or 0.43 lb/MWh useful output. NSPS Subpart KKKK also includes, for units greater than 30 MW output, a NO_X limit of 96 ppm at 15% O_2 or 4.7 lb/MWh useful output for turbine operation at ambient temperatures less than 0°F and turbine operation at loads less than 75% of peak load.[30] Compliance with the NO_X emission limit is determined on a 30 unit operating day rolling average basis.[31] As the combustion turbines and duct burners are presently subject to a NO_X limitation of 3.0 ppm at 15% O_2, 4-hour average per Condition 3.3.6.a of the existing Title V operating permit, the new NSPS Subpart KKKK NO_X limitations will be subsumed by the facility's NO_X BACT limitation.

SO_2 emissions from combustion turbines located in the continental U.S. are limited to 0.9 lb/MWh gross output (or 110 ng/J), or the units must not burn any fuel with total potential sulfur emissions in excess of 0.060 lb SO_2/MMBtu heat input.[32]

4.3.7.2 Monitoring and Testing Requirements

Pursuant to 40 CFR 60.4333(a), the combustion turbines, air pollution control equipment, and monitoring equipment will be maintained in a manner that is consistent with good air pollution control practices for minimizing emissions. This requirement applies at all times including during startup, shutdown, and malfunction.

4.3.7.2.1 NO_X Compliance Demonstration Requirements

The combustion turbine systems presently employ a continuous emission monitoring system (CEMS) for NO_X per the requirements of the Acid Rain Program (ARP), promulgated in 40 CFR Part 75. Pursuant to 40 CFR 60.4340(b)(1) and 40 CFR 60.4345, OPC Chattahoochee can rely on its existing NO_X CEMS installed and certified according to 40 CFR Part 75 Appendix A to demonstrate ongoing compliance with the NSPS Subpart KKKK NO_X emission limits. Sources demonstrating compliance with the NO_X emission limit via CEMS are not subject to the requirement to perform initial and annual NO_X stack tests.[33] Initial compliance with the NO_X emission limit will be demonstrated by comparing the arithmetic average of the NO_X emissions

[30] Table 1 to Subpart KKKK of Part 60

[31] 40 CFR 60.4350(h), 40 CFR 60.4380(b)(1)

[32] 40 CFR 60.4330(a)(1) or (a)(2), respectively

[33] 40 CFR 60.4340(b), 40 CFR 60.4405

measurements taken during the initial relative accuracy test audit (RATA) required pursuant to 40 CFR 60.4405 to the NO_X emission limit under this subpart.[34]

4.3.7.2.2 SO_2 Compliance Demonstration Requirements

For compliance with the SO_2 emission limit, facilities are required to perform regular determinations of the total sulfur content of the combustion fuel and to conduct initial and annual compliance demonstrations. The total sulfur content of gaseous fuel combusted in the combustion turbine must be determined and recorded once per operating day or using a custom schedule as approved by EPD;[35] however, OPC elects to opt out of this provision of the rule by using a fuel that is demonstrated not to exceed potential sulfur emissions of 0.060 lb/MMBtu SO_2.[36] This demonstration can be made using one of the following methods:

- By using a purchase contract specifying that the fuel sulfur content for the natural gas is less than or equal to 20 grains of sulfur per 100 standard cubic feet and results in potential emissions not exceeding 0.060 lb/MMBtu; or
- By using representative fuel sampling data meeting the requirements of 40 CFR 75, Appendix D, Sections 2.3.1.4 or 2.3.2.4 which show that the sulfur content of the fuel does not exceed 0.060 lb SO_2/MMBtu heat input.

OPC is currently required to monitor the sulfur content of the natural gas burned in the combustion turbines and duct burners through submittal of a semiannual analysis of the gas by the supplier or the facility to demonstrate that the sulfur content does not exceed its excursion threshold of 0.27 grains per 100 standard cubic feet.[37] This sulfur content analysis by the supplier or OPC satisfies the sulfur content demonstration requirement of 40 CFR 60.4365. Therefore, continued compliance with this existing permit condition will guarantee compliance with the NSPS Subpart KKKK sulfur monitoring requirement.

4.3.7.3 Initial Notification

Per 40 CFR 60.7(a)(4), this permit application serves as the required notification for any physical or operational change to an existing facility which qualifies as an NSPS modification.

4.3.8 40 CFR 60 Subpart TTTT – Greenhouse Gas Emissions for Electric Generating Units

NSPS Subpart TTTT, *Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units,* applies to any fossil fuel fired steam generating unit, Integrated Gasification Combined Cycle (IGCC) unit, or stationary combustion turbine constructed after January 8, 2014 or reconstructed after June 18, 2014, and to any steam generating unit or IGCC modified after June 18, 2014, provided that unit has a base load rating greater than 250 MMBtu/hr and serves a generator capable of selling greater than 25 MW of electricity to the grid.[38] The existing CCCT generating units for OPC Chattahoochee each have peak heat inputs greater than 250 MMBtu/hr and serve a generator greater than 25 MW. Therefore, the CCCT generating units (including the duct burners) could potentially be subject to the provisions of NSPS TTTT.

[34] 40 CFR 60.4405(c)

[35] 40 CFR 60.4370(b) and (c)

[36] 40 CFR 60.4365

[37] Permit No. 4911-149-0006-V-05-0, Conditions 5.2.3, 5.2.4, 6.1.7.c.i.

[38] 40 CFR 60.5509(a)

With respect to stationary combustion turbines, NSPS Subpart TTTT applies only to units that commenced construction or reconstruction after the specified dates, not modification. "Reconstruction" is defined under 40 CFR 60 Subpart A as the replacement of components of an existing affected facility such that the fixed capital cost of the new components exceeds 50% of the fixed capital cost that would be required to construct a comparable, entirely new affected facility that is technologically and economically capable of complying with the applicable standards.[39] The total cost of the TPU1 and LLTD upgrades is well under 50% of the cost for two comparable new units. As the combustion turbines at OPC Chattahoochee are existing units and the proposed project does not meet the reconstruction definition, the modifications to the turbine systems will not trigger applicability of NSPS Subpart TTTT requirements.[40]

4.3.9 Non-Applicability of All Other NSPS

NSPS are developed for particular industrial source categories. The applicability of a particular NSPS to the proposed project can be readily ascertained based on the industrial source category covered. All other NSPS, besides Subpart A, are categorically not applicable to the proposed project.

4.4 National Emission Standards for Hazardous Air Pollutants

NESHAP, located in 40 CFR 61 and 40 CFR 63, have been promulgated for source categories that emit HAP to the atmosphere. A facility that is a major source of HAP is defined as having potential emissions of greater than 25 tpy of total HAP and/or 10 tpy of individual HAP. Facilities with a potential to emit HAP at an amount less than that which is defined as a major source are otherwise considered an area source. Under 40 CFR 63, the NESHAP allowable emissions limits are most often established on the basis of a maximum achievable control technology (MACT) determination for the particular major source. These NESHAP apply to sources in specifically regulated industrial source categories (Clean Air Act Section 112(d)) or on a case-by-case basis (Section 112(g)) for facilities not regulated as a specific industrial source type.

Although emissions from OPC Chattahoochee alone do not exceed the HAP major source thresholds, EPD considers OPC Chattahoochee to be part of one Title V site that includes other neighboring utility units, which are operated by other entities.[41] The overall Title V site is a major source of HAP, and will remain so following the proposed project. The determination of applicability to NESHAP requirements for the proposed project is detailed in the following sections. Rules that are specific to certain source categories unrelated to the proposed project are not discussed in this regulatory review.

4.4.1 40 CFR 63 Subpart A – General Provisions

NESHAP Subpart A, *General Provisions*, contains national emission standards for HAP defined in Section 112(b) of the Clean Air Act. All affected sources, which are subject to another NESHAP in 40 CFR 63, are subject to the general provisions of NESHAP Subpart A, unless specifically excluded by the source-specific NESHAP.

4.4.2 40 CFR 63 Subpart YYYY – Combustion Turbines

NESHAP Subpart YYYY, *NESHAP for Stationary Combustion Turbines*, establishes emission and operating limitations for stationary combustion turbines at major sources of HAP. A stationary combustion turbine is

[39] 40 CFR 60.15

[40] 40 CFR 60.5509(a)

[41] See Section 1.1 of OPC Chattahoochee's Title V operating permit for additional information on EPD's site determination.

defined as "existing" if the affected source was constructed or reconstructed prior to January 14, 2003. The two combustion turbines at OPC Chattahoochee were constructed prior to that applicability date.

Reconstruction for the purposes of the NESHAP in 40 CFR 63 is defined as:[42]

> *The replacement of components of an affected or a previously nonaffected source to such an extent that:*
> *(1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable new source;*

As discussed in Section 4.3.8, the proposed project will not exceed more than 50% of the cost of two comparable new combustion turbines. Therefore, the combustion turbines at OPC Chattahoochee will remain existing sources under Subpart YYYY following the proposed project.

Pursuant to 40 CFR 63.6090(b)(4),

> *Existing stationary combustion turbines in all subcategories do not have to meet the requirements of this subpart and of subpart A of this part. No initial notification is necessary for any existing stationary combustion turbine, even if a new or reconstructed turbine in the same category would require an initial notification.*

Therefore, while NESHAP Subpart YYYY does apply to the facility combustion turbines, the turbines do not have to meet the requirements of the subpart, including the requirement for an initial notification.

4.4.3 40 CFR 63 Subpart DDDDD – Industrial, Commercial, and Institutional Boilers and Process Heaters

NESHAP Subpart DDDDD, *National Emissions Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters* (Major Source Boiler MACT) regulates boilers and process heaters at major sources of HAP. Pursuant to 40 CFR 63.7575:

> *Boiler means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in §241.3 of this chapter, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers are excluded from this definition.*
>
> *Waste heat boiler means a device that recovers normally unused energy (i.e., hot exhaust gas) and converts it to usable heat. Waste heat boilers are also referred to as heat recovery steam generators. Waste heat boilers are heat exchangers generating steam from incoming hot exhaust gas from an industrial (e.g., thermal oxidizer, kiln, furnace) or power (e.g., combustion turbine, engine) equipment. Duct burners are sometimes used to increase the temperature of the incoming hot exhaust gas.*

[42] 40 CFR 63.2

The rule defines a "boiler" as an enclosed device using controlled combustion to recover thermal energy in the form of steam and/or hot water. The combustion turbines at the OPC Chattahoochee use the thermal energy of natural gas directly through combustion and without use of steam or hot water. Therefore, they do not fall within the definition of a "boiler" and are not subject to the rule.

As the definition of "boiler" also specifically excludes "waste heat boilers," the heat recovery steam generators and duct burners at the OPC Chattahoochee are not subject to NESHAP Subpart DDDDD. Therefore, NESHAP Subpart DDDDD does not apply to the facility or the proposed project.

4.4.4 40 CFR 63 Subpart UUUUU – Electric Utility Steam Generating Units

NESHAP Subpart UUUUU, *NESHAP for Electric Utility Steam Generating Units*, applies to electric utility steam generating units (EGUs) that combust coal or oil.[43] As the OPC Chattahoochee combustion turbines and duct burners combust natural gas only, NESHAP Subpart UUUUU does not apply to the facility or the proposed project.

4.4.5 40 CFR 63 Subpart JJJJJJ – Industrial, Commercial, and Institutional Boilers at Area Sources

NESHAP Subpart JJJJJJ, *NESHAP for Industrial, Commercial, and Institutional Boilers Area Sources* (Area Source Boiler MACT) regulates boilers at area sources of HAP.[44] As the Title V site where OPC Chattahoochee is located is a major source of HAP, NESHAP Subpart JJJJJJ does not apply to the facility or the proposed project. Further, even if the facility were classified as an area source of HAP, the regulation still would not apply, because the combustion turbines do not meet the definition of a boiler[45], waste heat boilers (including the heat recovery steam generators and duct burners) are excluded from the definition of a boiler[46], and gas-fired units are exempt from Subpart JJJJJJ[47].

4.4.6 Non-Applicability of All Other NESHAP

NESHAP are developed for particular industrial source categories. The applicability of a particular NESHAP to the proposed project can be readily ascertained based on the industrial source category covered. All other NESHAP are categorically not applicable to the proposed project.

4.5 Compliance Assurance Monitoring

Under 40 CFR 64, Compliance Assurance Monitoring (CAM), facilities are required to prepare and submit monitoring plans for certain emissions units as part of Title V operating permit applications. The CAM plans are intended to provide an on-going and reasonable assurance of compliance with emission limits for units equipped with air pollution control devices. Pursuant to 40 CFR 64.2(b)(1)(vi), emission limits for which a Part 70 Permit specifies a continuous compliance determination method are exempt from CAM requirements. Since Condition 5.2.1 of OPC Chattahoochee's permit requires the operation of NO_X and CO CEMS for both CCCT stacks, EPD has previously determined that the emission units are exempt from CAM. Therefore, no CAM documentation has been included within this permit application.

[43] 40 CFR 63.9980

[44] 40 CFR 63.11193

[45] 40 CFR 63.11237

[46] Ibid.

[47] 40 CFR 63.11195(e)

4.6 Risk Management Plan

Subpart B of 40 CFR 68 outlines requirements for Risk Management Plans (RMP) pursuant to Section 112(r) of the Clean Air Act. Applicability of the subpart is determined based on the type and quantity of chemicals stored at a facility. OPC Chattahoochee operates a tank storing aqueous ammonia (greater than 20% concentration) in amounts exceeding the applicability threshold listed in 40 CFR 68 Subpart F of 20,000 pounds. Therefore, the facility is subject to and in compliance with the RMP Program 1 requirements for its aqueous ammonia. The proposed project will not involve changes to the facility's ammonia storage tank or the concentration of ammonia stored and, therefore, will not impact the facility's requirements under 40 CFR 68. OPC Chattahoochee will continue to comply with the applicable provisions of this regulation.

4.7 Stratospheric Ozone Protection

The requirements originating from Title VI of the Clean Air Act, entitled *Protection of Stratospheric Ozone*, are contained in 40 CFR 82. Subparts A through E and Subparts G and H of 40 CFR 82 are not applicable to OPC Chattahoochee. 40 CFR 82 Subpart F, *Recycling and Emissions Reduction*, potentially applies if the facility operates, maintains, repairs, services, or disposes of appliances that utilize Class I, Class II, or non-exempt substitute refrigerants.[48] Subpart F generally requires persons completing the repairs, service, or disposal to be properly certified. The facility utilizes certified technicians to perform repairs, service, and disposal of regulated refrigerants from such equipment (air conditioners, refrigerators, etc.). OPC Chattahoochee will continue to comply with 40 CFR 82 Subpart F.

4.8 Clean Air Markets Regulations

Starting with the Acid Rain Program (ARP) mandated by the 1990 Clean Air Act Amendments, U.S. EPA has developed several market-based "cap and trade" regulatory programs. All market-based regulatory programs are overseen by U.S. EPA's Clean Air Markets Divisions (CAMD) and are referred to as CAMD regulations. The programs that are potentially applicable to OPC Chattahoochee are:

- Acid Rain Program (ARP) – 1990 - ongoing
- Clean Air Interstate Rule (CAIR) – 2009 - 2014
- Cross-State Air Pollution Rule (CSAPR) – 2015 (ongoing)

4.8.1 Acid Rain Program

In order to reduce acid rain in the United States and Canada, Title IV (40 CFR 72 *et seq.*) of the Clean Air Act Amendments of 1990 established the ARP to substantially reduce SO_2 and NO_X emissions from electric utility plants. Affected units are specifically listed in Tables 1 and 2 of 40 CFR 73.10 under Phase I and Phase II of the program. Upon Phase III implementation, the ARP in general applies to fossil fuel-fired combustion sources that drive generators for the purposes of generating electricity for sale. The turbines at OPC Chattahoochee are utility units subject to the ARP. The facility is subject to the requirements of 40 CFR 72 (permits), 40 CFR 73 (SO_2), and 40 CFR 75 (monitoring) but is not subject to the NO_X provisions (40 CFR 76) of the ARP regulations because the turbines do not have the capability to burn coal.

Under 40 CFR 75 of the ARP, OPC Chattahoochee is required to operate a NO_X CEMS for each unit to monitor the NO_X emission rate (lb/MMBtu) and to determine SO_2 and CO_2 mass emissions (tons) following the procedures in Appendices D and G, respectively. Further, the ARP requires the facility to possess SO_2 allowances for each ton of SO_2 emitted. The ARP also requires initial certification of required monitoring

[48] 40 CFR 82.150

systems within 90 days of commencement of commercial operation and the submittal of quarterly reports and an annual compliance certification. The ARP requirements are outlined in Section 7.9 and Attachment D of the Title V Permit No. 4911-149-0006-V-05-0. The proposed project will not alter any applicable requirements or compliance options of ARP to the OPC Chattahoochee operations. The facility will continue to maintain sufficient allowances under ARP for its operations.

4.8.2 Clean Air Interstate Rule / Cross-State Air Pollution Rule

The CAIR, 40 CFR 96, called for reductions in SO_2 and NO_X emissions by utilizing an emissions trading program. More broadly, 40 CFR 96 also includes a forerunner to CAIR, the NO_X SIP Call / NO_X Budget program, and the name of 40 CFR 96 (NO_X Budget Trading Program for State Implementation Plans) still reflects the origins in regulating only NO_X.

The CSAPR was developed to require affected states to reduce emissions from power plants that contribute to ozone and/or particulate matter emissions.[49] Following legal challenges, CSAPR replaced CAIR[50] and began Phase 1 implementation on January 1, 2015 for annual programs and May 1, 2015 for the ozone season program. Phase 2 implementation began on January 1, 2017 for annual programs and May 1, 2017 for ozone season programs.

Therefore, since CSAPR is currently effective, potential applicability is evaluated against the CSAPR Program and not CAIR. CSAPR applicability is found in 40 CFR 97.404 and definitions in 40 CFR 97.402 and implemented via Georgia EPD through GRAQC 391-3-1-.02(12) – (13). Georgia is subject to CSAPR programs for both fine particles (SO_2 and annual NO_X) and ozone (ozone season NO_X).[51]

CSAPR applicability is similar but distinct from ARP, with applicability criteria and definitions per 40 CFR 97.402.[52] In general, CSAPR regulates fossil-fuel-fired boilers and combustion turbines serving, on any day starting November 15, 1990 or later, an electrical generator with a nameplate capacity exceeding 25 MWe and producing power for sale. OPC Chattahoochee's CCCTs are affected sources under this regulation, and the proposed project will not alter any applicable requirements or compliance options of CSAPR to the facility's operations. OPC Chattahoochee will continue to maintain sufficient allowances under CSAPR for its operations.

4.9 State Regulatory Requirements

In addition to federal air regulations, GRAQC Chapter 393-3-1 establishes regulations applicable at the emission unit level (source specific) and at the facility level.[53] This section reviews the source specific requirements for the proposed project and does not detail generally applicable requirements such as payment of permit fees.

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49 http://www.epa.gov/airtransport/

50 EME Homer City Generation, L.P. v. U.S. EPA. U.S. Court of Appeals for the District of Columbia Circuit, No. 11-1302, decided October 23, 2014 (lifting stay of CSAPR).

51 https://www.epa.gov/airmarkets/map-states-covered-csapr

52 CSAPR applicability and definitions are repeated in four separate subparts of 40 CFR 97, but each has identical definitions and applicability requirements. Subpart AAAAA (5A), which is for the NO_X Annual program, is used in this discussion.

53 Current through rules and regulations filed through May 8, 2020. http://rules.sos.ga.gov/gac/391-3-1

4.9.1 GRAQC 391-3-1-.02(2)(b) – Visible Emissions

Rule (b) limits the visible emissions from any emissions source not subject to some other visible emissions limitation under GRAQC 391-3-1-.02 to 40% opacity. Visible emissions testing may be required at the discretion of the Director. The combustion turbines at OPC Chattahoochee are subject to this regulation. The duct burners are subject to more stringent visible emissions standards through Rule 391-3-1-.02(2)(d) and are, therefore, not subject to Rule (b).

The combustion turbines fire pipeline-quality natural gas with emissions exhibiting minimal opacity; the firing of clean fuels in conjunction with proper operation ensures compliance with this rule. No applicable requirements per Rule (b) will be altered as a result of the proposed project. The opacity limitation for the combustion turbines is subsumed by the more stringent opacity limitation given in Condition 3.3.6.e of the current operating permit.

4.9.2 GRAQC 391-3-1-.02(2)(d) – Fuel-Burning Equipment

Rule (d) limits the PM emissions, visible emissions, and NO_X emissions from fuel-burning equipment. The standards are applied based on installation date, the heat input capacity of the unit, and the fuel(s) combusted. The GRAQC define "fuel-burning equipment" as follows:[54]

> *"Fuel-burning equipment" means equipment the primary purpose of which is the production of thermal energy from the combustion of any fuel. Such equipment is generally that used for, but not limited to, heating water, generating or super heating steam, heating air as in warm air furnaces, furnishing process heat indirectly, through transfer by fluids or transmissions through process vessel walls.*

The combustion turbines are used for the generation of electric power, not the production of thermal energy. Therefore, they do not meet the definition of fuel burning equipment. The duct burners do, however, meet this definition and are therefore subject to this rule.

The duct burners were installed or modified after January 1, 1972, making them subject to the PM standards for new units under 391-3-1-.02(2)(d)2. Since each duct burner has a heat input capacity of between 10 and 250 MMBtu/hr, each duct burner has a PM emission limit based on the following equation, where P is the PM emission limit (lb/MMBtu) and R is the unit's heat input capacity (MMBtu/hr):[55]

$$P = 0.5\left(\frac{10}{R}\right)^{0.5}$$

The PM emission limit will not change once the proposed modifications are complete. The PM emission limits for the duct burners are subsumed by the more stringent PM emission limit found in Condition 3.3.6.c of the current operating permit.

All fuel-burning equipment constructed after January 1, 1972 is subject to a visible emissions limit of 20% except for one six minute period per hour of not more than 27% opacity. This limit applies to the duct burners.[56] The opacity limit will not change once the propose modifications are complete. The opacity limitation for the duct burners is subsumed by the more stringent opacity limitation given in Condition 3.3.6.e of the current operating permit.

[54] GRAQC 391-3-1-.01(cc)

[55] GRAQC 391-3-1-.02(2)(d)2(ii)

[56] GRAQC 391-3-1-.02(2)(d)3

4.9.3 GRAQC 391-3-1-.02(2)(e) – Particulate Emissions from Manufacturing Processes

Rule (e), commonly known as the process weight rule, establishes PM limits where not elsewhere specified. As the duct burners are fuel-burning equipment, they are subject to a separate particulate limit per Rule (d). Combustion turbines are not subject to Rule (d) and historically have not been regulated by Rule (e). Therefore, the combustion turbines and duct burners at OPC Chattahoochee are not subject to this regulation.

4.9.4 GRAQC 391-3-1-.02(2)(g) – Sulfur Dioxide

Rule (g) limits the maximum sulfur content of any fuel combusted in a fuel-burning source, based on the heat input capacity. As this rule applies to fuel-burning sources, not "fuel-burning equipment," this regulation presently applies to both the combustion turbines and the duct burners. For the duct burners, which have heat input capacities below 100 MMBtu/hr, the fuel sulfur content is limited to not more than 2.5% by weight.[57] For the combustion turbines, which have heat input capacities greater than 100 MMBtu/hr, the fuel sulfur content is limited to not more than 3% by weight.[58] The proposed project does not alter the applicable requirements of Rule (g), and OPC Chattahoochee will continue to comply with Rule (g). This limit is subsumed by the more stringent fuel sulfur limit under NSPS Subpart KKKK.

4.9.5 GRAQC 391-3-1-.02(2)(n) – Fugitive Dust

Rule (n) requires facilities to take reasonable precautions to prevent fugitive dust from becoming airborne. OPC Chattahoochee will continue to take the appropriate precautions to prevent fugitive dust from becoming airborne for any applicable equipment.

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

Rule (tt) limits VOC emissions from facilities that are located in or near the original Atlanta 1-hour ozone nonattainment area. OPC Chattahoochee is not located within the geographic area covered by this rule and is, therefore, not subject to this regulation.[59]

4.9.7 GRAQC 391-3-1-.02(2)(uu) – Visibility Protection

Rule (uu) requires EPD to provide an analysis of a proposed major source or a major modification to an existing source's anticipated impact on visibility in any federal Class I area to the appropriate Federal Land Manager (FLM). The proposed project does not represent a major modification as defined in GRAQC 391-3-1-.02(2)(uu)6, and therefore is not subject to this regulation.

4.9.8 GRAQC 391-3-1-.02(2)(jjj) – NO_X from Electric Utility Steam Generating Units

Rule (jjj) limits NO_X emissions from coal-fired electric utility steam generating units with heat input capacity greater than 250 MMBtu/hr located in or near the original Atlanta 1-hour ozone nonattainment area. OPC Chattahoochee only combusts natural gas and is therefore not subject to Rule(jjj).

[57] GRAQC 391-3-1-.02(2)(g)2

[58] GRAQC 391-3-1-.02(2)(g)2

[59] GRAQC 391-3-1-.02(2)(tt)3

4.9.9 GRAQC 391-3-1-.02(2)(lll) – NO_X from Fuel-Burning Equipment

Rule (lll) limits the NO_X emissions from fuel-burning equipment with a maximum design heat input capacity between 10 and 250 MMBtu/hr that was installed or modified on or after May 1, 1999. While the duct burners are fuel-burning equipment of the correct size range, Rule (lll) specifically exempts duct burners associated with combined cycle gas turbines from regulation.[60] Therefore, Rule (lll) does not apply to OPC Chattahoochee.

4.9.10 GRAQC 391-3-1-.02(2)(mmm) – NO_X Emissions from Stationary Gas Turbines and Stationary Engines used to Generate Electricity

Rule (mmm) restricts NO_X emissions from small combustion turbines located in or near the Atlanta nonattainment area that are used to generate electricity. The combustion turbines at OPC Chattahoochee exceed 25 MWe capacity, and are, therefore, not subject to Rule (mmm).[61]

4.9.11 GRAQC 391-3-1-.02(2)(nnn) – NO_X Emissions from Large Stationary Gas Turbines

Rule (nnn) restricts NO_X emissions from sources located in or near the original Atlanta 1-hour ozone nonattainment area. Specifically, these regulations limit NO_X emissions from stationary gas turbines with nameplate capacity greater than 25 MWe used to generate electricity. OPC Chattahoochee is located in Heard County, which is one of the listed counties regulated under this rule.[62]

Affected sources permitted after April 1, 2000, such as OPC Chattahoochee's combustion turbines, are generally subject to a NO_X emissions limit of 6 ppmvd at 15% oxygen. However, Part 4 of Rule (nnn) states that the 6 ppmvd emission limit does not apply to individual sources subject to 391-3-1-.03(8)(c)15 (state NNSR requirements). Both of OPC Chattahoochee's combustion turbines were subject to and underwent NO_X NNSR permitting under 391-3-1-.03(8)(c)15, including a control technology review and the use of sufficient NO_X emissions offsets, prior to the construction. As such, the NO_X emission limit of Rule (nnn) does not apply.

4.9.12 GRAQC 391-3-1-.02(2)(rrr) – NO_X from Small Fuel-Burning Equipment

Rule (rrr) specifies requirements for fuel-burning equipment with capacities of less than 10 MMBtu/hr that are located in or near the original Atlanta 1-hour ozone nonattainment area. OPC Chattahoochee does not operate any fuel-burning equipment with a heat input capacity less than 10 MMBtu/hr and is, therefore, not subject to this regulation.

4.9.13 GRAQC 391-3-1-.02(2)(sss) – Multipollutant Control for Electric Utility Steam Generating Units

Rule (sss) applies to certain large electric utility steam generating units listed within the rule. OPC Chattahoochee is not subject to this regulation, because none of its units are listed in the regulation.

[60] GRAQC 391-3-1-.02(2)(lll)6(ii)

[61] GRAQC 391-3-1-.02(2)(mmm)1

[62] GRAQC 391-3-1-.02(2)(nnn)6

4.9.14 GRAQC 391-3-1-.02(2)(uuu) – SO_2 Emissions from Electric Utility Steam Generating Units

Rule (uuu) applies to certain large electric utility steam generating units listed within the rule. OPC Chattahoochee is not subject to this regulation, because none of its units are listed in the regulation.

4.9.15 GRAQC 391-3-1-.03(1) – Construction (SIP) Permitting

The proposed project will require physical modifications to complete the proposed upgrades. Emissions increases associated with the proposed project are above the *de minimis* construction permitting thresholds specified in GRAQC 391-3-1-.03(6)(i). Therefore, a construction permit application is necessary, and the appropriate forms are included in Appendix D. As noted in Question 7 on the SIP Air Permit Application in Appendix D, OPC has not relied on the exemption in Georgia Rule 391-3-1-.03(6)(i)(3) for any previous modifications to OPC Chattahoochee.

4.9.16 GRAQC 391-3-1-.03(10) – Title V Operating Permits

The potential emissions of certain pollutants exceed the major source thresholds established by Georgia's Title V operating permit program. Therefore, OPC Chattahoochee is a Title V major source. The facility currently operates under Permit No. 4911-149-0006-V-05-0. This application represents a significant modification to the existing Title V operating permit; accordingly a GEOS application has been submitted to address Title V related permitting requirements.

4.9.17 Incorporation of Federal Regulations by Reference

The following federal regulations are incorporated in the GRAQC by reference and were addressed previously in the application:

- GRAQC 391-3-1-.02(7) – PSD
- GRAQC 391-3-1-.02(8) – NSPS
- GRAQC 391-3-1-.02(9) – NESHAP
- GRAQC 391-3-1-.02(10) – Chemical Accident Prevention
- GRAQC 391-3-1-.02(11) – CAM
- GRAQC 391-3-1-.02(12) – CSAPR for Annual NO_X
- GRAQC 391-3-1-.02(13) – CSAPR for Annual SO_2
- GRAQC 391-3-1-.02(14) – CSAPR for Ozone Season NO_X
- GRAQC 391-3-1-.03(10) – Title V Operating Permits
- GRAQC 391-3-1-.13 – ARP

4.9.18 Non-Applicability of Other GRAQC

A thorough examination of the GRAQC applicability to the proposed project reveals many GRAQC that do not currently apply, will not apply once the proposed modifications are complete, and do not impose additional requirements on operations. Such GRAQC rules include those specific to a particular type of industrial operation which is not and will not be performed at OPC Chattahoochee or is not impacted by the proposed project.

5. TOXICS IMPACT ANALYSIS

EPD regulates the TAP emissions through a program approved under the provisions of GRAQC 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 EPD's review of toxic air pollutant emissions as part of air permit reviews are contained in EPD's *Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions (Guideline)*.[63]

5.1 Derivation of Facility-Wide Emission Rates

According to the *Guideline*, dispersion modeling should be completed for each potentially toxic pollutant which has quantifiable emission increases and for which the facility-wide potential emissions are above the Minimum Emission Rate (MER) provided in Appendix A of the *Guideline*. The *Guideline* infers that a pollutant is identified as a toxic pollutant if any of the following toxicity-determined values have been established for that pollutant:

- EPA Integrated Risk Information System (IRIS) reference concentration (RfC) or unit risk;
- Occupational Safety and Health Administration (OSHA) Permissible Exposure Limits (PEL);
- American Conference of Governmental Industrial Hygienists (ACGIH) Threshold Limit Values (TLV);
- National Institute for Occupational Safety and Health (NIOSH) Recommended Exposure Limits (REL);
- Lethal Dose – 50% (LD50) Standards; and
- The *Guideline* specifies that the resources should be referenced in the priority schedule listed above to determine long-term and short-term acceptable ambient concentrations (AACs) based on the exposure limits that are provided.

Per the *Guideline* under "Procedures for Demonstrating Compliance with AAC," the general procedure for determination of TAPs impact is a simple comparative method:

- When the facility-wide emission rate for a given TAP is below its respective MER established in the table in Appendix A, no further analysis is required for that TAP.
- When the facility-wide emission rate for a given TAP is above its respective MER established in the table in Appendix A, a toxic impact analysis for that TAP is required.

Table 5-1 summarizes OPC Chattahoochee's potential emission rates for individual TAPs and compares them to the respective MERs.

[63] *Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions*. Georgia Department of Natural Resources, Environmental Protection Division, Air Protection Branch, Revised, May, 2017.

Table 5-1. OPC Chattahoochee TAP Emissions and Respective MERs

Toxic Air Pollutant (TAP)	OPC Chattahoochee Annual Emissions (tpy)	OPC Chattahoochee Annual Emissions[1] (lb/yr)	Short Term Emission Rate[2] (g/s)	Minimum Emission Rate (MER)[3] (lb/yr)	Above MER?
Arsenic	1.63E-04	0.33	4.69E-06	0.057	Yes
Ammonia	184	367,920	5.29E+00	24,333	Yes
Beryllium	9.79E-06	0.02	2.82E-07	0.97	No
Cadmium	8.97E-04	1.8	2.58E-05	1.35	Yes
Acrolein	1.00E-01	201	3.06E-03	4.87	Yes
Lead	--	--	--	5.84	No
1,3-Butadiene	6.75E-03	13.5	2.06E-04	7.30	Yes
Cobalt	6.85E-05	0.14	1.97E-06	11.7	No
Manganese	3.10E-04	0.62	8.92E-06	12.2	No
Selenium	1.96E-05	0.04	5.63E-07	23.4	No
Chromium	1.14E-03	2.3	3.29E-05	24.33	No
Benzene	1.90E-01	380	5.79E-03	31.6	Yes
Nickel	1.71E-03	3.4	4.93E-05	38.6	No
Barium	3.59E-03	7.2	1.03E-04	57.9	No
Mercury	2.12E-04	0.42	6.10E-06	73.0	No
Copper	6.94E-04	1.4	1.99E-05	117	No
Sulfuric Acid	1.14	2,276	3.46E-02	117	Yes
Formaldehyde	1.85	3,699	5.63E-02	267	Yes
Propylene Oxide	4.55E-01	910	1.39E-02	657	Yes
Naphthalene	2.09E-02	41.8	6.37E-04	730	No
Acetaldehyde	0.63	1,255	1.92E-02	1,107	Yes
Molybdenum	8.97E-04	1.8	2.58E-05	1,738	No
Xylenes	1.00	2,008	3.06E-02	24,333	No
Hexane	1.47	2,937	4.22E-02	170,331	No
1,4-Dichlorobenzene	9.79E-04	2.0	2.82E-05	194,664	No
Propane	1.3	2,611	3.76E-02	208,600	No
Ethylbenzene	0.50	1,004	1.53E-02	243,330	No
Pentane	2.1	4,243	6.10E-02	341,858	No
Toluene	2.04	4,084	6.23E-02	1,216,650	No

1. Annual Emissions (lb/yr) = Annual Emissions (ton/yr) * 2,000 lb/ton.
2. Short Term Emission Rate (g/s) = Short Term Emissions (lb/hr) * 453.592 (g/lb) / 3,600 (s/hr)
3. From EPD's *Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions*, updated October 2018.

5.2 Determination of Toxic Air Pollutant Impact

Based on the comparison of OPC Chattahoochee's emissions of individual TAPs to their respective MERs, multiple pollutants have emission rates above the MER; therefore, SCREEN3 (version 13043) was used to evaluate the short-term (1-hour) concentration average for each individual TAP exceeding its MER. The modeled 1-hour average concentration was then converted to concentrations in both shorter (15-minute) and longer-term (24-hour or annual, as applicable) averaging periods.

For each TAP requiring further analysis, the total emissions of the TAP from both of the facility's CCCT stacks were conservatively modeled as being emitted from only one of the two stacks. This is conservative as this assumes perfect alignment of modeled impacts from both sources. The distance to the fence line between the two stacks have no eventual bearing on modeling results as the maximum modeled impacts were predicted well beyond the boundary area of the fence line. The stack parameters are included in Table 5-2.

Table 5-2. Stack Parameters

Source Type	Height (m)	Diameter (m)	Velocity (m/s)	Gas Temperature (K)
Point	39.624	5.03	24.81	366.2

The rural option of SCREEN3 was used, as is specified in the SCREEN3 modeling files. A single SCREEN3 run was conducted using an emission rate of 1 gram per second (g/s). The 1-hour maximum impact at the fence line generated from SCREEN3 was adjusted using the multiplying factors in the *Guideline* to obtain the estimated maximum impacts for the 15-minute, 24-hour, and annual averaging periods. The modeling results at 1 g/s are included in Table 5-3.

Table 5-3. SCREEN3 Modeling Results at 1 g/s

Maximum 1-Hour Impact	1.007 μg/m³
Maximum 15-Minute Impact[1]	1.329 μg/m³
Maximum 24-Hour Impact[2]	0.532 μg/m³
Maximum Annual Impact[3]	0.043 μg/m³

1. The 15-minute impact equals the 1-hour impact times 1.32 per the EPD *Guideline*.
2. The 24-hour impact equals the 1-hour impact times 0.4 per the EPD *Guideline*.
3. The annual impact equals the 1-hour impact times 0.08 per the EPD *Guideline*.

The modeled impact for each averaging period was then scaled from an emission rate of 1 g/s to the facility-wide emission rate of each pollutant, assuming all facility-wide emissions are emitted from the "worst case" of the facility's two stacks and that the modeled impact is directly proportional to the mass emission rate. As shown in Table 5-4, the impacts of all TAP from OPC Chattahoochee are well below the respective annual, 24-hour, and 15-minute AACs. The SCREEN3 modeling file and TAP emission calculations are included in Appendix C of this application.

Table 5-4. Modeling Results Compared to AAC Values

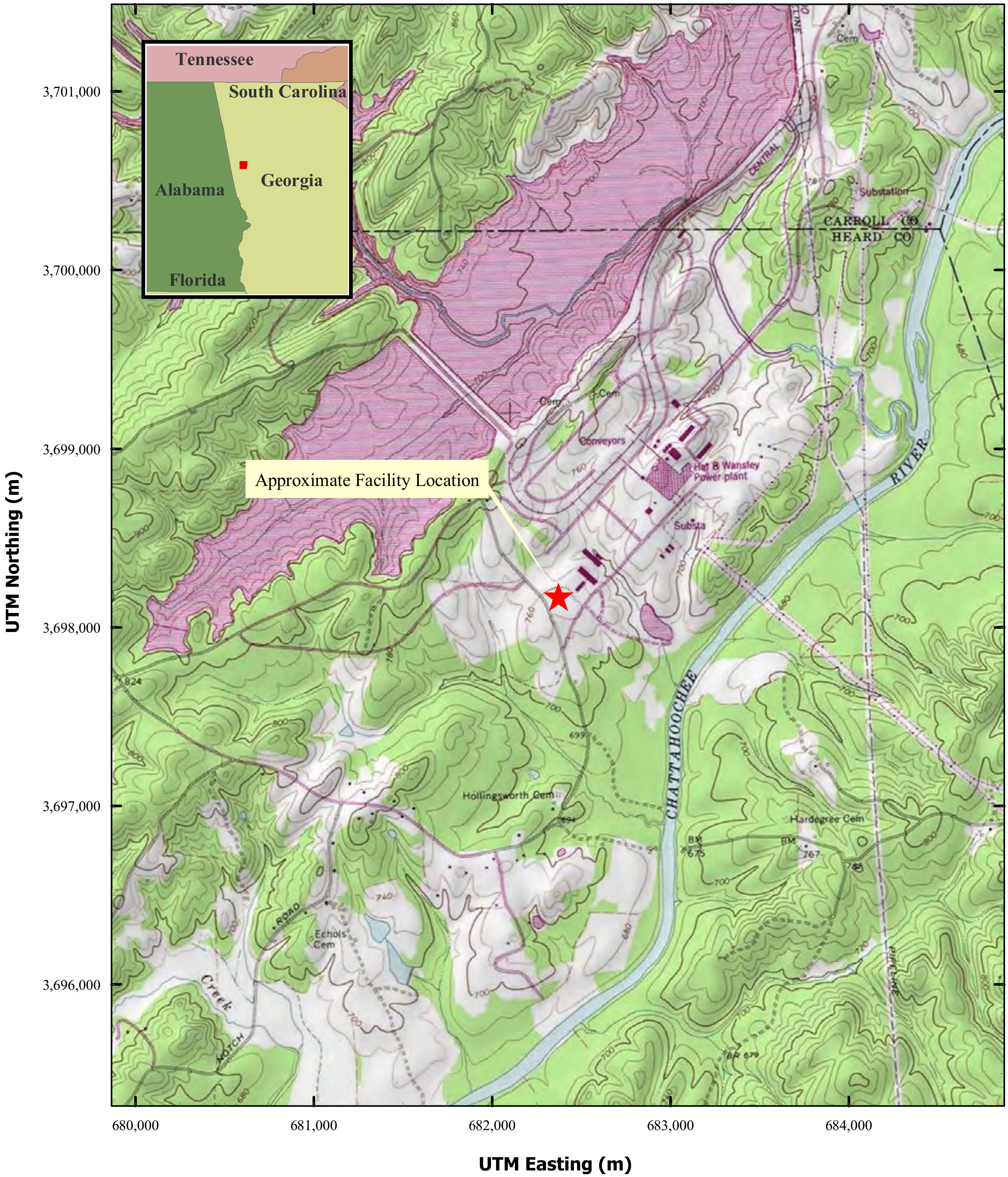
Toxic Air Pollutant (TAP)	Maximum Annual Impact µg/m³	Annual AAC µg/m³	% of AAC	Maximum 24-Hour Impact µg/m³	24-Hour AAC µg/m³	% of ACC	Maximum 15-Minute Impact µg/m³	15-Minute AAC µg/m³	% of AAC
Arsenic	2.00E-07	2.33E-04	< 1.00%	N/A	N/A	--	6.24E-06	2.00E-01	< 1.00%
Ammonia	2.25E-01	1.00E+02	< 1.00%	N/A	N/A	--	7.03E+00	2.40E+03	< 1.00%
Cadmium	1.10E-06	5.56E-03	< 1.00%	N/A	N/A	--	3.43E-05	3.00E+01	< 1.00%
Acrolein	1.30E-04	2.00E-02	< 1.00%	N/A	N/A	--	4.07E-03	2.30E+01	< 1.00%
1,3-Butadiene	8.76E-06	3.00E-02	< 1.00%	N/A	N/A	--	2.74E-04	1.10E+03	< 1.00%
Benzene	2.46E-04	1.30E-01	< 1.00%	N/A	N/A	--	7.70E-03	1.60E+03	< 1.00%
Sulfuric Acid	N/A	N/A	--	1.84E-02	2.40E+00	< 1.00%	4.60E-02	3.00E+02	< 1.00%
Formaldehyde	2.40E-03	1.10E+00	< 1.00%	N/A	N/A	--	7.49E-02	2.45E+02	< 1.00%
Propylene Oxide	5.91E-04	2.70E+00	< 1.00%	N/A	N/A	--	N/A	N/A	--
Acetaldehyde	8.15E-04	4.55E+00	< 1.00%	N/A	N/A	--	2.55E-02	4.50E+03	< 1.00%

1. AAC values from the EPD Guideline, updated October 2018.

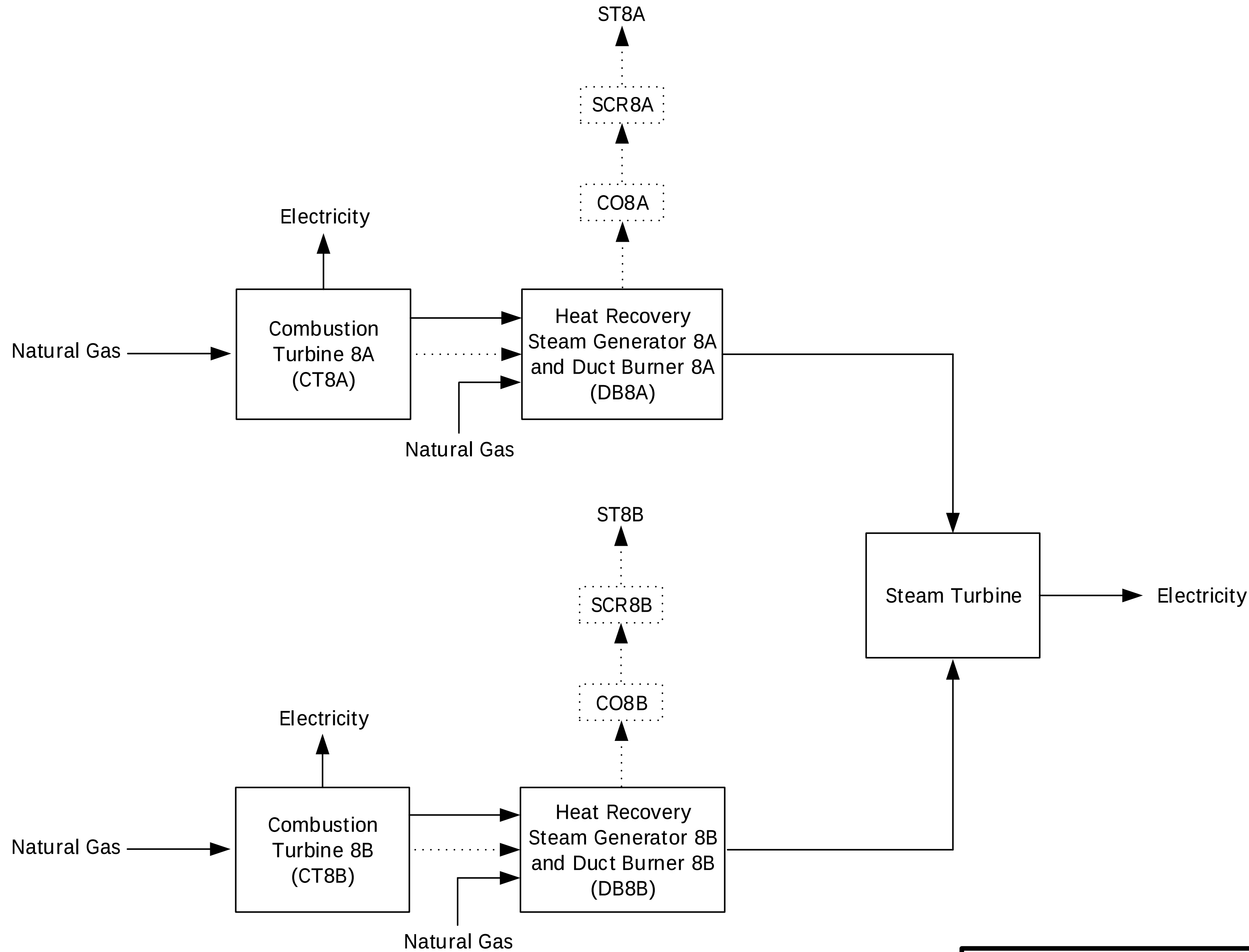
APPENDIX A. AREA MAP AND PROCESS FLOW DIAGRAM

Figure A-1. Facility Area Map

Oglethorpe Power Corporation
Chattahoochee Energy Facility
Franklin, Heard County, Georgia



Coordinates reflect UTM projection Zone 16, NAD83.



Legend

———	Material Flow
···········	Air Emissions
CT8A	Process Unit
SCR8A	Air Pollution Control Device

Oglethorpe Power Corporation
Chattahoochee Energy Facility
Franklin, Georgia

Figure A-2. Process Flow Diagram

Trinity Consultants

201101.0056
June 2020

APPENDIX B. EMISSION CALCULATIONS

Table B-1. Natural Gas Burning Equipment - Operating Parameters - Design Capacity

Emission Source	Source No.	Fuel Type	Maximum Annual Operating Capacity[1] (Million MMBtu/yr)	Potential Annual Operation (hr/yr)
CCCT8A	CT8A and DB8A	Natural Gas	16.5	8,760
CCCT8B	CT8B and DB8B	Natural Gas	16.5	8,760

1. Based on post project heat input capacity per turbine at 59F (1,790.7 MMBtu/hr) and the permitted heat input capacity for the duct burners (95 MMBtu/hr) times potential operation of 8,760 hrs/yr.

Table B-2. CCCT Potential Criteria Pollutant Emissions

Pollutant	Emission Factor (lb/MMBtu)	Potential Emissions[10] (tpy)
NO_X[1]	1.11E-02	179.6
CO[2]	4.48E-03	86.0
VOC[3]	2.59E-03	43
PM[4]	9.91E-03	164
Total PM_{10}[4]	9.91E-03	164
Total $PM_{2.5}$[4]	9.91E-03	164
SO_2[5]	6.00E-04	9.91
H_2SO_4[6]	6.89E-05	1.14
CO_2[7]	1.19E+02	1,963,369
CH_4[8]	2.20E-03	36.4
N_2O[8]	2.20E-04	3.64
CO_2e[9]	1.19E+02	1,965,365

1. Emission factor for NO_X based on 3.0 ppm @ 15% O_2 existing BACT limit. Permit Condition 3.3.4 limits NO_X emissions to 179.6 tpy (total from all CCCTs).

2. Emission factor for CO based on 2.0 ppm @ 15% O_2 existing BACT limit. Permit Condition 3.3.5 limits CO emissions to 86 tpy (total from all CCCTs).

3. VOC emission factor based on 2.0 ppm @ 15% O_2 existing BACT limit.

4. Condition 3.3.6.c limits PM to 0.011 lb/MMBtu, LHV basis. The limit was adjusted to HHV basis using a HHV/LHV ratio of 1.109805, consistent with the ratio used by Siemens in its performance data sheet for TPU1 dated 1/12/2020. It was conservatively assumed all PM is less than 2.5 microns in diameter (i.e., $PM_{2.5}$ = PM_{10} = PM).

5. SO_2 emissions were estimated using the default SO_2 emission rate for pipeline natural gas from 40 CFR 75, Appendix D, Section 2.3.1.1, consistent with the methodology used to report the facility's SO_2 emissions under the CAMD programs.

6. H_2SO_4 emissions were calculated assuming a 7.5% conversion of SO_2 to H_2SO_4, consistent with the facility's initial November 2000 PSD permit application.

7. CO_2 emissions were calculated in accordance with 40 CFR 75, Appendix G, Equation G-4 using the F-factor for natural gas, consistent with the methodology used to report the facility's CO_2 emissions under the CAMD programs and the EPA GHG reporting rule.

8. CH_4 and N_2O emission factors for natural gas combustion are from 40 CFR 98, Subpart C, Table C-2, converted from kg to lb, consistent with the methodology used to report the facility's emissions under the EPA GHG reporting rule.

9. Total GHG emissions in CO_2e is the sum of the product of each GHG and its respective global warming potential (GWP) per 40 CFR Part 98 Subpart A, Table A-1, effective January 1, 2014.

Pollutant	GWP
CO_2	1
CH_4	25
N_2O	298

10. Potential Emissions (tpy) = Emission Factor (lb/MMBtu) * Maximum Annual Operating Capacity (Million MMBtu/yr) * 1E6 MMBtu/ Million MMBtu / 2,000 lb/ton

Table B-3. Natural Gas Burning Equipment - Operating Parameters - Design Capacity

Emission Source	Source No.	Fuel Type	Maximum Annual Operating Capacity[1] (Million MMBtu/yr)	Potential Annual Operation (hr/yr)
CT8A Combustion Turbine	CT8A	Natural Gas	15.69	8,760
CT8B Combustion Turbine	CT8B	Natural Gas	15.69	8,760
DB8A Duct Burner	DB8A	Natural Gas	0.83	8,760
DB8B Duct Burner	DB8B	Natural Gas	0.83	8,760

1. Based on post project heat input capacity per turbine at 59F (1,790.7 MMBtu/hr) and the permitted heat input capacity for the duct burners (95 MMBtu/hr) times potential operation of 8,760 hrs/yr.

Table B-4. Combustion Turbines Potential HAP Emissions

Pollutant	Emission Factor[1] (lb/MMBtu)	Potential Emissions[2] Combustion Turbines (tpy)
Lead	--	--
1,3-Butadiene	4.30E-07	6.75E-03
Acetaldehyde	4.00E-05	6.27E-01
Acrolein	6.40E-06	1.00E-01
Benzene	1.20E-05	1.88E-01
Ethylbenzene	3.20E-05	5.02E-01
Formaldehyde[3]	1.14E-04	1.79
Naphthalene	1.30E-06	2.04E-02
Propylene Oxide	2.90E-05	4.55E-01
Toluene	1.30E-04	2.04
Xylenes	6.40E-05	1.00E+00
Total HAP[4]	4.29E-04	6.73
Max Single HAP[5]	1.30E-04	2.04

1. Emission factors per AP-42, Section 3.1 Stationary Gas Turbines, Tables 3.1.-2a and 3.1-3 unless otherwise noted.
2. Potential Emissions (tpy) = Emission Factor (lb/MMBtu) * Maximum Annual Operating Capacity (Million MMBtu/yr) * 1E6 MMBtu/ Million MMBtu / 2,000 lb/ton
3. Formaldehyde emission factor based on AP-42 Section 3.1 Database (April 2000) for Frame Type CTs greater than 40 MW.
4. Total HAP emission factor is the sum of all speciated HAP emission factors.
5. Largest HAP from combustion turbines is formaldehyde.

Table B-5. Potential HAP Emissions from Duct Burners

Pollutant	Emission Factor[1] (lb/MMscf)	Potential Emissions[2] (tpy)[3]
2-Methylnapthalene	2.40E-05	1.96E-05
3-Methylchloranthrene	1.80E-06	1.47E-06
7,12-Dimethylbenz(a)anthracene	1.60E-05	1.31E-05
Acenaphthene	1.80E-06	1.47E-06
Acenaphthylene	1.80E-06	1.47E-06
Anthracene	2.40E-06	1.96E-06
Benz(a)anthracene	1.80E-06	1.47E-06
Benzene	2.10E-03	1.71E-03
Benzo(a)pyrene	1.20E-06	9.79E-07
Benzo(b)fluoranthene	1.80E-06	1.47E-06
Benzo(g,h,i)perylene	1.20E-06	9.79E-07
Benzo(k)fluoranthene	1.80E-06	1.47E-06
Chrysene	1.80E-06	1.47E-06
Dibenzo(a,h)anthracene	1.20E-06	9.79E-07
1,4-Dichlorobenzene	1.20E-03	9.79E-04
Fluoranthene	3.00E-06	2.45E-06
Fluorene	2.80E-06	2.28E-06
Formaldehyde	7.50E-02	6.12E-02
Hexane	1.80E+00	1.47
Indeno(1,2,3-cd)pyrene	1.80E-06	1.47E-06
Naphthalene	6.10E-04	4.98E-04
Phenanathrene	1.70E-05	1.39E-05
Pyrene	5.00E-06	4.08E-06
Toluene	3.40E-03	2.77E-03
Arsenic	2.00E-04	1.63E-04
Beryllium	1.20E-05	9.79E-06
Cadmium	1.10E-03	8.97E-04
Chromium	1.40E-03	1.14E-03
Cobalt	8.40E-05	6.85E-05
Manganese	3.80E-04	3.10E-04
Mercury	2.60E-04	2.12E-04
Nickel	2.10E-03	1.71E-03
Selenium	2.40E-05	1.96E-05
Total HAP[3]	1.89	1.54
Max Single HAP[4]	1.80	1.47

1. Emission factors per AP-42, Section 1.4 Natural Gas Combustion, Tables 1.4-3 and 1.4-4.
2. Potential Emissions (tpy) = Emission Factor (lb/MMscf) / 1,020 (MMBtu/MMscf) * Maximum Annual Operating Capacity (Million MMBtu/yr) * 1E6 MMBtu/ Million MMBtu / 2,000 lb/ton
3. Total HAP emission factor is the sum of all speciated HAP emission factors.
4. Max single HAP from duct burners is hexane.

Table B-6. Cooling Tower Potential Emissions

Emission Source	Drift Loss Flow[1] (gpm)	Total Dissolved Solids[2] (mg/L)	Filterable PM Emissions[3,4] (lb/hr)	(tpy)	Total PM_{10} Emissions[5] (lb/hr)	(tpy)	Total $PM_{2.5}$ Emissions[5] (lb/hr)	(tpy)
Cooling Tower	7.03	602	2.12	9.28	2.02	8.87	4.54E-01	1.99

1. Based on cooling tower system operational data from Siemens.
2. Based on facility operational data.
3. Hourly PM emission rate (lb/hr) = Flow rate (gal/min) × TDS (mg/L) × 3.78541 (L/gal) × 2.2045E-06 (lb/mg) x 60 min/hr
4. Annual PM emission rate (ton/yr) = Hourly emission rate (lb/hr) × 8,760 (hours/yr)/2,000 (lb/ton).
5. PM_{10} and $PM_{2.5}$ emissions are estimated based on the particulate size distribution below, interpolated from data in *Calculating Realistic PM 10 Emissions from Cooling Towers* by Joel Reisman and Gordon Frisbie, 2002. Detailed derivation of PM_{10}/$PM_{2.5}$ fractions are discussed in Table B-7.

Table B-7. Derivation of PM_{10}/$PM_{2.5}$ Fraction[1]

Drift Droplet Diameter (D_d) (µm)	Drift Droplet Volume[2] ($V_{droplet}$) ($µm^3$)	Drift Droplet Mass[3] ($M_{droplet}$) (µg)	Droplet Particle Mass[4] (M_{TDS}) (µg)	Solid Particle Diameter[5] (D_{TDS}) (µm)	EPRI Cumulative % Mass Smaller[6] (%)	Interpolation Value for $PM_{2.5}$[7] (%)	Interpolation Value for PM_{10}[7] (%)
0	0.00E+00	0.00E+00	0.00E+00	0.000	0	--	--
10	5.24E+02	5.24E-04	5.24E-08	0.357	0	--	--
20	4.19E+03	4.19E-03	4.19E-07	0.714	0.196	--	--
30	1.41E+04	1.41E-02	1.41E-06	1.071	0.226	--	--
40	3.35E+04	3.35E-02	3.35E-06	1.428	0.514	--	--
50	6.54E+04	6.54E-02	6.54E-06	1.784	1.816	--	--
60	1.13E+05	1.13E-01	1.13E-05	2.141	5.702	--	--
70	1.80E+05	1.80E-01	1.80E-05	2.498	21.348	--	--
90	3.82E+05	3.82E-01	3.82E-05	3.212	49.812	21.421	--
110	6.97E+05	6.97E-01	6.97E-05	3.926	70.509	--	--
130	1.15E+06	1.15E+00	1.15E-04	4.639	82.023	--	--
150	1.77E+06	1.77E+00	1.77E-04	5.353	88.012	--	--
180	3.05E+06	3.05E+00	3.05E-04	6.424	91.032	--	--
210	4.85E+06	4.85E+00	4.85E-04	7.495	92.468	--	--
240	7.24E+06	7.24E+00	7.24E-04	8.565	94.091	--	--
300	1.41E+07	1.41E+01	1.41E-03	10.706	96.288	--	95.563
350	2.24E+07	2.24E+01	2.24E-03	12.491	97.011	--	--
400	3.35E+07	3.35E+01	3.35E-03	14.275	98.34	--	--
450	4.77E+07	4.77E+01	4.77E-03	16.060	99.071	--	--
600	1.13E+08	1.13E+02	1.13E-02	21.413	100	--	--

1. Based on the methodology discussed in "Calculating Realistic PM_{10} Emissions from Cooling Towers" by Joel Reisman and Gordon Frisbie, 2002 (the Document).
https://yosemite.epa.gov/r9/air/epss.nsf/6924c72e5ea10d5e882561b100685e04/44841bd36885b15e882579f80062a144/$FILE/Cooling%20Tower%20PM%20Emissions.pdf

Assumptions/helpful equations
Volume of a sphere = 4 π r^3/3

2. $V_{droplet}$ = 4/3 π (D_d /2)^3 [Equation 2 of the Document]
3. $M_{droplet}$ = density (ρ_w) of water * $V_{droplet}$ = ρ_w * 4/3 π (D_d /2)^3

ρ_w = 1.00E-06 µg/µm^3

4. M_{TDS} = TDS * $M_{droplet}$ [Equation 3 of the Document, with TDS in units of ppm]

TDS = 100 mg/L Total Dissolved Solids Per Table B-6

TDS = 100 ppm

5. M_{TDS} = (ρ_{TDS}) (V_{TDS}) = (ρ_{TDS}) (4/3)π (D_{TDS} /2)^3 [Equation 5 of the Document]

Therefore, the equation can be solved for D_{TDS}: $D_{TDS} = \{M_{TDS}/[(\rho_{TDS})* 4/3 * \pi]\}^{1/3} \times 2$

Assume solid particulates have the same density (ρ_{TDS}) as sodium chloride per the Document: 2.20E-06 µg/µm^3

6. Based on drift eliminator test data from a test conducted by Environmental Systems Corporation (ESC) at the Electric Power Research Institute (EPRI) test facility in Houston, Texas in 1988 (Aull, 1999) as documented in Table 1 of the Document.

7. D_{TDS} represents the particle size of collected material in droplet. The EPRI cumulative % mass smaller indicates the percentage of material in that specific water droplet size that has a diameter smaller than D_{TDS}. Therefore, linear interpolation between calculated D_{TDS} is necessary to ascertain the specific mass percentages to estimate PM_{10} and $PM_{2.5}$ emissions. For example, at 1,000 mg/L TDS:

%MassPM_{10} = %Mass Less than 10 D_{TDS} + [(10 - D_{TDS} Less Than 10) / (D_{TDS} Greater Than 10 - D_{TDS} Less Than 10)] * (%Mass Greater than 10 D_{TDS} - %Mass Less than 10 D_{TDS})

i.e. 82.041% = 82.023% + [(10 - 9.995) / (11.533 - 9.995)] * (88.012% - 82.023%)

Table B-8. Site-wide Potential to Emit

Pollutant	Potential Emissions (tpy)
NO_X	179.6
CO	86.0
VOC	42.8
PM	173
Total PM_{10}	173
Total $PM_{2.5}$	166
SO_2	9.91
H_2SO_4	1.14
CO_2	1,963,369
CH_4	36.4
N_2O	3.64
CO_2e	1,965,365
Total HAP	8.27
Max Single HAP[1]	2.10

1. Maximum single HAP is Formaldehyde.

Table B-9. Emission Factors for NSR Analysis

Pollutant	Emission Factor (lb/MMBtu)
VOC[1]	1.00E-03
$PM_{10}/PM_{2.5}$[2]	6.00E-03
SO_2[3]	6.00E-04
H_2SO_4[4]	6.89E-05
CO_2[5]	118.86
CH_4[6]	2.20E-03
N_2O[6]	2.20E-04
CO_2e[7]	118.98

1. VOC emissions were based on the most recent facility compliance testing data. The total VOC emission factor was calculated as the sum of the 2005 VOC as CH_4 (Method 25A) test results and the 2003 formaldehyde (Method 0011) test results. A 10% safety factor was conservatively applied to the stack test results. The emissions concentrations (ppm @ 15% O_2) were converted to emission factors (lb/MMBtu) using the following equation:

$$lb/MMBtu = (C_{gas,\ VOC\ as\ CH4} * MW_{VOC\ as\ CH4} + C_{gas,\ HCHO} * MW_{HCHO}) * Fd * 2.59E\text{-}9 * 20.9 / (20.9 - \%O_2)$$

where:

$C_{gas,\ VOC\ as\ CH4}$ =	0.596	ppmv, maximum VOC as CH_4 test result for either unit at any load
$MW_{VOC\ as\ CH4}$ =	16.043	lb/lb-mol, molecular weight of CH_4
$C_{gas,\ HCHO}$ =	0.061	ppmv, maximum HCHO test result for either unit at any load
MW_{HCHO} =	30.026	lb/lb-mol, molecular weight of HCHO
Fd =	8,710	dscf/MMBtu, natural gas fuel factor from 40 CFR 60, Method 19, Table 19-2
$\%O_2$ =	15	%, corrected basis for exhaust gas O_2 content

2. PM emissions are based on the average of the 2003 compliance testing results for units 8A (0.0069 lb/MMBtu) and 8B (0.0051 lb/MMBtu). The 2003 testing was inclusive of both the filterable and condensable portions of PM. It was conservatively assumed all PM is less than 2.5 microns in diameter (i.e., $PM_{2.5} = PM_{10} = PM$).

3. SO_2 emissions were estimated using the default SO_2 emission rate for pipeline natural gas from 40 CFR 75, Appendix D, Section 2.3.1.1, consistent with the methodology used to report the facility's SO_2 emissions under the CAMD programs.

4. H_2SO_4 emissions were calculated assuming a 7.5% conversion of SO_2 to H_2SO_4, consistent with the facility's initial November 2000 PSD permit application.

5. CO_2 emissions were calculated in accordance with 40 CFR 75, Appendix G, Equation G-4 using the F-factor for natural gas, consistent with the methodology used to report the facility's CO_2 emissions under the CAMD programs and the EPA GHG reporting rule.

6. CH_4 and N_2O emission factors for natural gas combustion are from 40 CFR 98, Subpart C, Table C-2, converted from kg to lb, consistent with the methodology used to report the facility's emissions under the EPA GHG reporting rule.

7. CO_2e was calculated as the sum of the emission factor for each GHG pollutant multiplied by that pollutant's global warming potential (GWP). GWPs were taken from 40 CFR 98, Subpart A, Table A-1:

CO_2:	1
CH_4:	25
N_2O:	298

Table B-10. Past Actual Emissions - Unit 8A

Month[1]	Monthly Heat Input (MMBtu/mo)[2]	Monthly Emissions (tons/mo)							
		NO_X[2]	CO	CO[3]	VOC	$PM_{10}/PM_{2.5}$	SO_2	H_2SO_4	CO_2e
Jul-15	1,020,758	5.0	0.33	0.33	0.51	3.1	0.31	0.04	60,724
Aug-15	994,411	5.2	0.95	0.95	0.50	3.0	0.30	0.03	59,157
Sep-15	764,809	4.8	1.50	1.50	0.38	2.3	0.23	0.03	45,498
Oct-15	1,045,517	5.3	0.78	0.78	0.52	3.1	0.31	0.04	62,197
Nov-15	594,288	3.2	2.28	1.33	0.30	1.8	0.18	0.02	35,354
Dec-15	912,953	4.4	3.31	2.04	0.46	2.7	0.27	0.03	54,311
Jan-16	1,082,755	4.7	3.01	2.42	0.54	3.2	0.32	0.04	64,412
Feb-16	687,197	3.2	2.03	1.54	0.34	2.1	0.21	0.02	40,881
Mar-16	237,308	1.1	0.11	0.11	0.12	0.7	0.07	0.01	14,117
Apr-16	3,242	0.2	0.30	0.01	0.00	0.0	0.00	0.00	193
May-16	1,159,578	4.8	0.95	0.95	0.58	3.5	0.35	0.04	68,982
Jun-16	1,058,882	4.3	0.55	0.55	0.53	3.2	0.32	0.04	62,992
Jul-16	1,092,489	4.1	1.13	1.13	0.55	3.3	0.33	0.04	64,991
Aug-16	1,121,686	4.3	1.34	1.34	0.56	3.4	0.34	0.04	66,728
Sep-16	1,076,934	4.3	1.20	1.20	0.54	3.2	0.32	0.04	64,066
Oct-16	1,166,258	4.1	0.92	0.92	0.58	3.5	0.35	0.04	69,380
Nov-16	412,349	1.6	0.65	0.65	0.21	1.2	0.12	0.01	24,530
Dec-16	1,017,572	4.8	0.47	0.47	0.51	3.1	0.31	0.04	60,534
Jan-17	1,139,725	5.2	0.22	0.22	0.57	3.4	0.34	0.04	67,801
Feb-17	1,053,333	4.7	0.13	0.13	0.53	3.2	0.32	0.04	62,662
Mar-17	823,350	3.7	0.10	0.10	0.41	2.5	0.25	0.03	48,980
Apr-17	784,288	3.5	1.29	1.29	0.39	2.4	0.24	0.03	46,656
May-17	1,081,582	4.4	1.35	1.35	0.54	3.2	0.32	0.04	64,342
Jun-17	1,074,670	4.6	1.06	1.06	0.54	3.2	0.32	0.04	63,931
Jul-17	1,154,981	4.9	0.87	0.87	0.58	3.5	0.35	0.04	68,709
Aug-17	1,113,454	4.8	1.01	1.01	0.56	3.3	0.33	0.04	66,238
Sep-17	1,116,481	4.4	0.73	0.73	0.56	3.3	0.33	0.04	66,418
Oct-17	1,191,038	4.7	0.52	0.52	0.60	3.6	0.36	0.04	70,854
Nov-17	704,062	3.2	0.51	0.51	0.35	2.1	0.21	0.02	41,884
Dec-17	975,918	3.9	0.34	0.34	0.49	2.9	0.29	0.03	58,056
Jan-18	1,029,711	3.9	0.62	0.62	0.52	3.1	0.31	0.04	61,256
Feb-18	934,663	3.7	0.51	0.51	0.47	2.8	0.28	0.03	55,602
Mar-18	273,177	1.3	0.37	0.37	0.14	0.8	0.08	0.01	16,251
Apr-18	962,750	4.4	0.92	0.92	0.48	2.9	0.29	0.03	57,273
May-18	1,037,073	4.7	0.72	0.72	0.52	3.1	0.31	0.04	61,694
Jun-18	995,806	3.8	0.46	0.46	0.50	3.0	0.30	0.03	59,240
Jul-18	1,129,935	3.4	0.10	0.10	0.57	3.4	0.34	0.04	67,219
Aug-18	1,030,553	3.3	0.79	0.79	0.52	3.1	0.31	0.04	61,307
Sep-18	1,083,855	2.9	0.46	0.46	0.54	3.3	0.33	0.04	64,477
Oct-18	188,835	0.5	0.05	0.05	0.09	0.6	0.06	0.01	11,234
Nov-18	315,838	1.5	0.48	0.48	0.16	0.9	0.09	0.01	18,789
Dec-18	915,394	3.8	1.22	1.22	0.46	2.7	0.27	0.03	54,456
Jan-19	1,075,633	4.0	0.82	0.82	0.54	3.2	0.32	0.04	63,988
Feb-19	920,427	4.0	0.57	0.57	0.46	2.8	0.28	0.03	54,755
Mar-19	708,361	3.5	0.59	0.59	0.35	2.1	0.21	0.02	42,140
Apr-19	1,033,526	5.0	0.84	0.84	0.52	3.1	0.31	0.04	61,483
May-19	1,049,466	5.1	0.36	0.36	0.53	3.1	0.31	0.04	62,432
Jun-19	1,005,922	4.9	0.35	0.35	0.50	3.0	0.30	0.03	59,841
Jul-19	1,121,571	5.1	0.11	0.11	0.56	3.4	0.34	0.04	66,721
Aug-19	1,125,943	5.1	0.24	0.24	0.56	3.4	0.34	0.04	66,981
Sep-19	1,016,000	4.8	0.94	0.94	0.51	3.0	0.30	0.03	60,441
Oct-19	760,008	3.8	0.53	0.53	0.38	2.3	0.23	0.03	45,212
Nov-19	895,090	4.3	0.73	0.73	0.45	2.7	0.27	0.03	53,248
Dec-19	816,265	4.0	0.75	0.75	0.41	2.4	0.24	0.03	48,559
Maximum	1,191,038	5.3	3.31	2.42	0.60	3.6	0.36	0.04	70,854

1. A five-year lookback period is allowed for determining baseline actual emissions for existing electric utility steam generating units, per 40 CFR 52.21(b)(48)(i).

2. Per the facility's quarterly Part 75 emissions reports to EPA submitted through the Emissions Collection and Monitoring Plan System (ECMPS).

3. Per the facility's quarterly Title V monitoring reports to the Georgia EPD. If the monthly average CO emission rate, based on the reported CO emissions divided by the heat input for the month, exceeded the facility's permitted CO emission limit of 2.0 ppmvd @ 15% O_2 (equivalent to 0.00448 lb/MMBtu), the CO emissions for that month were re-calculated using the CO emission limit multiplied by the monthly heat input.

Table B-11. Past Actual Emissions - Unit 8B

Month[1]	Monthly Heat Input (MMBtu/mo)[2]	Monthly Emissions (tons/mo) NO_X[2]	CO	CO[3]	VOC	$PM_{10}/PM_{2.5}$	SO_2	H_2SO_4	CO_2e
Jul-15	980,457	5.0	0.39	0.39	0.49	2.9	0.29	0.03	58,326
Aug-15	847,397	4.9	0.79	0.79	0.42	2.5	0.25	0.03	50,411
Sep-15	777,710	4.2	0.88	0.88	0.39	2.3	0.23	0.03	46,265
Oct-15	1,146,414	5.3	0.12	0.12	0.57	3.4	0.34	0.04	68,199
Nov-15	482,136	2.6	1.35	1.08	0.24	1.4	0.14	0.02	28,682
Dec-15	847,320	4.0	2.80	1.90	0.42	2.5	0.25	0.03	50,406
Jan-16	1,019,484	4.4	1.30	1.30	0.51	3.1	0.31	0.04	60,648
Feb-16	823,430	3.9	1.79	1.79	0.41	2.5	0.25	0.03	48,985
Mar-16	173,325	0.7	0.07	0.07	0.09	0.5	0.05	0.01	10,311
Apr-16	1,119,416	5.0	0.28	0.28	0.56	3.4	0.34	0.04	66,593
May-16	1,115,034	5.3	0.34	0.34	0.56	3.3	0.33	0.04	66,332
Jun-16	1,094,115	5.2	0.18	0.18	0.55	3.3	0.33	0.04	65,088
Jul-16	1,125,967	5.1	0.71	0.71	0.56	3.4	0.34	0.04	66,983
Aug-16	1,146,152	5.0	1.03	1.03	0.57	3.4	0.34	0.04	68,183
Sep-16	1,112,597	4.7	0.69	0.69	0.56	3.3	0.33	0.04	66,187
Oct-16	1,139,979	4.5	0.88	0.88	0.57	3.4	0.34	0.04	67,816
Nov-16	410,026	1.8	0.77	0.77	0.21	1.2	0.12	0.01	24,392
Dec-16	1,038,385	5.4	0.39	0.39	0.52	3.1	0.31	0.04	61,772
Jan-17	1,192,710	5.9	0.06	0.06	0.60	3.6	0.36	0.04	70,953
Feb-17	1,022,803	5.1	0.16	0.16	0.51	3.1	0.31	0.04	60,845
Mar-17	835,857	4.1	0.03	0.03	0.42	2.5	0.25	0.03	49,724
Apr-17	767,267	3.5	0.59	0.59	0.38	2.3	0.23	0.03	45,644
May-17	938,190	4.2	0.76	0.76	0.47	2.8	0.28	0.03	55,812
Jun-17	1,042,315	4.7	0.25	0.25	0.52	3.1	0.31	0.04	62,006
Jul-17	1,141,857	4.7	0.14	0.14	0.57	3.4	0.34	0.04	67,928
Aug-17	1,117,579	4.2	0.28	0.28	0.56	3.4	0.34	0.04	66,484
Sep-17	1,083,175	3.6	0.16	0.16	0.54	3.2	0.32	0.04	64,437
Oct-17	1,000,852	3.8	0.67	0.67	0.50	3.0	0.30	0.03	59,540
Nov-17	660,925	2.8	0.52	0.52	0.33	2.0	0.20	0.02	39,318
Dec-17	914,097	4.0	0.41	0.41	0.46	2.7	0.27	0.03	54,379
Jan-18	903,676	4.1	1.28	1.28	0.45	2.7	0.27	0.03	53,759
Feb-18	646,904	3.5	1.07	1.07	0.32	1.9	0.19	0.02	38,484
Mar-18	485,561	2.6	0.83	0.83	0.24	1.5	0.15	0.02	28,886
Apr-18	1,033,060	4.7	0.38	0.38	0.52	3.1	0.31	0.04	61,456
May-18	1,062,566	4.4	0.38	0.38	0.53	3.2	0.32	0.04	63,211
Jun-18	779,147	3.2	0.43	0.43	0.39	2.3	0.23	0.03	46,351
Jul-18	1,134,523	4.5	0.16	0.16	0.57	3.4	0.34	0.04	67,492
Aug-18	1,080,287	4.4	0.36	0.36	0.54	3.2	0.32	0.04	64,265
Sep-18	482,136	2.0	0.15	0.15	0.24	1.4	0.14	0.02	28,682
Oct-18	0	0	0	0	0	0	0	0	0
Nov-18	575,142	3.0	1.39	1.29	0.29	1.7	0.17	0.02	34,215
Dec-18	976,385	4.1	0.40	0.40	0.49	2.9	0.29	0.03	58,084
Jan-19	987,705	3.9	0.35	0.35	0.49	3.0	0.30	0.03	58,758
Feb-19	804,851	3.9	0.28	0.28	0.40	2.4	0.24	0.03	47,880
Mar-19	773,341	3.5	0.27	0.27	0.39	2.3	0.23	0.03	46,005
Apr-19	1,052,577	4.7	0.31	0.31	0.53	3.2	0.32	0.04	62,617
May-19	1,100,559	5.1	0.10	0.10	0.55	3.3	0.33	0.04	65,471
Jun-19	1,070,796	4.7	0.02	0.02	0.54	3.2	0.32	0.04	63,701
Jul-19	1,122,630	4.8	0.00	0.00	0.56	3.4	0.34	0.04	66,784
Aug-19	1,117,499	4.5	0.03	0.03	0.56	3.4	0.34	0.04	66,479
Sep-19	1,081,214	3.4	0.18	0.18	0.54	3.2	0.32	0.04	64,320
Oct-19	871,510	2.8	0.15	0.15	0.44	2.6	0.26	0.03	51,845
Nov-19	998,245	4.0	0.27	0.27	0.50	3.0	0.30	0.03	59,385
Dec-19	851,336	3.6	0.57	0.57	0.43	2.6	0.26	0.03	50,645
Maximum	1,192,710	5.9	2.80	1.90	0.60	3.6	0.36	0.04	70,953

1. A five-year lookback period is allowed for determining baseline actual emissions for existing electric utility steam generating units, per 40 CFR 52.21(b)(48)(i).

2. Per the facility's quarterly Part 75 emissions reports to EPA submitted through the Emissions Collection and Monitoring Plan System (ECMPS).

3. Per the facility's quarterly Title V monitoring reports to the Georgia EPD. If the monthly average CO emission rate, based on the reported CO emissions divided by the heat input for the month, exceeded the facility's permitted CO emission limit of 2.0 ppmvd @ 15% O_2 (equivalent to 0.00448 lb/MMBtu), the CO emissions for that month were re-calculated using the CO emission limit multiplied by the monthly heat input.

Table B-12. Baseline Actual Emissions - Units 8A and 8B

	Total Monthly Emissions (tons/mo)							12-Month Rolling Total Emissions (tpy)							24-Month Rolling Annual Average Emissions (tpy)						
Month	NO_X	CO	VOC	$PM_{10}/PM_{2.5}$	SO_2	H_2SO_4	CO_2e	NO_X	CO	VOC	$PM_{10}/PM_{2.5}$	SO_2	H_2SO_4	CO_2e	NO_X	CO	VOC	$PM_{10}/PM_{2.5}$	SO_2	H_2SO_4	CO_2e
Jul-15	10.0	0.7	1.0	6.0	0.60	0.07	119,050														
Aug-15	10.2	1.7	0.9	5.5	0.55	0.06	109,567														
Sep-15	9.0	2.4	0.8	4.6	0.46	0.05	91,763														
Oct-15	10.7	0.9	1.1	6.6	0.66	0.08	130,396														
Nov-15	5.9	2.4	0.5	3.2	0.32	0.04	64,035														
Dec-15	8.3	3.9	0.9	5.3	0.53	0.06	104,717														
Jan-16	9.1	3.7	1.1	6.3	0.63	0.07	125,060														
Feb-16	7.0	3.3	0.8	4.5	0.45	0.05	89,866														
Mar-16	1.8	0.2	0.2	1.2	0.12	0.01	24,428														
Apr-16	5.2	0.3	0.6	3.4	0.34	0.04	66,786														
May-16	10.1	1.3	1.1	6.8	0.68	0.08	135,314														
Jun-16	9.5	0.7	1.1	6.5	0.65	0.07	128,080	96.7	21.6	10.0	60.0	6.0	0.69	1,189,062							
Jul-16	9.3	1.8	1.1	6.7	0.67	0.08	131,974	96.0	22.7	10.1	60.6	6.1	0.70	1,201,985							
Aug-16	9.3	2.4	1.1	6.8	0.68	0.08	134,911	95.2	23.4	10.3	61.9	6.2	0.71	1,227,330							
Sep-16	9.1	1.9	1.1	6.6	0.66	0.08	130,253	95.2	22.9	10.7	63.8	6.4	0.73	1,265,820							
Oct-16	8.6	1.8	1.2	6.9	0.69	0.08	137,196	93.1	23.8	10.7	64.2	6.4	0.74	1,272,619							
Nov-16	3.4	1.4	0.4	2.5	0.25	0.03	48,922	90.7	22.8	10.6	63.4	6.3	0.73	1,257,506							
Dec-16	10.2	0.9	1.0	6.2	0.62	0.07	122,307	92.5	19.7	10.7	64.3	6.4	0.74	1,275,096							
Jan-17	11.1	0.3	1.2	7.0	0.70	0.08	138,754	94.6	16.3	10.8	65.0	6.5	0.75	1,288,790							
Feb-17	9.8	0.3	1.0	6.2	0.62	0.07	123,507	97.3	13.2	11.1	66.7	6.7	0.77	1,322,432							
Mar-17	7.9	0.1	0.8	5.0	0.50	0.06	98,705	103.3	13.2	11.8	70.4	7.0	0.81	1,396,708							
Apr-17	7.1	1.9	0.8	4.7	0.47	0.05	92,300	105.2	14.8	12.0	71.7	7.2	0.82	1,422,223							
May-17	8.7	2.1	1.0	6.1	0.61	0.07	120,154	103.8	15.6	11.8	71.0	7.1	0.81	1,407,063							
Jun-17	9.3	1.3	1.1	6.4	0.64	0.07	125,937	103.6	16.2	11.8	70.8	7.1	0.81	1,404,920	100.2	18.9	10.9	65.4	6.5	0.75	1,296,991
Jul-17	9.7	1.0	1.2	6.9	0.69	0.08	136,637	104.0	15.4	11.9	71.1	7.1	0.82	1,409,583	100.0	19.0	11.0	65.9	6.6	0.76	1,305,784
Aug-17	9.0	1.3	1.1	6.7	0.67	0.08	132,722	103.8	14.3	11.8	71.0	7.1	0.81	1,407,394	99.5	18.8	11.1	66.4	6.6	0.76	1,317,362
Sep-17	8.0	0.9	1.1	6.6	0.66	0.08	130,855	102.7	13.3	11.9	71.0	7.1	0.82	1,407,996	98.9	18.1	11.3	67.4	6.7	0.77	1,336,908
Oct-17	8.6	1.2	1.1	6.6	0.66	0.08	130,393	102.7	12.7	11.8	70.7	7.1	0.81	1,401,194	97.9	18.2	11.3	67.4	6.7	0.77	1,336,907
Nov-17	6.0	1.0	0.7	4.1	0.41	0.05	81,202	105.2	12.3	12.1	72.3	7.2	0.83	1,433,473	98.0	17.5	11.3	67.9	6.8	0.78	1,345,490
Dec-17	7.9	0.8	0.9	5.7	0.57	0.07	112,435	102.9	12.2	12.0	71.8	7.2	0.82	1,423,601	97.7	15.9	11.4	68.0	6.8	0.78	1,349,349
Jan-18	8.0	1.9	1.0	5.8	0.58	0.07	115,015	99.9	13.8	11.8	70.6	7.1	0.81	1,399,863	97.2	15.0	11.3	67.8	6.8	0.78	1,344,326
Feb-18	7.1	1.6	0.8	4.7	0.47	0.05	94,086	97.2	15.1	11.5	69.1	6.9	0.79	1,370,441	97.2	14.2	11.3	67.9	6.8	0.78	1,346,436
Mar-18	3.8	1.2	0.4	2.3	0.23	0.03	45,137	93.2	16.1	11.1	66.4	6.6	0.76	1,316,873	98.3	14.7	11.4	68.4	6.8	0.79	1,356,791
Apr-18	9.1	1.3	1.0	6.0	0.60	0.07	118,729	95.2	15.6	11.3	67.7	6.8	0.78	1,343,301	100.2	15.2	11.6	69.7	7.0	0.80	1,382,762
May-18	9.2	1.1	1.1	6.3	0.63	0.07	124,905	95.7	14.6	11.3	68.0	6.8	0.78	1,348,053	99.8	15.1	11.6	69.5	6.9	0.80	1,377,558
Jun-18	7.0	0.9	0.9	5.3	0.53	0.06	105,590	93.4	14.1	11.2	67.0	6.7	0.77	1,327,706	98.5	15.2	11.5	68.9	6.9	0.79	1,366,313
Jul-18	7.9	0.3	1.1	6.8	0.68	0.08	134,710	91.6	13.4	11.2	66.9	6.7	0.77	1,325,779	97.8	14.4	11.5	69.0	6.9	0.79	1,367,681
Aug-18	7.7	1.2	1.1	6.3	0.63	0.07	125,572	90.3	13.2	11.1	66.5	6.6	0.76	1,318,629	97.0	13.8	11.5	68.7	6.9	0.79	1,363,011
Sep-18	4.9	0.6	0.8	4.7	0.47	0.05	93,159	87.2	13.0	10.8	64.6	6.5	0.74	1,280,933	94.9	13.1	11.3	67.8	6.8	0.78	1,344,465
Oct-18	0.5	0.1	0.1	0.6	0.06	0.01	11,234	79.1	11.8	9.8	58.6	5.9	0.67	1,161,773	90.9	12.2	10.8	64.6	6.5	0.74	1,281,484
Nov-18	4.5	1.8	0.4	2.7	0.27	0.03	53,004	77.7	12.6	9.5	57.2	5.7	0.66	1,133,575	91.4	12.4	10.8	64.7	6.5	0.74	1,283,524
Dec-18	7.9	1.6	0.9	5.7	0.57	0.07	112,540	77.7	13.4	9.5	57.2	5.7	0.66	1,133,680	90.3	12.8	10.8	64.5	6.4	0.74	1,278,641
Jan-19	7.9	1.2	1.0	6.2	0.62	0.07	122,746	77.6	12.7	9.6	57.6	5.8	0.66	1,141,411	88.7	13.2	10.7	64.1	6.4	0.74	1,270,637
Feb-19	8.0	0.9	0.9	5.2	0.52	0.06	102,635	78.4	12.0	9.7	58.0	5.8	0.67	1,149,960	87.8	13.5	10.6	63.6	6.4	0.73	1,260,201
Mar-19	7.0	0.9	0.7	4.4	0.44	0.05	88,145	81.6	11.6	10.0	60.2	6.0	0.69	1,192,968	87.4	13.9	10.6	63.3	6.3	0.73	1,254,921
Apr-19	9.7	1.2	1.0	6.3	0.63	0.07	124,100	82.2	11.5	10.1	60.4	6.0	0.69	1,198,340	88.7	13.5	10.7	64.1	6.4	0.74	1,270,821
May-19	10.2	0.5	1.1	6.5	0.65	0.07	127,903	83.2	10.8	10.1	60.6	6.1	0.70	1,201,337	89.5	12.7	10.7	64.3	6.4	0.74	1,274,695
Jun-19	9.5	0.4	1.0	6.2	0.62	0.07	123,542	85.7	10.3	10.3	61.5	6.1	0.71	1,219,289	89.6	12.2	10.7	64.2	6.4	0.74	1,273,497
Jul-19	9.9	0.1	1.1	6.7	0.67	0.08	133,505	87.8	10.2	10.3	61.4	6.1	0.71	1,218,084	89.7	11.8	10.7	64.1	6.4	0.74	1,271,931
Aug-19	9.6	0.3	1.1	6.7	0.67	0.08	133,460	89.7	9.3	10.3	61.8	6.2	0.71	1,225,972	90.0	11.3	10.7	64.2	6.4	0.74	1,272,301
Sep-19	8.2	1.1	1.1	6.3	0.63	0.07	124,761	93.0	9.8	10.6	63.4	6.3	0.73	1,257,574	90.1	11.4	10.7	64.0	6.4	0.73	1,269,253
Oct-19	6.6	0.7	0.8	4.9	0.49	0.06	97,057	99.1	10.4	11.3	67.7	6.8	0.78	1,343,398	89.1	11.1	10.5	63.2	6.3	0.73	1,252,585
Nov-19	8.3	1.0	0.9	5.7	0.57	0.07	112,633	102.8	9.7	11.8	70.8	7.1	0.81	1,403,027	90.2	11.1	10.7	64.0	6.4	0.73	1,268,301
Dec-19	7.7	1.3	0.8	5.0	0.50	0.06	99,204	102.6	9.4	11.7	70.1	7.0	0.80	1,389,691	90.1	11.4	10.6	63.6	6.4	0.73	1,261,685
Maximum	11.1	3.9	1.2	7.0	0.70	0.08	138,754	105.2	23.8	12.1	72.3	7.2	0.83	1,433,473	100.2	19.0	11.6	69.7	7.0	0.80	1,382,762
														Baseline Period Start Date	May-16	Aug-15	May-16	May-16	May-16	May-16	May-16
														Baseline Period End Date	Apr-18	Jul-17	Apr-18	Apr-18	Apr-18	Apr-18	Apr-18

Table B-13. "Could Have Accommodated" Emissions (except CO) - Units 8A and 8B

Month	Actual Monthly Emissions (tons/mo)						Seasonally-Adjusted Monthly Emissions (tons/mo)[1]						Seasonally-Adjusted 12-Month Total Emissions (tpy)[2]					
	NO_X	VOC	$PM_{10}/PM_{2.5}$	SO_2	H_2SO_4	CO_2e	NO_X	VOC	$PM_{10}/PM_{2.5}$	SO_2	H_2SO_4	CO_2e	NO_X	VOC	$PM_{10}/PM_{2.5}$	SO_2	H_2SO_4	CO_2e
May-16	10.1	1.1	6.8	0.68	0.08	135,314	10.1	1.1	6.8	0.68	0.08	135,314						
Jun-16	9.5	1.1	6.5	0.65	0.07	128,080	9.5	1.1	6.8	0.68	0.08	134,911						
Jul-16	9.3	1.1	6.7	0.67	0.08	131,974	9.5	1.1	6.8	0.68	0.08	134,911						
Aug-16	9.3	1.1	6.8	0.68	0.08	134,911	9.5	1.1	6.8	0.68	0.08	134,911						
Sep-16	9.1	1.1	6.6	0.66	0.08	130,253	9.1	1.2	6.9	0.69	0.08	137,196						
Oct-16	8.6	1.2	6.9	0.69	0.08	137,196	9.1	1.2	6.9	0.69	0.08	137,196						
Nov-16	3.4	0.4	2.5	0.25	0.03	48,922	9.1	1.2	6.9	0.69	0.08	137,196						
Dec-16	10.2	1.0	6.2	0.62	0.07	122,307	11.1	1.2	7.0	0.70	0.08	138,754						
Jan-17	11.1	1.2	7.0	0.70	0.08	138,754	11.1	1.2	7.0	0.70	0.08	138,754						
Feb-17	9.8	1.0	6.2	0.62	0.07	123,507	11.1	1.2	7.0	0.70	0.08	138,754						
Mar-17	7.9	0.8	5.0	0.50	0.06	98,705	8.7	1.0	6.1	0.61	0.07	120,154						
Apr-17	7.1	0.8	4.7	0.47	0.05	92,300	8.7	1.0	6.1	0.61	0.07	120,154	116.4	13.5	81.1	8.1	0.93	1,608,206
May-17	8.7	1.0	6.1	0.61	0.07	120,154	8.7	1.0	6.1	0.61	0.07	120,154	115.0	13.4	80.3	8.0	0.92	1,593,046
Jun-17	9.3	1.1	6.4	0.64	0.07	125,937	9.7	1.2	6.9	0.69	0.08	136,637	115.1	13.4	80.4	8.0	0.92	1,594,771
Jul-17	9.7	1.2	6.9	0.69	0.08	136,637	9.7	1.2	6.9	0.69	0.08	136,637	115.3	13.4	80.5	8.1	0.92	1,596,496
Aug-17	9.0	1.1	6.7	0.67	0.08	132,722	9.7	1.2	6.9	0.69	0.08	136,637	115.4	13.5	80.6	8.1	0.93	1,598,222
Sep-17	8.0	1.1	6.6	0.66	0.08	130,855	8.6	1.1	6.6	0.66	0.08	130,855	114.9	13.4	80.3	8.0	0.92	1,591,881
Oct-17	8.6	1.1	6.6	0.66	0.08	130,393	8.6	1.1	6.6	0.66	0.08	130,855	114.4	13.3	80.0	8.0	0.92	1,585,541
Nov-17	6.0	0.7	4.1	0.41	0.05	81,202	8.6	1.1	6.6	0.66	0.08	130,855	113.9	13.3	79.6	8.0	0.91	1,579,200
Dec-17	7.9	0.9	5.7	0.57	0.07	112,435	8.0	1.0	5.8	0.58	0.07	115,015	110.9	13.1	78.4	7.8	0.90	1,555,461
Jan-18	8.0	1.0	5.8	0.58	0.07	115,015	8.0	1.0	5.8	0.58	0.07	115,015	107.9	12.9	77.2	7.7	0.89	1,531,722
Feb-18	7.1	0.8	4.7	0.47	0.05	94,086	8.0	1.0	5.8	0.58	0.07	115,015	104.8	12.7	76.0	7.6	0.87	1,507,983
Mar-18	3.8	0.4	2.3	0.23	0.03	45,137	9.1	1.0	6.0	0.60	0.07	118,729	105.3	12.7	76.0	7.6	0.87	1,506,558
Apr-18	9.1	1.0	6.0	0.60	0.07	118,729	9.1	1.0	6.0	0.60	0.07	118,729	105.7	12.7	75.9	7.6	0.87	1,505,133
"Could Have Accommodated" Emissions (tpy):[3]													116.4	13.5	81.1	8.1	0.93	1,608,206

1. The seasonally-adjusted monthly emissions are based on the highest monthly emissions during the three consecutive months in a season applied to all the consecutive months in the season. The seasons in Georgia are as follows:
   - Spring: March - May
   - Summer: June - August
   - Fall: September - November
   - Winter: December - February
2. Calculated as the 12 consecutive month totals of the seasonally-adjusted monthly emissions during the baseline period.
3. The "Could Have Accommodated" emissions for each pollutant are based on the maximum of the seasonally-adjusted 12-month totals during the baseline period.

Table B-14. "Could Have Accommodated" CO Emissions - Units 8A and 8B

Month	Actual Monthly CO Emissions (tons/mo)	Seasonally-Adjusted Monthly CO Emissions (tons/mo)[1]	Seasonally-Adjusted 12-Month Total CO Emissions (tpy)[2]
Aug-15	1.7	1.7	
Sep-15	2.4	2.4	
Oct-15	0.9	2.4	
Nov-15	2.4	2.4	
Dec-15	3.9	3.9	
Jan-16	3.7	3.9	
Feb-16	3.3	3.9	
Mar-16	0.2	1.3	
Apr-16	0.3	1.3	
May-16	1.3	1.3	
Jun-16	0.7	2.4	
Jul-16	1.8	2.4	29.4
Aug-16	2.4	2.4	30.0
Sep-16	1.9	1.9	29.5
Oct-16	1.8	1.9	29.0
Nov-16	1.4	1.9	28.5
Dec-16	0.9	0.9	25.4
Jan-17	0.3	0.9	22.3
Feb-17	0.3	0.9	19.2
Mar-17	0.1	2.1	20.1
Apr-17	1.9	2.1	20.9
May-17	2.1	2.1	21.7
Jun-17	1.3	1.3	20.6
Jul-17	1.0	1.3	19.6
"Could Have Accommodated" CO Emissions (tpy):[3]			30.0

1. The seasonally-adjusted monthly emissions are based on the highest monthly emissions during the three consecutive months in a season applied to all the consecutive months in the season. The seasons in Georgia are as follows:

Spring: March - May
Summer: June - August
Fall: September - November
Winter: December - February

2. Calculated as the 12 consecutive month totals of the seasonally-adjusted monthly emissions during the baseline period.
3. The "Could Have Accommodated" emissions for each pollutant are based on the maximum of the seasonally-adjusted 12-month totals during the baseline period.

Table B-15. Projected Actual Emissions - Units 8A and 8B

Estimated Future Max. Annual Heat Input (million MMBtu/yr)		30.2
Pollutant	Emission Factor (lb/MMBtu)	Projected Actual Emissions (tpy)
NO_X[1]	1.01E-02	153.1
CO[1]	4.48E-03	67.6
VOC	1.00E-03	15.1
$PM_{10}/PM_{2.5}$	6.00E-03	90.6
SO_2	6.00E-04	9.1
H_2SO_4	6.89E-05	1.0
CO_2e	118.98	1,796,567

1. The projected actual NO_X and CO emission rates were conservatively based on the maximum of the monthly average emission rates (monthly emissions divided by monthly heat input) during the 24-month baseline period for each pollutant.

Table B-16. Cooling Tower Associated Emissions Increase

Emission Source	Total Dissolved Solids[1] (mg/L)	Drift Loss Increase[2] (gpm)	PM Emissions Increase[3] (tpy)	PM_{10} Emissions Increase[4] (tpy)	$PM_{2.5}$ Emissions Increase[4] (tpy)
Cooling Tower	602	0.23	0.31	0.27	1.5E-03

1. Average cooling tower water TDS content, per facility documentation.
2. Based on cooling tower modeling performed by Siemens at 59 °F ambient with duct burners firing.
3. Annual PM Emission Rate (ton/yr) = Drift Loss Increase (gal/min) × TDS (mg/L) × 3.78541 (L/gal) × 2.2045E-06 (lb/mg) × 60 (min/hr) × 8,760 (hr/yr) / 2,000 (lb/ton)
4. PM_{10} and $PM_{2.5}$ emissions are estimated based on the particulate size distribution below, interpolated from data in *Calculating Realistic PM 10 Emissions from Cooling Towers* by Joel Reisman and Gordon Frisbie, 2002. Detailed derivation of PM_{10}/$PM_{2.5}$ fractions is shown in the table below.

Table B-17. Derivation of PM_{10}/$PM_{2.5}$ Fraction for Cooling Tower Emissions[1]

Drift Droplet Diameter [D_d] (μm)	Drift Droplet Volume [$V_{droplet}$][2] (μm^3)	Drift Droplet Mass [$M_{droplet}$][3] (μg)	Droplet Particle Mass [M_{TDS}][4] (μg)	Solid Particle Diameter [D_{TDS}][5] (μm)	EPRI Cumulative % Mass Smaller[6] (%)	Interpolation Value for PM_{10}[7] (%)	Interpolation Value for $PM_{2.5}$[7] (%)
0	0.00E+00	0.00E+00	0.00E+00	0.000	0	--	--
10	5.24E+02	5.24E-04	3.15E-07	0.649	0	--	--
20	4.19E+03	4.19E-03	2.52E-06	1.298	0.196	--	--
30	1.41E+04	1.41E-02	8.51E-06	1.948	0.226	--	--
40	3.35E+04	3.35E-02	2.02E-05	2.597	0.514	--	0.471
50	6.54E+04	6.54E-02	3.94E-05	3.246	1.816	--	--
60	1.13E+05	1.13E-01	6.81E-05	3.895	5.702	--	--
70	1.80E+05	1.80E-01	1.08E-04	4.545	21.348	--	--
90	3.82E+05	3.82E-01	2.30E-04	5.843	49.812	--	--
110	6.97E+05	6.97E-01	4.20E-04	7.141	70.509	--	--
130	1.15E+06	1.15E+00	6.93E-04	8.440	82.023	--	--
150	1.77E+06	1.77E+00	1.06E-03	9.738	88.012	--	--
180	3.05E+06	3.05E+00	1.84E-03	11.686	91.032	88.418	--
210	4.85E+06	4.85E+00	2.92E-03	13.634	92.468	--	--
240	7.24E+06	7.24E+00	4.36E-03	15.581	94.091	--	--
300	1.41E+07	1.41E+01	8.51E-03	19.477	96.288	--	--
350	2.24E+07	2.24E+01	1.35E-02	22.723	97.011	--	--
400	3.35E+07	3.35E+01	2.02E-02	25.969	98.34	--	--
450	4.77E+07	4.77E+01	2.87E-02	29.215	99.071	--	--
600	1.13E+08	1.13E+02	6.81E-02	38.953	100	--	--

1. Based on the methodology discussed in *Calculating Realistic PM 10 Emissions from Cooling Towers* by Joel Reisman and Gordon Frisbie, 2002 (the Document).
https://ww2.energy.ca.gov/sitingcases/palomar/documents/applicants_files/Data_Request_Response/Air%20Quality/Attachment%204-1.pdf

2. $V_{droplet} = 4/3\ \pi\ (D_d/2)^3$ [Equation 2 of the Document]
3. $M_{droplet}$ = density (ρ_w) of water * $V_{droplet} = \rho_w * 4/3\ \pi\ (D_d/2)^3$

$\rho_w =$ 1.00E-06 $\mu g/\mu m^3$

4. $M_{TDS} = TDS * M_{droplet}$ [Equation 3 of the Document, with TDS in units of ppm]

TDS = 602 mg/L Total Dissolved Solids content for CEF's cooling tower

TDS = 602 ppm

5. $M_{TDS} = (\rho_{TDS})\ (V_{TDS}) = (\rho_{TDS})\ (4/3)\pi\ (D_{TDS}/2)^3$ [Equation 5 of the Document]

Therefore, the equation can be solved for D_{TDS}: $D_{TDS} = \{M_{TDS}/[(\rho_{TDS}) * 4/3 * \pi]\}^{1/3} \times 2$

Assume solid particulates have the same density (ρ_{TDS}) as sodium chloride per the Document: 2.20E-06 $\mu g/\mu m^3$

6. Based on drift eliminator test data from a test conducted by Environmental Systems Corporation (ESC) at the Electric Power Research Institute (EPRI) test facility in Houston, Texas in 1988 (Aull, 1999) as documented in Table 1 of the Document.
7. D_{TDS} represents the particle size of collected material in droplet. The EPRI cumulative % mass smaller indicates the percentage of material in that specific water droplet size that has a diameter smaller than D_{TDS}. Therefore, linear interpolation between calculated D_{TDS} is necessary to ascertain the specific mass percentages to estimate PM_{10} and $PM_{2.5}$ emissions. For example, at 1,000 mg/L TDS:

%MassPM_{10} = %Mass Less than 10 D_{TDS} + [(10 - D_{TDS} Less Than 10) / (D_{TDS} Greater Than 10 - D_{TDS} Less Than 10)] * (%Mass Greater than 10 D_{TDS} - %Mass Less than 10 D_{TDS})
i.e., 82.041% = 82.023% + [(10 - 9.995) / (11.533 - 9.995)] * (88.012% - 82.023%)

Table B-18. Project Emissions Increase

Pollutant	Units 8A and 8B				Cooling Tower Associated Emissions Increase (tpy)	Total Project Emissions Increase (tpy)	NSR Significant Emission Rate[2] (tpy)	NSR Triggered?
	Baseline Actual Emissions (tpy)	"Could Have Accommodated" Emissions (tpy)	Projected Actual Emissions (tpy)	Project Emissions Increase[1] (tpy)				
NO_X	100.2	116.4	153.1	36.7	-	36.7	40	No
CO	19.0	30.0	67.6	37.6	-	37.6	100	No
VOC	11.6	13.5	15.1	1.59	-	1.6	40	No
PM	69.7	81.1	90.6	9.5	0.31	9.8	25	No
PM_{10}	69.7	81.1	90.6	9.5	0.27	9.8	15	No
$PM_{2.5}$	69.7	81.1	90.6	9.5	1.5E-03	9.5	10	No
SO_2	7.0	8.1	9.1	0.95	-	0.9	40	No
H_2SO_4	0.80	0.93	1.0	0.11	-	0.1	7	No
CO_2e[3]	1,382,762	1,608,206	1,796,567	188,361	-	188,361	75,000	No

1. Project Emissions Increase = (Projected Actual Emissions - Baseline Actual Emissions) - ("Could Have Accommodated" Emissions - Baseline Actual Emissions)
2. 40 CFR 52.21(b)23(i) and Georgia Air Quality Control Rule 391-3-1-.03(8)(c)15
3. NSR permitting for CO_2e is only required if the project emissions increase exceeds the NSR SER of 75,000 tpy and if NSR permitting is triggered for at least one other regulated pollutant.

APPENDIX C. TOXICS IMPACT ANALYSIS DOCUMENTATION

Table C-1. Natural Gas Burning Equipment - Operating Parameters

Emission Source	Source No.	Fuel Type	Estimated Maximum Annual Operating Capacity[1] (Million MMBtu/yr)	Estimated Maximum Short Term Operating Capacity (MMBtu/hr)
CT8A Combustion Turbine	CT8A	Natural Gas	15.69	1,900.0
CT8B Combustion Turbine	CT8B	Natural Gas	15.69	1,900.0
DB8A Duct Burner	DB8A	Natural Gas	0.83	95.0
DB8B Duct Burner	DB8B	Natural Gas	0.83	95.0

1. Based on post project heat input capacity per turbine at 59F (1,790.7 MMBtu/hr) and the permitted heat input capacity for the duct burners (95 MMBtu/hr) times potential operation of 8,760 hrs/yr.

Table C-2. Potential TAP Emissions from Combustion Turbines

Pollutant	Emission Factor[1] (lb/MMBtu)	Potential Emissions[2] Combustion Turbines (tpy)	Potential Emissions[3] Combustion Turbines (lb/hr)
Lead	--	--	--
1,3-Butadiene	4.30E-07	6.75E-03	1.63E-03
Acetaldehyde	4.00E-05	0.63	1.52E-01
Acrolein	6.40E-06	1.00E-01	2.43E-02
Ammonia[4]		1.84E+02	4.20E+01
Benzene	1.20E-05	1.88E-01	4.56E-02
Ethylbenzene	3.20E-05	0.50	1.22E-01
Formaldehyde[5]	1.14E-04	1.79	0.43
Naphthalene	1.30E-06	2.04E-02	4.94E-03
Propylene Oxide	2.90E-05	0.45	1.10E-01
Sulfuric Acid[6]	6.89E-05	1.08	2.62E-01
Toluene	1.30E-04	2.04	4.94E-01
Xylenes	6.40E-05	1.00	2.43E-01

1. Emission factors per AP-42, Section 3.1 Stationary Gas Turbine, Tables 3.1.-2a and 3.1-3 unless otherwise noted.
2. Potential Emissions (tpy) = Emission Factor (lb/MMBtu) * Maximum Annual Operating Capacity (Million MMBtu/yr) * 1E6 MMBtu/ Million MMBtu / 2,000 lb/ton
3. Potential Emissions (lb/hr) = Emission Factor (lb/MMBtu) * Maximum Short Term Operating Capacity (MMBtu/hr)
4. Based on ammonia slip of 10 ppmvd from the SCR system, as derived during the initial permitting for the facility
5. Formaldehyde emission factor based on AP-42 Section 3.1 Database (April 2000) for Frame Type CTs greater than 40 MW.
6. Sulfuric Acid emission factor based on a 7.5% conversion of SO_2 to H_2SO_4, consistent with the facility's initial November 2000 PSD permit application.

Table C-3. Potential TAP Emissions from Duct Burners

Pollutant	Emission Factor[1] (lb/MMscf)	Potential Emissions[2] Duct Burners (tpy)	Potential Emissions[3] Duct Burners (lb/hr)
Benzene	2.10E-03	1.71E-03	3.91E-04
1,4-Dichlorobenzene	1.20E-03	9.79E-04	2.24E-04
Formaldehyde	7.50E-02	6.12E-02	1.40E-02
Hexane	1.80E+00	1.47	3.35E-01
Naphthalene	6.10E-04	4.98E-04	1.14E-04
Pentane	2.60E+00	2.12	4.84E-01
Propane	1.60E+00	1.31	2.98E-01
Sulfuric Acid[4]	7.03E-02	5.73E-02	1.31E-02
Toluene	3.40E-03	2.77E-03	6.33E-04
Arsenic	2.00E-04	1.63E-04	3.73E-05
Barium	4.40E-03	3.59E-03	8.20E-04
Beryllium	1.20E-05	9.79E-06	2.24E-06
Cadmium	1.10E-03	8.97E-04	2.05E-04
Chromium	1.40E-03	1.14E-03	2.61E-04
Cobalt	8.40E-05	6.85E-05	1.56E-05
Copper	8.50E-04	6.94E-04	1.58E-04
Manganese	3.80E-04	3.10E-04	7.08E-05
Mercury	2.60E-04	2.12E-04	4.84E-05
Molybdenum	1.10E-03	8.97E-04	2.05E-04
Nickel	2.10E-03	1.71E-03	3.91E-04
Selenium	2.40E-05	1.96E-05	4.47E-06

1. Emission factors per AP-42, Section 1.4 Natural Gas Combustion, Tables 1.4-3 and 1.4-4.
2. Potential Emissions (tpy) = Emission Factor (lb/MMscf) / 1,020 (MMBtu/MMscf) * Maximum Annual Operating Capacity (Million MMBtu/yr) * 1E6 MMBtu/ Million MMBtu / 2,000 lb/ton
3. Potential Emissions (lb/hr) = Emission Factor (lb/MMBtu) * Maximum Short Term Operating Capacity (MMBtu/hr)
4. Sulfuric Acid emission factor based on a 7.5% conversion of SO_2 to H_2SO_4, consistent with the facility's initial November 2000 PSD permit application.

Table C-4. Toxic Air Pollutant Emissions Compared to Minimum Emission Rates

Toxic Air Pollutant (TAP)	OPC Chattahoochee Annual Emissions (tpy)	OPC Chattahoochee Annual Emissions[1] (lb/yr)	Short Term Emission Rate[2] (g/s)	Minimum Emission Rate (MER)[3] (lb/yr)	Above MER?
Arsenic	1.63E-04	0.33	4.69E-06	0.057	Yes
Ammonia	184	367,920	5.29E+00	24,333	Yes
Beryllium	9.79E-06	0.02	2.82E-07	0.97	No
Cadmium	8.97E-04	1.8	2.58E-05	1.35	Yes
Acrolein	1.00E-01	201	3.06E-03	4.87	Yes
Lead	--	--	--	5.84	No
1,3-Butadiene	6.75E-03	13.5	2.06E-04	7.30	Yes
Cobalt	6.85E-05	0.14	1.97E-06	11.7	No
Manganese	3.10E-04	0.62	8.92E-06	12.2	No
Selenium	1.96E-05	0.04	5.63E-07	23.4	No
Chromium	1.14E-03	2.3	3.29E-05	24.33	No
Benzene	1.90E-01	380	5.79E-03	31.6	Yes
Nickel	1.71E-03	3.4	4.93E-05	38.6	No
Barium	3.59E-03	7.2	1.03E-04	57.9	No
Mercury	2.12E-04	0.42	6.10E-06	73.0	No
Copper	6.94E-04	1.4	1.99E-05	117	No
Sulfuric Acid	1.14	2,276	3.46E-02	117	Yes
Formaldehyde	1.85	3,699	5.63E-02	267	Yes
Propylene Oxide	4.55E-01	910	1.39E-02	657	Yes
Naphthalene	2.09E-02	41.8	6.37E-04	730	No
Acetaldehyde	0.63	1,255	1.92E-02	1,107	Yes
Molybdenum	8.97E-04	1.8	2.58E-05	1,738	No
Xylenes	1.00	2,008	3.06E-02	24,333	No
Hexane	1.47	2,937	4.22E-02	170,331	No
1,4-Dichlorobenzene	9.79E-04	2.0	2.82E-05	194,664	No
Propane	1.3	2,611	3.76E-02	208,600	No
Ethylbenzene	0.50	1,004	1.53E-02	243,330	No
Pentane	2.1	4,243	6.10E-02	341,858	No
Toluene	2.04	4,084	6.23E-02	1,216,650	No

1. Annual Emissions (lb/yr) = Annual Emissions (ton/yr) * 2,000 lb/ton.
2. Short Term Emission Rate (g/s) = Short Term Emissions (lb/hr) * 453.592 (g/lb) / 3,600 (s/hr)
3. From EPD's *Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions,* updated October 2018.

Table C-5. Worst Case Stack Parameters for SCREEN3[1]

Source Type	Height (m)	Diameter (m)	Velocity (m/s)	Gas Temperature (K)
Point	39.624	5.03	24.81	366.2

1. Conservatively assumes all emissions are from a single stack.

Table C-6. SCREEN3 Modeling Results at 1 g/s

Maximum 1-Hour Impact	1.007 µg/m³
Maximum 15-Minute Impact[1]	1.329 µg/m³
Maximum 24-Hour Impact[2]	0.532 µg/m³
Maximum Annual Impact[3]	0.043 µg/m³

1. The 15-minute impact equals the 1-hour impact times 1.32 per the EPD *Guideline*.
2. The 24-hour impact equals the 1-hour impact times 0.4 per the EPD *Guideline*.
3. The annual impact equals the 1-hour impact times 0.08 per the EPD *Guideline*.

Table C-7. Modeling Results Compared to AAC Values[1]

Toxic Air Pollutant (TAP)	Maximum Annual Impact µg/m³	Annual AAC µg/m³	% of AAC	Maximum 24-Hour Impact µg/m³	24-Hour AAC µg/m³	% of ACC	Maximum 15-Minute Impact µg/m³	15-Minute AAC µg/m³	% of AAC
Arsenic	2.00E-07	2.33E-04	< 1.00%	N/A	N/A	--	6.24E-06	2.00E-01	< 1.00%
Ammonia	2.25E-01	1.00E+02	< 1.00%	N/A	N/A	--	7.03E+00	2.40E+03	< 1.00%
Cadmium	1.10E-06	5.56E-03	< 1.00%	N/A	N/A	--	3.43E-05	3.00E+01	< 1.00%
Acrolein	1.30E-04	2.00E-02	< 1.00%	N/A	N/A	--	4.07E-03	2.30E+01	< 1.00%
1,3-Butadiene	8.76E-06	3.00E-02	< 1.00%	N/A	N/A	--	2.74E-04	1.10E+03	< 1.00%
Benzene	2.46E-04	1.30E-01	< 1.00%	N/A	N/A	--	7.70E-03	1.60E+03	< 1.00%
Sulfuric Acid	N/A	N/A	--	1.84E-02	2.40E+00	< 1.00%	4.60E-02	3.00E+02	< 1.00%
Formaldehyde	2.40E-03	1.10E+00	< 1.00%	N/A	N/A	--	7.49E-02	2.45E+02	< 1.00%
Propylene Oxide	5.91E-04	2.70E+00	< 1.00%	N/A	N/A	--	N/A	N/A	--
Acetaldehyde	8.15E-04	4.55E+00	< 1.00%	N/A	N/A	--	2.55E-02	4.50E+03	< 1.00%

1. AAC values from the EPD Guideline, updated October 2018.

06/11/20
08:43:04

*** SCREEN3 MODEL RUN ***
*** VERSION DATED 13043 ***

OPC CEF

SIMPLE TERRAIN INPUTS:

SOURCE TYPE	=	POINT
EMISSION RATE (G/S)	=	1.000000
STACK HEIGHT (M)	=	39.6240
STK INSIDE DIAM (M)	=	5.0300
STK EXIT VELOCITY (M/S)	=	24.8100
STK GAS EXIT TEMP (K)	=	366.2000
AMBIENT AIR TEMP (K)	=	293.0000
RECEPTOR HEIGHT (M)	=	0.0000
URBAN/RURAL OPTION	=	RURAL
BUILDING HEIGHT (M)	=	0.0000
MIN HORIZ BLDG DIM (M)	=	0.0000
MAX HORIZ BLDG DIM (M)	=	0.0000

THE REGULATORY (DEFAULT) MIXING HEIGHT OPTION WAS SELECTED.
THE REGULATORY (DEFAULT) ANEMOMETER HEIGHT OF 10.0 METERS WAS ENTERED.

BUOY. FLUX = 307.606 M**4/S**3; MOM. FLUX = 3115.149 M**4/S**2.

*** FULL METEOROLOGY ***

****
*** SCREEN AUTOMATED DISTANCES ***
****

*** TERRAIN HEIGHT OF 0. M ABOVE STACK BASE USED FOR FOLLOWING DISTANCES ***

DIST (M)	CONC (UG/M**3)	STAB	U10M (M/S)	USTK (M/S)	MIX HT (M)	PLUME HT (M)	SIGMA Y (M)	SIGMA Z (M)	DWASH
20.	0.000	1	1.0	1.1	1134.0	1132.98	29.99	29.48	NO
100.	0.2489E-03	5	1.0	1.6	10000.0	210.49	41.52	41.21	NO
200.	0.8490E-02	5	1.0	1.6	10000.0	210.49	50.18	49.22	NO
300.	0.9384E-02	5	1.0	1.6	10000.0	210.49	51.66	49.59	NO
400.	0.1042E-01	5	1.0	1.6	10000.0	210.49	53.55	50.00	NO
500.	0.2185E-01	1	3.0	3.3	960.0	404.08	127.44	120.06	NO
600.	0.2120	1	3.0	3.3	960.0	404.08	148.57	167.67	NO
700.	0.5080	1	3.0	3.3	960.0	404.08	169.18	225.68	NO
800.	0.6735	1	3.0	3.3	960.0	404.08	189.36	294.23	NO
900.	0.8346	1	2.0	2.2	640.0	586.30	230.72	385.91	NO
1000.	0.9825	1	2.0	2.2	640.0	586.30	251.38	474.99	NO
1100.	1.004	1	2.0	2.2	640.0	586.30	271.70	575.02	NO

1200.	0.9674	1	2.0	2.2	640.0	586.30	290.61	685.62	NO
1300.	0.9286	1	1.5	1.7	769.5	768.53	335.42	817.80	NO
1400.	0.8971	1	1.5	1.7	769.5	768.53	349.46	948.29	NO
1500.	0.8629	1	1.5	1.7	769.5	768.53	363.68	1090.67	NO
1600.	0.8302	1	1.5	1.7	769.5	768.53	378.05	1244.85	NO
1700.	0.7996	1	1.5	1.7	769.5	768.53	392.54	1410.80	NO
1800.	0.7709	1	1.5	1.7	769.5	768.53	407.13	1588.50	NO
1900.	0.7441	1	1.5	1.7	769.5	768.53	421.78	1777.96	NO
2000.	0.7190	1	1.5	1.7	769.5	768.53	436.50	1979.20	NO
2100.	0.6955	1	1.5	1.7	769.5	768.53	451.26	2192.25	NO
2200.	0.6734	1	1.5	1.7	769.5	768.53	466.06	2417.14	NO
2300.	0.6527	1	1.5	1.7	769.5	768.53	480.88	2653.91	NO
2400.	0.6331	1	1.5	1.7	769.5	768.53	495.71	2902.61	NO
2500.	0.6147	1	1.5	1.7	769.5	768.53	510.56	3163.26	NO
2600.	0.5974	1	1.5	1.7	769.5	768.53	525.40	3435.93	NO
2700.	0.5810	1	1.5	1.7	769.5	768.53	540.24	3720.65	NO
2800.	0.5654	1	1.5	1.7	769.5	768.53	555.08	4017.46	NO
2900.	0.5507	1	1.5	1.7	769.5	768.53	569.90	4326.41	NO
3000.	0.5368	1	1.5	1.7	769.5	768.53	584.71	4647.55	NO
3500.	0.4858	2	2.0	2.2	640.0	586.30	494.16	459.40	NO
4000.	0.4783	2	2.0	2.2	640.0	586.30	549.96	524.02	NO
4500.	0.4582	2	1.5	1.7	769.5	768.53	620.80	606.10	NO
5000.	0.4438	2	1.5	1.7	769.5	768.53	674.43	672.02	NO

MAXIMUM 1-HR CONCENTRATION AT OR BEYOND 20. M:

1072.	1.007	1	2.0	2.2	640.0	586.30	265.84	544.88	NO

DWASH= MEANS NO CALC MADE (CONC = 0.0)
DWASH=NO MEANS NO BUILDING DOWNWASH USED
DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

****
*** SUMMARY OF SCREEN MODEL RESULTS ***
****

CALCULATION PROCEDURE	MAX CONC (UG/M**3)	DIST TO MAX (M)	TERRAIN HT (M)
SIMPLE TERRAIN	1.007	1072.	0.

****
** REMEMBER TO INCLUDE BACKGROUND CONCENTRATIONS **
****

APPENDIX D. EPD SIP FORMS

State of Georgia
Department of Natural Resources
Environmental Protection Division
Air Protection Branch

Stationary Source Permitting Program
4244 International Parkway, Suite 120
Atlanta, Georgia 30354
404/363-7000
Fax: 404/363-7100

EXPEDITED PERMITTING PROGRAM – APPLICATION FOR ENTRY TO PROGRAM FOR AIR PERMITS

EPD Use Only

Date Received: ____________ Application No. ____________

To be eligible for expedited review, this application form must be accompanied by the complete permit application for the type of air permit being requested, and a pre-application meeting with EPD must have been conducted.

1. Contact Information

Facility Name: Chattahoochee Energy Facility

AIRS No. (if known): 04-13-149 - 00006

Contact Person: Courtney Adcock Title: Sr. Environmental Specialist

Telephone No.: 770-270-7678 Alternate Phone No.: ____________

Email Address: courtney.adcock@opc.com

If EPD is unable to contact me, please contact the alternate contact person:

Contact Person: Justin Fickas Title: Managing Consultant

Telephone No.: 404-751-0228 Alternate Phone No.: ____________

Email Address: jfickas@trinityconsultants.com

On Page 2 of this form, please check the appropriate box for which type of air permit you are requesting expedited review.

I have read the Expedited Review Program Standard Operating Procedures and accept all of the terms and conditions within. I understand that it is my responsibility to ensure an application of the highest quality is submitted and to address any requests for additional information by the deadline specified. I understand that submittal of this request form is not a guarantee that expedited review will be granted.

Signature: Courtney Adcock Date: 6/18/2020

2. Applying For Which Type Of Permit: (Please Check Appropriate Box)

Expedited Review Fees for Air Permits	
Permit Type – Please Check One	**Expedited Review Fee***
☐ Generic Permit: Concrete Batch Plant – Minor Source	$1,000
☐ Generic Permit: Concrete Batch Plant – Synthetic Minor Source	$1,500
☐ Generic Permit: Hot Mix Asphalt Plant – Synthetic Minor Source	$2,000
☐ Minor Source Permit (or Amendment)	$3,000
☐ Synthetic Minor Permit (or Amendment)	$4,000
☐ Major Source SIP Permit not subject to PSD or 112(g)	$6,000
☐ Title V 502(b)(10) Permit Amendment	$4,000
☐ Title V Minor Modification with Construction	$4,000
☒ Title V Significant Modification	$6,000
☐ Major Source SIP Permit subject to 112(g) but not subject to PSD	$15,000
☐ PSD Permit (or Amendment) not subject to NAAQS and/or PSD Increment Modeling	$15,000
☐ PSD Permit (or Amendment) subject to NAAQS and/or PSD Increment Modeling but not subject to Modeling for $PM_{2.5}$, NO_2, or SO_2	$20,000
☐ PSD Permit (or Amendment) subject to NAAQS and/or PSD Increment Modeling for $PM_{2.5}$, NO_2, or SO_2	$25,000
☐ PSD Permit (or Amendment) subject to NAAQS and/or PSD Increment Modeling for $PM_{2.5}$, NO_2, or SO_2 and also impacting a Class I Area	$30,000
* Do not send fee payment with this form. Upon acceptance of application for the expedited permit program, EPD will notify you by phone. Fees must be paid via check to "Georgia Department of Natural Resources" within five (5) business days of acceptance.	

3. Comments.

This section is optional. Applicants may use this field to include specific comments or requests for EPD consideration. For example, the applicant may use this field to request a public hearing or to remind EPD of review time needs and/or expectations that may differ from the time frames in the procedures.

State of Georgia
Department of Natural Resources
Environmental Protection Division
Air Protection Branch

Stationary Source Permitting Program
4244 International Parkway, Suite 120
Atlanta, Georgia 30354
404/363-7000
Fax: 404/363-7100

SIP AIR PERMIT APPLICATION

EPD Use Only

Date Received: ____________ Application No. ____________

FORM 1.00: GENERAL INFORMATION

1. Facility Information

Facility Name: Chattahoochee Energy Facility
AIRS No. (if known): 04-13- 149 - 00006
Facility Location: Street: 3461 Hollingsworth Ferry Road
City: Franklin Georgia Zip: 30217 County: Heard
Is this facility a "small business" as defined in the instructions? Yes: ☐ No: ☒

2. Facility Coordinates

Latitude: 34° 24' 42" **NORTH** Longitude: 85° 02' 19" **WEST**
UTM Coordinates: 682383 **EAST** 3698649 **NORTH** **ZONE** 16

3. Facility Owner

Name of Owner: Oglethorpe Power Corporation
Owner Address Street: 2100 East Exchange Place
City: Tucker State: GA Zip: 30084

4. Permitting Contact and Mailing Address

Contact Person: Courtney Adcock Title: Sr. Environmental Specialist
Telephone No.: (770) 270-7678 Ext. ______ Fax No.: (770) 270-7920
Email Address: courtney.adcock@opc.com
Mailing Address: Same as: Facility Location: ☐ Owner Address: ☒ Other: ☐
If Other: Street Address: ____________
City: ______ State: ______ Zip: ______

5. Authorized Official

Name: James Messersmith Title: Sr. Vice President, Plant Operations
Address of Official Street: 2100 East Exchange Place
City: Tucker State: GA Zip: 30084

This application is submitted in accordance with the provisions of the Georgia Rules for Air Quality Control and, to the best of my knowledge, is complete and correct.

Signature: James A Messersmith Date: 6/18/2020

6. Reason for Application: (Check all that apply)

- ☐ New Facility (to be constructed)
- ☒ Existing Facility (initial or modification application)
- ☒ Permit to Construct
- ☒ Permit to Operate
- ☐ Change of Location
- ☒ Permit to Modify Existing Equipment: Affected Permit No.: 4911-149-0006-V-05-0

☐ Revision of Data Submitted in an Earlier Application

Application No.: ______

Date of Original Submittal: ______

7. Permitting Exemption Activities (for permitted facilities only):

Have any exempt modifications based on emission level per Georgia Rule 391-3-1-.03(6)(i)(3) been performed at the facility that have not been previously incorporated in a permit?

☒ **No** ☐ **Yes, please fill out the SIP Exemption Attachment** (See Instructions for the attachment download)

8. Has assistance been provided to you for any part of this application?

☐ **No** ☐ **Yes, SBAP** ☒ **Yes, a consultant has been employed or will be employed.**

If yes, please provide the following information:

Name of Consulting Company: Trinity Consultants

Name of Contact: Justin Fickas

Telephone No.: 404-751-0228 Fax No.: 678-441-9978

Email Address: jfickas@trinityconsultants.com

Mailing Address: Street: 3495 Piedmont Road Building 10, Suite 905

City: Atlanta State: GA Zip: 30305

Describe the Consultant's Involvement:

Preparation of application.

9. Submitted Application Forms: Select only the necessary forms for the facility application that will be submitted.

No. of Forms	Form
1	2.00 Emission Unit List
1	2.01 Boilers and Fuel Burning Equipment
	2.02 Storage Tank Physical Data
	2.03 Printing Operations
	2.04 Surface Coating Operations
	2.05 Waste Incinerators (solid/liquid waste destruction)
	2.06 Manufacturing and Operational Data
1	3.00 Air Pollution Control Devices (APCD)
	3.01 Scrubbers
	3.02 Baghouses & Other Filter Collectors
	3.03 Electrostatic Precipitators
1	4.00 Emissions Data
1	5.00 Monitoring Information
	6.00 Fugitive Emission Sources
1	7.00 Air Modeling Information

10. Construction or Modification Date

Estimated Start Date: December 1, 2020

11. If confidential information is being submitted in this application, were the guidelines followed in the "Procedures for Requesting that Submitted Information be treated as Confidential"?

☐ No ☐ Yes

12. New Facility Emissions Summary

Criteria Pollutant	New Facility	
	Potential (tpy)	Actual (tpy)
Carbon monoxide (CO)		
Nitrogen oxides (NOx)		
Particulate Matter (PM) (filterable only)		
PM <10 microns (PM10)		
PM <2.5 microns (PM2.5)		
Sulfur dioxide (SO_2)		
Volatile Organic Compounds (VOC)		
Greenhouse Gases (GHGs) (in CO2e)		
Total Hazardous Air Pollutants (HAPs)		
Individual HAPs Listed Below:		

13. Existing Facility Emissions Summary

Criteria Pollutant	Current Facility		After Modification	
	Potential (tpy)	Actual (tpy)	Potential (tpy)	Actual (tpy)
Carbon monoxide (CO)	86.0	< 86	86.0	< 86.0
Nitrogen oxides (NOx)	179.6	< 179.6	179.6	< 179.6
Particulate Matter (PM) (Total)	168	< 168	173	< 173
PM <10 microns (PM10) (Total)	167	< 167	173	< 173
PM <2.5 microns (PM2.5) (Total)	161	< 161	166	< 166
Sulfur dioxide (SO_2)	9.60	< 9.60	9.91	< 9.91
Volatile Organic Compounds (VOC)	41.5	< 41.5	42.8	< 42.8
Greenhouse Gases (GHGs) (in CO2e)	1,903,064	< 1,903,064	1,965,365	< 1,965,365
Total Hazardous Air Pollutants (HAPs)	7.78	< 7.78	8.27	< 8.27
Individual HAPs Listed Below:				
Maximum Single HAP (Formaldehyde)	1.97	< 1.97	2.10	< 2.10

14. 4-Digit Facility Identification Code:

SIC Code: 4911 SIC Description: Electric Services

NAICS Code: 221112 NAICS Description: Electric power generation, fossil fuel

15. Description of general production process and operation for which a permit is being requested. If necessary, attach additional sheets to give an adequate description. Include layout drawings, as necessary, to describe each process. References should be made to source codes used in the application.

See attached narrative.

16. Additional information provided in attachments as listed below:

Attachment A - Area Map and Process Flow Diagram

Attachment B - Emission Calculations

Attachment C - Toxics Impact Analysis

Attachment D - SIP Permit Application Forms

Attachment E -

Attachment F -

17. Additional Information: Unless previously submitted, include the following two items:

☒ Plot plan/map of facility location or date of previous submittal: See Appendix A

☒ Flow Diagram or date of previous submittal: See Appendix A

18. Other Environmental Permitting Needs:

Will this facility/modification trigger the need for environmental permits/approvals (other than air) such as Hazardous Waste Generation, Solid Waste Handling, Water withdrawal, water discharge, SWPPP, mining, landfill, etc.?

☒ **No** ☐ **Yes, please list below:**

19. List requested permit limits including synthetic minor (SM) limits.

See attached narrative.

20. Effective March 1, 2019, permit application fees will be assessed. The fee amount varies based on type of permit application. Application acknowledgement emails will be sent to the current registered fee contact in the GECO system. If fee contacts have changed, please list that below:

Fee Contact name: Courtney Adcock
Fee Contact email address: courtney.adcock@opc.com
Fee Contact phone number: 770-270-7678

Fee invoices will be created through the GECO system shortly after the application is received. It is the applicant's responsibility to access the facility GECO account, generate the fee invoice, and submit payment within 10 days after notification.

Facility Name: Chattahoochee Energy Facility **Date of Application:** June 2020

FORM 2.00 – EMISSION UNIT LIST

Emission Unit ID	Name	Manufacturer and Model Number	Description
CT8A	Combustion Turbine Unit 8A	Siemens-Westinghouse Model V84.3a2	Combustion Turbine
DB8A	HRSG Duct Burner for Turbine 8A	Forney	Duct Burner w/Low NOx burner to supplement HRSG
CT8B	Combustion Turbine Unit 8A	Siemens-Westinghouse Model V84.3a2	Combustion Turbine
DB8B	HRSG Duct Burner for Turbine 8A	Forney	Duct Burner w/Low NOx burner to supplement HRSG

Facility Name: Chattahoochee Energy Facility **Date of Application:** June 2020

FORM 2.01 – BOILERS AND FUEL BURNING EQUIPMENT

Emission Unit ID	Type of Burner	Type of Draft[1]	Design Capacity of Unit (MMBtu/hr Input)	Percent Excess Air	Dates		Date & Description of Last Modification
					Construction	Installation	
CCCT8A	Combined Combustion Turbine and Duct Burner (CT8A and DB8A)	N/A	1,995 MMBtu/hr[2]		2002	May 2002	N/A
CCCT8B	Combined Combustion Turbine and Duct Burner (CT8B and DB8B)	N/A	1,995 MMBtu/hr[2]		2002	May 2002	N/A

[1] This column does not have to be completed for natural gas only fired equipment.

[2] 1,995 MMBtu/hr represents the maximum short-term heat input capacity of each CCCT once the proposed project is complete. The projected actual heat input capacity is estimated to be 15.1 million MMBtu/yr per CCCT.

Facility Name: Chattahoochee Energy Facility **Date of Application:** June 2020

FUEL DATA

Emission Unit ID	Fuel Type	Potential Annual Consumption				Hourly Consumption		Heat Content		Percent Sulfur		Percent Ash in Solid Fuel	
		Total Quantity		Percent Use by Season									
		Amount	Units	Ozone Season May 1 - Sept 30	Non-ozone Season Oct 1 - Apr 30	Max.	Avg.	Min.	Avg.	Max.	Avg.	Max.	Avg.
CCCT8A	Natural Gas	16.5	Million MMBtu/yr			1,995 MMBtu/hr	Varies	~1,020 MMBtu/ MMscf	~1,020 MMBtu/ MMscf				
CCCT8B	Natural Gas	16.5	Million MMBtu/yr			1,995 MMBtu/hr	Varies	~1,020 MMBtu/ MMscf	~1,020 MMBtu/ MMscf				

Fuel Supplier Information

Fuel Type	Name of Supplier	Phone Number	Supplier Location			
			Address	City	State	Zip
Pipeline Quality Natural Gas						

Facility Name: Chattahoochee Energy Facility **Date of Application:** June 2020

Form 3.00 – AIR POLLUTION CONTROL DEVICES - PART A: GENERAL EQUIPMENT INFORMATION

APCD Unit ID	Emission Unit ID	APCD Type (Baghouse, ESP, Scrubber etc)	Date Installed	Make & Model Number (Attach Mfg. Specifications & Literature)	Unit Modified from Mfg Specifications?	Gas Temp. °F		Inlet Gas Flow Rate (acfm)
						Inlet	Outlet	
SCR8A	CCCT8A (CT8A and DB8A Combined)	Selective Catalytic Reduction	2016	Cormetech, Custom Built	N/A		Stack Outlet is 199.5°F	< 1,044,320
SCR8B	CCCT8B (CT8B and DB8B Combined)	Selective Catalytic Reduction	2016	Cormetech, Custom Built	N/A		Stack Outlet is 199.5°F	< 1,044,320
CO8A	CCCT8A (CT8A and DB8A Combined)	Catalytic Oxidation	2002	Engelhard PES, Custom Built	N/A		Stack Outlet is 199.5°F	< 1,044,320
CO8B	CCCT8B (CT8B and DB8B Combined)	Catalytic Oxidation	2002	Engelhard PES, Custom Built	N/A		Stack Outlet is 199.5°F	< 1,044,320

Facility Name: Chattahoochee Energy Facility **Date of Application:** June 2020

Form 3.00 – AIR POLLUTION CONTROL DEVICES – PART B: EMISSION INFORMATION

APCD Unit ID	Pollutants Controlled	Percent Control Efficiency		Inlet Stream To APCD		Exit Stream From APCD		Pressure Drop Across Unit (Inches of water)
		Design	Actual	lb/hr	Method of Determination	lb/hr	Method of Determination	
SCR8A	NO_X	~85%	< 85%	~137		~20.5	CEMS	N/A
SCR8B	NO_X	~85%	< 85%	~137		~20.5	CEMS	N/A
CO8A	CO	~85%	< 85%	~65.4		~9.8	CEMS	N/A
CO8B	CO	~85%	< 85%	~65.4		~9.8	CEMS	N/A

Facility Name: Chattahoochee Energy Facility **Date of Application:** June 2020

FORM 4.00 – EMISSION INFORMATION

Emission Unit ID	Air Pollution Control Device ID	Stack ID	Pollutant Emitted	Emission Rates				
				Hourly Actual Emissions (lb/hr)	Hourly Potential Emissions (lb/hr)	Actual Annual Emission (tpy)	Potential Annual Emission (tpy)	Method of Determination
CCCT8A	SCR8A	ST8A	See emission calculations in Appendix B: Emission Calculations					
CCCT8B	SCR8B	ST8B	See emission calculations in Appendix B: Emission Calculations					
CCCT8A	CO8A	ST8A	See emission calculations in Appendix B: Emission Calculations					
CCCT8B	CO8B	ST8B	See emission calculations in Appendix B: Emission Calculations					

Facility Name: Chattahoochee Energy Facility **Date of Application:** June 2020

FORM 5.00 MONITORING INFORMATION

Emission Unit ID/ APCD ID	Emission Unit/APCD Name	Monitored Parameter		Monitoring Frequency
		Parameter	Units	
CCCT8A	Combined Combustion Turbine and Duct Burner (CT8A and DB8A)	CO	ppmvd @ 15% O_2	3-Hour Rolling Average
CCCT8B	Combined Combustion Turbine and Duct Burner (CT8B and DB8B)	CO	ppmvd @ 15% O_2	3-Hour Rolling Average
CCCT8A	Combined Combustion Turbine and Duct Burner (CT8A and DB8A)	NO_X	ppmvd @ 15% O_2	4-Hour Rolling Average
CCCT8B	Combined Combustion Turbine and Duct Burner (CT8B and DB8B)	NO_X	ppmvd @ 15% O_2	4-Hour Rolling Average

Comments:

OPC requests that NSPS Subpart GG and NSPS Subpart Dc Monitoring & Testing conditions be removed since the facility will no longer be subject to these subparts after the proposed project is completed. OPC also requests that NSPS Subpart KKKK related Monitoring & Testing conditions be added as the combined cycle combustion turbines will be subject to that Subpart once the proposed project is completed.

Facility Name: Chattahoochee Energy Facility **Date of Application:** June 2020

FORM 7.00 – AIR MODELING INFORMATION: Stack Data

Stack ID	Emission Unit ID(s)	Stack Information			Dimensions of largest Structure Near Stack		Exit Gas Conditions at Maximum Emission Rate			
		Height Above Grade (ft)	Inside Diameter (ft)	Exhaust Direction	Height (ft)	Longest Side (ft)	Velocity (ft/sec)	Temperature (°F)	Flow Rate (acfm) Average	Flow Rate (acfm) Maximum
ST8A	CT8A and DB8B	130	16.5	Unobstructed Up	N/A		81.4	199.5	< 1,044,320	1,044,320
ST8B	CT8A and DB8B	130	16.5	Unobstructed Up	N/A		81.4	199.5	< 1,044,320	1,044,320

NOTE: If emissions are not vented through a stack, describe point of discharge below and, if necessary, include an attachment. List the attachment in Form 1.00 *General Information*, Item 16.

Facility Name: Chattahoochee Energy Facility **Date of Application:** June 2020

FORM 7.00 AIR MODELING INFORMATION: Chemicals Data

Chemical	Potential Emission Rate (lb/hr)	Toxicity	Reference	MSDS Attached
See Appendix C: Toxics Impact Analysis				☐
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APPENDIX C – FEMA FIRMETTE FLOOD MAP

National Flood Hazard Layer FIRMette

FEMA

85°2'37"W 33°24'33"N

85°2'W 33°24'3"N

0 250 500 1,000 1,500 2,000 Feet

1:6,000

Legend

SEE FIS REPORT FOR DETAILED LEGEND AND INDEX MAP FOR FIRM PANEL LAYOUT

SPECIAL FLOOD HAZARD AREAS
- Without Base Flood Elevation (BFE) *Zone A, V, A99*
- With BFE or Depth *Zone AE, AO, AH, VE, AR*
- Regulatory Floodway

OTHER AREAS OF FLOOD HAZARD
- 0.2% Annual Chance Flood Hazard, Areas of 1% annual chance flood with average depth less than one foot or with drainage areas of less than one square mile *Zone X*
- Future Conditions 1% Annual Chance Flood Hazard *Zone X*
- Area with Reduced Flood Risk due to Levee. See Notes. *Zone X*
- Area with Flood Risk due to Levee *Zone D*

OTHER AREAS
- NO SCREEN Area of Minimal Flood Hazard *Zone X*
- Effective LOMRs
- Area of Undetermined Flood Hazard *Zone D*

GENERAL STRUCTURES
- Channel, Culvert, or Storm Sewer
- Levee, Dike, or Floodwall

OTHER FEATURES
- B 20.2 17.5 Cross Sections with 1% Annual Chance Water Surface Elevation
- 8 Coastal Transect
- 513 Base Flood Elevation Line (BFE)
- Limit of Study
- Jurisdiction Boundary
- Coastal Transect Baseline
- Profile Baseline
- Hydrographic Feature

MAP PANELS
- Digital Data Available
- No Digital Data Available
- Unmapped

N

The pin displayed on the map is an approximate point selected by the user and does not represent an authoritative property location.

This map complies with FEMA's standards for the use of digital flood maps if it is not void as described below. The basemap shown complies with FEMA's basemap accuracy standards

The flood hazard information is derived directly from the authoritative NFHL web services provided by FEMA. This map was exported on 9/15/2020 at 8:27 PM and does not reflect changes or amendments subsequent to this date and time. The NFHL and effective information may change or become superseded by new data over time.

This map image is void if the one or more of the following map elements do not appear: basemap imagery, flood zone labels, legend, scale bar, map creation date, community identifiers, FIRM panel number, and FIRM effective date. Map images for unmapped and unmodernized areas cannot be used for regulatory purposes.

APPENDIX D – USFWS IPAC DOCUMENTATION

United States Department of the Interior

FISH AND WILDLIFE SERVICE
Georgia Ecological Services Field Office
355 East Hancock Avenue
Room 320
Athens, GA 30601
Phone: (706) 613-9493 Fax: (706) 613-6059

In Reply Refer To: April 13, 2020
Consultation Code: 04EG1000-2020-SLI-1928
Event Code: 04EG1000-2020-E-03553
Project Name: CEF TPU1/LLTD Project

Subject: List of threatened and endangered species that may occur in your proposed project location, and/or may be affected by your proposed project

To Whom It May Concern:

This list identifies threatened, endangered, proposed and candidate species, as well as critical habitat, that may be affected by your proposed project. This list may change before your project is completed. Under 50 CFR 402.12(e) of the regulations implementing section 7 of the Act, the accuracy of this list should be verified after 90 days. The Service recommends that verification be completed by visiting the ECOS-IPaC website at regular intervals during project planning and implementation.

Bald and golden eagles are protected under the Bald and Golden Eagle Protection Act (16 U.S.C. 668 *et seq*.). Projects affecting these species may require development of an eagle conservation plan (http://www.fws.gov/windenergy/eagle_guidance.html).

Wind energy projects should follow the wind energy guidelines http://www.fws.gov/windenergy/ for minimizing impacts to migratory birds and bats.

Guidance for minimizing impactsof communcation towers on migratory birds can be found under the "Bird Hazards" tab at: www.fws.gov/migratorybirds.

Attachment(s):

- Official Species List

Official Species List

This list is provided pursuant to Section 7 of the Endangered Species Act, and fulfills the requirement for Federal agencies to "request of the Secretary of the Interior information whether any species which is listed or proposed to be listed may be present in the area of a proposed action".

This species list is provided by:

Georgia Ecological Services Field Office
355 East Hancock Avenue
Room 320
Athens, GA 30601
(706) 613-9493

Project Summary

Consultation Code: 04EG1000-2020-SLI-1928

Event Code: 04EG1000-2020-E-03553

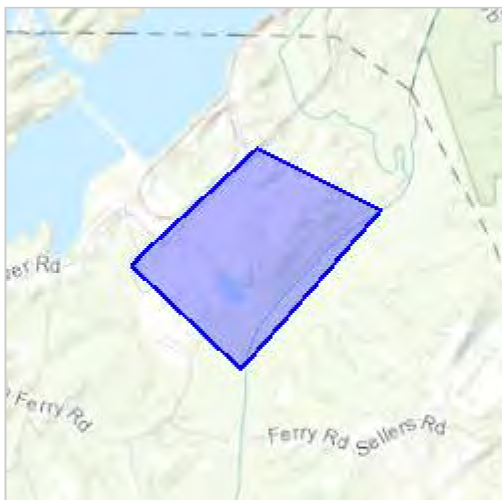
Project Name: CEF TPU1/LLTD Project

Project Type: POWER GENERATION

Project Description: Software and mechanical internal upgrades

Project Location:

Approximate location of the project can be viewed in Google Maps: https://www.google.com/maps/place/33.408564180973855N85.03283323029991W



Counties: Heard, GA

Endangered Species Act Species

There is a total of 0 threatened, endangered, or candidate species on this species list.

Species on this list should be considered in an effects analysis for your project and could include species that exist in another geographic area. For example, certain fish may appear on the species list because a project could affect downstream species.

IPaC does not display listed species or critical habitats under the sole jurisdiction of NOAA Fisheries[1], as USFWS does not have the authority to speak on behalf of NOAA and the Department of Commerce.

See the "Critical habitats" section below for those critical habitats that lie wholly or partially within your project area under this office's jurisdiction. Please contact the designated FWS office if you have questions.

---

1. NOAA Fisheries, also known as the National Marine Fisheries Service (NMFS), is an office of the National Oceanic and Atmospheric Administration within the Department of Commerce.

Critical habitats

THERE ARE NO CRITICAL HABITATS WITHIN YOUR PROJECT AREA UNDER THIS OFFICE'S JURISDICTION.

APPENDIX E – NWI MAP

U.S. Fish and Wildlife Service
National Wetlands Inventory

Wetlands

September 16, 2020

Wetlands

- Estuarine and Marine Deepwater
- Estuarine and Marine Wetland
- Freshwater Emergent Wetland
- Freshwater Forested/Shrub Wetland
- Freshwater Pond
- Lake
- Other
- Riverine

This map is for general reference only. The US Fish and Wildlife Service is not responsible for the accuracy or currentness of the base data shown on this map. All wetlands related data should be used in accordance with the layer metadata found on the Wetlands Mapper web site.