involved include an initial site screening, purchasing of injection equipment, well construction, permitting, and liability insurance.

Capital costs for carbon capture are calculated based on the difference between a natural gas combined-cycle energy facility with and without capture in terms of $/kW (net). Total plant capital cost for a turbine with no CO_2 capture is estimated as 796 $/kW, while total plant capital cost for a turbine with CO_2 capture is estimated as 1,593 $/kW.[131] As evidenced by these values, the cost of installing a system with CO_2 capture is double the cost of installing one without. The capital cost for installing the capture system at the proposed Facility is estimated by calculating the capital cost for each scenario and taking the difference to determine the additional cost from the installation of the system, then adjusting for inflation.

Capital costs for pipeline construction are based on default values in the FECM/NETL CO_2 Transport Cost Model using the default parameters provided coupled with site specific parameters for the proposed Facility.[132] The model projected the use of a nominal pipeline diameter of 16 inches and resulting pipeline cost based on the Parker model of 1,205,828 $/mi in terms of 2011 dollars (then adjusted for inflation). These costs do not include the cost for obtaining the necessary property rights to construct 288 miles of pipeline and, therefore, underestimate the actual costs of pipeline construction.

Capital costs for the injection systems and geological storage were estimated using NETL data conservatively assuming only one injection well. This projected cost exceeded $19.5 million after adjusting for inflation.

When the aforementioned costs are summed, the total capital costs for installing a CCS system are conservatively estimated to be greater than $1.3 billion in 2025 dollars. This cost alone is clearly prohibitive to the installation of the system but does not yet take operating and maintenance costs into account.

There are several costs related to the ongoing operation and maintenance of a CCS system that are not accounted for in the capital cost, including:

- Operating and maintenance costs for the CCS system such as labor, property taxes, and insurance, as well as costs to obtain the water and chemicals (including an MEA solvent) used in the system itself.
- The pipeline to transport the compressed gas to the storage site has fixed operation and maintenance costs.[133]
- The actual storage of the gas at a chosen location requires, for example, permitting, pore space acquisition, daily expenses, consumables, surface maintenance, and subsurface maintenance.[134]

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[131] *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity*, October 2022. Section 5.3.6 (Page 634) / Exhibit 5-61, Case B32A Total Plant Cost Details (page 637) and Section 5.3.10 (Page 652) / Exhibit 5-75, Case B32B.90 Total Plant Cost Details (page 653).

https://netl.doe.gov/projects/files/CostAndPerformanceBaselineForFossilEnergyPlantsVolume1BituminousCoalAndNaturalGasToElectricity_101422.pdf

[132] FECM/NETL CO2 Transport Cost Model (DOE/NETL-2023/4384) published in 2023 by the National Energy Technology Laboratory.

[133] *Carbon Dioxide Transport and Storage Costs in NETL Studies,* March 2013 DOE/NETL-2013/1614, Exhibit 2.

[134] *Estimating Carbon Dioxide Transport and Storage Costs*, March 2010 National Energy Technology laboratory, U.S. DOE, DOE/NETL-2010/1447, Table 3, March 2010.

Based on the calculations completed for these costs, the total annual cost for operation and maintenance alone of the CCS system will exceed $113 million. The full annualized cost (capital and O&M) of CCS will exceed $314 million per year resulting in an annualized total capital and operating cost per ton of CO_2 controlled of approximately $67 per ton.

The overall costs of installing and operating the CCS system are clearly prohibitive to completing the project, both in terms of absolute costs and cost effectiveness on a $/ton pollutant removed basis. Given the negative economic considerations, as well as the technical challenges associated with implementing CCS, Step 4 would eliminate CCS from consideration as BACT even if Step 2 had not already done so.

5.10.1.5 Selection of CO_2 BACT (Step 5)

CO_2 BACT for these projects includes efficient turbine design coupled with good combustion, operating, and maintenance practices.

BACT determinations for similar combined cycle generating units, as detailed in the RBLC summary tables in Appendix D, denote energy efficiency, good design and good combustion practices as BACT. BACT limits for natural gas combined cycle combustion turbine systems can be found expressed in terms of tons per year, lb/MWh, or Btu/kWh, typically with a 12-month rolling total averaging period.

Due to the usage of the turbine systems, the required monitoring systems, and the nature of GHGs, it is most effective to set a BACT limit for tons of CO_2e emitted over a 12-month rolling total averaging period for the proposed units at the Facility. To calculate the BACT limit, emission factors for fuel combustion were based on Appendix G to 40 CFR 75 for CO_2 and U.S. EPA default fuel combustion emission factors found in 40 CFR Part 98 Subpart C, Table C-2 for CH_4 and N_2O, converted from units of kg/MMBtu to lb/MMBtu.

As detailed in Appendix B, multiplying the 40 CFR 75 and U.S. EPA emission factors by the maximum annual operating capacity yields potential emissions of 2,608,711 tons of CO_2e/year per combined cycle combustion turbine system. This analysis appropriately reflects the intention to operate the Facility as a base-load unit to the extent doing so is compliant. And to the extent other operating scenarios may apply, this analysis remains conservative because base-load operating scenarios can generate lower CO_2 emission rates as compared to other operating scenarios.

Based on this information, OPC proposes the following as CO_2e BACT for each of the proposed combined cycle combustion turbine systems:

- 2,608,711 tpy per CCCT of CO_2e on a 12-month rolling averaging period for each combined cycle combustion turbine system;
- Any applicable requirements of an effective NSPS for GHG emissions.

Based on a review of the RBLC database, the results of which are in Appendix D, BACT is established as a mass-based limit (on a CO_2e basis), taking into account "Energy efficient design and operations". The BACT limit being proposed is comparable to other limits that have been established for facilities with similar systems in place. As such, the proposed BACT limit is appropriate to comply with PSD requirements.

Compliance with the proposed tons-per-year BACT limit will be demonstrated by monitoring fuel consumption. Specifically, the monthly CO_2e emissions will be calculated based on the monthly fuel use, the CO_2 emission factor based on Equation G-4 in Appendix G to 40 CFR 75, the CH_4 and N_2O emission factors from 40 CFR Part 98 Subpart C, Table and C-2, and the current GWPs from 40 CFR Part 98 Subpart A, Table A-1 (1 for CO_2, 28 for CH_4, and 265 for N_2O). These calculations will be performed on a monthly basis to ensure that the 12-month rolling total tons per year emission limit is not exceeded. In addition, because an NSPS may subject CO_2 from the combustion turbines to an emission limit on a lb/MWh basis, OPC proposes that the permit's CO_2 BACT provisions include an additional BACT component requiring compliance with both the above top-down tpy limit and any applicable requirements of an effective NSPS for GHG emissions to ensure that BACT would not allow emissions in excess of an applicable NSPS.

5.10.2 Turbine Systems CH_4 BACT

CH_4 emissions from the proposed natural gas fired combustion turbines form as a result of incomplete combustion of hydrocarbons present in the natural gas fuel. For the proposed CCCT units, the contribution of CH_4 to total CO_2e emissions is negligible and therefore should not warrant a detailed BACT review. Nonetheless, the following top-down analysis is provided for CH_4 emissions from the proposed units.

5.10.2.1 Identification of Potential CH_4 Control Technologies (Step 1)

The only available control option for minimizing CH_4 emissions from the combustion turbine systems is good combustion, operating, and maintenance practices to minimize unburned fuel. Oxidation catalysts are not considered available for reducing CH_4 emissions because oxidizing the very low concentrations of CH_4 present in the combustion turbine exhaust would require much higher temperatures, residence times, and catalyst loadings than those offered commercially for CO oxidation catalysts. For these reasons, catalyst providers do not offer products for reducing CH_4 emissions from gas-fired combustion turbines.

5.10.2.2 Eliminate Technically Infeasible CH_4 Control Options (Step 2)

As stated above, oxidation catalysts are not considered available for reducing CH_4 emissions. Good combustion, operating, and maintenance practices are the only technically feasible control option for reducing CH_4 emissions from the combustion turbines.

5.10.2.3 Ranking of Remaining CH_4 Control Technologies (Step 3)

Since good combustion, operating, and maintenance practices are the only technically feasible control option for reducing CH_4 emissions from the combustion turbines no ranking of control options is required.

5.10.2.4 Evaluation of Most Stringent CH_4 Control Technologies (Step 4)

No adverse energy, environment, or economic impacts are associated with good combustion, operating, and maintenance practices for reducing CH_4 emissions from the combustion turbines.

5.10.2.5 Selection of CH_4 BACT (Step 5)

Good combustion, operating, and maintenance practices is the selected control option for minimizing CH_4 emissions from the combustion turbine systems. OPC has determined that a numerical limit for CH_4 is unnecessary and that the work practices required for CO_2 BACT (i.e., monthly fuel consumption monitoring and emissions calculations), and efficient turbine design coupled with good combustion, operating, and maintenance practices, are sufficient for CH_4 BACT, in addition to the aforementioned CO_2e limit as proposed in Section 5.10.1.5. The CH_4 portion of the proposed CO_2e BACT limit will be calculated based on the emission factor from 40 CFR Part 98 Subpart C and the GWP of 28 (per 40 CFR 98 Subpart A).

5.10.3 Turbine Systems N_2O BACT

For the proposed projects, the contribution of N_2O to the total CO_2e emissions is trivial and, therefore, should not warrant a detailed BACT review. Nevertheless, the additional information provided supports the rationale that the proposed projects meet BACT for contributions of N_2O to CO_2e.

A tradeoff between NO_X and N_2O emissions from the combustion turbines exists when developing a combustion control strategy which influences the BACT selection process. There are five (5) primary pathways of NO_X production in gas-fired combustion turbine combustion processes: thermal NO_X, prompt NO_X, NO_X from N_2O intermediate reactions, fuel NO_X, and NO_X formed through reburning. For turbines using DLN combustors, the N_2O pathway is an important mechanism of NO_X formation. Flame radicals produced in the high temperature and pressure DLN combustion zone react with the N_2O molecule, creating N_2 and NO.[135] In premixed gas flames, N_2O is primarily formed in the flame front or oxidation zone. Once formed, the N_2O is readily destroyed due to the relatively high concentration of hydrogen radicals, and therefore, the N_2O emissions from premixed gas flames like DLN combustor flames are found experimentally to be very small (generally less than 1 ppm). However, any mechanisms which decrease the hydrogen atom concentration in the N_2O formation zone can increase N_2O emissions. These mechanisms include lowering the flame combustion temperature, air-to-fuel staging, and injection of ammonia, urea, or other amine or cyanide species into the exhaust stream which are all common NO_X control measures.[136] Therefore, there is a tradeoff between NO_X and N_2O emissions when developing a combustion control strategy which influences the BACT selection process.

5.10.3.1 Identification of Potential N_2O Control Technologies (Step 1)

N_2O catalysts are a potential control option, as these have been used in nitric/adipic acid plant applications to minimize N_2O emissions.[137] Through this technology, tail gas from the nitric acid production process is routed to a reactor vessel with a N_2O catalyst followed by ammonia injection and a NO_X catalyst.

5.10.3.2 Technically Infeasible N_2O Control Options (Step 2)

N_2O catalyst providers do not offer products to control N_2O emissions from gas-fired combustion turbines due to the very low N_2O concentrations present in exhaust streams.[138] In comparison, the application of a catalyst in the nitric acid industry sector has been effective due to the high (1,000-2,000 ppm) N_2O concentration in the exhaust stream.

With N_2O catalysts eliminated, good combustion practice is the only available control option.

Good combustion practices are technically feasible control options for reducing N_2O emissions from the combustion turbines.

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[135] Angello, L., Electric Power Research Institute, *Fuel Composition Impacts on Combustion Turbine Operability*, March 2006.

[136] American Petroleum Institute, *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry*, February 2004.

[137] *N_20 Emissions from Adipic Acid and Nitric Acid Production*, written by Heike Mainhardt (ICF Incorporated) and reviewed by Dina Kruger (U.S. EPA). http://www.ipcc-nggip.iges.or.jp/public/gp/bgp/3_2_Adipic_Acid_Nitric_Acid_Production.pdf

[138] *Emissions of Nitrous Oxide from Combustion Sources,* in Progress and Energy and Combustion Science 18(6): pages 529-552 , December 1992, found at: https://www.researchgate.net/publication/223546823_Emissions_of_nitrous_oxide_from_combustion_sources

5.10.3.3 Summary and Ranking of Remaining N_2O Control Technologies (Step 3)

Since good combustion practices are evaluated in the remaining steps of the BACT analysis, no ranking of control options is required.

5.10.3.4 Evaluation of Most Stringent N_2O Control Technologies (Step 4)

As indicated in U.S. EPA's guidance on GHG BACT, GHG control strategies may have the potential to produce higher criteria pollutants as in the case of the competing NO_X and N_2O combustion control strategies for combustion turbine systems. In such cases, the guidance suggests that the applicant should consider the effects of increases in emissions of other regulated pollutants that may result from the use of that GHG control strategy, and based on this analysis, the permitting authority can determine whether or not the application of that GHG control strategy is appropriate given the potential increases in other pollutants.[139]

Given the low N_2O emissions relative to NO_X emissions from the combined cycle combustion turbine systems and U.S. EPA's continued concern over adverse impacts from ozone formation due to NO_X and VOC emissions, OPC does not consider it appropriate to control the combustion processes of the combustion turbine to specifically reduce N_2O emissions due to the counteractive increase in NO_X emissions. Therefore, good combustion practice for the specific purpose of minimizing N_2O formation is eliminated on the basis of adverse criteria pollutant impacts.

5.10.3.5 Selection of N_2O BACT (Step 5)

Efficient turbine design and general good combustion, operating, and maintenance practices are the selected control options for reducing N_2O emissions from the combustion turbines. OPC has determined that a numerical limit for N_2O emissions is unnecessary and that the work practices required for CO_2 BACT (i.e., monthly fuel consumption monitoring and emissions calculations), and efficient turbine operation coupled with good combustion, operating, and maintenance practices, are appropriate for N_2O BACT, in addition to the aforementioned CO_2e limit as proposed in Section 5.10.1.5. The N_2O portion of the proposed CO_2e BACT limit will be calculated based on the emission factor from 40 CFR Part 98 Subpart C and the GWP of 265 (per 40 CFR 98 Subpart A).

5.11 Fuel Gas Heater NO_X Assessment

5.11.1 Characterization of Emissions

Equipment associated with the proposed project includes two natural gas-fired fuel gas (dew point) heaters, each with a heat input rating of 7 MMBtu/hr. NO_X formation mechanisms for fuel-burning equipment such as the proposed fuel gas heaters are generally the same as those discussed above for the proposed CCCT units, although thermal NO_X is expected to be the basis for the majority of NO_X emissions from the heaters.

5.11.2 Identify NO_X Control Options (Step 1)

OPC searched EPA's control technology database and considered relevant existing and proposed federal and state emissions standards to identify potential control options for NO_X emissions from the proposed fuel gas heaters. Generally, NO_X emissions from fuel burning equipment can be controlled through two types of emission control strategies: combustion controls and add-on controls. Combustion controls address thermal

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[139] *PSD and Title V permitting Guidance for Greenhouse Gases*. March 2011, page 39.

NO_X directly by reducing peak flame temperature by, for example, staging combustion and/or recirculating flue gas to reduce the oxygen content of the combustion air. Add-on controls employ various strategies to reduce NO_X emissions to water and nitrogen, which often includes the use of reagents in the presence of a catalyst.

Based on the RBLC search results, no add-on control options were identified. Many facilities listed some variation of use of clean fuels (such as natural gas), good combustion practices (e.g., tune-ups), and combustion controls (such as low NO_X burners), as BACT. Add-on controls potentially applicable to the proposed fuel gas heaters include SCR, selective non-catalytic reduction (SNCR), and non-selective catalytic reduction (NSCR).

5.11.3 Eliminate Technically Infeasible NO_X Control Options (Step 2)

Use of natural gas, good combustion practices, and low NO_X burners are inherent to the Project and technically feasible.

As discussed in the BACT analysis for the proposed CCCT units, Selective Catalytic Reduction (SCR), Selective Non-catalytic Reduction (SNCR), Non-selective catalytic reduction (NSCR) are all forms of post combustion add-on controls that reduce NO_X emissions to water and nitrogen.

OPC is unaware of any case in which these add-on controls have been installed and operated successfully on small fuel-burning equipment similar to the proposed fuel gas heaters. Combustion controls such as low NO_X burners, with or without flue gas recirculation, are the most effective controls that can be obtained through commercial channels for such units. Therefore, add-on controls are not considered available.

Additionally, both SNCR and NSCR are not applicable based on the physical and chemical characteristics of the exhaust gas from the proposed fuel gas heaters. For SNCR, the exhaust gas is not hot enough for this add-on control to be effective. For NSCR, the oxygen content of the exhaust gas is too high for this add-on control to be effective and the proposed fuel gas heaters cannot be tuned to such low levels of excess air without causing excessive unburned hydrocarbons, soot, smoke, and CO emissions. Accordingly, SCR, SNCR, and NSCR are not technically feasible.

5.11.4 Rank Remaining NO_X Control Options (Step 3)

No ranking of control options is required, as use of natural gas, good combustion practices, and low NO_X burners are the only available and technically feasible control options for NO_X emissions from the proposed fuel gas heaters.

5.11.5 Evaluation of NO_X Control Options (Step 4)

The top control options are being proposed for NO_X emissions from the proposed fuel gas heaters. Therefore, no evaluation of the NO_X control options is required.

5.11.6 Selection of NO_X BACT for Fuel Gas Heaters (Step 5)

NO_X BACT for the proposed fuel gas heaters is based on the exclusive use of natural gas, good combustion practices, and low NO_X burners. Based on the RBLC search results, NO_X emission limits for natural gas-fired fuel gas heaters with a heat input rating that is close to the proposed units range from 0.036 to 0.1 lb/MMBtu heat input based on the same technologies proposed by OPC. There were no other pollution controls listed as approved BACT in the RBLC.

Based on this information, OPC is proposing a NO_X BACT limit of 0.049 lb/MMBtu. Compliance will be demonstrated by an initial stack test.

5.12 Fuel Gas Heater CO Assessment

5.12.1 Characterization of Emissions

CO emissions from the two 7 MMBtu/hr proposed fuel gas heaters may result from incomplete conversion of carbon-containing compounds during combustion and are principally influenced by equipment operating conditions.

5.12.2 Identify CO Control Options (Step 1)

OPC searched EPA's control technology database and considered relevant existing and proposed federal and state emissions standards to identify potential control options for CO emissions from the proposed fuel gas heaters. Like NO_X, CO emissions from fuel burning equipment can be controlled through two types of emission control strategies: good combustion practices and add-on controls. For sources such as the proposed fuel gas heaters, there is typically a trade-off between emissions of NO_X and CO. For example, higher combustion temperatures and residence times may lead to more complete fuel combustion and thus lower CO emissions, but these control techniques may result in excessive NO_X emissions. Good combustion practices strive to optimize emissions for both pollutants. Add-on controls may employ various types of catalysts to oxidize CO emissions to CO_2. Based on the RBLC search results, no add-on control options were identified. Many facilities listed some variation of use of clean fuels such as natural gas and good combustion practices (e.g., tune-ups). Add-on controls potentially applicable to the proposed fuel gas heaters include oxidation catalysts.

5.12.3 Eliminate Technically Infeasible CO Control Options (Step 2)

Use of natural gas and good combustion practices are inherent to the proposed project and are technically feasible. Oxidation catalysts are add-on controls which convert emissions of CO to CO_2 in the presence of a catalyst without the addition of any chemical reagent. OPC is unaware of any case in which these add-on controls have been installed and operated successfully on small fuel-burning equipment like the proposed fuel gas heaters. Therefore, oxidation catalysts are not technically feasible. However, available combustion controls for such units are typically offered with performance guarantees for CO emissions.

5.12.4 Rank Remaining CO Control Options (Step 3)

No ranking of control options is required, as use of natural gas and good combustion practices are the only available and technically feasible control options for CO emissions from the proposed fuel gas heaters.

5.12.5 Evaluation of CO Control Options (Step 4)

The top control options are being proposed for CO emissions from the proposed fuel gas heaters. Therefore, no evaluation of the CO control options is required.

5.12.6 Selection of CO BACT for Fuel Gas Heaters (Step 5)

CO BACT for the proposed fuel gas heaters is based on the exclusive use of natural gas and good combustion practices. Based on the RBLC search results, CO emission limits for natural gas-fired fuel gas heaters with a heat input rating that is close to the proposed units range from 0.037 to 0.110 lb/MMBtu heat input based on the same technologies proposed by OPC. 0.08 lb/MMBtu heat input was the most common limit for units of similar size. There were no other pollution controls listed as approved BACT in the RBLC. As previously mentioned, good combustion practices seek to optimize emissions for both NO_X and CO emissions.

Based on this information, OPC is proposing a CO BACT limit of 0.082 lb/MMBtu. Compliance will be demonstrated by an initial stack test.

5.13 Fuel Gas Heater VOC Assessment

5.13.1 Characterization of Emissions

As described above for CO emissions, VOC emissions from the two 7 MMBtu/hr proposed fuel gas heaters may result from incomplete conversion of carbon-containing compounds during combustion and are principally influenced by equipment operating conditions.

5.13.2 Identify VOC Control Options (Step 1)

OPC searched EPA's control technology database and considered relevant existing and proposed federal and state emissions standards to identify potential control options for VOC emissions from the proposed fuel gas heaters. Like CO, VOC emissions from fuel-burning equipment have similar considerations and can be controlled through good combustion practices and add-on controls. Based on the RBLC search results, no add-on control options were identified. Many facilities listed some variation of use of clean fuels such as natural gas and good combustion practices. Add-on controls potentially applicable to the proposed fuel gas heaters include oxidation catalysts.

5.13.3 Eliminate Technically Infeasible VOC Control Options (Step 2)

Use of natural gas and good combustion practices are inherent to the proposed project and technically feasible. Oxidation catalysts are add-on controls which convert emissions of organic compounds to CO_2 and water vapor in the presence of a catalyst without the addition of any chemical reagent. OPC is unaware of any case in which these add-on controls have been installed and operated successfully on small fuel-burning equipment like the proposed fuel gas heaters. Therefore, oxidation catalysts are not technically feasible. However, available combustion controls for such units are typically offered with performance guarantees for VOC emissions.

5.13.4 Rank Remaining VOC Control Options (Step 3)

No ranking of control options is required, as use of natural gas and good combustion practices are the only available and technically feasible control options for VOC emissions from the proposed fuel gas heaters.

5.13.5 Evaluation of VOC Control Options (Step 4)

The top control options are being proposed for VOC emissions from the proposed fuel gas heaters. Therefore, no evaluation of the VOC control options is required.

5.13.6 Selection of VOC BACT for Fuel Gas Heaters (Step 5)

VOC BACT for the proposed fuel gas heaters is based on the exclusive use of natural gas and good combustion practices. Based on the RBLC search results, VOC emission limits for natural gas-fired fuel gas heaters with a heat input rating that is close to the proposed units range from 0.005 to 0.025 lb/MMBtu.

Based on the use of natural gas and good combustion practices, VOC emissions from the proposed fuel gas heaters should not exceed 0.0054 lb/MMBtu. However, instead of a numerical BACT limit, OPC is proposing the exclusive use of natural gas as BACT.

5.14 Fuel Gas Heater Filterable PM and Total PM_{10}/$PM_{2.5}$ Assessment

5.14.1 Characterization of Emissions

PM/PM_{10}/$PM_{2.5}$ emissions from fuel-burning equipment such as the proposed fuel gas heaters generally occur in the same manner as those discussed above for the proposed CCCT units, except that sulfates are expected to have a negligible contribution to the condensable portion of PM.

5.14.2 Identify PM Control Options (Step 1)

OPC searched EPA's control technology database and considered relevant existing and proposed federal and state emissions standards to identify potential control options for PM emissions from the proposed fuel gas heaters. Based on the RBLC search results, no add-on control options were identified. Generally, conventional add-on controls often applied to solid fuel boilers, such as baghouses, electrostatic precipitators, and scrubbers, have not been applied to gas fired fuel-burning equipment like the fuel gas heaters since combustion of natural gas inherently results in low levels of emissions. Instead, many facilities listed some variation of use of clean fuels such as natural gas and good combustion practices as BACT. Accordingly, these control options are the only options considered further.

5.14.3 Eliminate Technically Infeasible PM Control Options (Step 2)

Use of natural gas and good combustion practices are inherent to the proposed project and are technically feasible.

5.14.4 Rank Remaining PM Control Options (Step 3)

No ranking of control options is required, as use of natural gas and good combustion practices are the only available and technically feasible control options for PM emissions from the proposed fuel gas heaters.

5.14.5 Evaluation of PM Control Options (Step 4)

The top control options are being proposed for PM emissions from the proposed fuel gas heaters. Therefore, no evaluation of the PM control options is required.

5.14.6 Selection of PM BACT for Fuel Gas Heaters (Step 5)

PM BACT for the proposed fuel gas heaters is based on the exclusive use of natural gas and good combustion practices. Based on the RBLC search results, PM emission limits for natural gas-fired fuel gas heaters with a heat input rating that is close to the proposed units range from range from 0.007 to 0.010 lb/MMBtu.

Based on the use of natural gas and good combustion practices, PM emissions from the proposed fuel gas heaters should not exceed 0.0075 lb/MMBtu. However, instead of a numerical BACT limit, OPC is proposing exclusive use of natural gas as BACT.

5.15 Fuel Gas Heater Greenhouse Gases Assessment

5.15.1 Characterization of Emissions

As with the proposed CCCT units, GHG emissions that result from the combustion of natural gas in the proposed fuel gas heaters include CO_2, CH_4, and N_2O.

5.15.2 Identify GHG Control Options (Step 1)

Based on the RBLC search results, no add-on control options were identified that would reduce GHG emissions from the proposed fuel gas heaters. Instead, many facilities listed some variation of use of clean fuels (natural gas) and good combustion practices as BACT for GHG emissions.

CCS should not be considered as a potentially available control option for sources with minimal GHG emissions such as these small fuel gas heaters. Accordingly, use of natural gas and good combustion practices are the only potentially available control options for GHG emissions from the proposed fuel gas heaters.

5.15.3 Eliminate Technically Infeasible GHG Control Options (Step 2)

Exclusive use of natural gas and good combustion practices for the proposed fuel gas heaters are inherent to the proposed project and are technically feasible.

5.15.4 Rank Remaining GHG Control Options (Step 3)

No ranking of control options is required, as the exclusive use of natural gas and good combustion practices are the only available and technically feasible control options for GHG emissions from the proposed fuel gas heaters.

5.15.5 Evaluation of GHG Control Options (Step 4)

The top control options are being proposed for GHG emissions from the proposed fuel gas heaters. Therefore, no evaluation of the GHG control options is required.

5.15.6 Selection of GHG BACT for Fuel Gas Heaters (Step 5)

GHG BACT for the proposed fuel gas heaters is based on the exclusive use of natural gas as fuel and good combustion practices. OPC is proposing the exclusive use of natural gas as GHG BACT.

5.16 Emergency Generators and Fire Pump Engine NO_X Assessment

The following sections contain details on the "top down" BACT review, as well as the control technology and emission limits for proposed BACT for NO_X emissions from the emergency generators and the emergency diesel-fired fire pump engine. The proposed project includes the following equipment:

- One (1) ULSD fuel-fired emergency fire pump engine with an output rating of 420 bhp
- Two (2) ULSD fuel-fired emergency backup generators each with an electric output capacity of 2,000 kW (2,991 hp each engine)

NSPS Subpart IIII requires owners and operators of stationary CI internal combustion engines (ICE) that use diesel fuel to purchase engines certified to meet the emission standard applicable to the engine category for the same model year and maximum engine power as well as to use ULSD, with limited exceptions. The proposed emergency generators must be certified to Tier 2 standards (there are no Tier 3 standards for emergency generators of this size), while the fire water pump engine must be certified to meet the standards in Table 4 to Subpart IIII for stationary fire pump engines with a rated capacity between 300 hp and 600 hp.[140] Once purchased, the engines and control devices must be operated and maintained according to the manufacturer's emission-related instructions. Therefore, the only available control options for the proposed emergency generators and fire water pump engine are those that are included with the purchase of an emergency generator certified to Tier 2 standards, a fire water pump engine certified to meet the standards in Table 4 to Subpart IIII, or a non-emergency engine certified to Tier 4 standards and operated as an emergency generator or fire water pump engine.

5.16.1 NO_X Formation – Emergency Generators and Fire Pump Engine

The pathways of NO_X formation are similar to those discussed in Section 5.6.1. NO_X from the combustion of diesel (distillate fuel oil) primarily occurs due to either thermal fixation of atmospheric nitrogen in the combustion air (thermal NO_X), or the conversion of chemically bound nitrogen in the fuel (fuel NO_X).[141]

5.16.2 Identification of NO_X Control Technologies – Emergency Generators and Fire Pump Engine (Step 1)

As discussed above, available control options for NO_X emissions from the proposed emergency generators and fire water pump engine are limited to those that are included with purchasing a Tier 2 emergency generator, a fire water pump engine certified to meet the standards in Table 4 to Subpart IIII, or purchasing a Tier 4 non-emergency engine and operating it as an emergency generator or fire water pump engine. Based on the RBLC search results, there are cases in which Tier 4 was listed as BACT for at least one pollutant for an emergency engine. Therefore, Tier 4 is considered further for the purposes of BACT.

5.16.3 Elimination of Technically Infeasible NO_X Control Options – Emergency Generators and Fire Pump Engine (Step 2)

Purchasing a Tier 2 emergency generator and a fire water pump engine certified to meet the standards in Table 4 to Subpart IIII is inherent to the proposed project and is technically feasible. Tier 4 engines with similar power ratings appear to be commercially available based on a review of EPA's annual certification database for nonroad CI engines.[142] Therefore, Tier 4 is also considered technically feasible.

5.16.4 Summary and Ranking of Remaining NO_X Controls – Emergency Generators and Fire Pump Engine (Step 3)

In EPA's phased approach to regulating emissions from nonroad engines, each tier requires more stringent emissions reductions than the previous one. Tier 4 has the highest level of control effectiveness, whereas Tier 2 has the lowest, comparatively.

[140] See 40 CFR 60.4202(b)(2) for the emergency generator (Tier 2) and 40 CFR 60.4202(d), Table 4 to 40 CFR Part 60 Subpart IIII for the fire water pump (same as Table 3 to Appendix I in 40 CFR Part 1039 (Tier 3)).

[141] AP-42, Chapter 1, Section 3, *Fuel Oil Combustion*, May 2010

[142] Annual Certification Data for Vehicles, Engines, and Equipment, Nonroad Compression Ignition (NRCI) Engines, available online at https://www.epa.gov/compliance-and-fuel-economy-data/annual-certification-data-vehicles-engines-and-equipment.

5.16.5 Evaluation of Most Stringent NO_X Controls – Emergency Generators and Fire Pump Engine (Step 4)

In the 2005 NSPS Subpart IIII proposal, EPA estimated the cost effectiveness of Tier 4 control strategies for NO_X to be between ~$240,000 and $400,000 per ton when applied to emergency engines with similar power ratings.[143] Therefore, Tier 4 is eliminated from this BACT analysis for the proposed emergency generators and the fire water pump engine based on the unreasonable estimated annual cost of control.

5.16.6 Selection of Emission Limits and Controls for NO_X BACT – Emergency Generators and Fire Pump Engine (Step 5)

NO_X BACT for the proposed emergency generators and fire water pump engine is based on compliance with NSPS Subpart IIII. The Facility will purchase emergency generators certified to Tier 2 standards and fire water pump engine certified to meet the standards in Table 4 to Subpart IIII and will operate and maintain each according to the manufacturer's emission-related instructions. Each of the proposed emergency generators will be operated for emergency purposes for a maximum of 200 hours per year, including up to 100 hours per year for maintenance checks and readiness testing. The proposed fire water pump engine will be operated for emergency purposes for a maximum of 500 hours per year, including up to 100 hours per year for maintenance checks and readiness testing, of which up to 50 hours may be used in other non-emergency situations. Additionally, both the proposed emergency generators and fire water pump engine will exclusively use ULSD as fuel.

5.17 Emergency Generators and Fire Pump Engine CO Assessment

The following sections contain details on the "top down" BACT review, as well as the control technology and emission limits for proposed BACT for CO emissions from the emergency generators and the emergency diesel-fired fire pump engine.

5.17.1 CO Formation – Emergency Generators and Fire Pump Engine

CO emissions from the proposed emergency generators and fire water pump engine are influenced by engine design and operational features which promote fuel combustion efficiency and complete combustion.

5.17.2 Identification of CO Control Technologies – Emergency Generators and Fire Pump Engine (Step 1)

As discussed above, available control options for CO emissions from the proposed emergency generators and fire water pump engine are limited to those that are included with purchasing a Tier 2 emergency generator, a fire water pump engine certified to meet the standards in Table 4 to Subpart IIII, or purchasing a Tier 4 non-emergency engine and operating it as an emergency generator or fire water pump engine. Based on the RBLC search results, there are cases in which Tier 4 was listed as BACT for at least one pollutant for an emergency engine. Therefore, Tier 4 is considered further for the purposes of BACT. It should be noted, however, that the CO emission standard for Tier 2, 3, and 4 engines for the same engine category and model year with similar power ratings are identical (3.5 g/kW-hr).[144]

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[143] Cost per Ton for NSPS for Stationary CI ICE, Table 5, June 2004, available at https://www.epa.gov/sites/default/files/2014-02/documents/6-9-05_cost_per_ton_ci_nsps.pdf.

[144] See Tables 2 and 3 to Appendix I in 40 CFR Part 1039 for Tier 2 and 3 standards, respectively, and Table 1 of 40 CFR 1039.101 for Tier 4 final standards.

5.17.3 Elimination of Technically Infeasible CO Control Options – Emergency Generators and Fire Pump Engine (Step 2)

Purchasing Tier 2 emergency generators and a fire water pump engine certified to meet the standards in Table 4 to Subpart IIII is inherent to the proposed project and is technically feasible. Tier 4 engines with similar power ratings appear to be commercially available based on a review of EPA's annual certification database for nonroad CI engines. Therefore, Tier 4 is also considered to be technically feasible.

5.17.4 Summary and Ranking of Remaining CO Controls – Emergency Generators and Fire Pump Engine (Step 3)

In EPA's phased approach to regulating emissions from nonroad engines, each tier requires more stringent emissions reductions than the previous one. However, in the case of CO, the emissions standard for each tier is identical.

5.17.5 Evaluation of Most Stringent CO Controls – Emergency Generators and Fire Pump Engines (Step 4)

In the 2005 NSPS Subpart IIII proposal, EPA generally stated that the use of add-on controls for emergency stationary CI ICE could not be justified due to the cost of the technology relative to the emission reduction that would be obtained.[145] EPA has previously estimated the cost effectiveness of Tier 4 control strategies for CO to be between ~$10,000 and $24,000 per ton when applied to non-emergency engines with similar power ratings that operate for at least 1,000 hours per year.[146] The cost per ton will increase as operating hours decrease because capital costs remain unchanged, while emission reductions decrease with operating hours. This is especially true for the proposed emergency generators and the fire water pump engine, which will be operated for a maximum of 200 and 500 hours per year, respectively. Therefore, Tier 4 is eliminated from this BACT analysis for the proposed emergency generators and fire water pump engine based on the unreasonable estimated annual cost of control.

5.17.6 Selection of Emission Limits and Controls for CO BACT – Emergency Generators and Fire Pump Engine (Step 5)

CO BACT for the proposed emergency generators and fire water pump engines is based on compliance with NSPS Subpart IIII. OPC will purchase emergency generators certified to Tier 2 standards and a fire water pump engine certified to meet the standards in Table 4 to Subpart IIII and operate and maintain each according to the manufacturer's emission-related instructions. Each of the proposed emergency generators will be operated for emergency purposes for a maximum of 200 hours per year, including up to 100 hours per year for maintenance checks and readiness testing. The proposed fire water pump engine will be operated for emergency purposes for a maximum of 500 hours per year, including up to 100 hours per year for maintenance checks and readiness testing, of which up to 50 hours may be used in other non-emergency situations. Additionally, both the proposed emergency generators and fire water pump engine will exclusively use ULSD as fuel.

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[145] 70 Fed. Reg. 39874 (July 11, 2005).

[146] US EPA, Alternative Control Techniques Document: Stationary Diesel Engines, Final Report, EPA Contract No. EP-D-07-019, Table 5-6, March 2010.

5.18 Emergency Generators and Fire Pump Engine VOC Assessment

The following sections contain details on the "top down" BACT review, as well as the control technology and emission limits for proposed BACT for VOC emissions from the emergency generators and emergency diesel-fired fire pump engine.

5.18.1 VOC Formation – Emergency Generators and Fire Pump Engine

As with CO emissions, VOC emissions from the proposed emergency generators and fire water pump engine are influenced by engine design and operational features which promote fuel combustion efficiency and complete combustion.

5.18.2 Identification of VOC Control Technologies – Emergency Generators and Fire Pump Engine (Step 1)

As discussed above, available control options for VOC (non-methane hydrocarbon [NMHC]) emissions from the proposed emergency generators and fire water pump engine are limited to those that are included with purchasing a Tier 2 emergency generator, a fire water pump engine certified to meet the standards in Table 4 to Subpart IIII, or purchasing a Tier 4 non-emergency engine and operating it as an emergency generator or fire water pump engine. Based on the RBLC search results, there are cases in which Tier 4 was listed as BACT for at least one pollutant for an emergency engine. Therefore, Tier 4 is considered further for the purposes of BACT.

5.18.3 Elimination of Technically Infeasible VOC Control Options – Emergency Generators and Fire Pump Engine (Step 2)

Purchasing Tier 2 emergency generators and a fire water pump engine certified to meet the standards in Table 4 to Subpart IIII is inherent to the proposed project and is technically feasible. Tier 4 engines with similar power ratings appear to be commercially available based on a review of EPA's annual certification database for nonroad CI engines. Therefore, Tier 4 is also considered technically feasible.

5.18.4 Summary and Ranking of Remaining VOC Controls – Emergency Generators and Fire Pump Engine (Step 3)

In EPA's phased approach to regulating emissions from nonroad engines, each tier requires more stringent emissions reductions than the previous one. Tier 4 has the highest level of control effectiveness, whereas Tier 2 has the lowest.

5.18.5 Evaluation of Most Stringent VOC Controls – Emergency Generators and Fire Pump Engine (Step 4)

In the 2005 NSPS Subpart IIII proposal, EPA generally stated that the use of add-on controls for emergency stationary CI ICE could not be justified due to the cost of the technology relative to the emission reduction that would be obtained. EPA has previously estimated the cost effectiveness of Tier 4 control strategies for VOC (THC) to be between ~$80,000 and $100,000 per ton when applied to non-emergency engines with similar power ratings that operate for at least 1,000 hours per year.[147] The cost per ton will increase as operating hours decrease because capital costs remain unchanged, while emission reductions decrease with operating hours. This is especially true for the proposed emergency generators and the fire water pump

[147] US EPA, Alternative Control Techniques Document: Stationary Diesel Engines, Final Report, EPA Contract No. EP-D-07-019, Table 5-5, March 2010.

engine, which will be operated for a maximum of 200 and 500 hours per year, respectively. Therefore, Tier 4 is eliminated from this BACT analysis for the proposed emergency generators and fire water pump engine based on the unreasonable estimated annual cost of control.

5.18.6 Selection of Emission Limits and Controls for VOC BACT – Emergency Generators and Fire Pump Engine (Step 5)

VOC BACT for the proposed emergency generators and the fire water pump engine is based on compliance with NSPS Subpart IIII. OPC will purchase emergency generators certified to Tier 2 standards and a fire water pump engine certified to meet the standards in Table 4 to Subpart IIII and operate and maintain each according to the manufacturer's emission-related instructions. Each of the proposed emergency generators will be operated for emergency purposes for a maximum of 200 hours per year, including up to 100 hours per year for maintenance checks and readiness testing. The proposed fire water pump engine will be operated for emergency purposes for a maximum of 500 hours per year, including up to 100 hours per year for maintenance checks and readiness testing, of which up to 50 hours may be used in other non-emergency situations. Additionally, both the proposed emergency generators and fire water pump engine will exclusively use ULSD as fuel.

5.19 Emergency Generators and Fire Pump Engine Filterable PM and Total PM_{10}/$PM_{2.5}$ Assessment

The following sections contain details on the "top down" BACT review, as well as the control technology and emission limits for proposed BACT for filterable PM, total PM_{10}, and total $PM_{2.5}$ emissions from the emergency generators and the emergency diesel-fired fire pump engine.

5.19.1 PM Formation – Emergency Generators and Fire Pump Engine

PM emissions from the proposed emergency generators and fire water pump engine may consist of inorganic matter present in the fuel (e.g., ash, metals, etc.) and high molecular weight unburned hydrocarbons (soot). Generally, the use of clean fuels with negligible ash and sulfur content, such as ULSD, in conjunction with engine design and operational features to promote complete fuel combustion, minimizes PM emissions.

5.19.2 Identification of PM Control Technologies – Emergency Generators and Fire Pump Engine (Step 1)

As discussed above, in addition to use of ULSD, available control options for PM emissions from the proposed emergency generators and the fire water pump engine are limited to those that are included with purchasing a Tier 2 emergency generator, a fire water pump engine certified to meet the standards in Table 4 to Subpart IIII, or purchasing a Tier 4 non-emergency engine and operating it as an emergency generator or fire water pump engine. Based on the RBLC search results, there are cases in which Tier 4 was listed as BACT for at least one pollutant for an emergency engine. Therefore, Tier 4 is considered further for the purposes of BACT.

5.19.3 Elimination of Technically Infeasible PM Control Options – Emergency Generators and Fire Pump Engine (Step 2)

Purchasing Tier 2 emergency generators and a fire water pump engine certified to meet the standards in Table 4 to Subpart IIII and exclusive use of ULSD is inherent to the proposed project and technically feasible. Tier 4 engines with similar power ratings appear to be commercially available based on a review of

EPA's annual certification database for nonroad CI engines. Therefore, Tier 4 is also considered technically feasible.

5.19.4 Summary and Ranking of Remaining PM Controls – Emergency Generators and Fire Pump Engine (Step 3)

In EPA's phased approach to regulating emissions from nonroad engines, each tier requires more stringent emissions reductions than the previous one. Tier 4 has the highest level of control effectiveness, whereas Tier 2 has the lowest.

5.19.5 Evaluation of Most Stringent PM Controls – Emergency Generators and Fire Pump Engine (Step 4)

In the 2005 NSPS Subpart IIII proposal, EPA estimated the cost effectiveness of Tier 4 control strategies for PM to be between ~$160,000 and $970,000 per ton when applied to emergency engines with similar power. ratings.[148] Therefore, Tier 4 is eliminated from this BACT analysis for the proposed emergency generators and the fire water pump engine based on the unreasonable estimated annual cost of control.

5.19.6 Selection of Emission Limits and Controls for PM BACT – Emergency Generators and Fire Pump Engine (Step 5)

PM BACT for the proposed emergency generators and the fire water pump engine is based on compliance with NSPS Subpart IIII. OPC will purchase emergency generators certified to Tier 2 standards and a fire water pump engine certified to meet the standards in Table 4 to Subpart IIII and operate and maintain each according to the manufacturer's emission-related instructions. Each of the proposed emergency generators will be operated for emergency purposes for a maximum of 200 hours per year, including up to 100 hours per year for maintenance checks and readiness testing. The proposed fire water pump engine will be operated for emergency purposes for a maximum of 500 hours per year, including up to 100 hours per year for maintenance checks and readiness testing, of which up to 50 hours may be used in other non-emergency situations. Additionally, both the proposed emergency generators and fire water pump engine will exclusively use ULSD as fuel.

5.20 Emergency Generators and Fire Pump Engine GHG Assessment

The following sections contain details on the "top down" BACT review, as well as the control technology and emission limits for proposed BACT for GHG emissions from the emergency generators and the emergency diesel-fired fire pump engine.

5.20.1 GHG Formation – Emergency Generators and Fire Pump Engine

GHG emissions result from the combustion of ULSD in the proposed emergency generators and fire water pump engines and include CO_2, CH_4, and N_2O.

[148] Cost per Ton for NSPS for Stationary CI ICE, Tables 4 and 6, June 2004, available at https://www.epa.gov/sites/default/files/2014-02/documents/6-9-05_cost_per_ton_ci_nsps.pdf.

5.20.2 Identification of GHG Control Technologies – Emergency Generators and Fire Pump (Step 1)

While some engine-based technologies may promote fuel efficiency, EPA's tiered emission standards for CI ICE do not address GHG emissions directly. Based on the RBLC search results, no add-on control options were identified that would reduce GHG emissions from the proposed emergency generators and the fire water pump engine. Instead, many facilities listed some variation of use of clean fuels (natural gas and distillate oil), good combustion practices, and limiting annual operating hours as BACT for GHG emissions.

Potential control options not considered in this BACT analysis included use of natural gas and CCS. Relative to ULSD, natural gas inherently results in lower GHG emissions on a heat input basis. However, natural gas cannot be stored onsite and may not be available during an emergency, including when the emergency itself is unavailability of natural gas. Because natural gas is less likely to be available in emergency circumstances during which the emergency engines and fire pump are needed, that option will not be considered further in this analysis, as it would interfere with the intended function of the proposed Facility.

Additionally, CCS should not be considered as a potentially available control option since GHG emissions from the proposed emergency generators and the fire water pump engine are insignificant. CCS should only be considered as an available control option for facilities that emit CO_2 in larger amounts, or for industrial facilities with high-purity CO_2 streams, consistent with past EPA guidance.[149] OPC's analysis of CCS for the proposed CCCT units found CCS to be technically infeasible and the annual cost of control to be unreasonable. Applying CCS to these sources alone or in combination with the proposed CCCT units cannot reasonably be expected to change the outcome of that analysis. Accordingly, use of ULSD, good combustion practices, and limiting annual operating hours are the only potentially available control options for GHG emissions from the proposed emergency generators and the fire water pump engine.

5.20.3 Elimination of Technically Infeasible GHG Control Options – Emergency Generators and Fire Pump Engine (Step 2)

Exclusive use of ULSD as fuel and limiting annual operating hours for the proposed emergency generators and the fire water pump engine are inherent to the proposed project and are technically feasible.

5.20.4 Rank Remaining GHG Control Options – Emergency Generators and Fire Pump Engine (Step 3)

No ranking of control options is required, as the exclusive use of ULSD as fuel and limiting annual operating hours are the only available and technically feasible control options for GHG emissions from the proposed emergency generators and the fire water pump engine.

5.20.5 Evaluation of GHG Control Options – Emergency Generators and Fire Pump Engine (Step 4)

The top control options are proposed for emissions of GHG from the proposed emergency generators and the fire water pump engine. Therefore, no evaluation of the control options is required.

[149] US EPA, PSD and Title V Permitting Guidance for Greenhouse Gases, at 32 (March 2011).

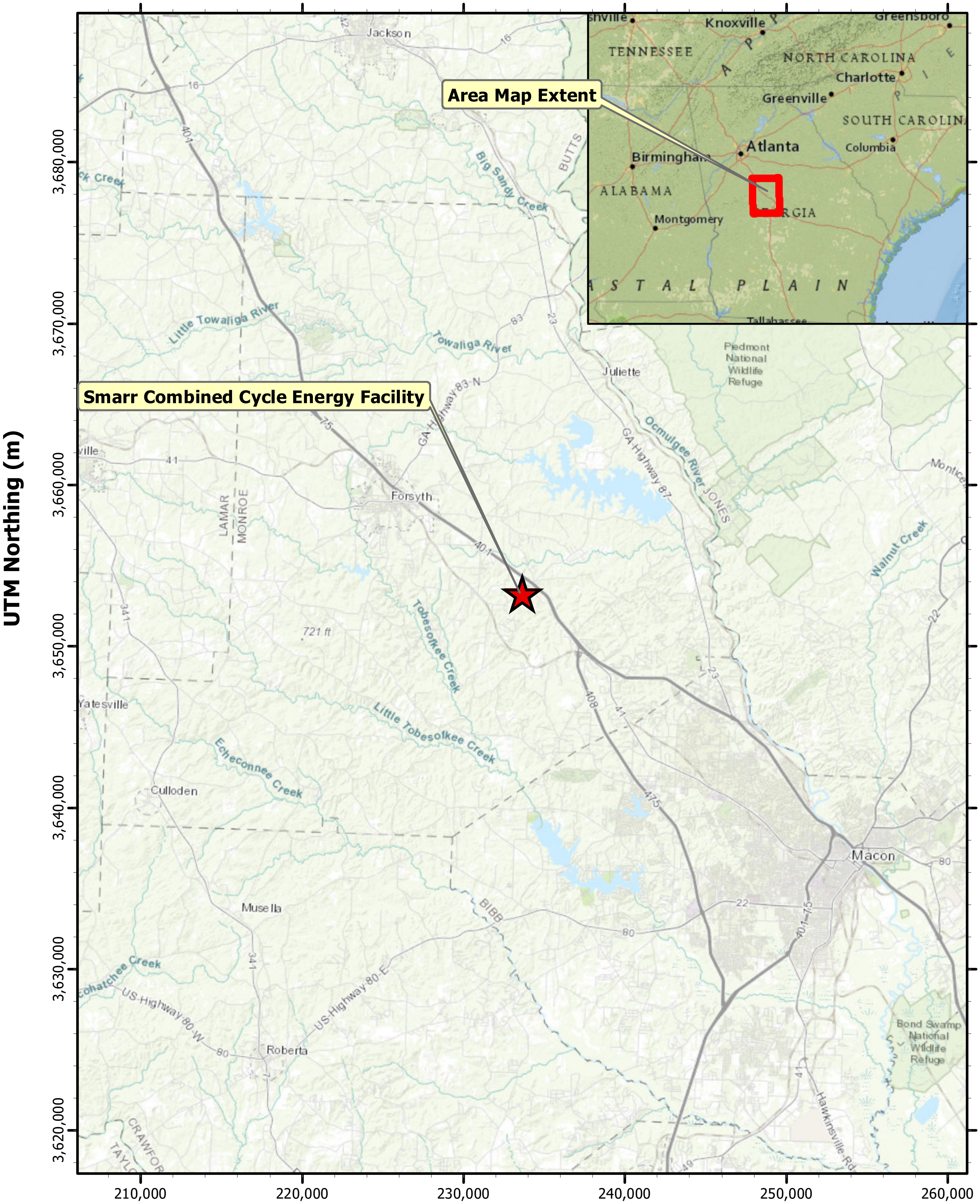
5.20.6 Select GHG BACT for Emergency Generators and Fire Pump Engine (Step 5)

GHG BACT for the proposed emergency generators and the fire water pump engine is based on the exclusive use of ULSD as fuel and limiting annual operating hours. Each of the proposed emergency generators will be operated for emergency purposes for a maximum of 200 hours per year, including up to 100 hours per year for maintenance checks and readiness testing. The proposed fire water pump engine will be operated for emergency purposes for a maximum of 500 hours per year, including up to 100 hours per year for maintenance checks and readiness testing, of which up to 50 hours may be used in other non-emergency situations.

APPENDIX A. AREA MAP AND PROCESS FLOW DIAGRAM

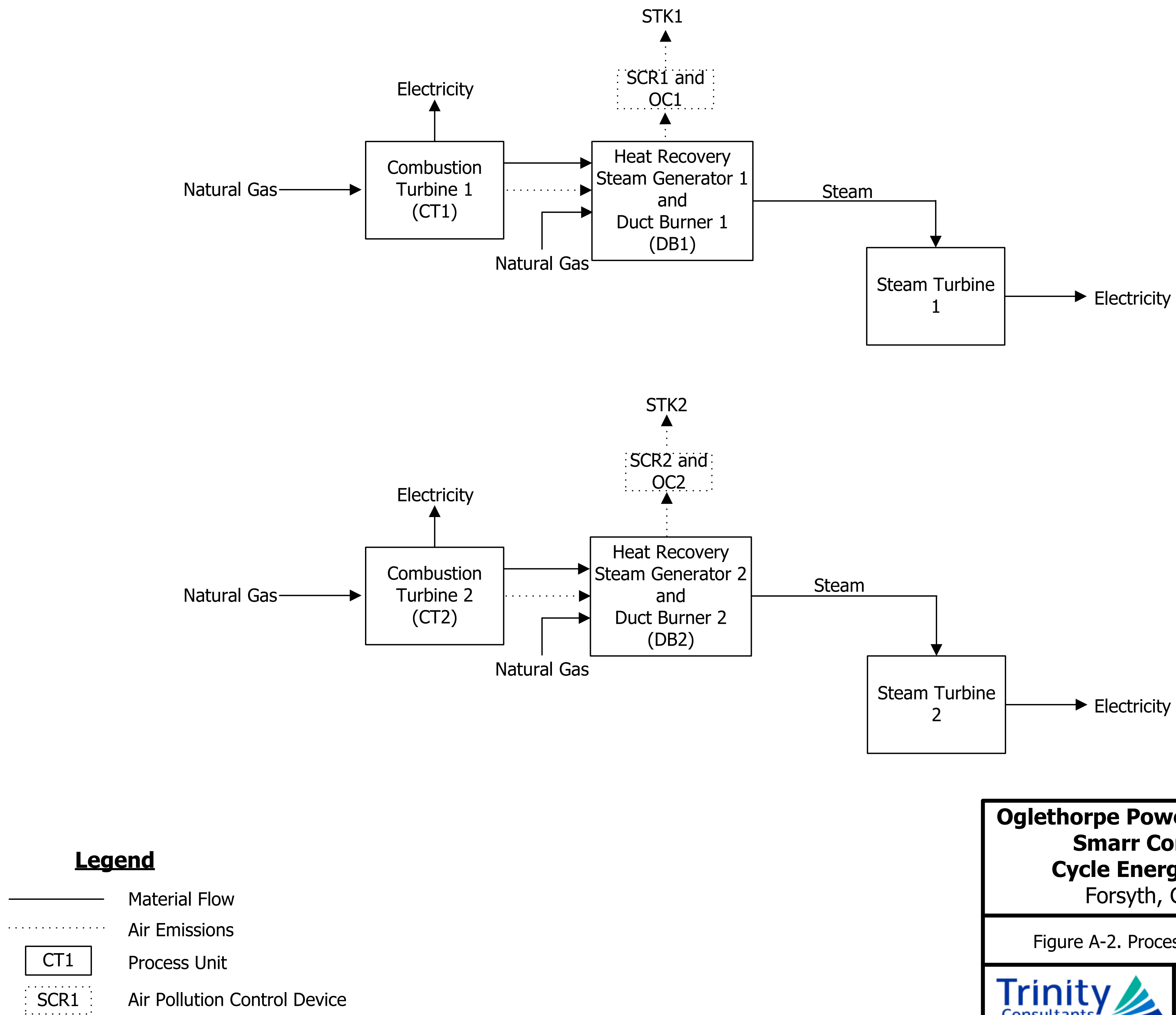
Figure A-1. Area Map

Oglethorpe Power Corporation - Forsyth, Monroe County, Georgia



All Coordinates shown in UTM Coordinates, Zone 17, NAD 83 Datum

Trinity Consultants



Oglethorpe Power Corporation
Smarr Combined
Cycle Energy Facility
Forsyth, Georgia

Figure A-2. Process Flow Diagram

Trinity Consultants

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April 2025

APPENDIX B. POTENTIAL EMISSIONS CALCULATIONS AND NSR EVALUATION

Table B-1. Criteria Pollutant and GHG Emission Factors for Combined Cycle Combustion Turbine Nos. 1 and 2 (Includes Duct Burner Nos. 1 and 2)

Pollutant	Emission Factor (lb/MMBtu, HHV Basis)	Emission Factor Basis
SO_2	6.00E-04	See Note 1
NO_X	8.13E-03	See Note 2
CO	4.95E-03	See Note 2
Total PM	5.55E-03	See Note 2
Filterable PM	4.55E-03	See Note 2
Condensable PM	9.99E-04	See Note 2
Total PM_{10}	5.55E-03	See Note 2
Total $PM_{2.5}$	5.55E-03	See Note 2
VOC	2.88E-03	See Note 2
Sulfuric Acid Mist (H_2SO_4)	6.00E-05	See Note 1
GHGs		
CO_2	118.86	See Note 3
CH_4	2.20E-03	See Note 4
N_2O	2.20E-04	See Note 4
CO_2e	118.98	See Note 5

1. SO_2 factor is the default emission rate for pipeline natural gas from 40 CFR 75, Appendix D, Section 2.3.1.1. Sulfuric Acid Mist conservatively assumed as a portion (10%) of the SO_2 emissions.

2. Emission factors as provided from GE. Emission factors represent post-control emissions (if applicable) at 100% load with duct burners on at ISO conditions.

3. Emission factor for CO_2 derived from Equation G-4 in Appendix G to 40 CFR 75.
CO_2 emission factor (lb/MMBtu) = $F_c * U_f * MW_{CO2}$
CO_2 emission factor (lb/MMBtu) = 1,040 (scf/MMBtu) * 1/385 (scf CO_2/lb-mol) * 44.0 (lb/lb-mol)

4. Emission factors for CH_4 and N_2O based on EPA default factors in 40 CFR Part 98 Subpart C, Table C-2, for Natural Gas. Emission factors were converted from units of kg/MMBtu to lb/MMBtu by multiplying the factors by 2.2046 lb/kg.

5. The CO_2e factor is calculated based on the emission factors for CO_2, CH_4, and N_2O and the global warming potential (GWP) for each pollutant per 40 CFR 98, Subpart A, Table A-1 (update to AR5 GWP effective January 1, 2025):

CO_2:	1
CH_4:	28
N_2O:	265

Table B-2. Criteria Pollutant Emission Factors for Startup/Shutdown Operations for Combined Cycle Combustion Turbine Nos. 1 and 2
(Includes Duct Burner Nos. 1 and 2)

Pollutant	Emission Factors[1] (lb/event)	Duration[1] (mins)	Events[2] (per CCCT)
Cold Startup			
NO_X	455	70	10 events/yr
CO	1,620		
VOC	520		
Warm Startup			
NO_X	265	60	10 events/yr
CO	660		
VOC	140		
Hot Startup			
NO_X	125	30	10 events/yr
CO	530		
VOC	135		
Shutdown			
NO_X	30	30	30 events/yr
CO	225		
VOC	90		

1. Startup/shutdown emission factors as provided from GE. These factors represent total emissions for the occurrence of a startup or shutdown event.

2. Number of SUSD events based on anticipated operation.

Table B-3. HAP/TAP Emission Factors for Combined Cycle Combustion Turbine Nos. 1 and 2 (Turbines Only)

Pollutant	Emission Factor[1] (lb/MMBtu, HHV Basis)	HAP (Y/N)	TAP[2] (Y/N)
1,3-Butadiene	4.30E-07	Y	Y
Acetaldehyde	4.00E-05	Y	Y
Acrolein	6.40E-06	Y	Y
Benzene	1.20E-05	Y	Y
Ethylbenzene	3.20E-05	Y	Y
Formaldehyde	1.45E-04	Y	Y
Hexane	2.34E-06	Y	Y
Naphthalene	1.30E-06	Y	Y
PAH	2.20E-06	Y	N
Propylene Oxide	2.90E-05	Y	Y
Toluene	1.30E-04	Y	Y
Xylenes	6.40E-05	Y	Y

1. Emission factors from AP-42 Section 3.1, *Stationary Gas Turbines*, Table 3.1-3, April 2000.

Emission factor for formaldehyde based on test data in AP-42 Section 3.1, *Stationary Gas Turbines*, April 2000, Related Information, for formaldehyde from all GE Turbines > 20 MW.

Site specific emission factor for CCCTs based on fuel composition used for hexane for both turbine and duct burner. The emission factor for hexane is determined based on the applicable gas composition test data for the pipeline-quality natural gas. Considering the fuel input to the CCCTs and the potential unburned hydrocarbons, an emission factor was developed based on the percent of fuel expected to be combusted (i.e. destroyed).

2. Based on Georgia EPD's *Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions*, Appendix A, updated October 2018.

Table B-4. HAP/TAP Emission Factors for Combined Cycle Combustion Turbine Nos. 1 and 2 (Duct Burners Only)

Pollutant	Emission Factor[1,2] (lb/MMBtu, HHV Basis)	HAP (Y/N)	TAP[3] (Y/N)
2-Methylnaphthalene	2.35E-08	Y	N
3-Methylchloranthrene	1.76E-09	Y	N
7,12-Dimethylbenz(a)anthracene	1.57E-08	Y	N
Acenaphthene	1.76E-09	Y	N
Acenaphthylene	1.76E-09	Y	N
Anthracene	2.35E-09	Y	N
Benzene	2.06E-06	Y	Y
Benz(a)anthracene	1.76E-09	Y	N
Benzo(a)pyrene	1.18E-09	Y	N
Benzo(b)fluoranthene	1.76E-09	Y	N
Benzo(g,h,i)perylene	1.18E-09	Y	N
Benzo(k)fluoranthene	1.76E-09	Y	N
Chrysene	1.76E-09	Y	N
Dibenzo(a,h)anthracene	1.18E-09	Y	N
Dichlorobenzene	1.18E-06	Y	N
Fluoranthene	2.94E-09	Y	N
Fluorene	2.75E-09	Y	N
Formaldehyde	7.35E-05	Y	Y
Hexane	2.34E-06	Y	Y
Indeno(1,2,3-cd)pyrene	1.76E-09	Y	N
Naphthalene	5.98E-07	Y	Y
Phenanthrene	1.67E-08	Y	N
Pyrene	4.90E-09	Y	N
Toluene	3.33E-06	Y	Y
Arsenic	1.96E-07	Y	Y
Beryllium	1.18E-08	Y	Y
Cadmium	1.08E-06	Y	Y
Chromium	1.37E-06	Y	Y
Chromium (VI)	5.49E-08	Y	Y
Cobalt	8.24E-08	Y	Y
Lead	4.90E-07	Y	Y
Manganese	3.73E-07	Y	Y
Mercury	2.55E-07	Y	Y
Nickel	2.06E-06	Y	Y
Selenium	2.35E-08	Y	Y

1. Emission factors for natural gas combustion taken from AP-42 Section 1.4, *Natural Gas Combustion*, Tables 1.4-2, -3, and -4, July 1998. Converted to lb/MMBtu based on AP-42 default 1,020 MMBtu/MMscf.

Site specific emission factor for CCCTs based on fuel composition used for hexane for both turbine and duct burner. The emission factor for hexane is determined based on the applicable gas composition test data for the pipeline-quality natural gas. Considering the fuel input to the CCCTs and the potential unburned hydrocarbons, an emission factor was developed based on the percent of fuel expected to be combusted (i.e. destroyed).

2. Chromium (VI) assumed to be 4% of the AP-42 Section 1.4 emission factor for Chromium per discussions between Trinity Consultants and GA EPD in July 2022.

3. Based on Georgia EPD's *Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions*, Appendix A, updated October 2018.

Combined Cycle Combustion Turbine Nos. 1 and 2 Operating Parameters

Number of CCCTs	2		
Heat Input (each CCCT, turbine only)	3,516	MMBtu/hr, LHV	
Heat Input (each CCCT, duct burner only)	1,000	MMBtu/hr, LHV	
Total Heat Input (each CCCT, includes duct burner)	4,516	MMBtu/hr, LHV	
Heat Rate Conversion	1.108	MMBtu, HHV / MMBtu, LHV	
Heat Input (each CCCT, turbine only)	3,898	MMBtu/hr, HHV	
Heat Input (each CCCT, duct burner only)	1,108	MMBtu/hr, HHV	
Total Heat Input (each CCCT, includes duct burner)	5,006	MMBtu/hr, HHV	
Operating Hours	8,718	hrs/yr	NO_X, CO, VOC
	8,760	hrs/yr	Other Pollutants

Table B-5. Criteria Pollutant and GHG Potential Emissions for Combined Cycle Combustion Turbine Nos. 1 and 2 (Includes Duct Burner Nos. 1 and 2)

Pollutant	Emission Factor[1] (lb/MMBtu, HHV Basis)	Hourly Emissions[2] (lb/hr per CCCT)	Annual Emissions[3] (tpy per CCCT)
SO_2	6.00E-04	3.00	13.16
NO_X	8.13E-03	40.70	177.42
CO	4.95E-03	24.80	108.11
Total PM	5.55E-03	27.80	121.76
Filterable PM	4.55E-03	22.80	99.86
Condensable PM	9.99E-04	5.00	21.90
Total PM_{10}	5.55E-03	27.80	121.76
Total $PM_{2.5}$	5.55E-03	27.80	121.76
VOC	2.88E-03	14.40	62.77
Sulfuric Acid Mist (H_2SO_4)	6.00E-05	0.30	1.32
GHGs			
CO_2	118.86	594,995	2,606,076
CH_4	2.20E-03	11.04	48.34
N_2O	2.20E-04	1.10	4.83
CO_2e	118.98	595,596	2,608,711

1. See Table B-1 for details on emission factors for CCCT Nos. 1 and 2 (includes duct burners).
2. Potential Emissions (lb/hr) = Emission Factor (lbs/MMBtu) * Heat Input (MMBtu/hr)
3. Potential Emissions (tpy) = Hourly Emissions (lb/hr) * Hours of Operation (hr/yr) / 2,000 (lb/ton)

Table B-6. Criteria Pollutant Potential Emissions for Startup/Shutdown Operations for Combined Cycle Combustion Turbine Nos. 1 and 2 (Includes Duct Burner Nos. 1 and 2)

Pollutant	Emission Factor[1] (lb/event)	Events[2] (per CCCT)	Emissions[3] (lb/hr per CCCT)	(tpy per CCCT)
Cold Startup				
NO_X	455	10	390.00	1.95
CO	1620		1,388.57	6.94
VOC	520		445.71	2.23
Warm Startup				
NO_X	265	10	265.00	1.33
CO	660		660.00	3.30
VOC	140		140.00	0.70
Hot Startup				
NO_X	125	10	250.00	1.25
CO	530		1,060.00	5.30
VOC	135		270.00	1.35
Shutdown				
NO_X	30	30	60.00	0.90
CO	225		450.00	6.75
VOC	90		180.00	2.70
Annual Emissions[4]				
NO_X	--	--	--	182.84
CO	--	--	--	130.40
VOC	--	--	--	69.75

1. Startup/shutdown emission factors as provided from GE. These factors represent total emissions for the occurrence of a startup or shutdown event.

2. Number of SUSD events based on anticipated operation.

3. Potential Emissions for Startup/Shutdown Period (tpy) = Emission Factor (lb/event) * Events / 2,000 (lbs/ton)
Potential Emissions for Startup/Shutdown Period (lb/hr) = Emission Factor (lb/event) * 2,000 (lbs/ton)

4. Annual emissions are the sum of emissions under normal operation period and startup/shutdown period.

Table B-7. HAP/TAP Potential Emissions for Combined Cycle Combustion Turbine Nos. 1 and 2 (Turbines Only)

Pollutant	Emission Factor[1] (lb/MMBtu, HHV Basis)	Hourly Emissions[2] (lb/hr per turbine)	Annual Emissions[3] (tpy per turbine)	HAP (Y/N)	TAP (Y/N)
1,3-Butadiene	4.30E-07	1.68E-03	7.34E-03	Y	Y
Acetaldehyde	4.00E-05	0.16	0.68	Y	Y
Acrolein	6.40E-06	2.49E-02	0.109	Y	Y
Benzene	1.20E-05	4.68E-02	0.205	Y	Y
Ethylbenzene	3.20E-05	0.12	0.55	Y	Y
Formaldehyde	1.45E-04	0.57	2.48	Y	Y
Hexane	2.34E-06	9.12E-03	4.00E-02	Y	Y
Naphthalene	1.30E-06	5.07E-03	2.22E-02	Y	Y
PAH	2.20E-06	8.57E-03	3.76E-02	Y	N
Propylene Oxide	2.90E-05	0.11	0.50	Y	Y
Toluene	1.30E-04	0.51	2.22	Y	Y
Xylenes	6.40E-05	0.25	1.09	Y	Y

1. See Table B-3 for details on emission factors for CCCT Nos. 1 and 2 (turbines only).

2. Potential Emissions (lb/hr) = Emission Factor (lbs/MMBtu) * Heat Input (MMBtu/hr)

3. Potential Emissions (tpy) = Hourly Emissions (lb/hr) * Hours of Operation (hr/yr) / 2,000 (lb/ton)

Table B-8. HAP/TAP Potential Emissions for Combined Cycle Combustion Turbine Nos. 1 and 2 (Duct Burners Only)

Pollutant	Emission Factor[1] (lb/MMBtu, HHV Basis)	Hourly Emissions[2] (lb/hr per duct burner)	Annual Emissions[3] (tpy per duct burner)	HAP (Y/N)	TAP (Y/N)
2-Methylnaphthalene	2.35E-08	2.61E-05	1.14E-04	Y	N
3-Methylchloranthrene	1.76E-09	1.96E-06	8.57E-06	Y	N
7,12-Dimethylbenz(a)anthracene	1.57E-08	1.74E-05	7.62E-05	Y	N
Acenaphthene	1.76E-09	1.96E-06	8.57E-06	Y	N
Acenaphthylene	1.76E-09	1.96E-06	8.57E-06	Y	N
Anthracene	2.35E-09	2.61E-06	1.14E-05	Y	N
Benzene	2.06E-06	2.28E-03	1.00E-02	Y	Y
Benz(a)anthracene	1.76E-09	1.96E-06	8.57E-06	Y	N
Benzo(a)pyrene	1.18E-09	1.30E-06	5.71E-06	Y	N
Benzo(b)fluoranthene	1.76E-09	1.96E-06	8.57E-06	Y	N
Benzo(g,h,i)perylene	1.18E-09	1.30E-06	5.71E-06	Y	N
Benzo(k)fluoranthene	1.76E-09	1.96E-06	8.57E-06	Y	N
Chrysene	1.76E-09	1.96E-06	8.57E-06	Y	N
Dibenz(a,h)anthracene	1.18E-09	1.30E-06	5.71E-06	Y	N
Dichlorobenzene	1.18E-06	1.30E-03	5.71E-03	Y	N
Fluoranthene	2.94E-09	3.26E-06	1.43E-05	Y	N
Fluorene	2.75E-09	3.04E-06	1.33E-05	Y	N
Formaldehyde	7.35E-05	8.15E-02	0.357	Y	Y
Hexane	2.34E-06	2.59E-03	1.14E-02	Y	Y
Indeno(1,2,3-cd)pyrene	1.76E-09	1.96E-06	8.57E-06	Y	N
Naphthalene	5.98E-07	6.63E-04	2.90E-03	Y	Y
Phenanthrene	1.67E-08	1.85E-05	8.09E-05	Y	N
Pyrene	4.90E-09	5.43E-06	2.38E-05	Y	N
Toluene	3.33E-06	3.69E-03	1.62E-02	Y	Y
Arsenic	1.96E-07	2.17E-04	9.52E-04	Y	Y
Beryllium	1.18E-08	1.30E-05	5.71E-05	Y	Y
Cadmium	1.08E-06	1.20E-03	5.24E-03	Y	Y
Chromium	1.37E-06	1.52E-03	6.66E-03	Y	Y
Chromium (VI)	5.49E-08	6.09E-05	2.67E-04	Y	Y
Cobalt	8.24E-08	9.13E-05	4.00E-04	Y	Y
Lead	4.90E-07	5.43E-04	2.38E-03	Y	Y
Manganese	3.73E-07	4.13E-04	1.81E-03	Y	Y
Mercury	2.55E-07	2.83E-04	1.24E-03	Y	Y
Nickel	2.06E-06	2.28E-03	1.00E-02	Y	Y
Selenium	2.35E-08	2.61E-05	1.14E-04	Y	Y

1. See Table B-4 for details on emission factors for CCCT Nos. 1 and 2 (duct burners only).
2. Potential Emissions (lb/hr) = Emission Factor (lbs/MMBtu) * Heat Input (MMBtu/hr)
3. Potential Emissions (tpy) = Hourly Emissions (lb/hr) * Hours of Operation (hr/yr) / 2,000 (lb/ton)

Table B-9. Potential Criteria Pollutant and GHG Emissions from Combined Cycle Combustion Turbines (Includes Duct Burners)

Pollutant	CCCT1 - Combined Cycle Combustion Turbine No. 1 (tpy)	CCCT2 - Combined Cycle Combustion Turbine No. 2 (tpy)	Potential CCCT Emissions (tpy)
SO_2	13.16	13.16	26.31
NO_X	182.84	182.84	365.69
CO	130.40	130.40	260.80
Total PM	121.76	121.76	243.53
Filterable PM	99.86	99.86	199.73
Condensable PM	21.90	21.90	43.80
Total PM_{10}	121.76	121.76	243.53
Total $PM_{2.5}$	121.76	121.76	243.53
VOC	69.75	69.75	139.50
Lead	2.4E-03	2.4E-03	4.8E-03
Sulfuric Acid Mist (H_2SO_4)	1.32	1.32	2.63
CO_2e	2,608,711	2,608,711	5,217,422

Gas Heater Nos. 1 and 2 Operating Parameters

Number of gas heaters	2	
Fuel Type	Natural Gas	
Fuel Heating Value	1,020	Btu/scf
Operating Hours	8,760	hrs/yr
Maximum Heat Input, each gas heater	7.00	MMBtu/hr, HHV

Table B-10. Criteria Pollutant and GHG Potential Emissions for Gas Heater Nos. 1 and 2

Pollutant	Emission Factor[1 to 5] (lb/MMBtu, HHV Basis)	Hourly Emissions[6] (lb/hr per gas heater)	Annual Emissions[7] (tpy per gas heater)
SO_2	5.88E-04	4.12E-03	1.80E-02
CO	8.24E-02	0.58	2.52
Filterable PM	1.86E-03	1.30E-02	5.71E-02
Total PM_{10}	7.45E-03	5.22E-02	0.23
VOC	5.39E-03	3.77E-02	0.17
GHGs			
CO_2	116.98	819	3,586
CH_4	2.20E-03	1.54E-02	6.76E-02
N_2O	2.20E-04	1.54E-03	6.76E-03
CO_2e	117.10	820	3,590

1. Emission factors AP-42 Section 1.4, *Natural Gas Combustion*, Tables 1.4-1 and -2, July 1998. Converted to lb/MMBtu based on AP-42 default 1,020 MMBtu/MMscf. Using emission factor for low NO_X burners.

2. Sulfuric Acid Mist conservatively assumed as a portion (10%) of the SO_2 emissions.

3. All filterable PM is assumed to be less than 2.5 microns in diameter, per footnote c to AP-42, Section 1.4, Table 1.4-2.

4. Based on EPA default factors in 40 CFR Part 98 Subpart C, Tables C-1 and C-2, for Natural Gas. Emission factors were converted from units of kg/MMBtu to lb/MMBtu by multiplying the factors by 2.2046 lb/kg.

5. The CO_2e factor is calculated based on the emission factors for CO_2, CH_4, and N_2O and the global warming potential (GWP) for each pollutant per 40 CFR 98, Subpart A, Table A-1 (update to AR5 GWP effective January 1, 2025):

CO_2: 1
CH_4: 28
N_2O: 265

6. Potential Emissions (lb/hr) = Emission Factor (lbs/MMBtu) * Heat Input (MMBtu/hr)
7. Potential Emissions (tpy) = Hourly Emissions (lb/hr) * Hours of Operation (hr/yr) / 2,000 (lb/ton)

Table B-11. HAP/TAP Potential Emissions for Gas Heater Nos. 1 and 2

Pollutant	Emission Factor[1,2] (lb/MMBtu, HHV Basis)	Hourly Emissions[3] (lb/hr per gas heater)	Annual Emissions[4] (tpy per gas heater)	HAP (Y/N)	TAP[5] (Y/N)
2-Methylnaphthalene	2.35E-08	1.65E-07	7.21E-07	Y	N
3-Methylchloranthrene	1.76E-09	1.24E-08	5.41E-08	Y	N
7,12-Dimethylbenz(a)anthracene	1.57E-08	1.10E-07	4.81E-07	Y	N
Acenaphthene	1.76E-09	1.24E-08	5.41E-08	Y	N
Acenaphthylene	1.76E-09	1.24E-08	5.41E-08	Y	N
Anthracene	2.35E-09	1.65E-08	7.21E-08	Y	N
Benzene	2.06E-06	1.44E-05	6.31E-05	Y	Y
Benz(a)anthracene	1.76E-09	1.24E-08	5.41E-08	Y	N
Benzo(a)pyrene	1.18E-09	8.24E-09	3.61E-08	Y	N
Benzo(b)fluoranthene	1.76E-09	1.24E-08	5.41E-08	Y	N
Benzo(g,h,i)perylene	1.18E-09	8.24E-09	3.61E-08	Y	N
Benzo(k)fluoranthene	1.76E-09	1.24E-08	5.41E-08	Y	N
Chrysene	1.76E-09	1.24E-08	5.41E-08	Y	N
Dibenz(a,h)anthracene	1.18E-09	8.24E-09	3.61E-08	Y	N
Dichlorobenzene	1.18E-06	8.24E-06	3.61E-05	Y	N
Fluoranthene	2.94E-09	2.06E-08	9.02E-08	Y	N
Fluorene	2.75E-09	1.92E-08	8.42E-08	Y	N
Formaldehyde	7.35E-05	5.15E-04	2.25E-03	Y	Y
Hexane	1.76E-03	1.24E-02	5.41E-02	Y	Y
Indeno(1,2,3-cd)pyrene	1.76E-09	1.24E-08	5.41E-08	Y	N
Naphthalene	5.98E-07	4.19E-06	1.83E-05	Y	Y
Phenanthrene	1.67E-08	1.17E-07	5.11E-07	Y	N
Pyrene	4.90E-09	3.43E-08	1.50E-07	Y	N
Toluene	3.33E-06	2.33E-05	1.02E-04	Y	Y
Arsenic	1.96E-07	1.37E-06	6.01E-06	Y	Y
Beryllium	1.18E-08	8.24E-08	3.61E-07	Y	Y
Cadmium	1.08E-06	7.55E-06	3.31E-05	Y	Y
Chromium	1.37E-06	9.61E-06	4.21E-05	Y	Y
Chromium (VI)	5.49E-08	3.84E-07	1.68E-06	Y	Y
Cobalt	8.24E-08	5.76E-07	2.52E-06	Y	Y
Lead	4.90E-07	3.43E-06	1.50E-05	Y	Y
Manganese	3.73E-07	2.61E-06	1.14E-05	Y	Y
Mercury	2.55E-07	1.78E-06	7.82E-06	Y	Y
Nickel	2.06E-06	1.44E-05	6.31E-05	Y	Y
Selenium	2.35E-08	1.65E-07	7.21E-07	Y	Y

1. Emission factors AP-42 Section 1.4, *Natural Gas Combustion*, Tables 1.4-2, -3, and -4, July 1998. Converted to lb/MMBtu based on AP-42 default 1,020 MMBtu/MMscf.

2. Chromium (VI) assumed to be 4% of the AP-42 Section 1.4 emission factor for Chromium per discussions between Trinity Consultants and GA EPD in July 2022.

3. Potential Emissions (lb/hr) = Emission Factor (lbs/MMBtu) * Heat Input (MMBtu/hr)

4. Potential Emissions (tpy) = Hourly Emissions (lb/hr) * Hours of Operation (hr/yr) / 2,000 (lb/ton)

5. Based on Georgia EPD's *Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions*, Appendix A, updated October 2018.

Backup Fire Pump Operating Parameters - Fuel Oil Combustion

Number of diesel-fired fire pumps	1	
Nameplate	420	hp
	313	kW
Heat Input Capacity - estimated based on 7,000 Btu/hp-hr	2.94	MMBtu/hr
Operating Hours	500	hrs/yr

Table B-12. Criteria Pollutant and GHG Potential Emissions for Backup Fire Pump

Pollutant	Emission Factor	Emission Factor Unit and Reference	Hourly Emissions[1] (lb/hr)	Annual Emissions[2] (tpy)
SO_2	2.05E-03	(lb/hp-hr), Note 3	0.86	0.22
NO_X	4.00	(g/kW-hr), Note 4	2.76	0.69
CO	3.50	(g/kW-hr), Note 4	2.42	0.60
Total PM	0.20	(g/kW-hr), Note 4	0.14	3.45E-02
Filterable PM	0.12	(g/kW-hr), Note 4,5	8.37E-02	2.09E-02
Condensable PM	7.88E-02	(g/kW-hr), Note 4,5	5.44E-02	1.36E-02
Total PM_{10}	0.20	(g/kW-hr), Note 4	0.14	3.45E-02
Total $PM_{2.5}$	0.20	(g/kW-hr), Note 4	0.14	3.45E-02
VOC	4.00	(g/kW-hr), Note 4	2.76	0.69
Sulfuric Acid Mist (H_2SO_4)	2.05E-04	(lb/hp-hr), Note 3	8.61E-02	2.15E-02
GHGs				
CO_2	163.05	(lb/MMBtu), Note 6	479.37	119.84
CH_4	6.61E-03	(lb/MMBtu), Note 6	1.94E-02	4.86E-03
N_2O	1.32E-03	(lb/MMBtu), Note 6	3.89E-03	9.72E-04
CO_2e	163.59	(lb/MMBtu), Note 7	480.95	120.24

1. Projected Actual Emissions (lb/hr) = Emission Factor * Nameplate Capacity, converted from grams to pounds if necessary.
2. Projected Actual Emissions (tpy) = Hourly Emissions (lb/hr) * Hours of Operation (hr/yr) / 2,000 (lb/ton)
3. SO_2 emission factor from AP-42 Section 3.3, *Gasoline And Diesel Industrial Engines*, Table 3.3-1, October 1996.
Sulfuric Acid Mist conservatively assumed as a portion (10%) of the SO_2 emissions.

4. Emission standard from Table 4 to NSPS Subpart IIII for stationary fire pump engines (300≤hp<600, 2009+).
The standard for NMHC + NO_X is 4.0 g/hp-hr. Conservatively using this value for both NO_X and VOC emissions.

5. Emission factors for filterable and condensable PM speciation are estimated from AP-42 Section 1.3, *Fuel Oil Combustion*, Tables 1.3-1 and -2, April 2000.

6. Based on EPA default factors in 40 CFR Part 98 Subpart C, Tables C-1 and C-2, for Petroleum Products/Distillate Fuel Oil No. 2.
Emission factors were converted from units of kg/MMBtu to lb/MMBtu by multiplying the factors by 2.2046 lb/kg.

7. The CO_2e factor is calculated based on the emission factors for CO_2, CH_4, and N_2O and the global warming potential (GWP) for each pollutant per 40 CFR 98, Subpart A, Table A-1 (update to AR5 GWP effective January 1, 2025):

CO_2: 1
CH_4: 28
N_2O: 265

Table B-13. HAP/TAP Potential Emissions for Backup Fire Pump

Pollutant	Emission Factor[1] (lb/MMBtu, HHV Basis)	Hourly Emissions[2] (lb/hr)	Annual Emissions[3] (tpy)	HAP (Y/N)	TAP[4] (Y/N)
Benzene	9.33E-04	2.74E-03	6.86E-04	Y	Y
Toluene	4.09E-04	1.20E-03	3.01E-04	Y	Y
Xylene (Total)	2.85E-04	8.38E-04	2.09E-04	Y	Y
1,3-Butadiene	3.91E-05	1.15E-04	2.87E-05	Y	Y
Formaldehyde	1.18E-03	3.47E-03	8.67E-04	Y	Y
Acetaldehyde	7.67E-04	2.25E-03	5.64E-04	Y	Y
Acrolein	9.25E-05	2.72E-04	6.80E-05	Y	Y
Naphthalene	8.48E-05	2.49E-04	6.23E-05	Y	Y

1. Emission factors AP-42 Section 3.3, *Gasoline And Diesel Industrial Engines*, Table 3.3-2, October 1996.
2. Potential Emissions (lb/hr) = Emission Factor (lbs/MMBtu) * Heat Input (MMBtu/hr)
3. Potential Emissions (tpy) = Hourly Emissions (lb/hr) * Hours of Operation (hr/yr) / 2,000 (lb/ton)
4. Based on Georgia EPD's *Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions*, Appendix A, updated October 2018.

Emergency Generator Nos. 1 and 2 Operating Parameters - Fuel Oil Combustion

Number of diesel-fired emergency generators	2	
Nameplate, each generator	2,991 2,230	hp kW
Heat Input Capacity, each generator - estimated based on 7,000 Btu/hp-hr	20.94	MMBtu/hr
Operating Hours	200	hrs/yr

Table B-14. Criteria Pollutant and GHG Potential Emissions for Emergency Generator Nos. 1 and 2

Pollutant	Emission Factor	Emission Factor Unit and Reference	Hourly Emissions[1] (lb/hr per generator)	Annual Emissions[2] (tpy per generator)
SO_2	1.21E-05	(lb/hp-hr), Note 3	3.63E-02	3.63E-03
NO_X	6.40	(g/kW-hr), Note 4	31.47	3.15
CO	3.50	(g/kW-hr), Note 4	17.21	1.72
Total PM	0.20	(g/kW-hr), Note 4	0.98	0.10
Filterable PM	0.18	(g/kW-hr), Note 4,5	0.87	0.09
Condensable PM	2.21E-02	(g/kW-hr), Note 4,5	0.11	1.1E-02
Total PM_{10}	0.20	(g/kW-hr), Note 4	0.98	0.10
Total $PM_{2.5}$	0.20	(g/kW-hr), Note 4	0.98	0.10
VOC	6.40	(g/kW-hr), Note 4	31.47	3.15
Sulfuric Acid Mist (H_2SO_4)	1.21E-06	(lb/hp-hr), Note 3	3.6E-03	3.6E-04
GHGs				
CO_2	163.05	(lb/MMBtu), Note 6	3,414	341.38
CH_4	6.61E-03	(lb/MMBtu), Note 6	0.14	1.38E-02
N_2O	1.32E-03	(lb/MMBtu), Note 6	2.77E-02	2.77E-03
CO_2e	163.59	(lb/MMBtu), Note 7	3,425	342.50

1. Projected Actual Emissions (lb/hr) = Emission Factor * Nameplate Capacity, converted from grams to pounds if necessary.
2. Projected Actual Emissions (tpy) = Hourly Emissions (lb/hr) * Hours of Operation (hr/yr) / 2,000 (lb/ton)
3. SO_2 emission factor from AP-42 Section 3.4, *Large Stationary Diesel and All Stationary Dual-fuel Engines*, Table 3.4-1, October 1996. Using ULSD as required by NSPS Subpart IIII. Sulfuric Acid Mist conservatively assumed as a portion (10%) of the SO_2 emissions.
4. Emission standard from 40 CFR 60.4202(a)(2) (NSPS Subpart IIII) which references 40 CFR 1039 Appendix I for stationary emergency engines (kW>560). The standard for NMHC + NO_X is 6.4 g/hp-hr. Conservatively using this value for both NO_X and VOC emissions.
5. Emission factors for filterable and condensable PM speciation are estimated from AP-42 Section 3.4, *Large Stationary Diesel and All Stationary Dual-fuel Engines*, Table 3.4-2, October 1996.
6. Based on EPA default factors in 40 CFR Part 98 Subpart C, Tables C-1 and C-2, for Petroleum Products/Distillate Fuel Oil No. 2. Emission factors were converted from units of kg/MMBtu to lb/MMBtu by multiplying the factors by 2.2046 lb/kg.
7. The CO_2e factor is calculated based on the emission factors for CO_2, CH_4, and N_2O and the global warming potential (GWP) for each pollutant per 40 CFR 98, Subpart A, Table A-1 (update to AR5 GWP effective January 1, 2025):

CO_2: 1
CH_4: 28
N_2O: 265

Table B-15. HAP/TAP Potential Emissions Emergency Generator Nos. 1 and 2

Pollutant	Emission Factor[1] (lb/MMBtu, HHV Basis)	Hourly Emissions[2] (lb/hr per generator)	Annual Emissions[3] (tpy per generator)	HAP (Y/N)	TAP[4] (Y/N)
Benzene	7.76E-04	1.62E-02	1.62E-03	Y	Y
Toluene	2.81E-04	5.88E-03	5.88E-04	Y	Y
Xylene (Total)	1.93E-04	4.04E-03	4.04E-04	Y	Y
Formaldehyde	7.89E-05	1.65E-03	1.65E-04	Y	Y
Acetaldehyde	2.52E-05	5.28E-04	5.28E-05	Y	Y
Acrolein	7.88E-06	1.65E-04	1.65E-05	Y	Y

1. Emission factors AP-42 Section 3.4, *Large Stationary Diesel and All Stationary Dual-fuel Engines* , Table 3.4-3, October 1996.
2. Potential Emissions (lb/hr) = Emission Factor (lbs/MMBtu) * Heat Input (MMBtu/hr)
3. Potential Emissions (tpy) = Hourly Emissions (lb/hr) * Hours of Operation (hr/yr) / 2,000 (lb/ton)
4. Based on Georgia EPD's *Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions* , Appendix A, updated October 2018.

Table B-16. Facility-wide Potential Emissions

Pollutant	Annual Emissions (tpy)
SO_2	26.57
NO_X	375.68
CO	269.90
Total PM	244.22
Filterable PM	200.04
Condensable PM	44.18
Total PM_{10}	244.22
Total $PM_{2.5}$	244.22
VOC	146.82
Lead	4.79E-03
Sulfuric Acid Mist (H_2SO_4)	2.66
GHGs (CO_2e)	5,225,407
Total HAP	16.86
Max Single HAP[1]	5.67

1. Max Single HAP is Formaldehyde.

Table B-17. Project PSD Emissions Increase Evaluation

Pollutant	New Unit Potential Emissions (tpy)[1]	Project Emissions Increases (tpy)[2]	PSD Significant Emission Rate[3] (tpy)	PSD Triggered? (Yes/No)
Filterable PM	200.04	200.04	25	Yes
Total $PM_{2.5}$	244.22	244.22	10	Yes
NO_X	375.68	375.68	40	Yes
CO	269.90	269.90	100	Yes
Lead	4.79E-03	4.79E-03	0.60	No

1. All units are new with respect to this PSD assessment.
2. Emissions Increase from New Units (tpy) = New Unit Potential Emissions (tpy)
3. For a greenfield source, once the PSD major source threshold is reached, all other PSD pollutants must be evaluated against their respective SERs. The PSD major source threshold of 100 tpy will be reached by multiple criteria pollutants. PSD for GHGs in terms of CO_2e can only be triggered if PSD is triggered by another PSD pollutant.

APPENDIX C. BACT CONTROL COSTS ANALYSES

Table C-1. Potential Emissions for Combined Cycle Combustion Turbine Systems[1]

Pollutant Emissions	Maximum Annual Emissions for each CCCT (tpy)
Total CO_2 Emissions (per turbine)	2,606,076

1. Emissions taken from Table B-5, identical for each of the combined cycle combustion turbines.

Table C-2. Calculation of Project Power Output Changes

Parameters	Value
Per CCCT:[1]	
Annual CO_2 Captured (tpy)	2,345,469
Gross Power Output (Natural Gas) (kW)	712,500
CO_2 Captured (kg/yr)[2]	2,127,775,967
Energy Used for Capture (kWh/kg CO_2 processed)[3]	0.556
Energy Used for Capture (kWh/yr)[4]	1,182,098,705
Energy Used for Capture (MWh/yr)	1,182,099
Power Output (without CCS) (MW)	712.5
Power Used for Capture if CCS included (MW)[5]	134.9
Power Output (with CCS)(MW)	577.6

1. Maximum nominal power output based on GE data (712.5 MW per CCCT system).

2. CO_2 Captured (kg/yr) = CO_2 Captured (tpy) * 2,000 (lb/ton) / 2.20462 (lb/kg)

3. Energy used for capture based on estimated reboiler duty between 2.0 and 3.5 GJ per tonne of CO_2 (equal to 0.56 to 0.97 kWh/kg) from the January 2025 report from the Global CCS Institute, *Advancements in CCS Technologies and Costs*. Conservatively using the lower range of this figure.
https://www.globalccsinstitute.com/wp-content/uploads/2025/01/Advancements-in-CCS-Technologies-and-Costs-Report-2025.pdf

4. Energy Used for Capture (kWh/yr) = Energy Used for Capture (kWh/kg CO_2 processed) * CO_2 Captured (kg/yr)

5. Power Used for Capture (MW) = Energy Used for Capture (MWh/yr) / Potential Hours of Operation (hr/yr).

Table C-3. Assumptions Used in CCS Cost Estimation for Combined Cycle Combustion Turbines

Parameters	**Value**	**Unit**
Pipeline Length[1]	288.13	mi
Pipeline Diameter[2]	16	in
Average Storage Site Depth[3]	3,000	m
	9,843	ft
Number of Injection Wells[4]	1	
Per CCCT:[5]		
CCCT Potential Operating Hours	8,760	hr/yr
Uncontrolled Annual Natural Gas CO_2 Emissions	2,606,076	tpy
Uncontrolled Maximum Natural Gas Daily CO_2 Emissions	7,140	tpd
Capture Efficiency[6]	90%	
Annual Captured CO_2 Emissions	2,345,469	tpy
Daily Maximum Captured CO_2 Emissions	6,426	tpd
Post-Project Net Power Output without CCS	712.5	MW
Post-Project Net Power Output with CCS[7]	577.6	MW
All CCCTs:	2	CCCTs
Annual Captured CO_2 Emissions	4,690,937	tpy
Daily Maximum Captured CO_2 Emissions	12,852	tpd
Post-Project Net Power Output without CCS	1,425	MW
Post-Project Net Power Output with CCS	1,155.1	MW

1. Distance from the proposed Facility to the nearest potential CO_2 sequestration facility (Paluxy Formation, Citronelle, Alabama) based upon review of the NETL NATCARB Viewer (2.0) for "Large Scale Projects". Information on this site per the Southeast Regional Carbon Sequestration Partnership (SECARB). Conservatively assuming the shortest distance as the pipeline route.

https://www.netl.doe.gov/sites/default/files/2018-11/Citronelle-SECARB-Project.PDF
https://netl.doe.gov/coal/carbon-storage/atlas/secarb/phase-III/citronelle-projects
https://edxspatial.arcgis.netl.doe.gov/maps/edxspatial-natcarb-index.html

2. Based on the FECM/NETL CO2 Transport Cost Model (DOE/NETL-2023/4384) published in 2023 by the National Energy Technology Laboratory. Assumes default parameters with 100% capacity factor, pipeline distance of 288.13 miles, and annual flow of 4.256 million metric tons per year of CO_2 (based on total annual captured CO_2 emissions of 4,690,937 tpy of CO_2 for both CCCTs). Resulting projection of pipeline diameter from the model is 14.51 inches. This corresponds to a nominal pipeline diameter of 16 inches.

3. The injection zone for the Citronelle Project is the upper Paluxy Formation, which occurs at a depth of 3,000 to 3,400 meters. Shallowest depth is used for conservatism.
https://netl.doe.gov/coal/carbon-storage/atlas/secarb/phase-III/citronelle-projects

4. Conservatively assumes only 1 injection well is needed.

5. Heat Inputs, Operating Hours, and Emissions taken from Table B-5, identical for each of the CCCTs.

6. 90% CCS Capture Efficiency from the January 2025 report from the Global CCS Institute, *Advancements in CCS Technologies and Costs*.
https://www.globalccsinstitute.com/wp-content/uploads/2025/01/Advancements-in-CCS-Technologies-and-Costs-Report-2025.pdf

7. Net Power Output with CCS = Power Output (without CCS) - Power Used for Capture if CCS included (MW); taken from Table D-2

Table C-4. Capital and O&M Costs of Carbon Capture

		December 2018 Dollars	January 2025 Dollars[2]
Capture Capital Costs for CCCTs[1,2,3]		$ 705,797,320	$ 898,770,696
	Total Capital	$ 705,797,320	$ 898,770,696
O&M			
Fixed Operating Costs[2,4]	Labor, Property Taxes, Insurance, etc.	$ 21,416,528	$ 27,272,062
Variable Operating Costs[2,5]	Water, Chemicals (MEA Solvent), etc.	$ 17,546,755	$ 22,344,247
	Total O&M	$ 38,963,284	$ 49,616,309

1. Based on the October 2022 DOE Report, *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity,* the total capital cost difference between a natural gas CCCT energy facility (H-Frame) with and without capture in terms of $/kW (net) is relied upon to estimate the capital costs associated with capture equipment. Section 5.3.6 (Page 634) / Exhibit 5-61, Case B32A Total Plant Cost Details (page 637) and Section 5.3.10 (Page 652) / Exhibit 5-75, Case B32B.90 Total Plant Cost Details (page 653). Cost results are reported in 2018 dollars.

Capture Capital Costs = [Total Plant Capital Cost (capture) ($/kW) * Net Power Output with CCS (kW)] - [Total Plant Capital Cost (no capture) ($/kW) * Power Output without CCS (kW)]

https://www.netl.doe.gov/projects/files/CostAndPerformanceBaselineForFossilEnergyPlantsVolume1BituminousCoalAndNaturalGasToElectricity_101422.pdf

Total Plant Capital Cost - No Capture	796	$/kW
Total Plant Capital Cost - With Capture	1,593	$/kW

2. The purchased equipment cost was corrected for inflation to January 2025 dollars via PPI industry group data for total manufacturing industries.

PPI for December 2018	195.2
PPI for January 2025	248.57

3. Note that the two CCCTs would share a carbon capture system; therefore, additional cost is required for connecting the CCCTs to a single carbon capture system. OPC conservatively estimated there is no additional cost for connecting the units into a single pipeline for purposes of this estimate.

4. Based on the October 2022 DOE Report, *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity,* the total fixed operating cost difference between a natural gas CCCT energy facility (H-Frame) with and without capture in terms of $/kW (net) is relied upon to estimate the fixed operating costs associated with capture equipment. Exhibit 5-63, Case B32A Initial and Annual Operating and Maintenance Costs (page 639) and Exhibit 5-77, Case B32B.90 Initial and Annual Operating and Maintenance Costs (page 657).

Fixed Operating Costs = [Total Fixed Operating Cost (capture) ($/kW) * Net Power Output with CCS (kW)] - [Total Fixed Operating Cost (no capture) ($/kW) * Net Power Output without CCS (kW)]

Total Fixed Operating Costs - No Capture	26.251	$/kW
Total Fixed Operating Costs - With Capture	50.925	$/kW

5. Based on the October 2022 DOE Report, *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity*, the total variable operating cost difference between a natural gas CCCT energy facility (H-Frame) with and without capture in terms of $/MWh (net) is relied upon to estimate the variable operating costs associated with capture equipment. Exhibit 5-63, Case B32A Initial and Annual Operating and Maintenance Costs (page 639) and Exhibit 5-77, Case B32B.90 Initial and Annual Operating and Maintenance Costs (page 657).

Variable Operating Costs = [Total Variable Operating Cost (capture) ($/MWh) * Net Power Output with CCS (MW)] - [Total Variable Operating Cost (no capture) ($/MWh) * Net Power Output without CCS (MW)] * Potential Hours of Operation (hr/yr)

Total Variable Operating Costs - No Capture	1.69016	$/MWh
Total Variable Operating Costs - With Capture	3.81913	$/MWh

Table C-5. Capital and O&M Costs of Pipeline Transportation

Capital Costs	Factor	Unit	December 2011 Dollars	January 2025 Dollars[3]
Pipeline Costs[1]				
Pipeline Cost	$ 1,205,828	$/mi for a 16 inch pipeline	$ 347,435,257	$ 455,495,684
		Total Capital	$ 347,435,257	$ 455,495,684
O&M[2]				
Fixed O&M	$ 8,477	$/mile/yr	$ 2,442,452	$ 3,202,111

1. Based on the FECM/NETL CO2 Transport Cost Model (DOE/NETL-2023/4384) published in 2023 by the National Energy Technology Laboratory. Assumes default parameters with 100% capacity factor, pipeline distance of 288.13 miles, and annual flow of 4.256 million metric tons per year of CO_2 (based on total annual captured CO_2 emissions of 4,690,937 tpy of CO_2 for both CCCTs). This projects a nominal pipeline diameter of 16 inches and resulting pipeline cost based on the Parker model of 1,205,828 $/mi in terms of 2011 dollars.

2. Based on the FECM/NETL CO2 Transport Cost Model (DOE/NETL-2023/4384) published in 2023 by the National Energy Technology Laboratory. Default annual pipeline O&M is $8,477/mi in terms of 2011 dollars.

3. Costs were adjusted from December 2011 to January 2025 dollars via PPI industry group data for total manufacturing industries.

PPI for December 2011	189.6
PPI for January 2025	248.57

Table C-6. Capital and O&M Costs of Geological Storage

Capital Costs[1]	Factor	Unit	June 2007 Dollars	January 2025 Dollars[2]
Site Screening and Evaluation		$	$ 4,738,488	$ 7,195,149
Injection Wells	240,714 * $e^{0.0008*\text{well-depth}}$	$/injection well, well-depth(m)	$ 2,653,433	$ 4,029,101
Injection Equipment	94,029 * $(7{,}389 / (280 * \text{\# of injection wells}))^{0.5}$	$/injection well	$ 483,032	$ 733,459
Liability Bond		$	$ 5,000,000	$ 7,592,242
		Total Capital	$ 12,874,953	$ 19,549,951
O&M[1]				
Pore Space Acquisition	0.334	$/short tons CO_2 captured	$ 1,566,773	$ 2,379,064
Normal Daily Expenses	11,566	$/injection well	$ 11,566	$ 17,562
Consumables	2,995	$/yr/short tons CO_2/day	$ 38,491,391	$ 58,447,190
Surface Maintenance	23,478 * $(7{,}389 / (280 * \text{\# of injection wells}))^{0.5}$	$/injection well	$ 120,608	$ 183,137
Subsurface Maintenance	7.08	$/ft depth/injection well	$ 69,685	$ 105,813
		Total O&M	$ 40,260,023	$ 61,132,766

1. "Estimating Carbon Dioxide Transport and Storage Costs," National Energy Technology laboratory, U.S. DOE, DOE/NETL-2010/1447, Table 3, March 2010.

2. Costs were adjusted from June 2007 dollars to January 2025 dollars via PPI industry group data for total manufacturing industries.

PPI for June 2007	163.7
PPI for January 2025	248.57

Table C-7. Overall Cost of CCS and Cost Effectiveness

			January 2025 Dollars
Total Capital Investment (TCI)[1]			$ 1,373,816,331
Capital Recovery Factor (CRF)[2]		0.1457	
Interest	7.50%		
Lifespan (years)	10		
Amortized Cost	CRF*TCI		$ 200,145,706
Total O&M Cost			$ 113,951,186
Total Annualized Cost	Amortized Cost + O&M Costs		$ 314,096,892
Cost Effectiveness ($/ton)[3]			$ 67

1. Total Capital Investment (TCI) is equal to the sum of capital costs for carbon capture, transportation, and storage.

2. The capital recovery factor, CRF, is a function of the equipment life and the opportunity cost of the capital (i.e., interest rate) calculated using the formula from the EPA OAQPS Control Cost Manual. Assuming a 10 year lifespan and a 7.5% interest rate (Bank Prime Rate based on U.S. Federal Reserve data).

3. Cost Effectiveness = Total Annualized Cost ($)/ CO_2 Emissions Captured (tons).

APPENDIX D. RBLC DATABASE TABLES

Table D-1. RBLC Search Results for Large Natural Gas Fired Turbines (Combined-Cycle) - NOx

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel	Throughput	Throughput Units	Process Notes	Pollutant	Control Method Description	Emission Limit	Emission Limit Unit	Emission Limit 1 Average Time Condition
COLORADO BEND ENERGY CENTER	COLORADO BEND II POWER, LLC	WHARTON	TX	4/1/2015	Combined cycle combustion turbine electric generating facility. These will be the first two General Electric (GE) Model 7HA.02 Combustion Turbines in a combined cycle power plant that uses two combustion turbines and one steam turbine using air-cooled condensers and controlled with Selective catalytic reduction (SCR) and oxidation catalyst.		Combined-cycle gas turbine electric generating facility	15.21	natural gas	1100	MW	combined cycle power plant that uses two combustion turbines and one steam turbine, model GE 7HA.02	Nitrogen Oxides (NOx)	SCR and oxidation catalyst	2	PPMVD @ 15% O2	24-HR AVERAGE
ROLLING HILLS GENERATING, LLC		VINTON	OH	5/20/2015	Electrical services	Note: The proposed modification was not installed.□ □ Chapter 31 major modification to convert four of the existing five simple cycle peaking units, SW501F turbines nominally rated at 209 megawatts (MW) each, to combined cycle configuration consisting of two 2x1 combined cycle blocks, the addition of four heat recovery steam generators (HRSGs), each of which will be equipped with duct burners, and two steam turbine generators.□ □ Permit includes 2 options for the units. Siemens Westinghouse Power Corp. SW501F, (Scenario 1: 200 MW, with 2022 MMBtu/hr input & 550 MMBtu/hr duct burner. Scenario 2: 207.5 MW with 2144 MMbtu/hr input & 550 MMBtu/hr duct burner.) combined cycle natural gas fired turbine with Dry Low-NOX combusters, SCR and duct burner. Emissions increase noted below is for scenario 1.□ Scenario 2 = 5101.7 CO, 449.31 NOx, 346.8 PM and 600.62 VOC.	Combustion Turbines, Scenario 1 (4, identical) (P001, P002, P004, P005)	15.21	Natural gas	2022	MMBTU/H	Scenario 1 only. Other scenario added as separate process. Siemens Westinghouse Power Corp. SW501F, (Scenario 1: 200 MW, with 2022 MMBtu/hr input & 550 MMBtu/hr duct burner. Scenario 2: 207.5 MW with 2144 MMBtu/hr input & 550 MMBtu/hr duct burner.) combined cycle natural gas fired turbine with Dry Low-NOX combusters, SCR and duct burner.	Nitrogen Oxides (NOx)	dry-low NOx (DLN) burner and selective catalytic reduction (SCR)	14.7	LB/H	WITHOUT DUCT BURNERS. SEE NOTES.
ROLLING HILLS GENERATING, LLC		VINTON	OH	5/20/2015	Electrical services	Note: The proposed modification was not installed.□ □ Chapter 31 major modification to convert four of the existing five simple cycle peaking units, SW501F turbines nominally rated at 209 megawatts (MW) each, to combined cycle configuration consisting of two 2x1 combined cycle blocks, the addition of four heat recovery steam generators (HRSGs), each of which will be equipped with duct burners, and two steam turbine generators.□ □ Permit includes 2 options for the units. Siemens Westinghouse Power Corp. SW501F, (Scenario 1: 200 MW, with 2022 MMBtu/hr input & 550 MMBtu/hr duct burner. Scenario 2: 207.5 MW with 2144 MMbtu/hr input & 550 MMBtu/hr duct burner.) combined cycle natural gas fired turbine with Dry Low-NOX combusters, SCR and duct burner. Emissions increase noted below is for scenario 1.□ Scenario 2 = 5101.7 CO, 449.31 NOx, 346.8 PM and 600.62 VOC.	Combustion Turbines, Scenario 2 (4, identical) (P001, P002, P004, P005)	15.21	Natural gas	2144	MMBTU/H	Scenario 1 only. Other scenario added as separate process. Siemens Westinghouse Power Corp. SW501F, (Scenario 1: 200 MW, with 2022 MMBtu/hr input & 550 MMBtu/hr duct burner. Scenario 2: 207.5 MW with 2144 MMBtu/hr input & 550 MMBtu/hr duct burner.) combined cycle natural gas fired turbine with Dry Low-NOX combusters, SCR and duct burner.	Nitrogen Oxides (NOx)	dry-low NOx (DLN) burner and selective catalytic reduction (SCR)	15.6	LB/H	WITHOUT DUCT BURNERS. SEE NOTES.
YORK ENERGY CENTER BLOCK 2 ELECTRICITY GENERATION PROJECT	CALPINE MID-MERIT, LLC	YORK	PA	6/15/2015	Calpine Mid-Merit, LLC. currently operates Block 1 of the York Energy Center under Title V operating permit 67-05083 with a rated capacity of 565 MW. This plan approval is for the construction and temporary operation of Block 2 Electricity Generation Project having a nominal generating capacity of 835 MW. Block 2 consists of two combined cycle NG/USLD fuel fired combustion turbines, one NG-fired auxiliary boiler, one cooling tower, NG piping componets, circuit breaker upgrades, five NG condensate tanks, and additional ULSD fuel oil storage tank. Each CT will be limited to 4500 hr/yr with duct firing; 480 hr/yr of ULSD		Two Combine Cycle Combustion Turbine with Duct Burner	15.21	Natural Gas	3001.57	MCF/hr	Two (2) Combustion Turbine, 235 MW / 2512.5 MMBtu/hr, will fire NG and with the design having no bypasss from the CT to HRSG the CT will always be in combined cycle mode the HRSG with NG-fired Duct Burner maximum rated heat input capacity 722 MMBtu/hr. CT will employ dry low NOx burner technology (NG firing), controled by SCR and oxidation catalyst. . (Operational limits are for each CCCT NG-fired with duct burner)	Nitrogen Oxides (NOx)	SCR, Dry Lo-NOx combustor, good combustion practices and low sulfur fuels	2	PPVDM @ 15 O2	
EAGLE MOUNTAIN STEAM ELECTRIC STATION	EAGLE MOUNTAIN POWER COMPANY LLC	TARRANT	TX	6/18/2015	Eagle is proposing to construct two new combined cycle combustion turbines (CTG) which will generate electric power for sale on the wholesale electric market. The ancillary equipment includes an auxiliary boiler, a firewater pump, an emergency generator, a steam turbine, and various support facilities.		Combined Cycle Turbines (>25 MW) â€“ natural gas	15.21	natural gas	210	MW	Two power configuration options authorized□ Siemens â€“ 231 MW + 500 million British thermal units per hour (MMBtu/hr) duct burner□ GE â€“ 210 MW + 349.2 MMBtu/hr duct burner	Nitrogen Oxides (NOx)	Selective Catalytic Reduction	2	PPM	ROLLING 24-HR AVERAGE
CLEAN ENERGY FUTURE - LORDSTOWN, LLC	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	TRUMBULL	OH	8/25/2015	962 MW (gross winter output) combined cycle gas turbine (CCGT) facility	Initial installation permit for the construction of the Lordstown Energy Center - a nominal 940 MW combined cycle gas turbine (CCGT) facility.	Combined Cycle Combustion Turbines (two, identical) (P001 and P002)	15.21	Natural gas	2725	MMBTU/H	Combined cycle combustion turbine (2,725 MMBtu/hr heat input turbine at ISO conditions and 179 MMBtu/hr heat input duct burner) with dry low NOx combustors, selective catalytic reduction (SCR), and catalytic oxidizer. □ Limits and throughputs are for single turbine.	Nitrogen Oxides (NOx)	dry low NOx combustors, selective catalytic reduction (SCR)	23.5	LB/H	WITH DUCT BURNER. SEE NOTES.

Table D-1. RBLC Search Results for Large Natural Gas Fired Turbines (Combined-Cycle) - NOx

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel	Throughput	Throughput Units	Process Notes	Pollutant	Control Method Description	Emission Limit	Emission Limit Unit	Emission Limit 1 Average Time Condition
MOXIE FREEDOM GENERATION PLANT	MOXIE FREEDOM LLC	LUZERNE	PA	9/1/2015	The Project is for the construction and operation of two identical 1 x 1 power blocks, each consisting of a combustion gas turbine (CGT or CT) and a steam turbine (ST) configured in single shaft alignment, where each CT and ST train share one common electric generator. The turbines to be used for this project are Two General Electric (GE) 7HA.02 CTs, each in 1 x 1 single shaft combined- cycle power islands. Each CT and duct burner will exclusively fire pipeline-quality natural gas. The HRSGs will be equipped with selective catalytic reduction (SCR) to minimize nitrogen oxide (NOx) emissions and oxidation catalysts to minimize carbon monoxide (CO) and volatile organic compound (VOC) emissions from the CTs and DBâ€™s. The Project will also include several pieces of ancillary equipment. The list of equipment includes: One fuel gas dew-point heater - natural gas fired, common for all CTs Two CT inlet evaporative coolers - one for each CT (not emissions sources) Two air-cooled condensers (ACCs) - one for each HRSG (not emissions sources) One auxiliary boiler, natural gas-fired One diesel engine powered emergency generator One diesel engine powered fire water pump Diesel fuel, lubricating oil, and aqueous ammonia storage tanks The project once operational will produce 1050 MW Electric Generation		Combustion Turbine With Duct Burner	15.21	Natural Gas	3727	MMBtu/hr	DLN burner, SCR, Oxidation Catalyst and shall maintain and operate the sources and associated air cleaning devices in accordance with good engineering practice. shall install, certify, maintain and operate continuous emission monitoring systems (CEMS) for nitrogen oxides, carbon monoxide, carbon dioxide, and ammonia emissions on the exhaust of each combined-cycle powerblock.□ Emissions limits are for each combustion turbine/duct burner block.	Nitrogen Oxides (NOx)	DLN burner, SCR, good engineering practice	2	PPMDV @ 15% O2	
LON C. HILL POWER STATION	LON C. HILL, L.P.	NUECES	TX	10/2/2015	The Lon C. Hill Power Station (LCHP) will include two natural gas-fired combined cycle combustion turbines (CTGs) equipped with dry low NOx burners (DLNs), heat recovery steam generators (HRSG), and natural gas-fired duct burners (DBs). Ancillary equipment includes evaporative coolers or inlet chillers, a single steam turbine (ST), auxiliary boiler, emergency generator, firewater pump, two cooling towers, oil water separator, degreaser, two diesel storage tanks, gasoline storage tank, selective catalytic reduction (SCR) and ammonia (NH3) handling systems including an NH3 storage tank, and two water tanks. The LCHP will be a 2x1 combined cycle power plant consisting of two CTGs, two HRSGs and one ST. The CTGs and ST will be one of two options: two Siemens SCC6-5000 CTGs and a SST6-5000 ST, or two General Electric 7FA CTGs and a D-11 ST.		Combined Cycle Turbines (>25 MW)	15.21	natural gas	195	MW	Two power configuration options authorized□ Siemens â€“ 240 MW + 250 million British thermal units per hour (MMBtu/hr) duct burner□ GE â€“ 195 MW + 670 MMBtu/hr duct burner	Nitrogen Oxides (NOx)	Selective Catalytic Reduction	2	PPM	ROLLING 24-HR AVERAGE
PSO COMANCHE POWER STATION	PUBLIC SERVICE COMPANY OF OKLAHOMA	COMANCHE	OK	10/8/2015	The facility is an electric utility plant, which burns natural gas to generate electricity. The Comanche Power Plant was constructed in 1971 and has operated continuously since that time without significant modification. The facility produces power using two Westinghouse gas combustion turbines(94 MW), Model W-501B, to supply a single steam turbine(120 MW). The turbines are fueled by Natural Gas and operate continuously.	American Electric Power (AEP) has requested a construction permit for their Comanche Power Station (SIC 4911, NAIC Code 221112) to install Dry Low-NOX burners (DLNB) to Units No. 1 and No. 2 to reduce emissions of NOX for the purpose of meeting Best Available Retrofit Technology (BART) requirements and Regional Haze Rule.	COMBINED CYCLE COMBUSTION TURBINE	15.21	NATURAL GAS	1250	MMBTUH	Two (2) turbines without duct burner that support one (1) steam turbine.	Nitrogen Oxides (NOx)	Use of Dry Low NOx Burners	0.15	LB/MMBTU	30-DAY ROLLING AVG
FGE EAGLE PINES PROJECT	FGE EAGLE PINES, LLC	CHEROKEE	TX	11/4/2015	The FGEEP Project will include three natural gas-fired combined cycle (NGCC) power blocks, each block comprised of two gas-fired combustion turbines, two supplemental fired duct burners (DBs) heat recovery steam generators (HRSGs), and one steam turbine. FGEEP selected Alstom GT36 combustion turbines (CTs), each nominally rated at 321 megawatts (MW). Each HRSG is equipped with DBs that will have a maximum design heat input capacity of 799 million British thermal units per hour (MMBtu/hr). The CTs and DBs are fueled with pipeline quality natural gas. Each power block will also have a steam turbine generator designed to produce approximately 502 MW with the additional duct firing. Each of the three blocks will include the following ancillary equipment: one multi-cell condenser/cooling tower, one emergency generator, one firewater pump, two diesel storage tanks, and pressurized aqueous ammonia storage tanks.		Combined Cycle Turbines (>25 MW)	15.21	natural gas	321	MW	Alstom GT36 combustion turbines (321 MW)+ 799 million British thermal units per hour (MMBtu/hr) duct burner	Nitrogen Oxides (NOx)	Selective Catalytic Reduction	2	PPM	24-HR AVERAGE
MATTAWOMAN ENERGY CENTER	MATTAWOMAN ENERGY, LLC	PRINCE GEORGE'S	MD	11/13/2015	990 MW COMBINED-CYCLE NATURAL GAS-FIRED POWER PLANTNOTE: PARTICULATE MATTER FACILITYWIDE EMISSIONS ARE PARTICULATE MATTER (FILTERABLE)	NOTE: PARTICULATE MATTER FACILITYWIDE EMISSIONS ARE PARTICULATE MATTER (FILTERABLE). THE FACILITY INCLUDES A WET MECHANICAL DRAFT COOLING TOWER (12 CELL) with 0.0005% RECIRCULATING WATER FLOW.	2 COMBINED-CYCLE COMBUSTION TURBINES - COLD STARTUP	15.21	NATURAL GAS	286	MW	TWO SIEMENS H-CLASS (SGT-8000H VERSION 1.4-OPTIMIZED) COMBINED CYCLE COMBUSTION TURBINES (CTS) WITH A NOMINAL GENERATING CAPACITY OF 286 MW (EACH), COUPLED WITH A HEAT RECOVERY STEAM GENERATOR (HRSG) EQUIPPED WITH DUCT BURNERS, DRY LOW-NOX BURNERS, SCR, OXIDATION CATALYST	Nitrogen Oxides (NOx)	GOOD COMBUSTION PRACTICES, DRY LOW-NOX COMBUSTOR DESIGN AND SELECTIVE CATALYTIC REDUCTION (SCR)	153	LB/EVENT	COLD STARTUP

Table D-1. RBLC Search Results for Large Natural Gas Fired Turbines (Combined-Cycle) - NOx

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel	Throughput	Throughput Units	Process Notes	Pollutant	Control Method Description	Emission Limit	Emission Limit Unit	Emission Limit 1 Average Time Condition
MATTAWOMAN ENERGY CENTER	MATTAWOMAN ENERGY, LLC	PRINCE GEORGE'S	MD	11/13/2015	990 MW COMBINED-CYCLE NATURAL GAS-FIRED POWER PLANTNOTE: PARTICULATE MATTER FACILITYWIDE EMISSIONS ARE PARTICULATE MATTER (FILTERABLE)	NOTE: PARTICULATE MATTER FACILITYWIDE EMISSIONS ARE PARTICULATE MATTER (FILTERABLE). THE FACILITY INCLUDES A WET MECHANICAL DRAFT COOLING TOWER (12 CELL) with 0.0005% RECIRCULATING WATER FLOW.	2 COMBINED-CYCLE COMBUSTION TURBINES	15.21	NATURAL GAS	286	MW	TWO SIEMENS H-CLASS (SGT-8000H VERSION 1.4-OPTIMIZED) COMBINED CYCLE COMBUSTION TURBINES (CTS) WITH A NOMINAL GENERATING CAPACITY OF 286 MW (EACH), COUPLED WITH A HEAT RECOVERY STEAM GENERATOR (HRSG) EQUIPPED WITH DUCT BURNERS, DRY LOW-NOX BURNERS, SCR, OXIDATION CATALYST. HEAT RATE LIMITED TO 6,793 BTU/KWH (NET) AT ALL TIMES WHEN THE CTS/HRSGS ARE OPERATING (LHV). INITIAL COMPLIANCE WITH THE HEAT RATE LIMITATION SHALL BE DEMONSTRATED USING ASME PTC-46 TEST METHOD. ANNUAL THERMAL EFFICIENCY TEST CONDUCTED ACCORDING TO ASME PTC-46, OR ANOTHER METHODOLOGY APPROVED BY MDE-ARMA, AND COMPARE RESULTS TO DESIGN THERMAL EFFICIENCY VALUE. AN EXCEEDANCE OF THE HEAT RATE LIMIT IS NOT CONSIDERED A VIOLATION OF THIS PERMIT, BUT TRIGGERS A REQUIREMENT FOR MATTAWOMAN TO SUBMIT A MAINTENANCE PLAN TO MDE-ARMA WHICH SPECIFIES THE ACTIONS MATTAWOMAN PLANS TO TAKE IN ORDER TO ACHIEVE THE HEAT RATE LIMIT. THE PLAN SHALL INCLUDE A TIMEFRAME THAT THE HEAT	Nitrogen Oxides (NOx)	GOOD COMBUSTION PRACTICES, DRY LOW-NOX COMBUSTOR DESIGN AND SELECTIVE CATALYTIC REDUCTION (SCR)	2	PPMVD @ 15% O2	3-HOUR BLOCK AVERAGE (EXCLUDING SU/SD)
MATTAWOMAN ENERGY CENTER	MATTAWOMAN ENERGY, LLC	PRINCE GEORGE'S	MD	11/13/2015	990 MW COMBINED-CYCLE NATURAL GAS-FIRED POWER PLANTNOTE: PARTICULATE MATTER FACILITYWIDE EMISSIONS ARE PARTICULATE MATTER (FILTERABLE)	NOTE: PARTICULATE MATTER FACILITYWIDE EMISSIONS ARE PARTICULATE MATTER (FILTERABLE). THE FACILITY INCLUDES A WET MECHANICAL DRAFT COOLING TOWER (12 CELL) with 0.0005% RECIRCULATING WATER FLOW.	2 COMBINED-CYCLE COMBUSTION TURBINES - WARM STARTUP	15.21	NATURAL GAS	286	MW	TWO SIEMENS H-CLASS (SGT-8000H VERSION 1.4-OPTIMIZED) COMBINED CYCLE COMBUSTION TURBINES (CTS) WITH A NOMINAL GENERATING CAPACITY OF 286 MW (EACH), COUPLED WITH A HEAT RECOVERY STEAM GENERATOR (HRSG) EQUIPPED WITH DUCT BURNERS, DRY LOW-NOX BURNERS, SCR, OXIDATION CATALYST	Nitrogen Oxides (NOx)	GOOD COMBUSTION PRACTICES, DRY LOW-NOX COMBUSTOR DESIGN AND SELECTIVE CATALYTIC REDUCTION (SCR)	132	LB/EVENT	WARM STARTUP
MATTAWOMAN ENERGY CENTER	MATTAWOMAN ENERGY, LLC	PRINCE GEORGE'S	MD	11/13/2015	990 MW COMBINED-CYCLE NATURAL GAS-FIRED POWER PLANTNOTE: PARTICULATE MATTER FACILITYWIDE EMISSIONS ARE PARTICULATE MATTER (FILTERABLE)	NOTE: PARTICULATE MATTER FACILITYWIDE EMISSIONS ARE PARTICULATE MATTER (FILTERABLE). THE FACILITY INCLUDES A WET MECHANICAL DRAFT COOLING TOWER (12 CELL) with 0.0005% RECIRCULATING WATER FLOW.	2 COMBINED-CYCLE COMBUSTION TURBINES - HOT STARTUP	15.21	NATURAL GAS	286	MW	TWO SIEMENS H-CLASS (SGT-8000H VERSION 1.4-OPTIMIZED) COMBINED CYCLE COMBUSTION TURBINES (CTS) WITH A NOMINAL GENERATING CAPACITY OF 286 MW (EACH), COUPLED WITH A HEAT RECOVERY STEAM GENERATOR (HRSG) EQUIPPED WITH DUCT BURNERS, DRY LOW-NOX BURNERS, SCR, OXIDATION CATALYST	Nitrogen Oxides (NOx)	GOOD COMBUSTION PRACTICES, DRY LOW-NOX COMBUSTOR DESIGN AND SELECTIVE CATALYTIC REDUCTION (SCR)	105	LB/EVENT	HOT STARTUP
MATTAWOMAN ENERGY CENTER	MATTAWOMAN ENERGY, LLC	PRINCE GEORGE'S	MD	11/13/2015	990 MW COMBINED-CYCLE NATURAL GAS-FIRED POWER PLANTNOTE: PARTICULATE MATTER FACILITYWIDE EMISSIONS ARE PARTICULATE MATTER (FILTERABLE)	NOTE: PARTICULATE MATTER FACILITYWIDE EMISSIONS ARE PARTICULATE MATTER (FILTERABLE). THE FACILITY INCLUDES A WET MECHANICAL DRAFT COOLING TOWER (12 CELL) with 0.0005% RECIRCULATING WATER FLOW.	2 COMBINED-CYCLE COMBUSTION TURBINES - SHUTDOWN	15.21	NATURAL GAS	286	MW	TWO SIEMENS H-CLASS (SGT-8000H VERSION 1.4-OPTIMIZED) COMBINED CYCLE COMBUSTION TURBINES (CTS) WITH A NOMINAL GENERATING CAPACITY OF 286 MW (EACH), COUPLED WITH A HEAT RECOVERY STEAM GENERATOR (HRSG) EQUIPPED WITH DUCT BURNERS, DRY LOW-NOX BURNERS, SCR, OXIDATION CATALYST	Nitrogen Oxides (NOx)	DRY LOW-NOX COMBUSTOR DESIGN, GOOD COMBUSTION PRACTICES AND SELECTIVE CATALYTIC REDUCTION (SCR)	23	LB/EVENT	SHUT DOWN
CPV TOWANTIC, LLC	CPV TOWANTIC, LLC	NEW HAVEN	CT	11/30/2015	805 MW Combined Cycle Power Plant		Combined Cycle Power Plant	15.21	Natural Gas	21200000	MMBtu/12 months		Nitrogen Oxides (NOx)	SCR	2	PPMVD @15% O2	1 HR BLOCK
CPV TOWANTIC, LLC	CPV TOWANTIC, LLC	NEW HAVEN	CT	11/30/2015	805 MW Combined Cycle Plant		Combined Cycle Power Plant	15.21	Natural Gas	21200000	MMBtu/yr		Nitrogen Oxides (NOx)	SCR	2	PPMVD @15% O2	1 HR BLOCK

Table D-1. RBLC Search Results for Large Natural Gas Fired Turbines (Combined-Cycle) - NOx

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel	Throughput	Throughput Units	Process Notes	Pollutant	Control Method Description	Emission Limit	Emission Limit Unit	Emission Limit 1 Average Time Condition
LACKAWANNA ENERGY CTR/JESSUP	LACKAWANNA ENERGY CENTER, LLC	LACKAWANNA	PA	12/23/2015	This plan approval is for the construction and temporary operation of three (3) identical General Electric Model 7HA.02 natural gas fired combustion turbines and heat recovery steam generator with duct burners (CT/HRSG). Each CT/HRSG combined-cycle process block includes one (1) combustion gas turbine and one (1) heat recovery steam generator with duct burners with all three (3) CT/HRSG sharing one (1) steam turbine. The entire power block is rated at 1,500 MW. Additional equipment includes: one (1) 2,000 kW diesel-fired emergency generator one (1) 315 HP diesel-fired emergency fire water pump one (1) 184.8 MM BTU/hr natural gas fired boiler one (1) 12 MMBTU/hr natural gas fuel gas heater two (2) Diesel fuel storage tanks four (4) lubricating oil tanks one (1) aqueous ammonia storage tank		Combustion turbine with duct burner	15.21	Natural gas	3304.3	MMBtu/hr	Limits are for each CCCT and yearly limits are for cumulative turbine and duct burner. Duct burner throughput is 637.9 MMBtu/hr.	Nitrogen Oxides (NOx)	Dry low-NOx burners, SCR, exclusive natural gas	2	PPMDV @15% O2	
TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	WESTMORELAND	PA	2/12/2016	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.	Application for plan approval 65-00990E received on 12/10/2015 from Tenaska to reduce the facility wide PTE authorized under plan approval 65-00990C based on revised emission information for startup and shutdown from the manufacturer.	Large combustion turbine	15.21	Natural Gas	0		This process entry is for operations with the duct burner. Limits entered are for each turbine.	Nitrogen Oxides (NOx)	SCR, DLN, and good combustion practice	2	PPMVD@15% O2	
DECORDOVA STEAM ELECTRIC STATION	DECORDOVA II POWER COMPANY LLC	HOOD	TX	3/8/2016	The DeCordova Station will consist of two combustion turbine generators (CTGs) operating in simple cycle or combined cycle modes. The gas turbines will be one of two options: Siemens or General Electric.		Combined Cycle & Cogeneration	15.21	natural gas	231	MW	2 CTGs to operate in simple cycle & combined cycle modes. 231 MW (Siemens) or 210 MW (GE). Simple cycle operations limited to 2,500 hr/yr.	Nitrogen Oxides (NOx)	Selective Catalytic Reduction	2	PPM	
OKEECHOBEE CLEAN ENERGY CENTER	FLORIDA POWER & LIGHT	OKEECHOBEE	FL	3/9/2016	Fossil-fueled power plant, consisting of a 3-on-1 combined cycle unit and auxiliary equipment. The combined cycle unit consists of three GE 7HA.02 turbines, each with nominal generating capacity of 350 MW. The total generating capacity for the combined cycle unit is 1,600 MW.	Technical evaluation of project available at http://depedms.dep.state.fl.us/Oculus/servlet/shell?command=getEntity&[guid=75.89000.1]&[profile=Permitting_Authorization]	Combined-cycle electric generating unit	15.21	Natural gas	3096	MMBtu/hr per turbine	3-on-1 combined cycle unit. GE 7HA.02 turbines, approximately 350 MW per turbine. Total unit generating capacity is approximately 1,600 MW. Primarily fueled with natural gas. Permitted to burn the base-load equivalent of 500 hr/yr per turbine on ULSD.	Nitrogen Oxides (NOx)	Selective catalytic reduction; dry low-NOx; and wet injection	2	PPMVD@15% O2	GAS, 24-HR BLOCK, EXCLUDING SSM
NECHES STATION	APEX TEXAS POWER LLC	CHEROKEE	TX	3/24/2016	either 4 simple cycle combustion turbine generators (CTGs) or two CTGs operating in simple cycle or combined cycle modes. The CTGs will be one of two options: Siemens or General Electric.		Combined Cycle & Cogeneration	15.21	natural gas	231	MW	2 CTGs to operate in simple cycle & combined cycle modes. 231 MW (Siemens) or 210 MW (GE) Simple cycle operations limited to 2,500 hr/yr.	Nitrogen Oxides (NOx)	Selective Catalytic Reduction	2	PPM	
JOHNSONVILLE COGENERATION	TENNESSEE VALLEY AUTHORITY	HUMPHREYS	TN	4/19/2016	Existing gas-fired combustion turbine with new heat recovery steam generator (HRSG) with duct burner and two new gas-fired auxiliary boilers.	Facility-wide emissions increases do not include decreases due to shutdown of coal-fired units.	Natural Gas-Fired Combustion Turbine with HRSG	15.21	Natural Gas	1339	MMBtu/hr	Turbine throughput is 1019.7 MMBtu/hr when burning natural gas and 1083.7 MMBtu/hr when burning No. 2 oil. Duct burner throughput is 319.3 MMBtu/hr. Duct burner firing will occur during natural gas combustion only.	Nitrogen Oxides (NOx)	Good combustion design and practices, selective catalytic reduction (SCR)	2	PPMVD @ 15% O2	30 UNIT-OPERATING-DAY MOVING AVERAGE

Table D-1. RBLC Search Results for Large Natural Gas Fired Turbines (Combined-Cycle) - NOx

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel	Throughput	Throughput Units	Process Notes	Pollutant	Control Method Description	Emission Limit	Emission Limit Unit	Emission Limit 1 Average Time Condition
GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	GREENSVILLE	VA	6/17/2016	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas.		COMBUSTION TURBINE GENERATOR WITH DUCT-FIRED HEAT RECOVERY STEAM GENERATORS (3)	15.21	natural gas	3227	MMBTU/HR	3227 MMBTU/HR CT with 500 MMBTU/HR Duct Burner, 3 on 1 configuration.	Nitrogen Oxides (NOx)	SCR	2	PPMVD	1 HR AVG
MIDDLESEX ENERGY CENTER, LLC	STONEGATE POWER, LLC	MIDDLESEX	NJ	7/19/2016	NEW 633 MEGAWATT (MW) GROSS FACILITY CONSISTING OF 1.ONE GENERAL ELECTRIC (GE) 7HA.02 CCCT NOMINALLY RATED AT 380 MW AT ISO CONDITIONS WITHOUT DUCT FIRING WITH A MAXIMUM HEAT INPUT RATE OF: O 3,462 MMBTU/HR(HHV) AT (0) DEGREES F, 100% LOAD COMBUSTING NATURAL GAS O 3,613 MMBTU/HR(HHV) AT (0) DEGREES F, 100% LOAD COMBUSTING ULSD WHICH WILL BE THE BACKUP FUEL OTHER EQUIPMENT INCLUDES: 2.ONE NATURAL GAS-FIRED DUCT BURNER (MAXIMUM HEAT INPUT OF 599 MMBTU/HR(HHV)) FOR SUPPLEMENTAL FIRING. 3.ONE 97.5 MMBTU/HR(HHV) NATURAL GAS FIRED AUXILIARY BOILER, EQUIPPED WITH LOW NOX BURNERS AND FLUE GAS RECIRCULATION FOR CONTROL OF NOX EMISSIONS; 4.ONE 2.25 MMBTU/HR(HHV), 327 BRAKE HORSEPOWER, ULSD FIRED EMERGENCY FIRE PUMP; 5.ONE 14.4 MMBTU/HR(HHV), APPROXIMATELY 1,500 KW ULSD FIRED EMERGENCY GENERATOR; AND 6.ONE 8-CELL, 124,800 GALLON PER MINUTE (GPM) MECHANICAL INDUCED DRAFT COOLING TOWER.		Combined Cycle Combustion Turbine firing Natural Gas with Duct Burner	15.21	natural gas	4000	h/yr		Nitrogen Oxides (NOx)	SELECTIVE CATALYTIC REDUCTION AND DRY LOW NOX	2	PPMVD@15% O2	3 H ROLLING AV BASED ON ONE H BLOCK AV
MIDDLESEX ENERGY CENTER, LLC	STONEGATE POWER, LLC	MIDDLESEX	NJ	7/19/2016	NEW 633 MEGAWATT (MW) GROSS FACILITY CONSISTING OF 1.ONE GENERAL ELECTRIC (GE) 7HA.02 CCCT NOMINALLY RATED AT 380 MW AT ISO CONDITIONS WITHOUT DUCT FIRING WITH A MAXIMUM HEAT INPUT RATE OF: O 3,462 MMBTU/HR(HHV) AT (0) DEGREES F, 100% LOAD COMBUSTING NATURAL GAS O 3,613 MMBTU/HR(HHV) AT (0) DEGREES F, 100% LOAD COMBUSTING ULSD WHICH WILL BE THE BACKUP FUEL OTHER EQUIPMENT INCLUDES: 2.ONE NATURAL GAS-FIRED DUCT BURNER (MAXIMUM HEAT INPUT OF 599 MMBTU/HR(HHV)) FOR SUPPLEMENTAL FIRING. 3.ONE 97.5 MMBTU/HR(HHV) NATURAL GAS FIRED AUXILIARY BOILER, EQUIPPED WITH LOW NOX BURNERS AND FLUE GAS RECIRCULATION FOR CONTROL OF NOX EMISSIONS; 4.ONE 2.25 MMBTU/HR(HHV), 327 BRAKE HORSEPOWER, ULSD FIRED EMERGENCY FIRE PUMP; 5.ONE 14.4 MMBTU/HR(HHV), APPROXIMATELY 1,500 KW ULSD FIRED EMERGENCY GENERATOR; AND 6.ONE 8-CELL, 124,800 GALLON PER MINUTE (GPM) MECHANICAL INDUCED DRAFT COOLING TOWER.		Combined Cycle Combustion Turbine firing Natural Gas without Duct Burner	15.21	Natural Gas	8040	H/YR		Nitrogen Oxides (NOx)	Selective Catalytic Reduction System and Dry Low NOx	2	PPMVD@15% O2	3 H ROLLING AV BASED ON ONE H BLOCK AV

Table D-1. RBLC Search Results for Large Natural Gas Fired Turbines (Combined-Cycle) - NOx

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel	Throughput	Throughput Units	Process Notes	Pollutant	Control Method Description	Emission Limit	Emission Limit Unit	Emission Limit 1 Average Time Condition
ST. CHARLES POWER STATION	ENTERGY LOUISIANA, LLC	ST. CHARLES	LA	8/31/2016	The St. Charles Power Station (SCPS) is a new electric power generating facility consisting of two (2) natural gas-fired combined cycle gas turbines, each with a heat recovery stem generator unit equipped with duct burners, and one (1) steam generator turbine. The SCPS will will have a predicted net nominal output of 980 MW at ISO conditions with supplemental duct firing.		SCPS Combined Cycle Unit 1A	15.21	Natural Gas	3625	MMBTU/hr		Nitrogen Oxides (NOx)	Selective Catalytic Reduction (SCR) with Dry Low NOx Burners (DLNB) during normal operations; Good Combustion Practices during Startup/Shutdown operations.	26.91	LB/H	HOURLY MAXIMUM
ST. CHARLES POWER STATION	ENTERGY LOUISIANA, LLC	ST. CHARLES	LA	8/31/2016	The St. Charles Power Station (SCPS) is a new electric power generating facility consisting of two (2) natural gas-fired combined cycle gas turbines, each with a heat recovery stem generator unit equipped with duct burners, and one (1) steam generator turbine. The SCPS will will have a predicted net nominal output of 980 MW at ISO conditions with supplemental duct firing.		SCPS Combined Cycle Unit 1B	15.21	Natural Gas	3625	MMBTU/hr		Nitrogen Oxides (NOx)	Selective Catalytic Reduction (SCR) with Dry Low NOx Burners (DLNB) during normal operations, and good combustion practices during startup/shutdown operations.	26.91	LB/H	HOURLY MAXIMUM
CPV FAIRVIEW ENERGY CENTER	CPV FAIRVIEW, LLC	CAMBRIA	PA	9/2/2016	This plan approval authorizes CPV Fairview, LLC to construct and temporarily operate the Fairview Energy Center. Air contamination sources and air cleaning devices authorized for construction and temporary operation under this plan approval include: A combined cycle electric generating unit consisting of two (2) General Electric ("GE") 7HA.02 "H"-class combustion turbines each with maximum fuel type-based heat input of 3,338-MMBtu/hr (natural gas), 3,274-MMBtu/hr (ULSD), 3,199 MMBtu/hr (ethane blend), and equipped with dry low-NOx combustors and evaporative turbine intake cooling; two (2) heat recovery steam generators (HRSGs) each equipped with a low-NOx duct burner with maximum heat input of 425-MMBtu/hr, and a common steam turbine generator. Exhaust emissions from each combined cycle electric generating unit will be controlled by oxidation catalyst and selective catalytic reduction (SCR). - One (1) up to 12-cell mechanical draft wet cooling tower with high-efficiency drift eliminator. - One (1) natural gas-fired auxiliary boiler with maximum heat input of 92.4 MMBtu/hr. - One (1) natural gas-fired dew point heater with maximum heat input of 12.8 MMBtu/hr. - One (1) natural gas-fired dew point heater with maximum heat input of 3.2 MMBtu/hr. - Two (2) 1,500-ekW diesel-fired emergency genset engines. - One (1) 422-bhp diesel-fired fire water pump engine		Combustion turbine and HRSG with duct burner NG only	15.21	Natural Gas	3338	MMBtu/hr	Emission limits are for each turbine operating with duct burner and do not include startup/shutdown emissions. Tons per year limits is a cumulative value for all three CCCT. CEMS for NOx, CO, and O2. Each CCCT and duct burner have 5 operational scenarios: 1 CCCT with duct burner fired - fueled by NG only 2 CCCT with duct burner fired - fueled by NG blend with ethane 3 CCCT without duct burner fired - fueled by NG only 4 CCCT without duct burner fired - fueled by NG blend with ethane 5 CCCT without duct burner fired - fueled by ULSD (Limited to emergency use only)	Nitrogen Oxides (NOx)	Dry Low NOx combustion technology, SCR at all steady state operating loads, good combustion and operating practices	2	PPMDV @ 15% O2	
SOUTH FIELD ENERGY LLC	SOUTH FIELD ENERGY LLC	COLUMBIANA	OH	9/23/2016	1150 MW combined-cycle gas turbine (CCGT) facility	Permit-to-install for the construction of the South Field Energy facility, a nominal 1,150 megawatt (MW) combined cycle gas turbine (CCGT) facility to be located in Wellsville, Ohio.	Combined Cycle Combustion Turbines (two, identical) (P001 and P002)	15.21	Natural gas	3131	MMBTU/H	Two identical combined cycle combustion turbine (3,131 MMBtu/hr heat input turbine at ISO conditions, natural gas firing with evaporative cooler on and 800 MMBtu/hr maximum heat input natural gas-fired duct burner) with dry low NOx combustors, selective catalytic reduction (SCR), catalytic oxidizer, and wet injection for ULSD firing. Heat input for ULSD firing at ISO conditions, with evaporative cooler on is 3,173 MMBtu/hr. Throughputs and limits are for single turbine except as noted.	Nitrogen Oxides (NOx)	Dry low NOx (DLN) burners for natural gas firing, wet injection when firing ultra low sulfur diesel, and selective catalytic reduction (SCR) for both natural gas and ultra low sulfur diesel.	30.51	LB/H	WITH DUCT BURNER. SEE NOTES.

Table D-1. RBLC Search Results for Large Natural Gas Fired Turbines (Combined-Cycle) - NOx

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel	Throughput	Throughput Units	Process Notes	Pollutant	Control Method Description	Emission Limit	Emission Limit Unit	Emission Limit 1 Average Time Condition
HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	HOLLAND BOARD OF PUBLIC WORKS	OTTAWA	MI	12/5/2016	Natural gas combined heat and power plant.	Permit Number 107-13E revised Permit 107-13C as follows:□ □ 1) All ppmdv limits were changed to ppmvd in the CTGHRSG section for NOx, CO and VOC. □ Also, □ 2) The process notes for the natural gas emergency engine and the diesel fire pump emergency engine were revised as well. No other changes were made. As such, this RBLC entry includes the updated information as identified above.□ □ Additionally, this is an updated determination for this facility, which is still under construction and has not yet operated. The original RBLC determination for the facility is identified as MI-0412.	FGCTGHRSG (2 Combined cycle CTGs with HRSGs; EUCTGHRSG10 & EUCTGHRSG11)	15.21	Natural gas	554	MMBTU/H, each	Two combined cycle natural gas fired combustion turbine generators (CTGs) with heat recovery steam generators (HRSG) (EUCTGHRSG10 & EUCTGHRSG11 in FGCTGHRSG). The total hours for both units combined for startup and shutdown shall not exceed 635 hours per 12-month rolling time period.	Nitrogen Oxides (NOx)	Selective catalytic reduction with dry low NOx burners (SCR with DLNB).	3	PPM AT 15% O2	24-H ROLLING AVG; EACH EU
HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	HOLLAND BOARD OF PUBLIC WORKS	OTTAWA	MI	12/5/2016	Natural gas combined heat and power plant.	Permit Number 107-13E revised Permit 107-13C as follows:□ □ 1) All ppmdv limits were changed to ppmvd in the CTGHRSG section for NOx, CO and VOC. □ Also, □ 2) The process notes for the natural gas emergency engine and the diesel fire pump emergency engine were revised as well. No other changes were made. As such, this RBLC entry includes the updated information as identified above.□ □ Additionally, this is an updated determination for this facility, which is still under construction and has not yet operated. The original RBLC determination for the facility is identified as MI-0412.	FGCTGHRSG--Startup/Shutdown (2 combined cycle CTGs with HRSGs; EUCTGHRSG10 & EUCTGHRSG11)	15.21	Natural gas	554	MMBTU/H; EACH	Two combined cycle natural gas-fired combustion turbine generators (CTGs) with heat recovery steam generators (HRSG) (EUCTGHRSG10 & EUCTGHRSG11 in FGCTGHRSG). The total hours for both units combined for startup and shutdown shall not exceed 635 hours per 12-month rolling time period. □ □ This process group is to identify emission limits during startup and shutdown.	Nitrogen Oxides (NOx)	Selective catalytic reduction with dry low NOx burners (SCR with DLNB).	43.7	LB/H	OPERATING HOUR DURING STARTUP; EACH EU
INDECK NILES, LLC	INDECK NILES, LLC	CASS	MI	1/4/2017	Natural gas combined cycle power plant.	The permit includes equipment not entered into the RBLC due to a lack of emission limits or material limits; these include a cold cleaner, a number of space heaters, and two fuel tanks.	FGCTGHRSG (2 Combined Cycle CTGs with HRSGs)	15.21	Natural gas	8322	MMBTU/H	There are 2 combined cycle natural gas-fired combustion turbine generators (CTGs) with heat recovery steam generators (HRSG) identified as EUCTGHRSG1 & EUCTGHRSG2 in the flexible group FGCTGHRSG. The total hours for startup and shutdown for each train shall not exceed 500 hours per 12-month rolling time period. □ □ The throughput capacity is 3421 MMBTU/H for each turbine, and 740 MMBTU/H for each duct burner for a combined throughput of 4161 MMBTU/H or 8322 MMBTU/H for both trains.	Nitrogen Oxides (NOx)	SCR with DLNB (selective catalytic reduction with dry low NOx burners)	38.1	LB/H	24-H ROLLING AVERAGE

Table D-1. RBLC Search Results for Large Natural Gas Fired Turbines (Combined-Cycle) - NOx

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel	Throughput	Throughput Units	Process Notes	Pollutant	Control Method Description	Emission Limit	Emission Limit Unit	Emission Limit 1 Average Time Condition
HILLTOP ENERGY CENTER, LLC	HILLTOP ENERGY CENTER, LLC	GREENE	PA	4/12/2017	The project consists of a single power block in a one-on-one (1x1), combined cycle, single shaft configuration, including a combustion turbine (CT) and heat recovery steam generator (HRSG) with a steam turbine (ST). â€¢ One (1) 3,509 MMBtu/hr General Electric International, Inc. (GE) model no. GE 7HA.02 natural gas-fired combined cycle combustion turbine equipped with a heat recovery steam generator (HRSG) with supplemental 981.4 MMBtu/hr natural gas fired duct burners; controlled by selective catalytic reduction and oxidation catalyst. â€¢ One (1) 42 MMBtu/hr natural gas-fired auxiliary boiler. â€¢ One (1) 6.4 MMBtu/hr natural gas-fired fuel gas heater. â€¢ One (1) 2.95 MMBtu/hr, 422 hp diesel-fired emergency firewater pump engine. â€¢ One (1) 18.77 MMBtu/hr, 2,682 hp diesel-fired emergency generator engine. â€¢ Eight-cell, mechanical draft, evaporative cooling tower controlled by drift eliminators. â€¢ One (1) 3,000 gallon emergency generator diesel storage tank. â€¢ One (1) 500 gallon firewater pump diesel storage tank. â€¢ One (1) 35,000 gallon 19% aqueous ammonia storage tank. â€¢ Lubricating oil storage tanks. â€¢ Miscellaneous components in natural gas service, and SF6 containing circuit breakers; controlled by leak detection and repair (LDAR)	The project consists of a single power block in a one-on-one (1x1), combined cycle, single shaft configuration, including a combustion turbine (CT) and heat recovery steam generator (HRSG) with a steam turbine (ST).□ â€¢ One (1) 3,509 MMBtu/hr General Electric International, Inc. (GE) model no. GE 7HA.02 natural gas-fired combined cycle combustion turbine equipped with a heat recovery steam generator (HRSG) with supplemental 981.4 MMBtu/hr natural gas fired duct burners; controlled by selective catalytic reduction and oxidation catalyst.□ â€¢ One (1) 42 MMBtu/hr natural gas-fired auxiliary boiler.□ â€¢ One (1) 6.4 MMBtu/hr natural gas-fired fuel gas heater.□ â€¢ One (1) 2.95 MMBtu/hr, 422 hp diesel-fired emergency firewater pump engine. □ â€¢ One (1) 18.77 MMBtu/hr, 2,682 hp diesel-fired emergency generator engine. □ â€¢ Eight-cell, mechanical draft, evaporative cooling tower controlled by drift eliminators.□ â€¢ One (1) 3,000 gallon emergency generator diesel storage tank.□ â€¢ One (1) 500 gallon firewater pump diesel storage tank.□ â€¢ One (1) 35,000 gallon 19% aqueous ammonia storage tank.□ â€¢ Lubricating oil storage tanks.□ â€¢ Miscellaneous components in natural gas service, and SF6 containing circuit breakers; controlled by leak detection and repair (LDAR) □	Combustion Turbine without Duct Burner	15.21	Natural Gas	3509	MMBtu/hr		Nitrogen Oxides (NOx)		2	PPMDV	CORRECTED TO 15% O2
GAINES COUNTY POWER PLANT	SOUTHWESTERN PUBLIC SERVICE COMPANY		TX	4/28/2017	constructed in phases, with natural gas-fired simple cycle combustion turbines (SCCTs) with dry low nitrogen oxide (NOx) burners (DLN) to be converted into 2-on-1 combined cycle combustion turbines (CCCTs) with selective catalytic reduction (SCRs), heat recovery steam generators (HRSGs, one per combustion turbine) and one steam turbine per two CCCTs. Federal control review only applies to the turbines and HRSGs.		Combined Cycle Turbine with Heat Recovery Steam Generator, fired Duct Burners, and Steam Turbine Generator	15.21	NATURAL GAS	426	MW	Four Siemens SGT6-5000F5 natural gas fired combustion turbines with HRSGs and Steam Turbine Generators	Nitrogen Oxides (NOx)	Selective Catalytic Reduction (SCR) and Dry Low NOx burners	2	PPMVD	15% O2 3-H AVG
KILLINGLY ENERGY CENTER	NTE CONNECTICUT, LLC	WINDHAM	CT	6/30/2017	550 MW Combined Cycle Plant		Natural Gas w/o Duct Firing	15.21	Natural Gas	2969	MMBtu/hr	Throughput is for turbine only	Nitrogen Oxides (NOx)	SCR	2	PPMVD @15% O2	1 HOUR BLOCK
KILLINGLY ENERGY CENTER	NTE CONNECTICUT, LLC	WINDHAM	CT	6/30/2017	550 MW Combined Cycle Plant		Natural Gas w/Duct Firing	15.21	Natural Gas	2639	MMBtu/hr	Duct burner MRC is 946 MMbtu/hr	Nitrogen Oxides (NOx)	SCR	2	PPMVD @15% O2	1 HOUR BLOCK
TRUMBULL ENERGY CENTER	TRUMBULL ENERGY CENTER	TRUMBULL	OH	9/7/2017	940 MW combined cycle gas turbine (CCGT) facility	Permit-to-install for the construction of the Trumbull Energy Center, a nominal 940 megawatt (MW) combined cycle gas turbine (CCGT) facility to be located in the Village of Lordstown, Ohio.	Combined Cycle Combustion Turbines (two, identical) (P001 and P002)	15.21	Natural gas	3025	MMBTU/H	Two identical combined cycle combustion turbine (3,025 mmBtu/hr heat input turbine at ISO conditions and 237 mmBtu/hr heat input duct burner) with dry low NOx combustors, selective catalytic reduction (SCR), and catalytic oxidizer. Throughputs and limits are for single turbine except as noted.	Nitrogen Oxides (NOx)	dry low NOx combustors (DLN) and selective catalytic reduction (SCR)	25.3	LB/H	WITH DUCT BURNER. SEE NOTES.
OREGON ENERGY CENTER	OREGON ENERGY CENTER	LUCAS	OH	9/27/2017	Combined cycle gas turbine (CCGT) facility	Installation of natural gas-fired combined cycle combustion turbine power plant.	Combined Cycle Combustion Turbines (two, identical) (P001 and P002)	15.21	Natural gas	3055	MMBTU/H	Combined cycle combustion turbine (3,055 mmBtu/hr heat input turbine at ISO conditions and 221.3 mmBtu/hr heat input duct burner) with dry low NOX combustors, selective catalytic reduction (SCR), and catalytic oxidation. All heat values are on a HHV basis.□ □ Throughputs and limits are for single turbine except as noted.	Nitrogen Oxides (NOx)	Dry low NOX combustors and selective catalytic reduction (SCR)	25.3	LB/H	WITH DUCT BURNER. SEE NOTES.

Table D-1. RBLC Search Results for Large Natural Gas Fired Turbines (Combined-Cycle) - NOx

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel	Throughput	Throughput Units	Process Notes	Pollutant	Control Method Description	Emission Limit	Emission Limit Unit	Emission Limit 1 Average Time Condition
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	GUERNSEY	OH	10/23/2017	1,650 MW combined cycle combustion turbine electrical generating facility	Installation PTI for a new 1,650 MW combined cycle natural-gas fired turbine plant and associated auxiliary boiler, firewater pumps, emergency generators and fuel gas heaters	Combined Cycle Combustion Turbines (3, identical) (P001 to P003)	15.21	Natural gas	3516	MMBTU/H	Three identical Combustion Turbines; GE 7HA.02 natural gas-fired lean pre-mix combined cycle combustion turbine generator equipped with dry low-NOx (DLN) burners nominally rated at 3,516 MMBtu/hr HHV at 100% load and -18Â° F exhausting through a heat recovery steam generator (HRSG) with supplemental natural gas-fired duct burners nominally rated at 997 MMBtu/hr HHV controlled with catalytic oxidation and selective catalytic reduction (SCR) and cooled with an air-cooled condenser (ACC) used to generate electricity. Throughputs and limits are for a single turbine except as noted.	Nitrogen Oxides (NOx)	dry low NOx burners and SCR	33.85	LB/H	WITH DUCT BURNER. SEE NOTES.
LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	MONROE	OH	11/7/2017	Combined cycle combustion turbine power generation facility	Initial installation permit for a 485 MW combined cycle electric generating facility in Monroe County. The emissions units include a combustion turbine with a heat recovery stream generator (HRSG) and duct burners, auxiliary boiler, emergency diesel generator engine, emergency fire pump engine, and an eight-cell mechanical draft low-mist wet cooling tower. The Project will use either a GE Model 7HA.02 (P004), Mitsubishi Model 501JAC (P005) or Siemens Model SCC6-8000H (P006) combustion turbine (CT) with duct firing in the HRSG to increase steam generation in the steam turbine. Only one turbine will be built but each of these turbines are included in this RBLC entry.	General Electric Combustion Turbine (P004)	15.21	Natural gas	3544	MMBTU/H	General Electric model 7HA.02 natural gas or natural gas+ethane fired combined cycle combustion turbine generator equipped with dry low-NOx (DLN) burners nominally rated at 3,544 MMBtu/hr at 100% load and -5Â° F exhausting through a heat recovery steam generator (HRSG) controlled with catalytic oxidation and selective catalytic reduction (SCR) used to generate additional electricity. The Project will use either a GE Model 7HA.02 (P004), Mitsubishi Model 501JAC (P005) or Siemens Model SCC6-8000H (P006) combustion turbine (CT) with duct firing in the HRSG to increase steam generation in the steam turbine. Only one turbine will be built but each of these turbines are included in this RBLC entry.	Nitrogen Oxides (NOx)	dry low NOx burners and an SCR system	26.1	LB/H	EXCEPT STARTUP AND SHUTDOWN. SEE NOTES
LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	MONROE	OH	11/7/2017	Combined cycle combustion turbine power generation facility	Initial installation permit for a 485 MW combined cycle electric generating facility in Monroe County. The emissions units include a combustion turbine with a heat recovery stream generator (HRSG) and duct burners, auxiliary boiler, emergency diesel generator engine, emergency fire pump engine, and an eight-cell mechanical draft low-mist wet cooling tower. The Project will use either a GE Model 7HA.02 (P004), Mitsubishi Model 501JAC (P005) or Siemens Model SCC6-8000H (P006) combustion turbine (CT) with duct firing in the HRSG to increase steam generation in the steam turbine. Only one turbine will be built but each of these turbines are included in this RBLC entry.	Mitsubishi Combustion Turbine (P005)	15.21	Natural gas	3320	MMBTU/H	Mitsubishi Model 501JAC natural gas or natural gas+ethane fired combined cycle combustion turbine generator equipped with dry low-NOx (DLN) burners nominally rated at 3,320 MMBtu/hr at 100% load and -5Â° F exhausting through a heat recovery steam generator (HRSG) with supplemental natural gas-fired duct burners nominally rated at 108 MMBtu/hr controlled with catalytic oxidation and selective catalytic reduction (SCR) used to generate electricity. The Project will use either a GE Model 7HA.02 (P004), Mitsubishi Model 501JAC (P005) or Siemens Model SCC6-8000H (P006) combustion turbine (CT) with duct firing in the HRSG to increase steam generation in the steam turbine. Only one turbine will be built but each of these turbines are included in this RBLC entry.	Nitrogen Oxides (NOx)	dry low NOx burners and an SCR system	25.1	LB/H	WITH DUCT BURNER. SEE NOTES.
LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	MONROE	OH	11/7/2017	Combined cycle combustion turbine power generation facility	Initial installation permit for a 485 MW combined cycle electric generating facility in Monroe County. The emissions units include a combustion turbine with a heat recovery stream generator (HRSG) and duct burners, auxiliary boiler, emergency diesel generator engine, emergency fire pump engine, and an eight-cell mechanical draft low-mist wet cooling tower. The Project will use either a GE Model 7HA.02 (P004), Mitsubishi Model 501JAC (P005) or Siemens Model SCC6-8000H (P006) combustion turbine (CT) with duct firing in the HRSG to increase steam generation in the steam turbine. Only one turbine will be built but each of these turbines are included in this RBLC entry.	Siemens Combustion Turbine (P006)	15.21	Natural gas	3602	MMBTU/H	Siemens Model SCC6-8000H natural gas or natural gas+ethane fired combined cycle combustion turbine generator equipped with dry low-NOx (DLN) burners nominally rated at 3,602 MMBtu/hr at 100% load and -5Â° F exhausting through a heat recovery steam generator (HRSG) with supplemental natural gas-fired duct burners nominally rated at 667 MMBtu/hr controlled with catalytic oxidation and selective catalytic reduction (SCR) used to generate electricity. The Project will use either a GE Model 7HA.02 (P004), Mitsubishi Model 501JAC (P005) or Siemens Model SCC6-8000H (P006) combustion turbine (CT) with duct firing in the HRSG to increase steam generation in the steam turbine. Only one turbine will be built but each of these turbines are included in this RBLC entry.	Nitrogen Oxides (NOx)	dry low NOx burners and an SCR system	27.1	LB/H	WITH DUCT BURNER. SEE NOTES.

Table D-1. RBLC Search Results for Large Natural Gas Fired Turbines (Combined-Cycle) - NOx

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel	Throughput	Throughput Units	Process Notes	Pollutant	Control Method Description	Emission Limit	Emission Limit Unit	Emission Limit 1 Average Time Condition
FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	MANISTEE	MI	11/17/2017	New natural gas combined heat and power plant proposed at existing cogenerating power plant permitted to burn wood, coal and tire derived fuel.		EUCCT (Combined cycle CTG with unfired HRSG)	15.21	Natural gas	1934.7	MMBTU/H	A 1,934.7 MMBTU/H natural gas fired heavy frame industrial combustion turbine. The turbine operates in combined-cycle with an unfired heat recovery steam generator (HRSG).	Nitrogen Oxides (NOx)	SCR with DLNB (Selective catalytic reduction with dry low NOx burners).	3	PPM	24-H ROLL.AVG., EXCEPT STARTUP/SHUTDOWN
FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	MANISTEE	MI	11/17/2017	New natural gas combined heat and power plant proposed at existing cogenerating power plant permitted to burn wood, coal and tire derived fuel.		EUCCT (Startup/Shutdown)	15.21	Natural gas	1934.7	MMBTU/H	This emission unit is being entered as a separate process to account for the emission limits associated with startup/shutdown events, which could not be included within the previous EUCCT original process name. A 1,934.7 MMBTU/H natural gas fired heavy frame industrial combustion turbine. The turbine operates in combined-cycle with an unfired heat recovery steam generator (HRSG).	Nitrogen Oxides (NOx)	SCR with DLNB (Selective catalytic reduction with dry low NOx burners).	32	POUNDS	PER EVENT

Table D-1. RBLC Search Results for Large Natural Gas Fired Turbines (Combined-Cycle) - NOx

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel	Throughput	Throughput Units	Process Notes	Pollutant	Control Method Description	Emission Limit	Emission Limit Unit	Emission Limit 1 Average Time Condition
RENOVO ENERGY CENTER, LLC	RENOVO ENERGY CENTER, LLC	CLINTON	PA	1/26/2018	"A natural-gas-fired combined-cycle power plant consisting of two (2) identical 1 x 1 powerblocks where each powerblock consists of a combustion turbine (CT) and a steam turbine (ST) with heat recovery steam generators (HRSG). Ancillary equipment for the facility also being proposed by REC include: one (1) diesel-fired emergency generator engine, one (1) diesel-fired fire pump engine, two (2) natural gas-fired auxiliary boilers, two (2) natural gas-fired water bath heaters, one (1) natural gas-fired dew point gas heater, one (1) ultra-low sulfur, diesel fuel (ULSD) storage tank, two (2) lube oil storage tanks, and two (2) aqueous ammonia storage tanks. ------------------------------------The permittee shall implement a methane (CH4) leak detection and repair program which includes audible, visual, and olfactory (AVO) inspections conducted on a monthly basis on the natural gas piping components. Records of each inspection shall be maintained in a log and, at a minimum, identify the date, time, name and title of the observer, along with any corrective action taken. Leaks shall be repaired as expeditiously as practicable, but no later than fifteen (15) calendar days after the leak is detected unless the owner or operator must purchase parts or the replacement is technically infeasible without process shutdown or would be unsafe to repair during operation of the unit."		Combustion Turbine Firing NG	15.21	Natural Gas	0		General Electric model 7AH.02 lean premix DLN natural-gas/ultra-low diesel-fired combustion turbine (CT) and steam turbine (ST), where the CT and ST train is configured in a single shaft alignment and drive one common electric generator capable of producing approximately 500 megawatts (MW) of electricity, shall be equipped with dry-low-NOx (DLN) combustors.	Nitrogen Oxides (NOx)	SCR	2	PPMDV	CORRECTED TO 15% O2
TVA - JOHNSONVILLE COGENERATION	TENNESSEE VALLEY AUTHORITY	HUMPHREYS	TN	2/1/2018	Combustion turbines and combined cycle plant	Permit 972969 adds startup and shutdown limits to the requirements established in PSD permit 970816F.	Dual-fuel CT and HRSG with duct burner	15.21	Natural Gas	1020	MMBtu/hr	Rated input capacity is 1020 MMBtu/hr (CT) and 319 MMBtu/hr (duct burner) when burning natural gas and 1084 MMBtu/hr when burning #2 oil.	Nitrogen Oxides (NOx)	SCR, good combustion design & practices	2	PPMVD @ 15% O2	30-DAY AVG WHEN BURNING NATURAL GAS
HARRISON COUNTY POWER PLANT	ESC HARRISON COUNTY POWER, LLC	HARRISON	WV	3/27/2018	Nominal 640 mWe natural gas-fired combined-cycle power plant. Small sources: Emergency Generator, Fire Water Pump, Fuel Gas Heater not included in RBLC - may request info or see permit for details.		GE 7HA.02 Turbine	15.21	Natural Gas	3496.2	mmBtu/hr	Nominal 640 mWe All emission limits steady-state and include 1000 mmBtu/hr Duct Burner in operation Short Term startup and shutdown limits in lb/event given in permit.	Nitrogen Oxides (NOx)	Dry-Low NOx Burners, SCR	32.9	LB/HR	1-HOUR AVERAGE
MONTGOMERY COUNTY POWER STATIOIN	ENTERGY TEXAS INC	MONTGOMERY	TX	3/30/2018			Combined Cycle Turbine	15.21	NATURAL GAS	2635	MMBTU/HR/UNIT	Two Mitsubishi M501GAC turbines (without fast start)	Nitrogen Oxides (NOx)	SCR and Dry Low NOx burners	2	PPMVD	15% O2 1-HOUR AVERAGE
MONTGOMERY COUNTY POWER STATIOIN	ENTERGY TEXAS INC	MONTGOMERY	TX	3/30/2018			COMBINED CYCLE TURBINE MSS REDUCED LOAD	15.21	NATURAL GAS	0		9 HOURS STARTUP, 1 HOUR SHUTDOWN	Nitrogen Oxides (NOx)	minimizing duration of startup / shutdown events, engaging the pollution control equipment as soon as practicable (based on vendor recommendations and guarantees), and meeting the emissions limits on the MAERT	170	LB/H	

Table D-1. RBLC Search Results for Large Natural Gas Fired Turbines (Combined-Cycle) - NOx

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel	Throughput	Throughput Units	Process Notes	Pollutant	Control Method Description	Emission Limit	Emission Limit Unit	Emission Limit 1 Average Time Condition
HARRISON POWER	HARRISON POWER	HARRISON	OH	4/19/2018	1000 MW natural gas-fired combined cycle combustion turbine plant	Initial installation permit for a 1000 MW combined cycle electric generating facility in Harrison County that includes two (2) combustion turbines with a heat recovery stream generator (HRSG) and duct burners, auxiliary boiler, emergency diesel generator engine, and emergency fire pump engine. The permit includes the option to install either General Electric turbines (with 80 MMBTU aux boiler B002) or Mitsubishi turbines (with 44.55 MMBTU aux boiler B001). The facility-wide pollutants table below is for the GE turbines. The Mitsubishi emissions are as follows: PM10/2.5 155.2, SO2 59.2, NOx 249.9, CO 219.7, VOC 169.5	General Electric (GE) Combustion Turbines (P005 & P006)	15.21	Natural gas	3459.6	MMBTU/H	Two identical GE Combustion Turbines 1 and 2; GE model 7HA.02 natural gas-fired combined cycle combustion turbine generator equipped with dry low-NOx (DLN) burners nominally rated at 3,459.6 MMBtu/hr (HHV) at 100% load and -2Â° F exhausting through a heat recovery steam generator (HRSG) with supplemental natural gas-fired duct burners nominally rated at 570.45 MMBtu/hr (HHV) controlled with catalytic oxidation and selective catalytic reduction (SCR) used to generate additional electricity. The permit includes the option to install either General Electric turbines (with 80 MMBTU aux boiler B002) or Mitsubishi turbines (with 44.55 MMBTU aux boiler B001). Limits and throughputs are for single turbine except as noted.	Nitrogen Oxides (NOx)	dry low NOx burners and an SCR system	29.5	LB/H	WITH DUCT BURNER. SEE NOTES.
HARRISON POWER	HARRISON POWER	HARRISON	OH	4/19/2018	1000 MW natural gas-fired combined cycle combustion turbine plant	Initial installation permit for a 1000 MW combined cycle electric generating facility in Harrison County that includes two (2) combustion turbines with a heat recovery stream generator (HRSG) and duct burners, auxiliary boiler, emergency diesel generator engine, and emergency fire pump engine. The permit includes the option to install either General Electric turbines (with 80 MMBTU aux boiler B002) or Mitsubishi turbines (with 44.55 MMBTU aux boiler B001). The facility-wide pollutants table below is for the GE turbines. The Mitsubishi emissions are as follows: PM10/2.5 155.2, SO2 59.2, NOx 249.9, CO 219.7, VOC 169.5	Mitsubishi Hitachi Power Systems (MHPS) Combustion Turbines (P007 & P008)	15.21	Natural gas	3231	MMBTU/H	Two identical MHPS Combustion Turbines 1 and 2; Mitsubishi Model M501JAC natural gas-fired combined cycle combustion turbine generator equipped with dry low-NOx (DLN) burners nominally rated at 3,231 MMBtu/hr (HHV) at 100% load and 51Â° F exhausting through a heat recovery steam generator (HRSG) with supplemental natural gas-fired duct burners nominally rated at 306 MMBtu/hr (HHV) controlled with catalytic oxidation and selective catalytic reduction (SCR) used to generate electricity. The permit includes the option to install either General Electric turbines (with 80 MMBTU aux boiler B002) or Mitsubishi turbines (with 44.55 MMBTU aux boiler B001). Limits and throughputs are for single turbine except as noted.	Nitrogen Oxides (NOx)	dry low NOx burners and an SCR system	28	LB/H	WITH DUCT BURNER. SEE NOTES.
PALMDALE ENERGY PROJECT	PALMDALE ENERGY, LLC	LOS ANGELES	CA	4/25/2018	645 MW (nominal) Natural Gas-fired Combined Cycle Power Plant, 2 x 1 configuration, auxiliary boiler for faster startup	See also docket: https://www.regulations.gov/docket?D=EPA-R09-OAR-2017-0473. Permit decision was appealed to EPA's Environmental Appeals Board. Board denied review on October 23, 2018. Information available through www.epa.gov/eab and https://yosemite.epa.gov/oa/EAB_Web_Docket.nsf/f22b4b245fab46c6852570e6004df1bd/ad735c0b822500258525829d004217eb!OpenDocument. 1/31/20 -- SYS MGR -- Link to permit is <https://www.regulations.gov/document?D=EPA-R09-OAR-2017-0473-0028>	Combustion Turbines (GEN1 and GEN2)	15.21	Natural Gas	2217	MMBTU/H	Each combustion turbine rated at 214 MW, with a maximum heat input rate of 2,217 MMBtu/H (HHV, at ISO conditions); natural gas-fired Siemens SGT6-5000F; each vents to dedicated Heat Recovery Steam Generator and a shared 276 MW Steam Turbine Generator; 160-ft stack height; 22-ft stack diameter	Nitrogen Oxides (NOx)	Selective Catalytic Reduction, Dry Low NOx Burners	2	PPM @ 15% O2	1-HOUR
C4GT, LLC	NOVI ENERGY	USA	VA	4/26/2018	Natural gas-fired combined cycle power plant	The permit was written with two options for the turbines: Option 1 - GE 7HA.02 Option 2 - Siemens SGT6-8000H Facility Wide Pollutants for Siemens: CO: 293.5 NOx: 295.8 PM: 253.8 SOx: 39.3 VOC: 113.7	GE Combustion Turbine - Option 1 - Normal Operation	15.21	natural gas	34000	MMCF/YR	Option 1: Two on one configuration: 3,482 MMBtu/hr combustion turbine with 475 MMBtu/hr duct-fired HRSG. Emission limits reflect the operation of one turbine with or without duct firing.	Nitrogen Oxides (NOx)	dry, low NOx burners and selective catalytic reduction	2	PPMVD @ 15% O2	1 H AV

Table D-1. RBLC Search Results for Large Natural Gas Fired Turbines (Combined-Cycle) - NOx

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel	Throughput	Throughput Units	Process Notes	Pollutant	Control Method Description	Emission Limit	Emission Limit Unit	Emission Limit 1 Average Time Condition
C4GT, LLC	NOVI ENERGY	USA	VA	4/26/2018	Natural gas-fired combined cycle power plant	The permit was written with two options for the turbines:□ Option 1 - GE 7HA.02□ Option 2 - Siemens SGT6-8000H□ Facility Wide Pollutants for Siemens: □ CO: 293.5□ NOx: 295.8□ PM: 253.8□ SOx: 39.3□ VOC: 113.7	Siemens Combusion Turbine - Option 2 - Normal Operation	15.21	Natural Gas	35000	MMCF/YR	Option 2: □ Two on one configuration: 3,116 MMBtu/hr combustion turbine with 991 MMBtu/hr duct-fired HRSG. Emission limits reflect the operation of one turbine with or without duct firing.	Nitrogen Oxides (NOx)	DRY, LOW NOx BURNERS & SCR	2	PPMVD @ 15% O2	1 H AV
C4GT, LLC	NOVI ENERGY	USA	VA	4/26/2018	Natural gas-fired combined cycle power plant	The permit was written with two options for the turbines:□ Option 1 - GE 7HA.02□ Option 2 - Siemens SGT6-8000H□ Facility Wide Pollutants for Siemens: □ CO: 293.5□ NOx: 295.8□ PM: 253.8□ SOx: 39.3□ VOC: 113.7	GE Combustion Turbine - Tuning & Water Washing	15.21	natural gas	34000	MMCF/YR	Alternative operating scenario: during periods of tuning and water washing	Nitrogen Oxides (NOx)	dry, low NOx burners and SCR	638	LB/TURBINE/ CAL DAY	24 HR AV
C4GT, LLC	NOVI ENERGY	USA	VA	4/26/2018	Natural gas-fired combined cycle power plant	The permit was written with two options for the turbines:□ Option 1 - GE 7HA.02□ Option 2 - Siemens SGT6-8000H□ Facility Wide Pollutants for Siemens: □ CO: 293.5□ NOx: 295.8□ PM: 253.8□ SOx: 39.3□ VOC: 113.7	GE Combustion Turbine - Startup and Shutdown	15.21	natural gas	34000	MMCF/YR	Startup and Shutdown	Nitrogen Oxides (NOx)	Dry, low NOx burners and SCR	273	LB/TURBINE/ EVENT	COLD START 60 MIN OR LESS
C4GT, LLC	NOVI ENERGY	USA	VA	4/26/2018	Natural gas-fired combined cycle power plant	The permit was written with two options for the turbines:□ Option 1 - GE 7HA.02□ Option 2 - Siemens SGT6-8000H□ Facility Wide Pollutants for Siemens: □ CO: 293.5□ NOx: 295.8□ PM: 253.8□ SOx: 39.3□ VOC: 113.7	Siemens Combustion Turbine - Tuning & Water Washing	15.21	Natural Gas	35000	MMCF/YR	Alternative operating scenario: during periods of tuning and water washing	Nitrogen Oxides (NOx)	dry, low NOx burners and SCR	564	LB/TURBINE CAL DAY	24 HR AV
C4GT, LLC	NOVI ENERGY	USA	VA	4/26/2018	Natural gas-fired combined cycle power plant	The permit was written with two options for the turbines:□ Option 1 - GE 7HA.02□ Option 2 - Siemens SGT6-8000H□ Facility Wide Pollutants for Siemens: □ CO: 293.5□ NOx: 295.8□ PM: 253.8□ SOx: 39.3□ VOC: 113.7	Siemens Combustion Turbine - Startup & Shutdown	15.21	Natural Gas	35000	MMCF/YR	Startup and Shutdown	Nitrogen Oxides (NOx)	dry, low NOx burners and SCR	95	LB/TURBINE/ EVENT	COLD START 55 MIN OR LESS

Table D-1. RBLC Search Results for Large Natural Gas Fired Turbines (Combined-Cycle) - NOx

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel	Throughput	Throughput Units	Process Notes	Pollutant	Control Method Description	Emission Limit	Emission Limit Unit	Emission Limit 1 Average Time Condition
INDECK NILES LLC	INDECK NILES LLC	CASS	MI	6/26/2018	Natural gas combined cycle power plant	The permit includes equipment not entered into the RBLC due to a lack of emission limits or material limits; these include a cold cleaner, a number of space heaters, and two fuel tanks. Also, the permit revises the concentration-based NOx emission limit applied to the two combined-cycle natural gas-fired combustion turbines with heat recovery steam generators (identifed as EUCTGHRSG1 and EUCTGHRSG2) in the original permit 75-16.	FGCTGHRSG (2 Combined Cycle CTG with HRSGs)	15.21	Natural gas	3421	MMBTU/H	3421 MMBTU/H for each turbine and 740 MMBTU/H for each duct burner for a combined throughput of 4161 MMBTU/H or 8322 MMBTU/H for both trains. Two combined-cycle natural gas-fired combustion turbine generators (CTGs) with Heat Recovery Steam Generators (HRSG) (EUCTGHRSG1 & EUCTGHRSG2). The total hours for startup and shutdown for each train shall not exceed 500 hours per 12-month rolling time period.	Nitrogen Oxides (NOx)	SCR with DLNB (Selective Catalytic Reduction with Dry Low NOx Burners)	2	PPM	AT 15%O2; 24-HR ROLL AVG
MEC NORTH, LLC AND MEC SOUTH LLC	MARSHALL ENERGY CENTER LLC	CALHOUN	MI	6/29/2018	Natural gas combined cycle power plant (two plants: north and south)	There are two plants that will operate as separate entities and each received a separate Air Permit to Install, but they are considered one stationary source and were reviewed as one project.	EUCTGHRSG (South Plant): A combined cycle natural gas-fired combustion turbine generator with heat recovery steam generator.	15.21	Natural gas	500	MW	A combined-cycle natural gas-fired combustion turbine generator (CTG) with heat recovery steam generator (HRSG) in a 1x1 configuration with a steam turbine generator (STG) for a nominal 500 MW electricity production. The CTG is a H-class turbine with a rating of 3,080 MMBTU/H (HHV). The HRSG is equipped with a natural gas-fired duct burner rated at 755 MMBTU/H (HHV) at ISO conditions to provide heat for additional steam production. The HRSG is not capable of operating independently from the CTG. The CTG/HRSG is equipped with dry low NOx burner (DLNB), SCR and an oxidation catalyst.	Nitrogen Oxides (NOx)	SCR with DLNB (Selective catalytic reduction with dry low NOx burners).	2	PPMV	AT 15%O2; 24-HR ROLL AVG NOT S.S.
MEC NORTH, LLC AND MEC SOUTH LLC	MARSHALL ENERGY CENTER LLC	CALHOUN	MI	6/29/2018	Natural gas combined cycle power plant (two plants: north and south)	There are two plants that will operate as separate entities and each received a separate Air Permit to Install, but they are considered one stationary source and were reviewed as one project.	EUCTGHRSG (North Plant): A combined-cycle natural gas-fired combustion turbine generator with heat recovery steam generator.	15.21	Natural gas	500	MW	Nominal 500 MW electricity production. Turbine rating of 3,080 MMBTU/hr (HHV) and HRSG duct burner rating of 755 MMBTU/hr (HHV). A combined-cycle natural gas-fired combustion turbine generator (CTG) with heat recovery steam generator (HRSG) in a 1x1 configuration with a steam turbine generator (STG) for a nominal 500 MW electricity production. The CTG is a H-class turbine with a rating of 3,080 MMBTU/hr (HHV). The HRSG is equipped with a natural gas-fired duct burner rated at 755 MMBTU/hr (HHV) at ISO conditions to provide heat for additional steam production. The HRSG is not capable of operating independently from the CTG. The CTG/HRSG is equipped with dry low NOx burner (DLNB), SCR, and an oxidation catalyst.	Nitrogen Oxides (NOx)	SCR with DLNB (Selective catalytic reduction with Dry Low NOx burners).	2	PPMVD	AT 15%O2; 24-H ROLL AVG; NOT S.S.

Table D-1. RBLC Search Results for Large Natural Gas Fired Turbines (Combined-Cycle) - NOx

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel	Throughput	Throughput Units	Process Notes	Pollutant	Control Method Description	Emission Limit	Emission Limit Unit	Emission Limit 1 Average Time Condition
BELLE RIVER COMBINED CYCLE POWER PLANT	DTE ELECTRIC COMPANY	ST. CLAIR	MI	7/16/2018	Natural gas combined-cycle power plant	The new combined cycle plant is proposed to be located near DTE's existing Belle River and St. Clair coal fired power plants. The three plants will be considered a single stationary source. It will have a capacity of 1,150 megawatts.	FGCTGHRSG (EUCTGHRSG1 & EUCTGHRSG2)	15.21	Natural gas	0		Two (2) combined-cycle natural gas-fired combustion turbine generators, each with a heat recovery steam generator (CTGHRSG). Plant nominal 1,150 MW electricity production. Turbines are each rated at 3,658 MMBTU/H and HRSG duct burners are each rated at 800 MMBTU/H. The HRSGs are not capable of operating independently from the CTGs.	Nitrogen Oxides (NOx)	SCR with DLNB (Selective catalytic reduction with dry low NOx burners).	2	PPMVD	AT 15%O2; 24-H ROLL AVG; EACH UNIT;
BELLE RIVER COMBINED CYCLE POWER PLANT	DTE ELECTRIC COMPANY	ST. CLAIR	MI	7/16/2018	Natural gas combined-cycle power plant	The new combined cycle plant is proposed to be located near DTE's existing Belle River and St. Clair coal fired power plants. The three plants will be considered a single stationary source. It will have a capacity of 1,150 megawatts.	FGCTGHRSG (EUCTGHRSG1 & EUCTGHRSG2)--Startup & Shutdown	15.21	Natural gas	0		This section is the startup and shutdown emission limits for FGCTGHRSG. Two 3,658 MMBTU/H natural gas-fired combustion turbine generators (CTGs) coupled with heat recovery steam generators (HRSGs). The HRSGs are equipped with natural gas-fired duct burners rated at 800 MMBTU/H to provide heat for additional steam production. The HRSGs are not capable of operating independently from the CTGs.	Nitrogen Oxides (NOx)	SCR with DLNB (Selective catalytic reduction with dry low NOx burners).	262.4	LB/H	EACH UNIT; OPERATING HOUR DURING S.S.
SHADY HILLS COMBINED CYCLE FACILITY	SHADY HILLS ENERGY CENTER, LLC	PASCO	FL	7/27/2018	A 573-megawatt (MW) (winter) 1-on-1 combined cycle plant which includes a heat recovery steam generator with duct firing, along with supporting equipment. Natural gas is the only permitted fuel for the combined cycle unit.	THIS PROJECT WAS SUPERSEDED BY PERMIT NO. 1010524-003-AC UNDER RBLC ID FL-0371	1-on-1 combined cycle unit (GE 7HA)	15.21	Natural Gas	3266.9	MMBtu/hour	One nominal 385 MW GE 7HA.02 CTG and one HRSG with duct firing [approximately 210 MMBtu/hour], and one nominal 210 MW steam turbine generator (STG)	Nitrogen Oxides (NOx)	Dry low-NOX combustors and Selective Catalytic Reduction (SCR)	2	PPMVD AT 15% O2	24-HOUR BLOCK AVERAGE BASIS (BACT)
CPV THREE RIVERS ENERGY CENTER	CPV THREE RIVERS, LLC	GRUNDY	IL	7/30/2018	The proposed facility is designed to generate baseload power. It will consist of two combined-cycle generating units, each with a combustion turbine and associated heat recovery steam generator (HRSG). The turbines would burn natural gas and ultra-low sulfur diesel (ULSD) as a backup fuel. Other units include an auxiliary boiler, fuel heater, engines, natural gas piping and components, circuit breakers and roadways.		Combined Cycle Combustion Turbines	15.21	Natural Gas	3474	mmBtu/hr	Throughput of ultra-low sulfur diesel (ULSD) is 3798 mmBtu/hr. Combined cycle combustion turbines w/ heat recovery steam generator (HRSG). Turbine inlets will have inlet evaporative cooling systems to cool inlet air during warm weather to increase power output.	Nitrogen Oxides (NOx)	Selective catalytic reduction (SCR) and low-NOx combustion technology (dry low-NOx combustion technology for natural gas; water injection for ULSD)	2	PPMV @ 15% O2	3-UNIT OPERATING HOURS

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Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel	Throughput	Throughput Units	Process Notes	Pollutant	Control Method Description	Emission Limit	Emission Limit Unit	Emission Limit 1 Average Time Condition
NEW COVERT GENERATING FACILITY	NEW COVERT GENERATING COMPANY, LLC	VAN BUREN	MI	7/30/2018	Power plant	The equipment consists of three advanced firing temperature Mitsubishi 501G combustion turbines, three heat recovery steam generators supplemented with gas-fired duct burners each with a max firing rate of 256 million British thermal units per hour (MMBtu/hr), three steam turbine generators. Auxiliary equipment includes three mechanical draft evaporative cooling towers, one natural gas auxiliary boiler, one diesel emergency generator, one diesel fire water pump, one aqueous parts cleaner, and one gas heater.	FG-TURB/DB1-3 (3 combined cycle combustion turbine and heat recovery steam generator trains)	15.21	Natural gas	1230	MW	Three (3) combined-cycle combustion turbine (CT) / heat recovery steam generator (HRSG) trains. Each CT is a natural gas fired Mitsubishi model 501G, equipped with dry low NOx combustor and inlet air evaporative cooling. Each HRSG includes a natural gas fired duct burner with a 256 MMBtu/hr heat input capacity and a dry low NOx burner.	Nitrogen Oxides (NOx)	Good combustion practices, DLN burners and SCR.	2	PPMVD	AT 15%O2; EACH INDIV. CT/HRSG TRAIN
NEW COVERT GENERATING FACILITY	NEW COVERT GENERATING COMPANY, LLC	VAN BUREN	MI	7/30/2018	Power plant	The equipment consists of three advanced firing temperature Mitsubishi 501G combustion turbines, three heat recovery steam generators supplemented with gas-fired duct burners each with a max firing rate of 256 million British thermal units per hour (MMBtu/hr), three steam turbine generators. Auxiliary equipment includes three mechanical draft evaporative cooling towers, one natural gas auxiliary boiler, one diesel emergency generator, one diesel fire water pump, one aqueous parts cleaner, and one gas heater.	FG-TURB/DB1-3--Startup/Shutdown Operations	15.21	Natural gas	1230	MW	Three (3) combined-cycle combustion turbine (CT) / heat recovery steam generator (HRSG) trains. Each CT is a natural gas fired Mitsubishi model 501G, equipped with dry low NOx combustor and inlet air evaporative cooling. Each HRSG includes a natural gas fired duct burner with a 256 MMBTU/Hr heat input capacity and a dry low NOx burner. This scenario identifies the emission limits applicable during startup and shutdown operations.	Nitrogen Oxides (NOx)	Good combustion practices, DLN burners and SCR.	249	LB/H	EACH CT/HRSG TRAIN;STARTUP/SHUT DOWN
RENAISSANCE ENERGY CENTER	APV RENAISSANCE PARTNERS	GREENE	PA	8/27/2018	This Plan Approval is to allow the construction and temporary operation of a natural gas-fired combined cycle power plant to be located in Monongahela Township, Greene County. with Two (2) Siemens, SGT6-8000H (or equivalent), natural gas-fired combustion turbines 3,580 MMBtu/hr heat input rating (LHV) each (controlled with low NOx burners), including natural gas-fired duct burners, 914.1 MMBtu/hr heat input rating each; controlled by Ultra-low NOx combustors, SCR, and oxidation catalysts; 1,127 MW total net generating capacity. One (1) natural gas-fired auxiliary boiler, 90 MMBtu/hr heat input rating. One (1) Cummins model #CFP15E-F20 (or equivalent), diesel-fired fire pump engine, 411 bhp rating; including One (1) diesel fuel storage tank, 2,175 gallons One (1) Caterpillar 3516 (or equivalent), diesel-fired emergency generator engine rated at 2000 kW. Miscellaneous components in natural gas service, and circuit breakers; controlled by leak detection and repair (â€œLDARâ€) One (1) aqueous ammonia (19%) storage vessel rated at 19,000 gallons (or as determined during final design).		COMBUSTION TURBINE UNIT w/o DUCT BURNERS UNIT	15.21	Natural Gas	2665.9	MMBtu/hr		Nitrogen Oxides (NOx)	SCR	2	PPMDV	@15% O2

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BROOKE COUNTY POWER PLANT	ESC BROOKE COUNTY POWER I, LLC	BROOKE	WV	9/18/2018	Nominal 925 mWe natural gas-fired combined-cycle power plant. Small sources: Emergency Generator, Fire Water Pump, Fuel Gas Heater not included in RBLC - may request info or see permit for details.		GE 7HA.01 Turbine	15.21	Natural Gas/Ethane	2737.7	mmBtu/hr	Facility has 2 identical units, only 1 entry in RBLC. Nominal 462.5 mWe. All emission limits steady-state and include 424 mmBtu/hr Duct Burner in operation. Short Term startup and shutdown limits in lb/event given in permit.	Nitrogen Oxides (NOx)	Dry-Low NOx Burners, SCR	23.2	LB/HR	
CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	CAMERON	LA	9/21/2018	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Application Received September 2, 2015.	Combined Cycle Combustion Turbines (CCCT1 to CCCT5)	15.21	Natural Gas	921	MM BTU/h		Nitrogen Oxides (NOx)	Low NOx Burners, SCR, and Good Combustion Practices	2.5	PPMV	30 DAY ROLLING AVERAGE
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/21/2018	Natural gas combined-cycle power plant.	The proposed new plant will be replacing the electrical generating capacity of both BWL's existing coal-fired power plants. BWL intends to retire those coal-fired power plants from service by 2025. However, before they can be retired, the new natural gas power plant must be operational. Emissions in the area will increase for a short period if the new combined-cycle plant is built. However, there will be overall reductions in emissions when the existing coal fired power plants are taken out of service.	EUCTGHRSG2--A 667 MMBTU/H natural gas fired CTG with a HRSG.	15.21	Natural gas	667	MMBTU/H	EUCTGHRSG2 is a nominally rated 667 MMBTU/H natural gas fired CTG coupled with a HRSG. The HRSG is equipped with a natural gas fired duct burner rated at 204 MMBTU/h to provide heat for additional steam production. The CTG is capable of operating in combined-cycle mode where the exhaust is routed to the HRSG or in simple-cycle mode where the HRSG is bypassed. The HRSG is not capable of operating independently from the CTG. The CTG/HRSG is equipped with a DLNB, SCR and oxidation catalyst.	Nitrogen Oxides (NOx)	Dry low NOx burners and selective catalytic reduction for NOx control.	3	PPM	PPMVD@15%O2; 24-H AVG; SEE NOTES
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/21/2018	Natural gas combined-cycle power plant.	The proposed new plant will be replacing the electrical generating capacity of both BWL's existing coal-fired power plants. BWL intends to retire those coal-fired power plants from service by 2025. However, before they can be retired, the new natural gas power plant must be operational. Emissions in the area will increase for a short period if the new combined-cycle plant is built. However, there will be overall reductions in emissions when the existing coal fired power plants are taken out of service.	EUCTGHRSG1--A 667 MMBTU/H NG fired combustion turbine generator coupled with a heat recovery steam generator (HRSG)	15.21	Natural gas	667	MMBTU/H	A nominally rated 667 MMBTU/hr natural gas-fired combustion turbine generator (CTG) coupled with a heat recovery steam generator (HRSG). The HRSG is equipped with a natural gas-fired duct burner rated at 204 MMBTU/hr to provide heat for additional steam production. The CTG is capable of operating in combined-cycle mode where the exhaust is routed to the HRSG or in simple-cycle mode where the HRSG is bypassed. The HRSG is not capable of operating independently from the CTG. The CTG/HRSG is equipped with a dry low NOx burner (DLNB), selective catalytic reduction (SCR) and oxidation catalyst.	Nitrogen Oxides (NOx)	Dry low NOx burners and selective catalytic reduction for NOx control.	3	PPM	PPMVD@15%O2; 24-H ROLL AVG; SEE NOTES

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JACKSON ENERGY CENTER	JACKSON GENERATION, LLC	WILL	IL	12/31/2018	The proposed facility is designed to generate baseload power. It will consist of two combined-cycle generating units, each with a combustion turbine and associated heat recovery steam generator (HRSG). The turbines would only burn natural gas. Other units include an auxiliary boiler, fuel heater, emergency engines, natural gas piping and components, circuit breakers and roadways	Additional pollutants: Sulfuric Acid Mist: 48 tons/year; GHG as CO2e: 4,752,085 tons/year	Combined-Cycle Combustion Turbine	15.21	Natural Gas	3864	mmBtu/hr	Combined-cycle combustion turbines with heat recovery steam generator (HRSG). Turbines will have inlet evaporative cooling systems to cool inlet air during warm weather to increase power output.	Nitrogen Oxides (NOx)	Selective Catalytic Reduction (SCR) and low-NOx technology (dry low-NOx combustion technology)	2	PPMV	3-UNIT OPERATING HOURS @ 15% O2
JACKSON GENERATING STATION	CONSUMERS ENERGY COMPANY	JACKSON	MI	4/2/2019	Natural gas combined-cycle power plant		FGLMDB1-6 (6 combined cycle natural gas fired CTG each equipped with a HRSG)	15.21	natural gas	420	MW	FGLMDB1-6 is 6 combined cycle natural gas fired combustion turbine generators (CTG) each equipped with a heat recovery steam generator (HRSG). Nominal rating 420 MW. Each combustion turbine (CT) is a GE LM6000 with a rating of 440 MMBTU/HR (HHV) and a duct burner rating of 222 MMBTU/HR (HHV). A combined cycle natural gas fired combustion turbine generator (CTG) with heat recovery steam generator (HRSG) in a 1x1 configuration with a steam turbine generator (STG) for a nominal 420 MW electricity production. The HRSG is not capable of operating independently from the CTG.	Nitrogen Oxides (NOx)	Steam injection, good combustion practices and only combust natural gas.	25	PPM	AT 15% O2; 30 DAY ROLLING AVG; EACH UNIT
CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	CHARLES CITY	VA	6/24/2019	Natural gas-fired combined cycle power plant, three 1 x1 configuration, 310 MW each, no duct firing, air cooled with two 84 MMBtu/H natural gas-fired auxiliary boilers, three fuel gas heaters, an emergency generator, fire water pump, and circuit breakers.	The proposed project will be a new combined-cycle electrical power generating facility utilizing three power blocks consisting of a combustion turbine with a heat recovery steam generator (HRSG) and a reheat condensing steam turbine generator (three 1 x 1 configuration). The turbine model proposed is a MHPS M501JAC turbine. The project will have a nominal net generating capacity of 1,650 MW. The proposed fuel for the turbines is pipeline-quality natural gas. Emissions from the turbines will be controlled by the use of low carbon fuels and high efficiency design (for GHG), clean fuels and GCPs (for PM, PM10 and PM2.5), SCR and dry low NOx burners (for NOx), and oxidation catalyst (for CO and VOC). Other equipment at the site, including two natural gas-fired auxiliary boilers, three fuel gas heaters, a diesel-fired emergency fire water pump, and a diesel-fired emergency generator, are also proposed and will be subject to emission controls. Natural gas piping components and electrical circuit breakers potentially emit GHG pollutants (expressed as carbon dioxide equivalents, or CO2e) and they will also be covered in the permit. This facility is not proposing duct firing in the HRSGs and is proposing air-cooled turbines that will not require cooling towers.	Three (3) Mitsubishi Hitachi Power Systems combustion turbine generators	15.21	natural gas	35000	MMCF/YR	One on one configuration: 4,066 MMBtu/H combustion turbine. Emission limits reflect the operation of each of the three turbines.	Nitrogen Oxides (NOx)	Controlled by dry, low NOx burners and selective catalytic reduction (SCR).	2	PPMVD 15% O2	1 HR AVG

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CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	CHARLES CITY	VA	6/24/2019	Natural gas-fired combined cycle power plant, three 1 x1 configuration, 310 MW each, no duct firing, air cooled with two 84 MMBtu/H natural gas-fired auxiliary boilers, three fuel gas heaters, an emergency generator, fire water pump, and circuit breakers.	The proposed project will be a new combined-cycle electrical power generating facility utilizing three power blocks consisting of a combustion turbine with a heat recovery steam generator (HRSG) and a reheat condensing steam turbine generator (three 1 x 1 configuration). The turbine model proposed is a MHPS M501JAC turbine. The project will have a nominal net generating capacity of 1,650 MW. The proposed fuel for the turbines is pipeline-quality natural gas. Emissions from the turbines will be controlled by the use of low carbon fuels and high efficiency design (for GHG), clean fuels and GCPs (for PM, PM10 and PM2.5), SCR and dry low NOx burners (for NOx), and oxidation catalyst (for CO and VOC). Other equipment at the site, including two natural gas-fired auxiliary boilers, three fuel gas heaters, a diesel-fired emergency fire water pump, and a diesel-fired emergency generator, are also proposed and will be subject to emission controls. Natural gas piping components and electrical circuit breakers potentially emit GHG pollutants (expressed as carbon dioxide equivalents, or CO2e) and they will also be covered in the permit.□ □ This facility is not proposing duct firing in the HRSGs and is proposing air-cooled turbines that will not require cooling towers.	Three (3) Mitsubishi Hitachi Power Systems Combustion	15.21	natural gas	35000	MMCF/YR	Alternative operating scenario: during periods of tuning	Nitrogen Oxides (NOx)	dry, low NOx burners and selective catalytic reduction	703	LB/TURBINE/ CAL. DAY	24 HR TOTAL
CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	CHARLES CITY	VA	6/24/2019	Natural gas-fired combined cycle power plant, three 1 x1 configuration, 310 MW each, no duct firing, air cooled with two 84 MMBtu/H natural gas-fired auxiliary boilers, three fuel gas heaters, an emergency generator, fire water pump, and circuit breakers.	The proposed project will be a new combined-cycle electrical power generating facility utilizing three power blocks consisting of a combustion turbine with a heat recovery steam generator (HRSG) and a reheat condensing steam turbine generator (three 1 x 1 configuration). The turbine model proposed is a MHPS M501JAC turbine. The project will have a nominal net generating capacity of 1,650 MW. The proposed fuel for the turbines is pipeline-quality natural gas. Emissions from the turbines will be controlled by the use of low carbon fuels and high efficiency design (for GHG), clean fuels and GCPs (for PM, PM10 and PM2.5), SCR and dry low NOx burners (for NOx), and oxidation catalyst (for CO and VOC). Other equipment at the site, including two natural gas-fired auxiliary boilers, three fuel gas heaters, a diesel-fired emergency fire water pump, and a diesel-fired emergency generator, are also proposed and will be subject to emission controls. Natural gas piping components and electrical circuit breakers potentially emit GHG pollutants (expressed as carbon dioxide equivalents, or CO2e) and they will also be covered in the permit.□ □ This facility is not proposing duct firing in the HRSGs and is proposing air-cooled turbines that will not require cooling towers.	Three (3) Mitsubishi Hitachi Power Systems combustion turbine generators	15.21	natural gas	35000	MMCF/YR	Startup and Shutdown	Nitrogen Oxides (NOx)	dry, low NOx burners and selective catalytic reduction	60	LB/TURBINE/ EVENT	COLD START-42 MINUTES OR LESS
BIG CAJUN I POWER PLANT	LOUISIANA GENERATING, LLC	POINTE COUPEE	LA	6/27/2019	Electric power generating station using two natural gas fed turbines (120 MW each)		Combustion Turbine #1 (EQT0002, CTG-1)	15.21	Natural Gas	1679	MM BTU/hr		Nitrogen Oxides (NOx)	Dry low NOX Burners & water injection	23	PPMV	THREE HOUR ROLLING AVERAGE
BIG CAJUN I POWER PLANT	LOUISIANA GENERATING, LLC	POINTE COUPEE	LA	6/27/2019	Electric power generating station using two natural gas fed turbines (120 MW each)		Combustion Turbine #2 (EQT0003, CTG-2)	15.21	Natural Gas	1679	MM BTU/hr		Nitrogen Oxides (NOx)	Dry low NOX burners & water injection	23	PPMV	THREE HOUR ROLLING AVERAGE

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COGEN TECH LINDEN VENTURE LP	COGEN TECH LINDEN VENTURE LP	UNION	NJ	7/30/2019	1182 megawatts (MW) electric and steam generating plant	New 250 MW General Electric (GE) 7F.05 CCCT with unfired heat recovery steam generator combusting natural gas (primary fuel) and back up ULSD equivalent to 800 hours per year.	250 MW COMBINED CYCLE COMBUSTION TURBINE FIRING NATURAL GAS	15.21	Natural Gas	21042	MMCubic ft/yr	One New 250 MW General Electric 7F.05 Combined cycle combustion turbine with a Maximum heat Input rate of Size: 2517 MMBtu/hr (HHV) at 10 degrees F, equipped with add-on controls and SCR and Oxidation Catalyst.	Nitrogen Oxides (NOx)	Selective Catalytic Reduction, Dry Low NOx, and use of Natural gas as Primary fuel	18.3	LB/H	AV OF THREE ONE H STACK TESTS EVERY 5 YR
ESC TIOGA COUNTY POWER LLC/ELEC PWR GEN FAC	ESC TIOGA COUNTY POWER, LLC	TIOGA	PA	8/20/2019		This plan approval is for the construction and operation of a 635 Megawatt natural gas-fired combustion turbine power plant with ancillary equipment	COMBUSTION TURBINE/DUCT BURNER	15.21	Natural Gas	4469	MMBtu/Hr		Nitrogen Oxides (NOx)	SCR, Catalytic Oxidizer	2	PPMVD	@ 15% O2 / 1 HR
THOMAS TOWNSHIP ENERGY, LLC	THOMAS TOWNSHIP ENERGY, LLC	SAGINAW	MI	8/21/2019	New power plant	Thomas Township Energy is proposing to install two combustion turbine generators (CTG). Each CTG is connected to a heat recovery steam generator (HRSG), together referred to as a CTGHRSG. To reduce emissions of nitrogen oxides (NOx), the high-efficiency CTGHRSGs will be equipped with dry low-NOx burners and selective catalytic reduction (SCR). To reduce the emissions of carbon monoxide (CO) and volatile organic compounds (VOCs), each CTGHRSG will be equipped with an oxidation catalyst.	FGCTGHRSG	15.21	Natural gas	625	MW	Two (2) combined-cycle natural gas-fired combustion turbine generators (CTGs), each with a heat recovery steam generator (HRSG) in a 1x1 configuration with a steam turbine generator (STG). Each CTGHRSG has a combined nominal 625 MW electricity production (ISO) and a maximum combined heat input rating of 4,200 MMBTU/hr (HHV). Each HRSG is equipped with a natural gas-fired duct burner with a maximum rating of 560 MMBTU/hr (HHV) (ISO) to provide heat for additional steam production.	Nitrogen Oxides (NOx)	Good combustion practices, dry low NOx burners and selective catalytic reduction (SCR).	2	PPM	EACH; 24-HR ROLL.AVG EXCEPT START/SHUT
INDECK NILES, LLC	INDECK NILES, LLC	CASS	MI	11/26/2019	Natural gas combined cycle power plant		FGCTGHRSG	15.21	Natural gas	3421	MMBTU/H	3421 MMBTU/H for each turbine 740 MMBTU/H for each duct burner for a combined throughput of 4161 MMBTU/H or 8322 MMBTU/H for both trains. Two combined-cycle natural gas-fired combustion turbine generators (CTGs) with Heat Recovery Steam Generators (HRSG) (EUCTGHRSG1 & EUCTGHRSG2 in FGCTGHRSG). The total hours for startup and shutdown for each train shall not exceed 500 hours per 12-month rolling time period.	Nitrogen Oxides (NOx)	SCR with DLNB (Selective Catalytic Reduction with Dry Low NOx Burners)	2	PPM	PPMVD @15% O2. 24HR ROLL AVG EXCEPT SS
WPL- RIVERSIDE ENERGY CENTER	WPL- RIVERSIDE ENERGY CENTER	ROCK	WI	2/28/2020	Electric Power Generation		Natural Gas Fired Combustion Turbine (P20, P21) Phase I Commissioning	15.21	Natural Gas	2208	MMBTU/H	Natural gas fired combustion turbine with heat recovery steam generator (HRSG). Phase I commissioning is the period of initial cranking and steam blows when starting a turbine for the first time. Total fuel input (natural gas) to the turbines may not exceed 882 million cubic feet for both turbines combined and 1.20 million cubic feet in any hour for a single turbine.	Nitrogen Oxides (NOx)		110	PPMVD, 15% OXYGEN	AVG. ANY 24-HR OPERATIONAL PERIOD

Table D-1. RBLC Search Results for Large Natural Gas Fired Turbines (Combined-Cycle) - NOx

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel	Throughput	Throughput Units	Process Notes	Pollutant	Control Method Description	Emission Limit	Emission Limit Unit	Emission Limit 1 Average Time Condition
WPL- RIVERSIDE ENERGY CENTER	WPL- RIVERSIDE ENERGY CENTER	ROCK	WI	2/28/2020	Electric Power Generation		Natural Gas Fired Combustion Turbine (P20, P21)- Startup operation during Phase I Commissioning	15.21	Natural Gas	2208	MMBTU/H	Two natural gas fired combustion turbine with heat recovery steam generator (HRSG). Phase I commissioning is the period of initial cranking and steam blows when starting a turbine for the first time. Startup is defined as the beginning of firing natural gas in the combustion turbine until the turbine/HRSG train reaches the minimum emissions compliance load, or the intended operating load if lower than the minimum emission compliance load.	Nitrogen Oxides (NOx)		110	PPMVD, 15% OXYGEN	AVG. ANY 24-HR OPERATIONAL PERIOD
WPL- RIVERSIDE ENERGY CENTER	WPL- RIVERSIDE ENERGY CENTER	ROCK	WI	2/28/2020	Electric Power Generation		Natural Gas Fired Combustion Turbine (P20, P21) Phase II Commissioning	15.21	Natural Gas	2208	MMBTU/H	Natural gas fired combustion turbine with heat recovery steam generator (HRSG). Phase II commissioning is the period when synchronizing the turbine through SCR tuning after Phase I. Total fuel input (natural gas) to the turbines may not exceed 1,960 Million cubic feet for both turbines combined. Oxidation catalyst must run at all times during Phase II commissioning.	Nitrogen Oxides (NOx)		55	PPMVD, 15% OXYGEN	AVG. ANY 24-HR OPERATIONAL PERIOD
WPL- RIVERSIDE ENERGY CENTER	WPL- RIVERSIDE ENERGY CENTER	ROCK	WI	2/28/2020	Electric Power Generation		Natural Gas Fired Combustion Turbine (P20, P21)- Startup operation during Phase II Commissioning	15.21	Natural Gas	2208		Natural gas fired combustion turbine with heat recovery steam generator (HRSG). Phase II commissioning is the period when synchronizing the turbine through SCR tuning after Phase I. Startup is defined as the beginning of firing natural gas in the combustion turbine until the turbine/HRSG train reaches the minimum emissions compliance load, or the intended operating load if lower than the minimum emission compliance load.	Nitrogen Oxides (NOx)		55	PPMVD, 15% OXYGEN	AVG. ANY 24-HR OPERATIONAL PERIOD
NEMADJI TRAIL ENERGY CENTER	NEMADJI TRAIL ENERGY CENTER	DOUGLAS	WI	9/1/2020	Natural gas-fired power plant		Natural-Gas-Fired Combined-Cycle Turbine (P01)	15.21	Natural Gas	4671	MMBTU/H	One Natural-Gas-Fired Siemens SGT6-8000 H Combined-Cycle Turbine with Natural Gas-Fired Duct Burner and Diesel Fuel Oil Back-Up [Maximum continuous rating: 4,671 MMBtu/hr higher heating value (HHV) when combusting natural gas, 4,027 MMBtu/hr, HHV when combusting diesel fuel oil], Selective Catalytic Reduction (SCR) (C01a) and Oxidation Catalyst (C01b)	Nitrogen Oxides (NOx)	Selective Catalytic Reduction (SCR), low-NOx burners, Water injection when firing diesel fuel oil.	2	PPM AT 15% O2	24-HR ROLLING AVG., NATURAL GAS
NEMADJI TRAIL ENERGY CENTER	NEMADJI TRAIL ENERGY CENTER	DOUGLAS	WI	9/1/2020	Natural gas-fired power plant		Natural Gas-Fired Combined-Cycle Turbine (P01) Start-up and Shutdown (Natural Gas)	15.21	Natural Gas	0		One Natural-Gas-Fired Siemens SGT6-8000H Combined-Cycle Turbine with Natural Gas-Fired Duct Burner and Diesel Fuel Oil Back-Up [Maximum continuous rating: 4,671 MMBtu/hr higher heating value (HHV) when combusting natural gas, 4,027 MMBtu/hr, HHV when combusting diesel fuel oil	Nitrogen Oxides (NOx)		335	LB/START-UP	
NEMADJI TRAIL ENERGY CENTER	NEMADJI TRAIL ENERGY CENTER	DOUGLAS	WI	9/1/2020	Natural gas-fired power plant		Natural-Gas-Fired Combined-Cycle Turbine (P01) Start-Up and Shutdown (diesel)	15.21	Natural Gas	0		One Natural-Gas-Fired Siemens SGT6-8000H Combined-Cycle Turbine with Natural Gas-Fired Duct Burner and Diesel Fuel Oil Back-Up [Maximum continuous rating: 4,671 MMBtu/hr higher heating value (HHV) when combusting natural gas, 4,027 MMBtu/hr, HHV when combusting diesel fuel oil],	Nitrogen Oxides (NOx)		860	LB/START-UP	
PLANT BARRY	ALABAMA POWER COMPANY	MOBILE	AL	11/9/2020			Two 744 MW Combined Cycle Units	15.21	Natural Gas	744	MW		Nitrogen Oxides (NOx)	SCR	2	PPM	3 HOUR AVG / @15% O2

Table D-1. RBLC Search Results for Large Natural Gas Fired Turbines (Combined-Cycle) - NOx

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel	Throughput	Throughput Units	Process Notes	Pollutant	Control Method Description	Emission Limit	Emission Limit Unit	Emission Limit 1 Average Time Condition
DOMINION ENERGY - BRUNSWICK	VIRGINIA ELECTRIC AND POWER COMPANY	BRUNSWICK	VA	12/1/2020	Natural gas-fired combined cycle power plant.	The Dominion Brunswick County Power station received its initial PSD permit to construct and operate on March 12, 2013. At the time of the issuance of that permit, alternative operating scenarios for combustion turbines, such as tuning and online turbine blade washing had not been developed. □ □ This permit includes alternative emission limits for the Brunswick□ plant during tuning and online water washing. There is no increase in annual emissions from the turbines due to the inclusion of alternative short term emission limits for NOx and CO during tuning and water-washing.	COMBUSTION TURBINE GENERATORS, (3) with Alternate Operating Scenario - Turbine Tuning	15.21	natural gas	3442	MMBTU/H	Three Mitsubishi M501 GAC combustion turbine generators with HRSG duct burners. □ □ For the purpose of this permit, tuning is defined as the manipulation of the units and associated emission controls to ensure optimized operation and minimized emissions. No tuning event shall last more than 18 consecutive hours. Annual tuning events shall be limited to 96 hours per CT per 12-month rolling period.	Nitrogen Oxides (NOx)	Dry, low NOx burners and selective catalytic reduction (SCR) with a NOx performance of 2.0 ppmvd at 15% O2.	604	LBS	CALENDAR DAY/PER TURBINE
DOMINION ENERGY - BRUNSWICK	VIRGINIA ELECTRIC AND POWER COMPANY	BRUNSWICK	VA	12/1/2020	Natural gas-fired combined cycle power plant.	The Dominion Brunswick County Power station received its initial PSD permit to construct and operate on March 12, 2013. At the time of the issuance of that permit, alternative operating scenarios for combustion turbines, such as tuning and online turbine blade washing had not been developed. □ □ This permit includes alternative emission limits for the Brunswick□ plant during tuning and online water washing. There is no increase in annual emissions from the turbines due to the inclusion of alternative short term emission limits for NOx and CO during tuning and water-washing.	COMBUSTION TURBINE GENERATORS, (3) with Alternate Operating Scenario - Turbine Blade Water Washing	15.21	Natural Gas	3442	MMBTU/H	Three Mitsubishi M501 GAC combustion turbine generators with HRSG duct burners. □ □ On-line water washing is defined as spraying water through the turbine while a unit is operating for the purpose of cleaning the CT compressor blades. No on-line water wash event shall last for more than 60 minutes in a calendar day. Annual on-line water wash events shall not exceed 52 hours per CT per 12-month rolling period.	Nitrogen Oxides (NOx)	Dry, low NOx burners and selective catalytic reduction (SCR) with a NOx performance of 2.0 ppmvd at 15% O2.	604	LBS	CALENDAR DAY/PER TURBINE
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	1/7/2021	Natural gas combined-cycle power plant	The proposed new plant will be replacing the electrical generating capacity of both BWL's existing coal-fired power plants. BWL intends to retire those coal-fired power plants from service by 2025. However, before they can be retired, the new natural gas power plant must be operational. Emissions in the area will increase for a short period if the new combined-cycle plant is built. However, there will be overall reductions in emissions when the existing coal fired power plants are taken out of service.	EUCTGHRSG1	15.21	Natural gas	667	MMBTU/H	EUCTGHRSG1--A nominally rated 667 MMBTU/hr natural gas-fired combustion turbine generator (CTG) coupled with a heat recovery steam generator (HRSG). The HRSG is equipped with a natural gas-fired duct burner rated at 204 MMBTU/hr to provide heat for additional steam production. The CTG is capable of operating in combined-cycle mode where the exhaust is routed to the HRSG or in simple-cycle mode where the HRSG is bypassed. The HRSG is not capable of operating independently from the CTG. The CTG/HRSG is equipped with a dry low NOx burner (DLNB), selective catalytic reduction (SCR), and oxidation catalyst.	Nitrogen Oxides (NOx)	Dry low NOx burners and selective catalytic reduction for NOx control for each CTG/HRSG unit.	60	LB/H	HOURLY; INCL STRT/SHUT IN COMBINED CYCLE

Table D-1. RBLC Search Results for Large Natural Gas Fired Turbines (Combined-Cycle) - NOx

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel	Throughput	Throughput Units	Process Notes	Pollutant	Control Method Description	Emission Limit	Emission Limit Unit	Emission Limit 1 Average Time Condition
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	1/7/2021	Natural gas combined-cycle power plant	The proposed new plant will be replacing the electrical generating capacity of both BWL's existing coal-fired power plants. BWL intends to retire those coal-fired power plants from service by 2025. However, before they can be retired, the new natural gas power plant must be operational. Emissions in the area will increase for a short period if the new combined-cycle plant is built. However, there will be overall reductions in emissions when the existing coal fired power plants are taken out of service.	EUCTGHRSG2	15.21	Natural gas	667	MMBTU/H	EUCTGHRSG2--A nominally rated 667 MMBTU/hr natural gas-fired CTG coupled with a HRSG. The HRSG is equipped with a natural gas-fired duct burner rated at 204 MMBTU/hr to provide heat for additional steam production. The CTG is capable of operating in combined-cycle mode where the exhaust is routed to the HRSG or in simple-cycle mode where the HRSG is bypassed. The HRSG is not capable of operating independently from the CTG. The CTG/HRSG is equipped with a DLNB, SCR, and oxidation catalyst.	Nitrogen Oxides (NOx)	Dry low NOx burners and selective catalytic reduction for NOx control for each CTG/HRSG unit.	60	LB/H	HOURLY; INCL STRT/SHUT IN COMBINED CYCLE
RENOVO ENERGY CENTER LLC/RENOVO PLT	RENOVO ENERGY CENTER LLC	CLINTON	PA	4/29/2021		This plan approval is for the construction and operation of a 1,240-Megawatt natural gas/ultra-low sulfur diesel-fired combustion turbine, combined-cycle power plant with ancillary equipment.	COMBUSTION TURBINE w DUCT BURNER #2 (Natural Gas)	15.21	Natural Gas	4546	MMBtu/Hr	The air contaminants from each power block will be controlled by a selective catalytic reduction (SCR) system and an oxidation catalyst.	Nitrogen Oxides (NOx)	SCR, CATALYTIC OXIDIZER	2	PPMVD	@ 15% O2 / 1 HR
RENOVO ENERGY CENTER LLC/RENOVO PLT	RENOVO ENERGY CENTER LLC	CLINTON	PA	4/29/2021		This plan approval is for the construction and operation of a 1,240-Megawatt natural gas/ultra-low sulfur diesel-fired combustion turbine, combined-cycle power plant with ancillary equipment.	COMBUSTION TURBINE w DUCT BURNER #1 (Natural Gas)	15.21	Natural Gas	4546	MMBtu/Hr	The air contaminants from each power block will be controlled by a selective catalytic reduction (SCR) system and an oxidation catalyst.	Nitrogen Oxides (NOx)	SCR, Catalytic Oxidizer	2	PPMVD	@ 15% O2 / 1 HR
SHADY HILLS COMBINED CYCLE FACILITY	SHADY HILLS ENERGY CENTER, LLC	PASCO	FL	6/7/2021	The Shady Hills Combined Cycle Facility (SHCCF), a new 573-megawatt (MW) (winter) 1-on-1 combined cycle electrical generating facility to be owned and operated by Shady Hills Energy Center, LLC, which will be located at 14350 Merchant Energy Way, Spring Hill, Florida. The proposed work will be conducted on an approximately 14-acre parcel east of and located adjacent to the existing Shady Hills Generating Station (SHGS) power plant, which is owned and operated by Shady Hills Power Company, L.L.C.		GE 7HA.02 Combustion Turbine and HRSG with Duct Firing	15.21	Natural Gas	3622.1	MMBtu/hour	Throughput based on a compressor inlet air temperature of 59Â° F, the higher heating value (HHV) of natural gas, and 100% load	Nitrogen Oxides (NOx)	Dry low-NOX combustors and Selective Catalytic Reduction (SCR)	2	PPMVD AT 15% O2	24-HOUR BLOCK AVERAGE BASIS (BACT)

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Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel	Throughput	Throughput Units	Process Notes	Pollutant	Control Method Description	Emission Limit	Emission Limit Unit	Emission Limit 1 Average Time Condition
MAIDSVILLE	MOUNTAIN STATE CLEAN ENERGY, LLC	MONONGALIA	WV	1/5/2022	This project consist of constructing two combined cycle combustion turbine with duct burners, two fuel gas heaters, two emergency engines (emergency generator and fire water pump), and cooling tower. The configuration of these combustion turbines with heat recovery steam generators will be a 2X1. This facility will be co-located next to existing EGU (Longview Power LLC). The CCCTs with duct burners and fuel gas heaters will operate only on natural gas. Both emergency engines will be diesel fired units.	A bi-direction steam line between the Mountain State Clean Energy and Longview Power will be use to provide startup steam in lieu of a auxiliary boiler.□ No limits on operating hours or fuel use for the duct burners.□ Applicant proposed two different model combustion turbine (GE 7HA.03 and MHPS M501JAC).□ Gross Generation for the facility is 1275 MWh.	Combustion Turbine & Duct Burner (CT-01/HRSG1 & CT-02/HRSG2)	15.21	Pipeline Natural Gas	1275	mw	CT - 3,875 MMBtu/hr DB - 586 MMBtu/hr Gross Generation - 1275 MW	Nitrogen Oxides (NOx)	Dry Low NOx Combustion w/ SCR	2	PPMDV @ 15% O2	3-HOUR ROLLING AVERAGE
MAIDSVILLE	MOUNTAIN STATE CLEAN ENERGY, LLC	MONONGALIA	WV	1/5/2022	This project consist of constructing two combined cycle combustion turbine with duct burners, two fuel gas heaters, two emergency engines (emergency generator and fire water pump), and cooling tower. The configuration of these combustion turbines with heat recovery steam generators will be a 2X1. This facility will be co-located next to existing EGU (Longview Power LLC). The CCCTs with duct burners and fuel gas heaters will operate only on natural gas. Both emergency engines will be diesel fired units.	A bi-direction steam line between the Mountain State Clean Energy and Longview Power will be use to provide startup steam in lieu of a auxiliary boiler.□ No limits on operating hours or fuel use for the duct burners.□ Applicant proposed two different model combustion turbine (GE 7HA.03 and MHPS M501JAC).□ Gross Generation for the facility is 1275 MWh.	Combustion Turbine & Duct Burner (CT-01/HRSG1 & CT-02/HRSG2)	15.21	Pipeline Natural Gas	1275	mw	CT - 3,875 MMBtu/hr DB - 586 MMBtu/hr Gross Generation - 1275 MW	Nitrogen Oxides (NOx)	Dry Low NOx Combustor with SCR	2	PPMDV @ 15% O2	3-HOUR ROLLING AVERAGE
MAGNOLIA POWER GENERATING STATION UNIT 1	MAGNOLIA POWER LLC	IBERVILLE	LA	6/3/2022	Magnolia Power LLC (Magnolia Power) is proposing to construct and operate a power plant, Magnolia Power Generating Station Unit 1, consisting of a natural gas-fired combined cycle gas turbine (CCGT Unit) in Iberville Parish, Louisiana. The CCGT Unit (EQT001), which includes a heat recovery steam generator (HRSG) equipped with duct burners, will have a predicted net nominal output of 730 megawatts (MW)		Combined Cycle Gas Turbine w/ Duct Burners and HRSG	15.21	Natural Gas	5081	mm BTU/h	Normal operating rate is 4930 MMBTU/h.	Nitrogen Oxides (NOx)	Dry low-NOx combustor design, selective catalytic reduction (SCR), and good combustion practices.	2	PPMVD	24-HR ROLLING AVG BASED ON 1-HR AVG
MAGNOLIA POWER GENERATING STATION UNIT 1	MAGNOLIA POWER LLC	IBERVILLE	LA	6/3/2022	Magnolia Power LLC (Magnolia Power) is proposing to construct and operate a power plant, Magnolia Power Generating Station Unit 1, consisting of a natural gas-fired combined cycle gas turbine (CCGT Unit) in Iberville Parish, Louisiana. The CCGT Unit (EQT001), which includes a heat recovery steam generator (HRSG) equipped with duct burners, will have a predicted net nominal output of 730 megawatts (MW)		Combined Cycle Gas Turbine Startup and Shutdown	15.21	Natural Gas	5081	mm BTU/h	Startup and shutdown emissions from the combined cycle gas turbine.	Nitrogen Oxides (NOx)	Good combustion practices.	260	LB/HR	
MEC NORTH, LLC	MARSHALL ENERGY CENTER, LLC	CALHOUN	MI	6/23/2022	Natural gas combined-cycle power plant (two plants: north and south).	The two plants (MEC North, LLC and MEC South, LLC) will operate as separate entities but they are considered a single stationary source and the installation of the two new plants was reviewed as a single project.	EUCTGHRSG (North Plant): A combined cycle natural gas fired combustion turbine generator with heat recovery steam generator	15.21	Natural gas	3064	MMBTU/H	Throughput Information: Nominal 500 MW electricity production. Turbine rating of 3,064 MMBTU/hr (HHV) and HRSG duct burner rating of 889 MMBTU/Hr (HHV).□ □ A combined-cycle natural gas-fired combustion turbine generator (CTG) with heat recovery steam generator (HRSG) in a 1x1 configuration with a steam turbine generator (STG) for a nominal 500 MW electricity production. The CTG is a H-class turbine with a rating of 3,064 MMBTU/hr (HHV). The HRSG is equipped with a natural gas fired duct burner, with a maximum heat input rating of 889 MMBTU/hr (HHV) and rated at 874 MMBTU/hr (HHV) at ISO conditions to provide heat for additional steam production. The HRSG is not capable of operating independently from the CTG. The CTG/HRSG is equipped with dry low NOx burner (DLNB), SCR, and an oxidation catalyst.	Nitrogen Oxides (NOx)	SCR with DLNB (Selective catalytic reduction with Dry low NOx burners)	2.5	PPM	24-HR ROLLING AVG