March 22, 2011 113-87509

Ms. Susan Jenkins, Environmental Engineer
Stationary Source Permitting Program
Georgia Department of Natural Resources
4244 International Parkway, Suite 120
Atlanta, Georgia 30354

**RE: APPLICATION NO. 19810**
**MACKINAW POWER – EFFINGHAM COUNTY POWER PLANT**
**RESPONSE TO COMMENTS IN LETTERS OF DECEMBER 3, 2010 AND JANUARY 25, 2011**

Dear Ms. Jenkins:

Mackinaw Power received comments from the Georgia Environmental Protection Division (EPD) in letters dated December 3, 2010 and January 25, 2011, regarding the Prevention of Significant Deterioration (PSD) Application for the Effingham County Power Plant expansion project submitted in July 2010. Responses to Georgia EPD's comments are presented as follows.

## RESPONSES TO DECEMBER 3, 2010 LETTER

**Comment 1. Georgia EPD is required to address both filterable and condensable particulate matter (CPM) in establishing enforceable emissions limits for particulate matter less than 10 microns (PM10) and fine particulate matter (PM2.5) in New Source Review (NSR) permits as of January 1, 2011. Mackinaw Power notes that PM10 and PM2.5 emissions for the combustion turbines (CTs) include filterable and back-half emissions. Is it correct to assume that the phrase "back-half emissions" corresponds to CPM? Do the projected potential emissions of PM10 and PM2.5 include both filterable and CPM from the other applicable pieces of equipment? If not, please update the projected potential emissions for these two regulated NSR pollutants as found in the application.**

**Response**: The projected potential PM emission for the project is based on total PM (filterable and condensable) for the proposed emission units, as appropriate. The phrase "back-half emissions" does correspond to CPM. Detailed calculations of back-half emissions for the proposed emission units were presented in Appendix A (Tables A-2, A-4, A-6, A-8, A-10, and A-12). CPM emissions are based on a fraction of sulfur dioxide ($SO_2$) converted to sulfur trioxide ($SO_3$) in the combustion turbine (CT), in the duct burner, and in the selective catalytic reduction (SCR) and assuming all $SO_3$ converts to ammonium sulfate. Potential hourly PM emissions presented in Table 2-1 and 2-2 for the CT include both filterable and condensable PM.

The PM emissions from the fuel gas heater and the auxiliary boiler were calculated using the emission factors from AP-42 for total PM, which includes filterable and condensable PM. The PM emissions from the cooling tower have no back-half component because there is no combustion process associated with the cooling tower. The PM emissions are calculated based on total dissolved solids in the amount of circulating water that is emitted from the tower in the form of drift.

**Comment 2. Will the proposed new equipment use the same source of water as the existing equipment? Please explain.**

**Response**: Yes, the proposed new equipment will use the same source of water as the existing equipment. The source of water for the facility is from the City of Savannah.



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**Comment 3.** **Mackinaw Power proposes to combust fuel oil in the combustion turbines (CTs) and natural gas in the duct burners. Mackinaw Power has proposed best available control technology (BACT) emission limits for carbon monoxide (CO), volatile organic compounds (VOCs), and particulate matter (PM, PM10, and PM2.5) for fuel oil firing of the CTs with duct firing. This operational scenario is not included as a potential operating scenario in Tables 2-4 or 4-8 which define the facility's potential emissions as well as BACT economic analysis. Georgia EPD cannot consider permitting this operational scenario without the applicant providing for the scenario in the facility's potential emissions and subsequent BACT economic analysis and air impact assessment. Please revise Tables 2-4 and 4-8 and the air impact assessment (if applicable) to account for this operational scenario**

**Response**: This scenario was not presented in the potential annual emissions calculation in Table 2-4 because this scenario does not produce the highest annual emissions among the oil-firing scenarios. The duct burner will always be fired with natural gas regardless of the CT fired with natural gas or oil. Since oil-firing is limited to 1,000 hours per year (hr/yr) and duct-firing is limited to 4,000 hr/yr per CT, if the CT is fired with oil for 1,000 hrs and the duct burner is also operating, then for the same annual scenario, the CT and duct burner, both firing natural gas, will be limited to 3,000 hr/yr. A revised Table 2-4 is attached, which includes two additional annual operating scenarios including oil-firing case based on CT and duct burner – one without startup and shutdown and one with startup and shutdown.

As shown, potential annual emissions for both new scenarios that include oil-firing based on CT and duct burner are less than the potential annual emissions for respective similar scenarios that include oil-firing case based on CT only. As a result, there is no need to revise Table 2-8, which is based on the worst-case annual emissions for the CTs and duct burners.

**Comment 4.** **Mackinaw Power proposes a BACT emissions limit for CO for the operational scenario of natural gas combustion in the CT with duct firing of 10.5 ppmvd @ 15% oxygen. This emission rate corresponds to a CT operating at baseload at an ambient temperature of 95 deg F. This limit cannot be considered because the applicant used a limit of 10.0 ppmvd @15% oxygen in the BACT economic analysis noted in Table 4-8. Please update the application accordingly if Mackinaw Power request a CO BACT emissions limit of 10.5 ppmvd @15% oxygen. Note: The limit of 10.0 ppmvd @15% oxygen corresponds to the operational scenario of natural gas combustion in the CT with duct firing at an ambient temperature of 59 deg F.**

**Response**: The economic analysis presented in Table 4-8 is based on an annualized cost of installing an oxidation catalyst system. Therefore, the annual operating scenario that produces the worst-case potential annual emissions was used to determine the cost-effectiveness value. As shown in Table 2-4, the potential annual emissions are based on operating scenarios at an annualized ambient temperature of 59 degrees Fahrenheit (°F). The carbon monoxide (CO) emission limit of 10.5 ppmvd at 15-percent oxygen ($O_2$) is based on ambient temperature of 95°F and does not represent the average annual operation. The purpose of the economic analysis is to present an annualized cost-effectiveness value based on the estimated potential annual emissions. The estimated emissions at 95°F and 20°F provide a range of potential emissions that could occur for shorter durations and were considered in the air impact analysis.

Please note that the warm startup hourly emission rate of 153.6 pounds per hour (lb/hr) used in Table 4-8 should have been 238.2 lb/hr. A revised Table 4-8 is attached with the corrected warm startup hourly emission rate for CO. This did not affect any other parts of the application.

**Comment 5.** **On page 4 of the application, Mackinaw Power notes that, "For this Project, the combustion process is based on lean premix staged combustion…. also referred to as DLN combustors." On page 5 of the application, Mackinaw Power notes that, "… the CTs typically will operate between 50 and 100 percent of load for an annual average capacity factor of approximately 40 to 60 percent."**

**a. At what minimum CT load, for each fuel type, does DLN combustion begin (i.e., at what maximum load does diffusion flame combustion end)?**

**b. What is the maximum percent load at the end of a 'warm startup"? Is it approximately 23.7% as stated in Table 2-3?**

**c. What is the maximum percent load at the end of a "cold startup"? Is it approximately 68.5% as stated in Table 2-3?**

**d. At what minimum CT load (per fuel type) is the SCR operational?**

**e. At what minimum CT load is water injection operational?**

**Response**: a. The minimum load for Mode 6Q for natural gas is approximately 60 percent of the maximum load adjusted for ambient conditions.

Fuel oil combustion does not use the Mode 6Q combustion; rather water injection is used to reduce nitrogen oxides ($NO_x$) emissions. DLN combustion is not used during fuel oil combustion.

b. The warm startup load of 23.7 percent is a time-period average instead of the actual load value at the end of warm startup. Based on data from the existing CTs, the actual load at the initiation of Mode 6Q was 112 MW or 68 percent load. The maximum percent load at the end of warm startup would be approximately 70 percent.

c. The maximum percent load at the end of cold startup would be approximately 70 percent.

d. For natural gas, the SCR is operational when required temperature and volumetric flow parameters are achieved and Mode 6Q has been initiated. Under most circumstances ammonia flow to the SCR is initiated within 5 minutes of achieving Mode 6Q. For fuel oil the SCR is operational when temperature and volumetric flow parameters are met at approximately 60 percent of maximum load adjusted for ambient conditions.

e. For fuel oil, water injection is operational at approximately 50 percent of maximum load adjusted for ambient conditions.

**Comment 6. Mackinaw Power proposes BACT emissions limits for the applicable regulated NSR pollutants. The proposal does not include the following:**

**a. At what minimum loads (per fuel type) do these limits apply?**

**b. Averaging periods for each proposed BACT emission limit.**

**c. A discussion of BACT for periods of startup and shutdown of the combustion turbines.**

**d. Short-term BACT emission limits or work practice standards for periods of startup and shutdown.**

**Response**: a. For each natural gas and fuel oil-firing scenario, BACT emission limits for $NO_x$, CO, and volatile organic compound (VOC) emissions from the CTs with and without duct burner firing are based on the maximum exhaust concentration expected for normal steady operation. Therefore, the proposed limits apply at operating loads between approximately 50 percent load and base load. Similarly, for particulate matter equal to or less than 10 microns ($PM_{10}$) and particulate matter equal to or less than 2.5 microns ($PM_{2.5}$), the proposed BACT emission limits for the CTs, in units of lb/MMBtu, apply to operating loads between 50-percent load and base load.

b. The proposed averaging period for the $NO_x$, CO, VOC, and $PM_{10}$/$PM_{2.5}$ BACT limits is a 24-hour block average. Continuous compliance with CO and $NO_x$ emissions limits will also be monitored with continuous emissions monitoring systems (CEMS).

c. The proposed BACT emission limits for the CTs apply to steady-state normal operation between approximately 50-percent load and base load. Even though startup and shutdown of the CTs are a normal part of the power plant operation, they are not part of the steady-state CT operation.

Startup of the CTs is defined by the period when the CTs, the heat recovery steam generators (HRSGs), and the steam turbine are started in a sequential order until the combined-cycle system is in a steady-state fully operational mode. During the initial part of the startup, the CT must be held at low load as the other process equipment is started, and the load is gradually increased until the normal operating load (approximately 50 percent or higher in this case) is achieved. The proposed CTs will be equipped with SCR, a post-combustion $NO_x$ control technology. However, during low CT loads (i.e., less than 50-percent load), the SCR system cannot be turned on until the exhaust flow, temperature, and other operational parameters are within range. When temperatures are low, ammonia will not react completely with the $NO_x$. The use of SCR during startup will also increase ammonia slip. Since SCR cannot be operated, $NO_x$ emissions during startup are higher than normal operation.

In addition, incomplete combustion at low loads results in higher CO and VOC emission rates. Post-combustion control, such as the oxidation catalyst system, requires specific exhaust temperature ranges to be fully effective. As a result, CO and VOC emissions are also higher during startup and shutdown than normal operation.

However, $SO_2$ and $PM_{10}$ emissions result from the characteristics and amount of the fuel burned. During low-load operation, the amount of fuel burned is less than during normal operation. Therefore, $SO_2$ and $PM_{10}/PM_{2.5}$ emissions during startup and shutdown are lower than for normal operation.

d. The annual emissions rates proposed for the project includes emissions expected during 300 startups and 300 shutdowns expected for the proposed CTs. The expected startup and shutdown emissions are based on similar CTs currently operating at the facility. Since emission control is not technically feasible during startup and shutdown, the total annual emissions, which include startup and shutdown emissions are proposed as long-term BACT emissions limits (example: 12-month rolling $NO_x$ limit). Best practices will be used to minimize the number of startups.

**Comment 7. Please conduct an air impact assessment for a requested operational scenario for the combustion of fuel oil in the combustion turbines during startup and shutdown.**

**Response**: At this time, fuel oil startup and shutdown emissions data have not been obtained. When data are received, an air impact assessment shall be conducted.

**Comment 8. On page 7 of the application Mackinaw Power notes, "To provide a conservative estimate of maximum pollutant emissions, the maximum emissions assume that the inlet chillers would be used when the ambient temperature is 95 deg F."**

**a. Will the inlet chillers be used at non-base load operational scenarios that occur at 95 deg F?**

**b. Do the emission estimates in Tables 2-1, 2-2, and 2-4 reflect an operational scenario of use of inlet chillers at 95 deg F?**

**c. Is the use of inlet chillers irrespective of fuel burned in the combustion turbines?**

**Response**: a. It is not anticipated that the inlet chillers will be used at non-base load operation that occur at 95 deg F. The inlet chillers are used to optimize the output of the facility.

b. Yes, inlet chiller operation at 95 deg F is assumed to be the same as operation at 59 deg F. The inlet chillers are expected to maintain the inlet air at 59 deg F on a 95 deg F day.

c. Yes, the use of inlet chillers are irrespective of fuel burned in the combustion turbines.

**Comment 9. The application appears to be silent on whether Mackinaw Power intends on construction and operating additional storage tanks for ammonia.**

**a. Will Mackinaw Power construct and operate additional ammonia storage at the existing site? If so, please complete the applicable air permit application forms and please include the concentration of ammonia stored in these proposed new storage tanks.**

**Response**: Mackinaw Power will construct two additional 17,000-gallon storage tanks containing 19 percent aqueous ammonia. There are no applicable forms for tanks containing ammonia, which is an inorganic compound.

**Comment 10. Please address the potential applicability of the proposed Boiler MACT standard to applicable equipment.**

**Response**: On June 4, 2010, the U.S. Environmental Protection Agency (EPA) proposed Maximum Achievable Control Technology standards for boilers ("Boiler MACT"). This rule, which was finalized on February 21, 2011, will reduce emissions of toxic air pollutants from existing and new industrial, commercial, and institutional boilers located at facilities classified as major and area source facilities. An area source facility emits or has the potential to emit less than 10 tons per year (TPY) of any single air toxic or less than 25 TPY of any combination of air toxics. The existing Effingham power plant is classified as an area source facility and would remain as an area source facility after the proposed expansion project.

The final rule covers boilers located at area source facilities that burn coal, oil, or biomass or non-waste materials, but not boilers that burn only gaseous fuels or any solid waste. The proposed 17 million British thermal units per hour (MMBtu/hr) auxiliary boiler and the 8.75 MMBtu/hr fuel heater will be fired by natural gas only. Therefore, these units are not covered by the air toxics standards for industrial, commercial, and institutional boilers at area source facilities.

**Comment 11. Greenhouse gas (GHG) emissions from the largest stationary sources will, for the first time, be covered by the Prevention of Significant Deterioration (PSD) and title v Operating Permit Programs beginning January 2, 2011. In light of this requirement, Georgia EPD requests that Mackinaw Power provide the following information:**

**a. Please conduct a "five-step" top-down BACT analysis for GHGs proposed to be emitted by the new equipment. The U.S. EPA's website for Clean Air Act Permitting for Greenhouse Gases is at www.epa.gov/nsr/ghgpermitting.html.**

**Response**: A five-step top-down BACT analysis for greenhouse gas (GHG) emissions for the proposed project is presented in Attachment A.

## RESPONSES TO JANUARY 25, 2011 LETTER

Mackinaw Power proposes to install an oxidation catalyst as the best available control technology (BACT) for carbon monoxide (CO) and proposes an emission limit of 2.0 ppmvd at 15 percent oxygen when firing natural gas. For fuel oil firing, Mackinaw Power proposes an emission limit of 4.0 ppmvd at 15 percent oxygen.

As requested by Georgia EPD, the air modeling performed for the project was reevaluated. Based on information presented in the air permit application, the air modeling analysis is sufficient to address compliance with the National Ambient Air Quality Standards (NAAQS). From Table 6-9 of the application, the project's CO impacts were predicted to be below the 1-hour and 8-hour average PSD Class II significant impact levels with the higher emission rates proposed in the application. With the lower CO emission rate now accepted with installation of CO oxidation catalyst, the project's CO impacts will be lower and remain well below the significant impact levels and, therefore, well below the NAAQS, with no additional modeling needed to demonstrate compliance.

As shown in Table 6-9 in the application, the project's annual average $NO_2$ impacts were predicted to be lower than the annual average PSD Class II significant impact level, using the 0.75 factor for conversion of $NO_x$ to $NO_2$ emissions. This factor is recommended by EPA in the Guidelines on Air Quality Models (GAQM), updated through 2005 in Appendix W, 40 CFR 51.

For the 1-hour average $NO_2$ impacts, project impacts are presented without and with applying the 0.75 factor, indicating in both cases that the project's impacts are predicted to be greater than the 1-hour average significant impact level. As such, additional modeling was performed which including modeling background sources and adding in a non-modeled background concentration provided by GEPD. As shown in Table 6-11 of the application, model results for the 1-hour average $NO_2$ concentrations are presented for 3 cases: modeling assumed 100 percent (1.0 factor) of predicted $NO_x$ concentrations were converted to $NO_2$ concentrations; modeling assumed 75 percent (0.75 factor) of $NO_x$ concentrations were converted to $NO_2$ concentrations, and modeling was based on using the plume volume molar ratio method (PVMRM) approach with $NO_2/NO_x$ ambient equilibrium ratio of 0.90 and in-stack $NO_2/NO_x$ ratio of 0.10.

In all cases, the maximum 1-hour average $NO_2$ concentrations were predicted to be less than the NAAQS even with the assumption that 100 percent of $NO_x$ concentrations were assumed to be $NO_2$ concentrations. For that case, the maximum total 1-hour average $NO_2$ concentration was predicted to be 130.4 micrograms per cubic meter ($\mu g/m^3$), less than the NAAQS of 188 $\mu g/m^3$. For the other cases, the maximum total 1-hour average $NO_2$ concentrations were also predicted to be less than the NAAQS. Therefore, no additional modeling is required to demonstrate compliance the NAAQS.

It should be noted that on March 1, 2011, EPA released guidance memorandum for modeling $NO_2$ impacts (Additional Clarification Regarding Applications of Appendix W Modeling Guidance for the 1-hour $NO_2$ National Ambient Air Quality Standard). In that memorandum, EPA recommended use of the 0.80 factor as a default ambient ratio for the 1-hour $NO_2$ standard under Tier 2 without additional justification. In addition, EPA recommended general acceptance of 0.50 as a default in-stack $NO_2/NO_x$ ratio for input to PVMRM option, in the absence of more appropriate source-specific information on in-stack ratios. These recommendations are consistent with the approaches used for the later two cases discussed previously.

Thank you for your consideration of this information. If you have any questions, please do not hesitate to call us at (352) 336-5600.

Sincerely,

**GOLDER ASSOCIATES INC.**

Robert C. McCann
Principal and Air Group Leader

Salahuddin K. Mohammad
Senior Project Engineer

cc: M. Lydon, Mackinaw Power

Enclosures

RCM/SKM/edk/nav/tz

**TABLE 2-4 (Revised 3/21/11)**
**SUMMARY OF MAXIMUM POTENTIAL ANNUAL EMISSIONS FOR THE PROPOSED COMBUSTION TURBINES AND DUCT BURNERS**
**EFFINGHAM PLANT EXPANSION PROJECT**

| | | Maximum emissions (lb/hr) [a] | | | | | | | Maximum Emissions (tons/year) | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | Operating Scenario | Operating Hours | | | | |
| | Fuel: | NG | NG | Oil | Oil [d] | NG | NG | NG | CT(NG) Base Load | 8,760 | 4,760 | 3,760 | 4,760 | 1,601 | 2,601 |
| | | | | | | | | | CT&DB(NG) Base Load | 0 | 4,000 | 4,000 | 3,000 | 4,000 | 3,000 |
| | | | | | | | | | CT(Oil) Base Load | 0 | 0 | 1,000 | 0 | 1,000 | 0 |
| | | | | | | | | | CT(Oil) DB(NG) Base Load | 0 | 0 | 0 | 1,000 | 0 | 1,000 |
| | | | | | | | | | Warm start [b] | 0 | 0 | 0 | 0 | 749 | 749 |
| | | | | | | | | | Cold start [b] | 0 | 0 | 0 | 0 | 50 | 50 |
| | | | | | | | | | Shutdown [b] | 0 | 0 | 0 | 0 | 300 | 300 |
| | Load: | Base | Base w/DB | Base | Base w/DB | Warm | Cold | Shut- | Downtime [c] | 0 | 0 | 0 | 0 | 1060 | 1,060 |
| **Pollutant** | **Temp:** | **59 °F** | **59 °F** | **59 °F** | **59 °F** | **start** | **start** | **down** | **TOTAL** | **8,760** | **8,760** | **8,760** | **8,760** | **8,760** | **8,760** |
| One Combustion Turbine | | | | | | | | | | | | | | | |
| $SO_2$ | | 2.5 | 3.2 | 3.1 | 3.7 | 0.39 | 1.12 | 0.11 | | 11.1 | 12.4 | 12.6 | 12.6 | 10.1 | 10.1 |
| $PM/PM_{10}/PM_{2.5}$ | | 9.7 | 13.5 | 17.8 | 18.3 | 2.25 | 6.38 | 0.63 | | 42.3 | 50.1 | 54.1 | 52.4 | 44.8 | 43.1 |
| $NO_x$ | | 17.1 | 27.6 | 76.2 | 85.2 | 67.7 | 144.0 | 21.7 | | 74.9 | 95.8 | 125.4 | 124.7 | 139.1 | 138.4 |
| CO | | 12.5 | 52.0 | 92.8 | 132.3 | 238.2 | 289.1 | 62.0 | | 54.7 | 133.7 | 173.9 | 173.9 | 266.1 | 266.1 |
| VOC (as methane) | | 3.3 | 5.9 | 9.3 | 11.9 | 0.74 | 2.10 | 0.21 | | 14.6 | 19.8 | 22.7 | 22.7 | 19.5 | 19.5 |
| Sulfuric Acid Mist | | 0.5 | 0.5 | 0.6 | 0.6 | 0.08 | 0.22 | 0.02 | | 2.2 | 2.2 | 2.3 | 2.2 | 1.8 | 1.7 |
| Lead | | 0.00 | 0.00 | 0.027 | 0.027 | 0.00 | 0.00 | 0.00 | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Two Combustion Turbines | | | | | | | | | | | | | | | |
| $SO_2$ | | 5.1 | 6.3 | 6.2 | 7.4 | 0.8 | 2.2 | 0.2 | | 22 | 25 | 25 | 25 | 20 | 20 |
| $PM/PM_{10}$ | | 19.3 | 27.1 | 35.6 | 36.5 | 4.5 | 12.8 | 1.3 | | 84.6 | 100.1 | 108.3 | 104.9 | 90 | 86 |
| $NO_x$ | | 34.2 | 55.1 | 152 | 170 | 135 | 288 | 43 | | 150 | 192 | 251 | 249 | 278 | 277 |
| CO | | 25.0 | 104 | 185.6 | 264.6 | 476 | 578 | 124 | | 109 | 267 | 348 | 348 | 532 | 532 |
| VOC (as methane) | | 6.7 | 11.8 | 18.6 | 23.7 | 1.5 | 4.2 | 0.4 | | 29.2 | 39.5 | 45.5 | 45.5 | 39.0 | 39.0 |
| Sulfuric Acid Mist | | 1.0 | 1.0 | 1.2 | 1.2 | 0.2 | 0.4 | 0.0 | | 4.3 | 4.4 | 4.5 | 4.5 | 3.5 | 3.5 |
| Lead | | 0.00 | 0.00 | 0.055 | 0.055 | 0.000 | 0.000 | 0.000 | | 0.000 | 0.000 | 0.027 | 0.027 | 0.027 | 0.027 |

[a] Based on 59 °F ambient inlet air temperature.

[b]

| Event | min/event | hr/event | No. of events/yr | hr/yr |
|---|---|---|---|---|
| Warm start | 155 | 2.58 | 290 | 749 |
| Cold start | -- | 5 | 10 | 50 |
| Shutdown | -- | 1 | 300 | 300 |

[c] Unit downtime hours are based on a minimum 2 hours of shutdown before a warm start and a minimum of 48 hours shutdown before a cold start.

| Event | downtime hr before event | No. of events/yr | downtime hr/yr |
|---|---|---|---|
| Warm start | 2 | 290 | 580 |
| Cold start | 48 | 10 | 480 |
| | | Total = | 1060 |

[d] DB will be fired with natural gas only. So in this scenario, CT will be fired with oil and DB will be fired with natural gas.

Source: Mackinaw Power, 2010, Golder Associates, 2010.

**TABLE 4-8 (Revised 3/22/11)**

**COST EFFECTIVENESS CALCULATION FOR OXIDATION CATALYST SYSTEM FOR ONE GE 7FA CT**

| Cost Items/Emissions | Parameters | Oxidation Catalyst System for GE 7FA CT |
|---|---|---|
| **ANNUALIZED COSTS (AC) ($):** | See Table 4-7 | 629,110 |
| UNCONTROLLED CO EMISSIONS | | |
| CO emissions for NG Firing and without DB (TPY) : | 3.0 ppmvd, 12.5 lb/hr for 1,601 hours (see Table 2-4) | 10.0 |
| CO emissions for NG Firing and with DB (TPY) : | 10.0 ppmvd, 52.0 lb/hr for 4,000 hours (see Table 2-4) | 104.0 |
| CO emissions for fuel oil-firing (TPY) : | 20.0 ppmvd, 92.8 lb/hr for 1,000 hours (see Table 2-4) | 46.4 |
| CO emissions from startup/shutdown (TPY) : | Warm - 238.2 lb/hr (749 hrs), Cold - 289.1 lb/hr (50 hrs), Shutdown - 62 lb/hr (300 hrs) | 105.7 |
| Potential CO emissions from one CT (TPY) : | | 266.1 |
| CONTROLLED CO EMISSIONS [(a)] | | |
| CO emissions for NG Firing and without DB (TPY) : | 2.0 ppmvd | 6.7 |
| CO emissions for NG Firing and with DB (TPY) : | 2.0 ppmvd, 80% control | 20.8 |
| CO emissions for fuel oil-firing (TPY) : | 4.0 ppmvd, 80% control | 9.3 |
| CO emissions from startup/shutdown (TPY) : | 80% Control | 21.1 |
| Potential controlled CO emissions from one CT (TPY) : | | 57.9 |
| Reduction in CO Emissions (TPY): | | 208 |
| UNCONTROLLED VOC EMISSIONS | | |
| VOC emissions for NG Firing and without DB (TPY) : | 1.4 ppmvd, 3.3 lb/hr for 3,760 hours (see Table 2-4) | 6.2 |
| VOC emissions for NG Firing and with DB (TPY) : | 2.0 ppmvd, 5.9 lb/hr for 4,000 hours (see Table 2-4) | 11.8 |
| VOC emissions for fuel oil-firing (TPY) : | 3.5 ppmvd, 9.3 lb/hr for 1,000 hours (see Table 2-4) | 4.7 |
| Potential VOC emissions from one CT (TPY) : | | 22.7 |
| CONTROLLED VOC EMISSIONS [(b)] | | |
| VOC emissions for NG Firing and without DB (TPY) : | 1.0 ppmvd | 4.4 |
| VOC emissions for NG Firing and with DB (TPY) : | 1.0 ppmvd, 50% control | 5.9 |
| VOC emissions for fuel oil-firing (TPY) : | 1.75 ppmvd, 50% control | 2.3 |
| Potential Controlled VOC emissions from one CT (TPY) : | | 12.7 |
| Reduction in VOC Emissions (TPY): | | 10 |
| Total Reduction in CO and VOC Emissions (TPY): | | 218 |
| **Cost Effectiveness:** | $ per ton of CO and VOC Removed | 2,883 |

Notes:

[(a)] Controlled emissions are calculated based on an estimated CO BACT limit of 2.0 ppmvd for natural gas firing with an oxidation catalyst system. For the oil-firing case and startup/shutdown cases, controlled emissions are based on 80% control.

[(b)] Controlled emissions are calculated based on an estimated 50% control of VOC emissions. For NG-firing only case, controlled emissions are based on the BACT limit of 1.0 ppmvd with an oxidation catalyst system.

**ATTACHMENT A**

# 1.0 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

## 1.1 Introduction

The United States Environmental Protection Agency (EPA) published the Prevention of Significant Deterioration (PSD) and Title V Permitting Guidance for Greenhouse Gases (GHGs) in November, 2010.

On June 3, 2010, EPA issued a final rule that "tailors" the applicability provisions of the PSD and Title V programs to enable EPA and states to phase in permitting requirements for GHGs in a common sense manner ("Tailoring Rule").

Since January 2, 2011, GHGs are a regulated NSR pollutant under the PSD major source permitting program when they are emitted by new sources or modifications in amounts that meet the Tailoring Rule's set of applicability thresholds, which phase in over time.

For PSD purposes, GHGs are a single air pollutant defined as the aggregate group of the following six gases:

- Carbon dioxide ($CO_2$)
- Nitrous oxide ($N_2O$)
- Methane ($CH_4$)
- Hydrofluorocarbons (HFCs)
- Perfluorocarbons (PFCs)
- Sulfur hexafluoride ($SF_6$)

In Tailoring Rule Step 1, beginning on January 2, 2011 and continuing through June 30, 2011, GHG sources will become subject to PSD if they increase GHG emissions by 75,000 TPY of $CO_2$ equivalent ($CO_2e$) or more if they undergo PSD permitting anyway, either for new construction or for modification projects based on emissions of non-GHG pollutants. These sources are referred to as "anyway" sources.

In Tailoring Rule Step 2, beginning on July 1, 2011, and continuing thereafter, anyway PSD sources will remain subject to PSD. In addition, sources with the potential to emit 100,000 TPY $CO_2e$ or more of GHG will be considered major sources for PSD permitting purposes. Additionally, any physical change or change in the method of operation at a major source resulting in a net GHG emissions increase of 75,000 TPY $CO_2e$ or more will be subject to PSD review.

Once major sources become subject to PSD, these sources must, in order to obtain a PSD permit, meet the various PSD requirements such as, they must apply Best Available Control Technology (BACT),

The proposed Effingham expansion project is a major modification and subject to PSD review. In light of the new Tailoring Rule requirements, the Georgia EPD has determined that the GHGs emitted from the proposed project is subject to PSD review and has requested a BACT analysis for the GHGs.

This section presents the proposed BACT for these pollutants. The approach to the BACT analysis is based on the regulatory definitions of BACT, as well as consideration of EPA's current policy guidelines requiring a "top-down" approach. The CAA and corresponding implementing regulations require that a BACT analysis be conducted on a case-by-case basis taking into consideration the amount of emissions reductions that each available emissions-reducing technology or technique would achieve, as well as the energy, environmental, economic and other costs associated with each technology or technique.

EPA recommends that permitting authorities continue to use the Agency's five-step "top down" BACT process to determine BACT for GHGs. In brief, the top-down process calls for all available control technologies for a given pollutant to be identified and ranked in descending order of control effectiveness. The permit applicant should first examine the highest-ranked ("top") option. The top-ranked options should be established as BACT unless the permit applicant demonstrates to the satisfaction of the permitting authority that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the top ranked technology is not "achievable" in that case. If the most effective control strategy is eliminated in this fashion, then the next most effective alternative should be evaluated, and so on, until an option is selected as BACT.

EPA has broken down this analytical process into the following five steps:

Step 1: Identify all available control technologies.

Step 2: Eliminate technically infeasible options.

Step 3: Rank remaining control technologies.

Step 4: Evaluate most effective controls and document results.

Step 5: Select the BACT.

The Clean Air Act specifies that BACT cannot be less stringent than any applicable standard of performance under the New Source Performance Standards (NSPS). As of November, 2010, EPA has not promulgated any NSPS that contain emissions limits for GHGs.

EPA believes that in BACT reviews, it is important to consider options that improve the overall energy efficiency of the source or modification – through technologies, processes and practices at the emitting unit. In general, a more energy efficient technology burns less fuel than a less energy efficient technology on a per-unit-of-output basis. Thus, considering the most energy efficient technologies in the BACT

analysis helps reduce the products of combustion, which includes not only GHGs but other regulated NSR pollutants (e.g., $NO_X$, $SO_2$, $PM/PM_{10}/PM_{2.5}$, CO, etc.). Thus, EPA emphasizes that energy efficiency should be considered in BACT determinations for all regulated NSR pollutants (not just GHGs).

The following sections provide the required BACT analysis.

## 1.2 Combined Cycle CTs

This section contains the BACT analysis for the GHG emissions from the combined cycle CTs.

### *1.2.1 Step 1 – Identify All Available Control Technologies*

The first step in the top-down BACT process is to identify all "available" control options. Available control options are those air pollution control technologies or techniques (including lower-emitting processes and practices) that have the potential for practical application to the emissions unit and the regulated pollutant under evaluation.

EPA has placed potentially applicable control alternatives identified and evaluated in the BACT analysis into the following three categories:

- Inherently Lower-Emitting Processes/Practices/Designs
- Add-on Controls
- Combinations of Inherently Lower Emitting Processes/Practices/Designs and Add-on Controls

EPA recommends that the BACT analysis should consider potentially applicable control techniques from all of the above three categories.

In the BACT analysis, GHGs are considered as a single air pollutant, which is the aggregate group of the six principal gases, $CO_2$, $N_2O$, $CH_4$, HFCs, PFCs, and $SF_6$. $CO_2$ emissions result from the oxidation of carbon in the fuel. $CH_4$ emissions result from incomplete combustion and $N_2O$ emissions result primarily from low temperature combustion. $CO_2$, $N_2O$, and $CH_4$ are the principal GHGs that will be emitted from the proposed CTs at the Effingham Power Plant.

The combustion of natural gas emits almost 30 percent less $CO_2$ than oil, and just under 45 percent less $CO_2$ than coal (source: www.naturalgas.org). The proposed CTs at the Effingham Power Plant will be fired primarily with natural gas. Ultra low sulfur diesel fuel will only be used as backup fuel and will be limited to a maximum of 1,000 hrs/yr per CT. The definition of BACT in 40 CFR 52.21(b)(12) includes use of clean fuels as a pollution control technique. The PSD and the Title V Permitting Guidance for GHGs states that clean fuels which would reduce GHG emissions should be considered while recognizing at the same time that the BACT analysis does not need to include a clean fuel option that would fundamentally

redefine the source. Therefore, the proposed CTs will be fired with "clean fuels" as included in the definition for BACT in the CAA Part 169(3).

EPA recommends that permit applicants and permitting authorities should identify all "available" GHG control options that have the potential for practical application to the source under consideration. In the PSD and Title V Permitting Guidance for GHGs, EPA emphasizes on two mitigation approaches for $CO_2$ – energy efficiency and carbon capture and storage (CCS).

Emissions of $CH_4$ and $N_2O$ from CTs are extremely low. As a result, control options for these pollutants are not discussed except the oxidation catalyst system, which controls $CH_4$ as an added benefit. Effingham is proposing to install oxidation catalyst system for each CT.

## Energy Efficiency

Energy efficiency falls under the general category of lower-polluting processes/practices. Applying technologies, measures and options that are energy efficient translates not only in the reduction of emissions of the particular regulated NSR air pollutant undergoing BACT review, but it also may achieve collateral reductions of emissions of other pollutants. There are different categories of energy efficient improvements:

- Technologies or processes that maximize the efficiency of the individual emissions unit
- Options that could reduce emissions from a new green field facility by improving the utilization of thermal energy and electricity that is generated and used on site

When the efficiency of the power generation process is increased, less fuel is burned to produce the same amount of electricity. This provides the benefits of lower fuel costs and reduced air pollutant emissions (including $CO_2$). Several recent BACT determinations for GHG emissions concluded that high-efficiency power generation technology is the only available and feasible control technology. Efficient power generation is also considered to be technically feasible for the proposed CTs at the Effingham Power Plant.

## Carbon Capture and Storage (CCS)

Carbon capture and storage (CCS) falls under the category of add-on controls, which are air pollution control technologies that remove pollutants from a facility's emissions stream. EPA classifies CCS as an add-on pollution control technology that is "available" for large $CO_2$-emitting facilities including fossil fuel-fired power plants and industrial facilities with high-purity $CO_2$ streams. As a result, EPA requires that CCS be considered in Step 1 of the BACT analysis.

CCS is composed of three main components: $CO_2$ capture and/or compression, transport, and storage.

Carbon Capture - Before $CO_2$ gas can be sequestered, it must be captured as a relatively pure gas, so that it can be feasibly stored. Most power plants and other large point sources use air-fired combustors, a

process that exhausts $CO_2$ diluted with nitrogen. Based on US Department of Energy, flue gas from natural gas combined cycle plants contains only 3-6 percent $CO_2$. For effective carbon sequestration, the $CO_2$ in these exhaust gases must be separated and concentrated.

The most likely options currently identifiable for $CO_2$ separation and capture include:

- Absorption (chemical and physical)
- Adsorption (physical and chemical)
- Low-temperature distillation
- Gas separation membranes
- Mineralization and biomineralization

Carbon Transport – After the $CO_2$ is captured, it must be transported to a carbon sequestration site. Pipelines are the most common method for transporting large quantities of $CO_2$ over long distances. Shipping $CO_2$ via pipeline involves compressing gaseous $CO_2$ to a pressure above 1,160 pounds per square inch (psi), to increase $CO_2$ density and make it easier and less expensive to ship. A $CO_2$ pipeline would be similar to a high pressure natural gas pipeline and is technically feasible. $CO_2$ also can be transported as a liquid in seagoing vessels or via tankers on roads or railways. In these instances, the $CO_2$ is held in insulated tanks at low temperatures and relatively low pressures.

Carbon Storage – In a CCS system, $CO_2$ is captured, it is transported, if necessary, and then stored. Geologic formations such as depleted oil and gas reservoirs, unmineable coal seams, and underground saline formations are potential options for long-term storage. Pressurized $CO_2$ is injected into the deep geologic formations through drilled wells. Under high pressure, $CO_2$ turns to liquid and can move through a formation as a fluid. Once injected, the liquid $CO_2$ tends to be buoyant and will flow upward until it encounters a barrier of non-porous rock, which can trap the $CO_2$ and prevent further upward migration. When $CO_2$ is injected into a coal seam, it is adsorbed onto the coal surfaces, and methane gas is released and produced in adjacent wells. There are other mechanisms for $CO_2$ trapping as well: $CO_2$ molecules can dissolve in brine; react with minerals to form solid carbonates; or adsorb in the pores of the porous rock.

Deep saline formations, which are layers of porous rock saturated with brine present an enormous potential for geologic storage of $CO_2$. However, the industry doesn't have as much experience with saline formations as they have acquired through resource recovery from oil and gas reservoirs and coal seams. There are ongoing research focused on storage in organic rich shale, which is a thin horizontal layer of sedimentary rock with low vertical permeability and in basalt formations, which are geologic formations of solidified lava. Other possible options include liquid storage in the ocean.

### Oxidation Catalyst

Catalytic oxidation technology, which is primarily designed to reduce CO emissions (VOC emissions are also reduced to a lesser extent) will also reduce $CH_4$ emissions. Oxidation catalysts operate at elevated temperatures. In the presence of an oxidation catalyst, excess $O_2$ in the exhaust reacts with $CH_4$ to form $CO_2$. No chemical reagent is necessary. The oxidation catalyst is typically a precious metal catalyst. None of the catalyst components is considered toxic.

Oxidation catalysts are susceptible to fine particles suspended in the exhaust gases that can foul and poison the catalyst. Catalyst poisoning reduces catalyst activity and pollutant removal efficiencies. The most effective oxidation of CO and VOC emissions is achieved if the catalyst bed is located prior to the HRSG in the high-temperature region.

## *1.2.2 Step 2 – Identification of Technically Feasible Control Alternatives*

Under the second step of the top-down BACT analysis, a potentially applicable control technique listed in Step 1 may be eliminated from further consideration if it is not technically feasible for the specific source under review. EPA considers a technology to be potentially applicable if it has been demonstrated in practice or is available.

### Energy Efficiency

Efficient power generation is considered to be technically feasible for the proposed CTs at the Effingham Power Plant. This is discussed in detail in Step 5.

### Carbon Capture and Storage (CCS)

In the PSD and Title V permitting guidance for GHGs, EPA states that it does not believe CCS will be a technically feasible BACT option in certain cases at this time. To establish that an option is technically feasible, the permitting record should show either that an available control option has been demonstrated in practice or is available and applicable, with the term “applicable” generally meaning a technology can reasonably be installed and operated on the source type under consideration. EPA recognizes the significant logistical hurdles that the installation and operation of a CCS system presents and that sets it apart from other add-on controls that are typically used to reduce emissions of other regulated pollutants and already have an existing reasonably accessible infrastructure in place to address waste disposal and other offsite needs. It should also be noted that while CCS may be available according to EPA, it is not “commercially available”. All current CCS projects for power plants are primarily in the demonstration stage.

Logistical hurdles for CCS may include obtaining contracts for offsite land acquisition (including the availability of land), the need for funding (including, for example, government subsidies), timing of available transportation infrastructure, and developing a site for secure long term storage. Not every

source has the resources to overcome the offsite logistical barriers necessary to apply CCS technology to its operations.

The Effingham Power Plant is located near Savannah, GA. Based on the maps presented at the NETL's Carbon Sequestration Storage webpage, there are no oil and gas reservoirs or unmineable coal seams near the facility. The nearest such geologic storage areas are more than 200 km away and a very long pipeline would be required if storage is desired in such areas. There are deep saline formations near the facility location. However, little is much less is known about saline formations because they lack the characterization experience that industry has acquired through resource recovery from oil and gas reservoirs and coal seams. Based on NETL maps, there are basalt formations near the facility, which are geologic formations of solidified lava. However, carbon storage potential of basalt formations is currently being researched. Therefore, logistical hurdle does exist for the application of CCS at the Effingham Power Plant.

There are no CCS systems commercially available for full-scale power plants in the United States. On February 3, 2010, President Obama established an Interagency Task Force on Carbon Capture and Storage, composed of 14 Executive Departments and Federal Agencies. The Task Force, co-chaired by the Department of Energy (DOE) and the Environmental Protection Agency (EPA), was charged with proposing a comprehensive and coordinated strategy to overcome the barriers to the widespread, cost-effective deployment of carbon capture and storage (CCS) within ten years, with a goal of bringing five to ten commercial demonstration projects online by 2016. These projects, to be deployed with the help of federal funding, are intended to demonstrate a range of current generation CCS technologies applied to coal-fired power plants and industrial facilities. Therefore, the application of CCS to power plants is very much in the development stage.

In November 2010, EPA published the final rule for Federal Requirements Under the Underground Injection Control (UIC) for $CO_2$ Geologic Sequestration (GS) Wells, as authorized by the Safe Drinking Water Act (SDWA). The final rule establishes new federal requirements for the underground injection of carbon dioxide for the purpose of long-term underground storage, or geologic sequestration, and a new well class – Class VI – to ensure the protection of underground sources of drinking water (USDWs) from injection related activities. Therefore, authorization must be obtained from EPA prior to geologic sequestration. Permitting for a Class VI well may take a long time and may be very expensive, as this may include drilling deep holes, testing, etc., prior to use as an injection well. Indeed, these requirements may require an exploratory well to assess the formation that can take over 18 months to drill and test.

Based on these considerations, it can be reasonably concluded that CCS is not applicable to the Effingham Expansion project, and consequently not technically feasible, even if the type of equipment needed to accomplish the compression, capture, and storage of GHGs are determined to be generally available from commercial vendors.

### Oxidation Catalyst

Catalytic oxidation is a feasible control technology for $CH_4$. As discussed in Section 1.1, oxidation catalyst system is primarily designed to control CO emissions with the following reaction:

$$2CO + O_2 \rightarrow 2CO_2$$

The oxidation catalyst will reduce $CH_4$ with the following reaction:

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

Effingham is proposing to install oxidation catalyst system to control CO emissions, which will also reduce $CH_4$ as an added benefit. However, there is a trade-off between controlling $CH_4$ emissions and additional $CO_2$ emissions generated. But since the global warming potential of $CH_4$ is 21 times the global warming potential of $CO_2$, there will be a reduction in the global warming potential by using the oxidation catalyst system.

### *1.2.3 Step 3 – Rank Remaining Control Technologies*

After the list of all available controls is narrowed down to a list of the technically feasible control technologies in Step 2, Step 3 of the top-down BACT process calls for the remaining control technologies to be listed in order of overall control effectiveness for the regulated NSR pollutant under review. The most effective control alternative (i.e., the option that achieves the lowest emissions level) should be listed at the top and the remaining technologies ranked in descending order of control effectiveness.

Based on the discussion in Steps 1 and 2, the only technically feasible control option for GHGs is energy efficiency.

### *1.2.4 Step 4 – Economic, Energy, and Environmental Impacts*

Under Step 4 of the top-down BACT analysis, economic, energy, and environmental impacts must be evaluated for each option remaining under consideration.

The “top” control option should be established as BACT unless the applicant demonstrates, and the permitting authority agrees, that the energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not “achievable” in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on.

Where GHG control strategies affect emissions of other regulated pollutants, EPA recommends that applicants should consider the potential trade-offs between emissions of GHGs and emissions of other regulated NSR pollutants. For example, controlling CO, VOC, or $CH_4$ emissions with an oxidation catalyst system creates GHG emissions in the form of $CO_2$. But because of the higher global warming potential of $CH_4$, there will be a reduction in global warming potential. Energy efficiency improvements generally

reduce emissions of all pollutants resulting from combustion processes, so no significant trade offs in emissions expected from energy efficiency improvements.

The proposed CTs at the Effingham Power plant will be operating at the combined-cycle mode, which is more energy efficient than simple cycle. Therefore, no additional improvements are necessary.

The CCS option was eliminated in Step 2 as not technically feasible for the project. Although EPA considers CCS as available, it is not commercially available. Indeed, EPA recognizes that at present CCS is an expensive technology, largely because of the costs associated with $CO_2$ capture and compression. In the Guidance, EPA states that even if not eliminated in Step 2 of the BACT analysis, on the basis of the current costs of CCS, CCS is more likely to be eliminated from consideration in Step 4 of the BACT analysis, even in some cases where underground storage of the captured $CO_2$ near the power plant is feasible.

### *1.2.5 Step 5 – Select the BACT*

In Step 5 of the BACT determination process, the most effective control option not eliminated in Step 4 should be selected as BACT for the pollutant and emissions unit under review and included in the permit.

#### BACT

Energy efficiency, the only remaining and feasible control technology is selected as BACT for the GHG emissions from the proposed CTs at the Effingham Power Plant. Energy efficiency plays a major role in affecting GHG emissions and EPA expects that more emphasis will be given to energy efficiency in GHG BACT analysis in permit applications after July, 2011.

The efficiency of the generation technology in producing electricity and fuel utilized are the most important aspects in greenhouse gas (GHG) emissions from electric generation projects. Together, efficiency and fuel type dictate the amount of GHG emissions per unit of generation.

An important measure of the efficiency for an electrical generating facility is the units' heat rate. Heat rate is a measurement of how efficiently a generator uses heat energy. It is expressed as the number of BTUs of heat required to produce a kilowatt-hour of energy. A heat rate of 3,413 Btu/kW-hr reflects a conversion efficiency of 100 percent from thermal energy to electrical energy.

The proposed CTs heat rate and energy efficiency was compared to data obtained from the US Energy Information Administration (US EIA). Based on data provided in the Annual Energy Review 2009, the approximate heat rate for electricity for fossil-fueled power plants in the U.S. in 2009 was 9,854 Btu/kW-hr (34.7 percent efficiency) (http://www.eia.doe.gov/emeu/aer/txt/ptb1306.html). Based on US EIA's 2009 annual review of the electrical power industry, the reported average heat rate for natural gas firing was 8,157 Btu/kW-hr (41.8 percent efficiency) including all types of generation (http://www.eia.doe.gov/cneaf/

electricity/epa/epat5p3.html). Of the generation types, the average heat rates are (http://www.eia.doe.gov/cneaf/electricity/epa/epat5p4.html):

- Steam turbine – 10,399 Btu/kW-hr (32.8 percent efficiency)
- Gas turbine – 11,497 Btu/kW-hr (29.7 percent efficiency)
- Internal combustion – 9,973 Btu/kW-hr (34.2 percent efficiency)
- Combined cycle – 7,543 (45.3 percent efficiency) Btu/kW-hr

Using actual data to estimate the power output of the steam turbine (ST) and incremental power output due to duct firing, the heat rate and efficiency of the proposed 2x1 combined cycle power block can be estimated as follows:

- Gas-firing only – 6,852 Btu/kW-hr (49.8 percent efficiency) (Baseload at 59°F, heat input – 2 CTs at 1,859 MMBtu/hr each, power output – 2 CTs at 173.8 MW each and ST at 195 MW for a total 542.6 MW)
- Gas-firing along with duct burner firing – 7,051 Btu/kW-hr (48.4 percent efficiency) (Baseload at 59°F, heat input – 2 CTs at 1,859 MMBtu/hr each and 2 DBs at 470 MMBtu/hr, power output – 2 CTs at 173.8 MW each, 59 MW incremental power for each DB, and ST at 195 MW for a total 660.6 MW)
- Oil-firing only – 7,032 (48.5 percent efficiency) (Baseload at 59°F, heat input – 2 CTs at 1,962 MMBtu/hr each, power output – 2 CTs at 181.5 MW each and ST at 195 MW for a total 558 MW)

Using these heat rates and an operating scenario of 1000 hrs/yr of CT on oil-firing, 4000 hrs/yr of CT and DB on gas firing, and 3,760 hrs/yr of CT only on gas firing, the overall heat rate of the proposed power block can be estimated as 6,963 Btu-kW-hr (49 percent efficiency). These estimated heat rates are well below the approximate heat rate for all fossil-fueled power plants in the U.S. in 2009 and the proposed power block is 14.3 percent more efficient. When comparing to all types of generation using natural gas, the proposed power block will be 8 percent more efficient than all generation using natural gas.

When compared to existing combined cycle generation, the proposed power block will be more efficient than existing combined cycle plants. This is a result of utilizing a combined cycle configuration where the exhaust heat from an efficient combustion turbine/electric generator is utilized to generate steam in the heat recovery steam generator (HRSG). The steam is used in a matching steam turbine to generate additional electrical energy. The proposed project will be designed to produce the maximum efficiency for the size of the project (approximately 660 MW).

## BACT Emission Limit

The fuel utilized determines the amount of GHG emissions per unit of energy. For example, based on 40 CFR 75 (Acid Rain) Appendix G – Determination of $CO_2$ Emissions, the emission factors for $CO_2$ are 118.86 lb $CO_2$/MMBtu for natural gas and 162.29 lb $CO_2$/MMBtu for distillate oil. For individual operating scenarios of the proposed power block, using the heat rate and the GHG emission factors, GHG

emissions can be calculated in units of mass/MWh, which is a measure of GHG emission per unit energy output. Emissions of $CO_2$, $N_2O$, and $CH_4$ were calculated for the individual scenarios of natural gas-firing with no duct firing, natural gas-firing with duct firing, and fuel oil-firing, which are presented in Table A-1. The $CO_2$ emission rates were determined to be as follows:

- Natural gas-firing with no duct firing – 814.2 lb $CO_2$/MWh
- Natural gas-firing with duct firing – 837.9 lb $CO_2$/MWh
- Fuel oil firing – 1,141.3 lb $CO_2$/MWh
- Overall – 862.4 lb $CO_2$/MWh (3,760 hrs/yr NG with no duct firing, 4,000 hrs/yr NG with duct firing, 1,000 hrs/yr fuel oil-firing) [(814.2 x 3760 + 837.9 x 4000 + 1141.3 x 1000)/8760]

As part of EPA's clean energy initiatives, EPA developed the Emissions & Generation Resource Integrated Database (eGRID) as a resource tool in assessing GHG emissions. eGrid is a comprehensive source of data on the environmental characteristics of almost all electric power generated in the United States with data available based on a variety of geographic regions and locations. Data is also available on a plant specific basis. Based on the latest available eGrid data the following are the emissions of $CO_2$ on a generation basis for generation facilities located in the same sub-region as the project:

- SERC Reliability Corporation's (SERC's) Southeastern Sub-Region (major portions of Georgia, Alabama and a small portion of Mississippi) – Total Fossil Fuel – 1,894.3 lb $CO_2$/MWh
- SERC Southeastern Sub-Region – Non-Baseload – 1,551.1 lb $CO_2$/MWh, 21.7 lb $N_2O$/GWh, 28.5 lb $CH_4$/GWh
- Georgia Power Company – 1,617.5 lb $CO_2$/MWh for all generation (includes nuclear); 1,936.9 lb $CO_2$/MWh for fossil fuel combustion

When compared, it can be seen that the proposed power blocks GHG emission rates that are significantly lower than the existing generation facilities in the region. Therefore, the GHG on a generation basis are much lower than the existing generation and when operated would likely displace less efficient generation resulting in overall GHG reduction. For example, when operational, if the project's generation displaced non-baseload generation, with an overall $CO_2$ emission rate of 862.4 lb/MWh, there would be an 1,804,474 ton per year reduction [(1551.1 − 862.4) lb/MWh x 598.2 MW (overall power calculated from 3760 hrs at 542.6 MW, 4000 hrs at 660.6 MW, and 1000 hours at 558 MW) x 8760 hrs/yr] in the SERC Southeastern sub-region emissions.

The conclusions from the comparisons for energy efficiency and GHG emissions are as follows:

- The proposed project will be one of the most efficient electric generating facilities in Georgia.
- The proposed project will result in GHG emissions that are of the lowest in the SERC sub-region and Georgia.

- The proposed project will likely reduce GHG emissions in SERC sub-region and Georgia by displacing less efficient and greater GHG emitting technologies.

The use of natural gas and distillate fuel oil as backup and a combined cycle configuration for the project is proposed as BACT. This is consistent with the definition of BACT, which allows "a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology." A numerical emission limit is not necessary or appropriate for GHG emissions based on the project's design and fuel use.

## 1.3 Auxiliary Boiler

Mackinaw Power is proposing an auxiliary boiler with a maximum design heat input rating of 17 MMBtu/hr, which will be exclusively fueled by pipeline quality natural gas. The boiler will be used during the startup sequences of the CTs to provide steam to the steam cycle and shorten the cold and warm start duration, thus decreasing start-up emissions. Mackinaw Power proposes to limit the hours of operation of the auxiliary boiler to 2,500 hr/yr. Using a $CO_2$ emission factor of 116.86 lb/MMBtu (Table C-1; 40 CFR 98, Subpart C), the auxiliary boiler will have a potential to emit 1,987 lb/hr or approximately 1 ton/hr of $CO_2$ emissions. The $CO_2$ emissions potential is negligible.

Also, combustion of natural gas emits less $CO_2$ than combusting oil or coal and is considered as clean fuel. The auxiliary boiler will be fired by natural gas only.

## 1.4 Fuel Gas Heater

The maximum heat input rate of the proposed fuel heater is 8.75 MMBtu/hr. Using the same $CO_2$ emission factor as for the auxiliary boiler, the fuel heater will have a potential to emit 1,023 lb/hr or 0.51 ton/hr of $CO_2$ emissions. This rate is negligible.

The fuel heater will be fired by natural gas only, which will have the potential to emit less $CO_2$ than firing other fossil fuel like oil.

## 1.5 Cooling Towers

The proposed cooling towers will not emit any GHGs.

## 1.6 Fuel Oil Storage Tank

The proposed fuel oil storage tank will not emit any GHGs.

**TABLE A-1**
**GHG EMISSIONS FOR THE PROPOSED 2X1 POWER BLOCK**
**EFFINGHAM PLANT EXPANSION PROJECT**

| | | | $CO_2$ Emissions | | | | $N_2O$ Emissions (e) | | | | $CH_4$ Emissions (e) | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Unit | Heat Input (MMBtu/hr) | Power Output (MW) | Emission Factor (lb/MMBtu) | Emission Rate (lb/hr) | Emission Rate (tons/hr) | Per Unit Output (lb/MWh) | Emission Factor (lb/MMBtu) | Emission Rate (lb/hr) | Emission Rate (tons/hr) | Per Unit Output (lb/GWh) | Emission Factor (lb/MMBtu) | Emission Rate (lb/hr) | Emission Rate (tons/hr) | Per Unit Output (lb/GWh) |
| ***Scenario 1: Baseload, 59 F, Natural Gas-Firing, CT Only*** | | | | | | | | | | | | | | |
| CT1 | 1,859 | 173.80 | 118.86 (a) | 220,901 | 110.5 | | 2.20E-04 (b) | 0.4 | 0.0002 | | 2.2E-03 (b) | 4.1 | 0.0020 | |
| CT2 | 1,859 | 173.80 | 118.86 (a) | 220,901 | 110.5 | | 2.20E-04 (b) | 0.4 | 0.0002 | | 2.2E-03 (b) | 4.1 | 0.0020 | |
| ST (d) | -- | 195 | -- | -- | -- | | -- | -- | -- | | -- | -- | -- | |
| | 3,717 | 542.6 | | 441,803 | 220.9 | 814.2 | | 1 | 0.0004 | 1.5 | | 8 | 0.004 | 15.1 |
| ***Scenario 2: Baseload, 59 F, Oil-Firing, CT Only*** | | | | | | | | | | | | | | |
| CT1 | 1,962 | 181.50 | 162.29 (c) | 318,425 | 159.2 | | 1.32E-03 (b) | 2.6 | 0.0013 | | 6.6E-03 (b) | 13.0 | 0.0065 | |
| CT2 | 1,962 | 181.50 | 162.29 (c) | 318,425 | 159.2 | | 1.32E-03 (b) | 2.6 | 0.0013 | | 6.6E-03 (b) | 13.0 | 0.0065 | |
| ST (d) | -- | 195 | -- | -- | -- | | -- | -- | -- | | -- | -- | -- | |
| | 3,924 | 558.0 | | 636,850 | 318.4 | 1,141.3 | | 5 | 0.0026 | 9.3 | | 26 | 0.013 | 46.5 |
| ***Scenario 3: Baseload, 59 F, Natural Gas-Firing, CT and DB*** | | | | | | | | | | | | | | |
| CT1 | 1,859 | 173.80 | 118.86 (a) | 220,901 | 110.5 | | 2.20E-04 (b) | 0.4 | 0.0002 | | 2.2E-03 (b) | 4.1 | 0.0020 | |
| CT2 | 1,859 | 173.80 | 118.86 (a) | 220,901 | 110.5 | | 2.20E-04 (b) | 0.4 | 0.0002 | | 2.2E-03 (b) | 4.1 | 0.0020 | |
| DB1 (d) | 470 | 59 | 118.86 (a) | 55,864 | 27.9 | | 2.20E-04 (b) | 0.1 | 0.0001 | | 2.2E-03 (b) | 1.0 | 0.0005 | |
| DB2 (d) | 470 | 59 | 118.86 (a) | 55,864 | 27.9 | | 2.20E-04 (b) | 0.1 | 0.0001 | | 2.2E-03 (b) | 1.0 | 0.0005 | |
| ST (d) | -- | 195 | -- | -- | -- | | -- | -- | -- | | -- | -- | -- | |
| | 4,657 | 660.6 | | 553,531 | 276.8 | 837.9 | | 1 | 0.0005 | 1.6 | | 10 | 0.005 | 15.5 |

(a) Appendix G - Determination of $CO_2$ Emissions, 40 CFR Part 75. Natural gas-firing $CO_2$ lb/MMBtu = 1040 scf/MMBtu x (1/385) scf $CO_2$/lb-mole x 44 lb/lb-mole = 118.86 lb/MMBtu.

(b) Table C-2, Subpart C, 40 CFR Part 98. Emission factors in kg/MMBtu were converted to lb/MMBtu by multiplying by 2.204.

(c) Appendix G - Determination of $CO_2$ Emissions, 40 CFR Part 75. Oil-firing $CO_2$ lb/MMBtu = 1420 scf/MMBtu x (1/385) scf $CO_2$/lb-mole x 44 lb/lb-mole = 162.29 lb/MMBtu.

(d) Steam turbine power output and incremental power output due to duct burner firing were obtained from the actual operating data of a 4x1 power plant with GE 7FA CTs.

(e) $N_2O$ and $CH_4$ emissions per unit output are presented in units of pound per gigawatt-hour (lb/GWh), where 1 GW = 1000 MW.