TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

EXAMPLE A

**NOTICE OF APPLICATION AND PRELIMINARY DECISION
FOR AN AIR QUALITY PERMIT**

PROPOSED AIR QUALITY PERMIT GHGPSDTX115

APPLICATION AND PRELIMINARY DECISION. Eagle Mountain Power Company LLC, 1601 Bryan Street, Dallas, Texas 75201-3401, has applied to the Texas Commission on Environmental Quality (TCEQ) for issuance of proposed Greenhouse Gas (GHG) Prevention of Significant Deterioration (PSD) Air Quality Permit GHGPSDTX115, which would authorize construction of the Eagle Mountain Steam Electric Station located at 10029 Morris Dido Newark Rd, Fort Worth, Tarrant County, Texas 76179. This application was submitted to the TCEQ on November 19, 2014. The proposed facility will emit greenhouse gases.

The executive director has determined that the emissions of air contaminants from the proposed facility which are subject to PSD review will not violate any state or federal air quality regulations and will not have any significant adverse impact on soils, vegetation, or visibility. All air contaminants have been evaluated, and best available control technology will be used for the control of these contaminants.

The executive director has completed the technical review of the application and prepared a draft permit which, if approved, would establish the conditions under which the facility must operate. The permit application, executive director's preliminary decision, draft permit, and the executive director's preliminary determination summary will be available for viewing and copying at the TCEQ central office, the TCEQ Dallas/Fort Worth regional office, and at John Ed Keeter Public Library, 355 West McLeroy Boulevard, Saginaw, Tarrant County, Texas, beginning the first day of publication of this notice. The facility's compliance file, if any exists, is available for public review at the TCEQ Dallas/Fort Worth Regional Office, 2309 Gravel Dr, Fort Worth, Texas.

INFORMATION AVAILABLE ONLINE. The following documents are accessible through the Commission's Web site at www.tceq.texas.gov/goto/cid: the executive director's preliminary decision which includes the draft permit, the executive director's preliminary determination summary, and, once available, the executive director's response to comments and the final decision on this application. You may access the Commissioners' Integrated Database (CID) using the above link and enter the permit number for this application. The John Ed Keeter Public Library, 355 West McLeroy Boulevard, Saginaw, Tarrant County, Texas, provides public access to the internet. The following link to an electronic map of the site or facility's general location is provided as a public courtesy and not part of the application or notice. For exact location, refer to application http://www.tceq.texas.gov/assets/public/hb610/index.html?lat=32.906666&lng=-97.480277&zoom=13&type=r.

PUBLIC COMMENT/PUBLIC MEETING. You may submit public comments or request a public meeting about this application. The purpose of a public meeting is to provide the opportunity to submit comment or to ask questions about the application. The TCEQ will hold a public meeting if the executive director determines that there is a significant degree of public interest in the application, if requested by an interested person, or if requested by a local legislator. A public meeting is not a contested case hearing. There is no opportunity to request a contested case hearing for this application. **You may submit additional written public comments within 30 days of the date of newspaper publication of this notice in the manner set forth in the AGENCY CONTACTS AND INFORMATION paragraph below.**

After the deadline for public comment, the executive director will consider the comments and prepare a response to all public comment. **The response to comments, along with the executive director's decision on the application will be mailed to everyone who submitted public comments or is on a mailing list for this application.**

EXECUTIVE DIRECTOR ACTION. The executive director may issue final approval of the application. The response to comments, along with the executive director's decision on the application will be mailed to everyone who submitted public comments or is on a mailing list for this application, and will be posted electronically to the CID.

MAILING LIST. In addition to submitting public comments, you may ask to be placed on a mailing list to obtain additional information on this application by sending a request to the Office of the Chief Clerk at the address below.

AGENCY CONTACTS AND INFORMATION. Public comments and requests must be submitted either electronically at www.tceq.texas.gov/about/comments.html, or in writing to the Texas Commission on Environmental Quality, Office of the Chief Clerk, MC-105, P.O. Box 13087, Austin, Texas 78711-3087. If you communicate with the TCEQ electronically, please be aware that your email address, like your physical mailing address, will become part of the agency's public record. For more information about this permit application or the permitting process, please call the Public Education Program toll free at 1-800-687-4040. Si desea información en Español, puede llamar al 1-800-687-4040.

Further information may also be obtained from Eagle Mountain Power Company LLC at the address stated above or by calling Mr. Paul Coon, Air Permitting Manager Environmental Services at (214) 875-8376.

Notice Issuance Date: November 18, 2015

Emission Sources - Maximum Allowable Emission Rates

Permit Number GHGPSDTX115

This table lists the maximum allowable emission rates of greenhouse gas (GHG) emissions, as defined in Title 30 Texas Administrative Code § 101.1, for all sources of GHG air contaminants on the applicant's property that are authorized by this permit. The emission rates shown are those derived from information submitted as part of the application for permit and are the maximum rates allowed for these facilities, sources, and related activities. Any proposed increase in emission rates may require an application for a modification of the facilities authorized by this permit.

Air Contaminants Data

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**
			TPY (4)
		Option 1	
EM-CT1S	Unit 1 Siemens SGT6-5000 F(5)ee	CO_2 (5)	1,498,890
		CH_4 (5)	28
		N_2O (5)	3
		CO_2e	1,500,414
EM-CT2S	Unit 2 Siemens SGT6-5000 F(5)ee	CO_2 (5)	1,498,890
		CH_4 (5)	28
		N_2O (5)	3
		CO_2e	1,500,414
		Option 2	
EM-CT1S	Unit 1 GE 7FA.05	CO_2 (5)	1,283,747
		CH_4 (5)	24
		N_2O (5)	2
		CO_2e	1,285,052
EM-CT2S	Unit 2 GE 7FA.05	CO_2 (5)	1,283,747
		CH_4 (5)	24
		N_2O (5)	2
		CO_2e	1,285,052

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates
			TPY (4)
Ancillary Emissions			
EM-ABS	Auxiliary Boiler	CO_2 (5)	37,527
		CH_4 (5)	1
		N_2O (5)	<1
		CO_2e	37,566
EM-EDGV	Emergency Diesel Generator	CO_2 (5)	77
		CH_4 (5)	<1
		N_2O (5)	<1
		CO_2e	77
EM-DFPV	Diesel Firewater Pump	CO_2 (5)	16
		CH_4 (5)	<1
		N_2O (5)	<1
		CO_2e	16
EM-1&2NGF	Natural Gas Component Fugitives	CO_2 (5)	<1
		CH_4 (5)	1
		CO_2e	33
EM-SF6FUG	Circuit Breaker Insulation Fugitives	SF_6 (5)	<1
		CO_2e	23
EM-MSSFUG	Planned Maintenance Activities Fugitives	CO_2 (5)	<1
		CH_4 (5)	6
		CO_2e	143

(1) Emission point identification - either specific equipment designation or emission point number from plot plan.
(2) Specific point source name. For fugitive sources, use area name or fugitive source name.
(3) CO_2 - carbon dioxide
N_2O - nitrous oxide

Emission Sources - Maximum Allowable Emission Rates

CH_4 - methane
SF_6 - sulfur hexafluoride
CO_2e - carbon dioxide equivalents based on the following Global Warming Potentials (01/2015): CO_2 (1), N_2O (298), CH_4(25), SF_6 (22,800)

(4) Compliance with annual emission limits (tons per year) is based on a 12-month rolling period. These rates include emissions from maintenance, startup, and shutdown.
(5) Emission rate is given for informational purposes only and does not constitute enforceable limit.

Date: October, 2015

Special Conditions

Permit Number GHGPSDTX115

1. This permit covers only those sources of emissions listed in the attached table entitled "Emission Sources – Maximum Allowable Emission Rates (MAERT)," including planned maintenance, startup, and shutdown (MSS) activities, and those sources are limited to the emission limits on that table and other conditions specified in this permit.

Federal Applicability

2. These facilities shall comply with applicable requirements of the EPA regulations on Standards of Performance for New Stationary Sources, Title 40 Code of Federal Regulations Part 60 (40 CFR Part 60):

   A. Subpart A: General Provisions.

   B. Subpart TTTT: Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units, as adopted.

   If any condition of this permit is more stringent than the regulations so incorporated, then for the purposes of complying with this permit, the permit shall govern and be the standard by which compliance shall be demonstrated.

3. This permit authorizes two natural gas fired combustion turbines (CTGs) to operate in combined cycle [Emission Point Numbers (EPNs): EM-CT1S and EM-CT2S] from one of the following model options:

   A. Two Siemens Model SGT6-5000F (5)ee CTGs each rated at nominal capability of 231 gross megawatts (MW). Each CTG will have a duct fired heat recovery steam generator (HRSG) with a maximum heat input of 500 million British thermal units per hour (MMBtu/hr), operating as a combined cycle CTG.

   B. Two General Electric (GE) Model 7FA.05 CTGs each rated at nominal capability of 210 gross megawatts (MW). Each CTG will have a duct fired heat recovery steam generator (HRGS) with a maximum heat input of 349.2 million British thermal units per hour (MMBtu/hr), operating as a combined cycle CTG.

Emissions Standards and Operating Specifications

4. The combined cycle turbines (EPNs: EM-CT1S and EM-CT2S) during turbine load operations which may include duct burner and steam turbine contributions, shall not exceed the following limits based on a 12-month rolling average subject to the following specifications:

Turbine Model	Gross Heat Rate (Btu/kWh)	Output Specific CO_2 Emission Rate (lb CO_2/MWh)
Siemens	7,710	917
GE	7,415	882

Emissions associated with the activities listed below shall not be included in determining compliance with the performance standards listed above and shall be minimized through the application of work practices. Emissions during all operating modes shall not exceed the carbon dioxide equivalent (CO_2e) mass emission rates identified in the MAERT.

A. Each startup period shall not exceed four hours and shall be excluded. A startup period ends when the CTG output achieves steady operation in the low NO_x operating mode, and the selective catalytic reduction (SCR) and oxidation catalytic control systems achieve steady operation.

B. Each shutdown period shall not exceed one hour and shall be excluded. A shutdown period will begin when the CTG receives a shutdown command and the CTG operating level drops below its minimum sustainable load. The shutdown period ends when a flame detection signal is no longer recorded in the plant's control system.

C. Emissions from maintenance activities listed in Attachments A and B authorized in Permit Number 117026 are excluded.

5. During MSS operations each CTG (EPN: EM-CT1S and EM-CT2S) on a one-hour block shall not exceed the following:

Turbine Model	tons CO_2/hr
Siemens	156
GE	154

Auxiliary Boiler – Emission Limitations and Operating Specifications

6. The auxiliary boiler (EPN: EM-ABS) shall not exceed a maximum heat input of 73 MMBtu/hr.

7. The auxiliary boiler (EPN: EM-ABS) shall not exceed an annual heat input of 642,108 MMBtu/yr on a rolling 12-month average.

8. The auxiliary boiler (EPN: EM-ABS) tips and convection tubes shall be inspected annually and cleaned as needed.

9. An automated air/fuel control system shall be installed, operated, and maintained on the auxiliary boiler.

Maintenance

10. The Eagle Mountain facility (EPNs: EM-CT1S, EM-CT2S, EM-ABS, and EM-MSSFUG) is authorized a total annual blowdown volume of gas not to exceed 294,635 cubic feet per year.

Initial Determination of Compliance

11. After the first full calendar month of operation, the permit holder shall compare that month's gross heat rate and output specific CO_2 emission rate to the limits in Special Condition No. 4 and the MAERT. Within 45 days after collecting the data, the permit holder shall submit a report to the region identifying whether the data causes any concerns regarding the permit holder's ability to comply with the applicable limitations.

Continuous Demonstration of Compliance (CTGs)

12. The permit holder shall monitor and calculate natural gas fuel flow, electricity output, GHG emissions, and the average heat rate from each CTG and duct burner (DB) (EPNs: EM-CT1S and EM-CT2S) as specified in Special Condition Nos. 13 and 14.

13. Hourly Calculations

    A. Fuel Flow

        (1) The holder of this permit shall install, calibrate, maintain, and operate continuous fuel flow meters to measure and record, during all periods of operation, the hourly natural gas consumption of the CTGs and DBs (EPNs: EM-CT1S and EM-CT2S).

        (2) The fuel flow meters must meet the applicable requirements of 40 CFR Part 75, Appendix D and 40 CFR Part 60.

        (3) The fuel flow meter must be accurate to ± 2.0 percent of the unit's maximum flow.

        (4) The fuel flow data must be automatically recorded with a data acquisition and handling system.

    B. Heat Input

        (1) During all periods of operation calculate the hourly heat input in MMBtu/hr, consistent with Equation F-20 and the procedures for determining the HHV, in 40 CFR Part 75, Appendix F, Section 5.5.2.

        (2) The fuel supply shall be sampled and analyzed for HHV monthly.

    C. Carbon Dioxide (CO_2) Emission Rate

        (1) Calculate the hourly CO_2 emission rate in short tons per hour, during all periods of operation.

        (2) Calculate the CO_2 emission rate in accordance with 40 CFR Part 75, Appendix G, section 2.3, Equation G-4, using:

            (a) the default emission factor of 118.9 lb CO_2/MMBtu based on using a F-factor of 1,040 scf/MMBtu; or

(b) a custom emission factor determined in accordance with 40 CFR Part 75, Appendix F, section 3.3.6, Equation F-7b.

D. Gross Electrical Output

(1) Measure and record the hourly gross output (MWh) from each CTG/HRSG on an hourly basis.

(2) The hourly gross electrical output for the steam turbine generator shall be apportioned to each CTG/HRSG based on the hourly proportion of each HRSG's thermal output to the steam generator.

E. Heat Rate

(1) Calculate the hourly heat rate in Btu/kWh by dividing the hourly heat input by the corresponding gross electrical output.

(2) Exclude periods of MSS and reduced load operations as specified in Special Condition No. 4 in the permit and Attachments A and B of Permit No. 117026.

F. Output Specific CO_2 Emission Rate

(1) Calculate the output-specific CO_2 emission rate in lb CO_2/MWh by dividing the hourly CO_2 emission rate by the corresponding hourly gross output in MWh of the CTG/HRSG.

(2) Exclude periods of MSS as specified in Special Condition No. 4 of this permit and Attachments A and B of Permit No. 117026.

G. Methane (CH_4) and Nitrous Oxide (N_2O) Emissions

(1) Calculate the CH_4 and N_2O emission rates in short tons per hour during all periods of operation, using the following:

(a) Measured hourly heat input; and

(b) default emission factors Table C-2 of 40 CFR Part 98, Subpart A.

H. CO_2e Emission Rate

(1) CO_2e emission rate, in short tons per hour, equals the sum of the CO_2 emissions and the CO_2e-converted emissions of CH_4 and N_2O. Include all periods of operation.

(2) The CH_4 and N_2O emission rates are converted to CO_2e emissions using the Global Warming Potentials of 25 for CH_4 and 298 for N_2O, from Table A-1 of 40 CFR Part 98, Subpart A, version effective January 1, 2015.

14. Compiling 12-month Rolling Data

A. Average heat rate and output-specific CO_2 emissions to show compliance with the limits of Special Condition No. 4 are calculated using the following:

(1) Gross Heat Rate

(a) Monthly heat rate is the sum of the hourly heat input for the month, excluding periods of MSS, divided by the sum of the hourly gross output for the same hourly periods.

(b) At the end of each calendar month, add the monthly heat input to the monthly heat input for the preceding 11 operating months and divide the resulting sum by the gross output in kWh for the same period.

(2) Output-specific CO_2 Emissions

(a) Monthly output-specific CO_2 emissions are the sum of the hourly CO_2 emissions for the month, excluding periods of MSS, divided by the sum of the hourly gross output for the same hourly periods.

(b) At the end of each calendar month, add the monthly CO_2 emissions to the monthly CO_2 emissions for the preceding 11 months and divide the resulting sum by the gross output in MWh for the same period.

B. Emissions of CO_2, CH_4, N_2O, and CO_2e in tons per year to show compliance with the limits of the MAERT.

(1) Monthly emissions are the sum of the hourly emissions for that month and include all periods of operation.

(2) At the end of each calendar month, add the monthly emissions to the monthly emissions for the previous 11 months.

Continuous Demonstration of Compliance (Auxiliary Boiler)

15. The holder of this permit shall install, calibrate, maintain, and operate a continuous fuel flow meter to measure and record the hourly natural gas consumption of the auxiliary boiler.

A. The fuel flow meter must meet the applicable requirements of 40 CFR Part 75, Appendix D and 40 CFR Part 60.

B. The fuel flow meter must be accurate to ± 2.0 percent of the unit's maximum flow.

C. The fuel flow data must be automatically recorded with a data acquisition and handling system.

16. Auxiliary boiler calculations.

A. Calculate hourly and 12-month rolling GHG emissions from the auxiliary boiler, for all periods of operation, using the measured fuel flow and the equations (converting metric tons to short tons) in 40 CFR Part 98 as follows:

B. Equation C-1, for CO_2; and

C. Equation C-8, for CH_4 and N_2O.

Continuous Demonstration of Compliance (Circuit Breakers)

17. The sulfur hexafluoride (SF_6)-enclosed circuit breakers shall be designed to meet the latest American National Standards Institute (ANSI) C37.013 standard for high voltage circuit breakers. The circuit breakers must be guaranteed to achieve a SF_6 leak rate of 0.5% by weight or less annually. The circuit breakers must be in a totally enclosed, pressurized compartment equipped with an alarm that signals the plant control room in the event that any circuit breaker loses pressure to the extent that 10% of the SF_6 has leaked.

18. The permit holder shall equip the circuit breakers with a low pressure alarm and a low pressure lockout. As soon as practicable following the detection of a leak, plant personnel shall take one or more of the following actions:

    A. Locate and isolate the leak using a sulfur hexafluoride (SF_6) leak collections or containment system to control the leak until repair or replacement can be made if immediate repair is not possible.

    B. Commence repair or replacement of the leaking component.

Continuous Demonstration of Compliance (Natural Gas Fugitives)

19. The permit holder shall minimize emissions from pressurized components and equipment containing natural gas as follows:

    A. Piping and valves in natural gas service installed in association with the facilities authorized by this permit must be checked each calendar month for leaks using audio, visual, and olfactory (AVO) sensing for natural gas leaks. If the site is not manned for a given month, an AVO check shall be performed within one week after plant personnel return to the site for the purpose of operating the facilities authorized by this permit.

    B. As soon as practicable following the detection of a leak, plant personnel shall take one or more of the following actions:

        (1) Locate and isolate the leak, if necessary.

        (2) Commence repair or replacement of the leaking component.

        (3) Use a leak collection or containment system to control the leak until repair or replacement can be made if immediate repair is not possible.

Recordkeeping Requirements

20. The following records shall be kept at the plant for the life of the permit. All records required in this permit shall be made available at the request of personnel from the TCEQ, EPA, or any air pollution control agency with jurisdiction:

    A. A copy of this permit.

B. Permit application dated November 18, 2014, and subsequent representations submitted to the TCEQ.

21. The following information shall be maintained by the holder of this permit in a form suitable for inspection for a period of five years after collection and shall be made available upon request to representatives of the TCEQ, EPA, or any local air pollution control program having jurisdiction:

A. Records of fuel usage on an hourly and 12-month rolling average for the combustion turbines, duct burner, and auxiliary boiler.

B. Records of calibrations, preventative maintenance, and/or repairs performed on fuel gas flow meters.

C. For the combustion turbines, records of the following:

(1) Hourly electricity generation in MW, kept hourly, monthly, and 12-month rolling average, including the MW generated from the steam turbine and its apportionment to the appropriate CTG.

(2) Hours of operation, identifying startup and shutdown periods.

(3) Monthly averages of CH_4, N_2O, CO_2, and CO_2e hourly, monthly, and on a 12-month rolling average.

(4) Monthly averages of lb CO_2/MWh on a 12-month rolling average.

(5) Records of monthly sampling of natural gas HHV determinations.

D. For the auxiliary boiler, records of the following:

(1) Hours of operation.

(2) CH_4, N_2O, CO_2 and CO_2e emission rates on an hourly and rolling 12 month basis.

(3) Records of annual inspections, cleaning, replacement/repair of the boiler tips and convection tubes.

(4) Records of calibrations, maintenance and repair/replacement of the air/fuel system.

E. For the Circuit Breakers, records of the following:

(1) Records of maintenance or leak repair performed on SF_6 containing circuit breakers.

(2) Records of monthly and 12-month rolling average of SF_6 emissions to demonstrate compliance with the MAERT.

Preliminary Determination Summary

Eagle Mountain Power Company LLC
Permit Number GHGPSDTX115

I. Applicant

Eagle Mountain Power Company LLC
1601 Bryan St
Dallas, Texas 75201-3401

II. Project Location

Eagle Mountain Steam Electric Station
10029 Morris Dido Newark Rd
Tarrant County
Fort Worth, Texas 76179

III. Project Description

Eagle Mountain Power Company LLC (EMPC) is proposing to construct an electric generating facility near Fort Worth, Tarrant County, Texas. The Eagle Mountain Steam Electric Station (EMSES) will include two natural gas-fired combined cycle combustion turbine generators (CTG) equipped with heat recovery steam generators (HRSG), natural gas-fired dry low NO_x (DLN) combustors, and natural gas-fired duct burner systems. Ancillary equipment includes natural gas piping and metering equipment, a natural gas-fired auxiliary boiler, a diesel emergency generator, a diesel firewater pump engine, and circuit breakers.

Combustion Turbine and Heat Recovery Steam Generator

The facility will consist of either two General Electric (GE) 7FA.05 gas fired combustion turbines nominally rated at 210 megawatts (MW), or two Siemens SGT6-5000F(5)ee gas fired combustion turbines nominally rated at 231 megawatts (MW). Either model chosen will be equipped with a HRSG and DB with a maximum design capacity of 349 million British thermal units per hour (MMBtu/hr). The gross nominal output of the CTG with a HRSG and Duct Burners (DB) is 310 MW for the GE configuration and 350 MW for the Siemens configuration.

Natural Gas Piping Fugitives

Natural gas will be delivered to the site via pipeline and then metered and piped to the combustion turbines. The piping and fittings associated with the pipeline will be sources of fugitive emissions.

Auxiliary Boiler

The auxiliary boiler will have a maximum heat input of 73.3 MMBtu/hr and will be limited to brief periods of time between startups and shutdowns, as well as during startup to allow for shorter startup times. The boiler may also be used to prevent freezing of equipment during cold weather conditions.

Diesel-Fired Emergency Generator

The 1,340-hp diesel-fired emergency generator will be installed to provide electricity to the station in case of power failure. It will be limited to 100 hours of non-emergency operation per year.

Diesel-Fired Firewater Pump

The 282-hp diesel fired fire water pump will be installed in case of fire and will be limited to 100 hours of non-emergency operation per year.

Maintenance, Startup and Shutdown (MSS)

Planned MSS activities are authorized in Permit Number 117026, identified in Attachment A, and are quantified on the Maximum Allowable Emission Rate Table (MAERT) as Emission Point Number (EPN): EM-MSSFUG. One maintenance activity (total annual blowdown) has an emission limitation quantified in the Special Conditions of this permit.

IV. Greenhouse Gas (GHG) Emissions

The total emission rate is the sum of the CTG, auxiliary boiler, natural gas piping fugitives, emergency generator, diesel-fired firewater pump, planned maintenance activities, and circuit breakers. The carbon dioxide equivalents (CO_2e) are based on the following Global Warming Potentials (1/2015): (CO_2) (1), (N_2O) (298), (CH_4) (25), and (SF_6) (22,800).

Air Contaminant	Current Allowable Emission Rates (tpy)	Proposed Change in Allowable Emission Rates (tpy)*
SF_6	-	<1
N_2O	-	9
CH_4	-	66
CO_2	-	3,035,403
CO_2e	-	3,038,686

*Emissions in this table represent the worst case scenario of the two proposed turbine options.

V. Federal Applicability

The proposed project triggers PSD review for non-GHG NSR regulated pollutants. As shown in the table below, because the project increase is more than 75,000 tpy of CO2e, PSD review is triggered for GHG emissions. The worst case emission rate from the two turbine models was chosen for this demonstration. The total includes MSS emissions.

Pollutant	Project Emissions (tpy)	Major Source or Major Mod Trigger Level (tpy)	PSD Triggered Y/N
CO_2e	3,038,686	75,000	Y

VI. Control Technology Review

Emissions sources of GHG from the proposed project consist of the CTG, auxiliary boiler, natural gas piping fugitives, emergency generator, diesel-fired firewater pump, planned maintenance activities, and circuit breakers. As shown on the MAERT, the majority of GHG emissions are from the combustion sources, mainly the CTG, DBs, and auxiliary boiler. These sources account for approximately 99.9% of the GHG emissions. Emissions of CO_2 comprise 99.8% of the total annual tons of GHG pollutants (CO_2, CH_4, N_2O, and SF_6) as CO_2e.

EMPC conducted a BACT analysis that was reviewed and verified by the TCEQ. It included the identification and evaluation of add-on controls, energy efficient processes/practices, equipment design, and available control options for the turbine, auxiliary boiler, natural gas fugitives, emergency generator, diesel-fired firewater pump and SF_6 insulated equipment. The evaluation included information from the Environmental Protection Agency's (EPA's) RACT/BACT/LAER Clearinghouse (RBLC), on-going permitting in Texas and other states. Only facilities that emit GHGs are in the BACT discussion below.

Carbon Capture and Storage (CCS) was the only add-on pollution control technology that EMPC evaluated in the course of their BACT analysis. CCS systems involve the use of adsorption or absorption processes to remove CO_2 from flue gas, with subsequent desorption to produce a concentrated CO_2 stream. The three main capture technologies for CCS are pre-combustion capture, post-combustion capture, and oxy-fuel combustion. Pre-combustion control is currently applicable primarily to gasification plants and is not currently available to power plants. Oxy-fuel combustion has not yet reached commercial deployment for gas turbine applications. Finally, the third approach, post-combustion control, is not a technically feasible technology to be applied to power plants due to the need for amine absorption in considerably larger flow volumes than are readily available. The last barrier for CCS technology is the lack of sequestration sites currently in operation. Several geologic formations are currently being surveyed and studied in Texas, but no injection sites are currently operational in the state.

The capture and compression equipment associated with CCS would have cost impacts based on the installation of additional process equipment *(e.g. amine units, cryogenic units, dehydration unit, and compression facilities)*. In addition, power/energy must be provided for the additional combustion unit, and/or increase the parasitic load on the proposed facilities which significantly reduces the net heat rate (efficiency) of the plant. This would result in increases in GHG emissions, as well as criteria pollutants, per megawatt of net electricity produced. Based on the excessive costs and additional negative environmental impacts, CCS was eliminated as a control option for the proposed project.

Consistent with the RBLC, turbine GHGPSD permits issued by EPA and TCEQ and the turbine GHGPSD permits currently being reviewed by TCEQ, the following GHG control technologies and/or work practices are BACT:

Turbines

GHG Emissions – A worst case emission rate of pound carbon dioxide per megawatt hour (lb CO_2/MWh) of 917 represents BACT. This emission rate is within the proposed EPA limit of 1000 lb CO_2/MWh in accordance with 40 CFR Part 60 Subpart TTTT.

Fuel Selection - Natural gas has the lowest GHG emission factor of all available turbine fuel sources.

Turbine design – Good turbine design maximizes thermal efficiency.

Waste Heat Recovery – A HRSG is utilized to recover what would otherwise be waste heat lost to the atmosphere in the turbine exhaust. The recovered heat can be used to produce steam to power a steam turbine which in turn generates additional electricity without the further combustion of natural gas. The reduction in fuel necessary to generate electricity because of heat recovery leads to greater unit efficiency and lower emissions.

HRSG design - Efficient design of the HRSG improves overall thermal efficiency.

Auxiliary Boiler

Operational Limitation/Fuel – The boiler will fire natural gas which has the lowest GHG emission factor of all available fossil fuels, will be limited to a firing rate of 73 MMBtu/hr, and shall meet an annual heat input of 642,108 MMBtu/yr on a rolling 12-month average.

Other Emission Sources

Natural Gas Process Fugitives – Fugitive GHG emissions will be calculated for all natural gas piping components on an annual basis to demonstrate compliance with the annual GHG emissions limit. GHG emissions will be calculated using emissions factors contained in EPA's Mandatory Reporting of GHG Rule, 40 CFR Part 98, Table W-1A, Default Whole Gas Emissions Factors for Onshore Petroleum and Natural Gas Production. GHG emissions from natural gas piping components will be calculated on an annual basis.

Leak detection and repair programs are potentially applicable and available although natural gas piping fugitive CO_2e emissions are less than 0.01% of the project total. Hand-held analyzers, remote sensing and audio, visual, and olfactory (AVO) detection methods are among the possible control methods. Based on the very small amount of emissions, the least costly of these methods, AVO programs, have been required in recent GHG permits and will be required of EMPC on a periodic basis consistent with the conditions of the permit.

Diesel-Fired Emergency Engines - EMPC proposes a maximum annual CO_2e emissions limit of approximately 77 tpy for the emergency generator and 16 tpy for the firewater pump based on minimal operation scenarios. Good combustion practices will include complying with manufacturers recommended operation and maintenance procedures. Compliance with NSPS Subpart IIII will demonstrate efficient engine design.

SF_6 Electrical Equipment – The use of circuit breakers with totally enclosed insulation systems equipped with a low pressure alarm and low pressure lockout is BACT.

Maintenance, Startup, and Shutdown

Operation of the combustion turbine will result in emissions from startup and shutdown. The combustion turbine will be started up and shut down in a manner that minimizes the emissions during these events. BACT will be achieved by minimizing the duration of the startup and shutdown events and meeting the normal operating emission rates listed on the MAERT. The duration of each startup is limited to 4 hours and the duration of each shutdown is limited to 1 hour.

Maintenance activities are authorized in Permit Number 117026. Gaseous fuel venting is the one maintenance activity that contributes to CO_2e; therefore, there is an annual blowdown volume of gas quantified in this permit. The emissions of CO_2 from turbines are entirely from the combusting of fuel. Therefore, during MSS activities the turbines are an inherently low emitting source of GHG. Given the nature of these emissions no control is BACT.

VII. Air Quality Analysis

EPA has stated that unlike the criteria pollutants for which EPA has historically issued PSD permits, there is no National Ambient Air Quality Standard (NAAQS) for GHGs, including no PSD increment. The global climate-change inducing effects of GHG emissions, according to the "Endangerment and Cause or Contribute Finding", are far-reaching and multi-dimensional (75 FR 66497). Climate change modeling and evaluations of risks and impacts are typically conducted for changes in emissions that are orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible [EPA's PSD and Title V Permitting Guidance for GHGs at 48]. Thus, EPA has concluded in other GHG PSD permitting actions it would not be meaningful to evaluate impacts of GHG emissions on a local community in the context of a single permit.

The TCEQ has determined that an air quality analysis would provide no meaningful data and has not required the applicant to perform one. As stated in the preamble to TCEQ's adoption of the GHG PSD program, the impacts review for individual air contaminants will continue to be addressed, as applicable, in the state's traditional minor and major NSR permits program per 30 TAC Chapter 116.

VIII. Conclusion

EMPC has demonstrated that this project meets all applicable rules, regulations and requirements of the Texas and Federal Clean Air Acts. The proposed facility controls and combustion practices represent BACT.

The Executive Director of the TCEQ proposes a preliminary determination of issuance of this permit for EMPC to construct the electric power generating facilities and the associated support facilities, as proposed.