Luminant

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September 10, 2014

Mr. Jeff Robinson
Chief, Air Permits Section
U.S. Environmental Protection Agency Region 6, 6PD
1445 Ross Avenue, Suite 1200
Dallas, Texas 75202-2733

Subject: **Application for Approval of Greenhouse Gas Emissions BACT Combined Cycle Combustion Turbine Units Eagle Mountain Power Company LLC (Texas CN 604515361) Eagle Mountain Steam Electric Station (Texas RN100693308)**

Dear Sir/Madam:

On behalf of Eagle Mountain Power Company LLC (EMPC), Luminant Generation Company LLC (Luminant) is submitting the enclosed application for Best Available Control Technology (BACT) review in support of EMPC's Non-Attainment New Source Review (NNSR) and Prevention of Significant Deterioration (PSD) application, currently pending with the Texas Commission on Environmental Quality (TCEQ), for authorization to construct and operate the referenced project to be located in Tarrant County, Texas. The preconstruction air permit application for criteria pollutant emissions and other air contaminants associated with this project was submitted to the TCEQ on January 23, 2014. A copy of that application was also provided to EPA Region 6 at that time.

EMPC began preparation of this application prior to the June 23, 2014 U.S. Supreme Court decision affecting the Environmental Protection Agency (EPA) Tailoring Rule (UARG decision), which, prior to the Court's ruling, established applicability requirements for PSD permitting of GHG emissions. Recognizing that changes to the EPA GHG permitting requirements are probable, but also understanding that the full import and implications of the UARG decision for EMPC's proposed project are still uncertain, EMPC has elected to submit this application without substantive revisions that might be appropriate following the UARG decision. To move forward with the permitting of the project during this time of legal uncertainty, the enclosed application may contain information that is reflective of EPA requirements regarding EMPC GHG permitting obligations that were in place prior to the UARG decision (but are now altered by that decision), or information that proves to be superfluous. In any case, the enclosed submittal requesting GHG BACT review for the EMPC project is consistent with guidance issued to the EPA Regional Offices by Ms. Janet G. McCabe on July 24, 2014 ("Next Steps and Preliminary Views on the Application of Clean Air Act Permitting Programs to Greenhouse Gases Following the Supreme Court's Decision in *Utility Air Regulatory Group v. Environmental Protection Agency*"). As the legal requirements clarify, EMPC will work the reviewing agency to clarify and revise application content, as appropriate and necessary.

If you have questions regarding this permit application, please contact Mr. Paul Coon of my staff at (214) 875-8376.

Sincerely,

David P. Duncan

David P. Duncan
Director, Environmental Generation

Attachment

cc: Mr. Mike Wilson, PE, TCEQ Air Permits Division, Austin, Texas
Mr. Tony Walker, Regional Director, TCEQ Region 4, Fort Worth
Mr. T.C. Michael, Air Program Manager,
Department of Environmental Management, City of Fort Worth

PREVENTION OF SIGNIFICANT DETERIORATION GREENHOUSE GAS PERMIT APPLICATION FOR A COMBINED CYCLE POWER PLANT AT THE EAGLE MOUNTAIN STEAM ELECTRIC STATION TARRANT COUNTY, TEXAS

SUBMITTED TO:

U.S. ENVIRONMENTAL PROTECTION AGENCY
REGION 6
MULTIMEDIA PLANNING AND PERMITTING DIVISION
FOUNTAIN PLACE 12TH FLOOR, SUITE 1200
1445 ROSS AVENUE
DALLAS, TEXAS 75202-2733

SUBMITTED BY:

EAGLE MOUNTAIN POWER COMPANY LLC
1601 BRYAN STREET
DALLAS, TEXAS 75201

PREPARED BY:

ZEPHYR ENVIRONMENTAL CORPORATION
TEXAS REGISTERED ENGINEERING FIRM F-102
2600 VIA FORTUNA, SUITE 450
AUSTIN, TEXAS 78746

SEPTEMBER 2014

zephyr

TABLE OF CONTENTS

1.0 INTRODUCTION

Eagle Mountain Power Company LLC (EMPC) is hereby submitting this application for a Greenhouse Gas (GHG) Best Available Control Technology (BACT) review/Prevention of Significant Deterioration (PSD) air quality permit to construct and operate two new combined cycle combustion turbine electric generating units and a single common steam turbine generator (the "Project") at the Eagle Mountain Steam Electric Station (EMSES), located approximately 4 miles east-northeast from the City of Azle in Tarrant County, Texas. The new, high efficiency, combined cycle units will replace the lower efficiency, natural gas-fired electric generation boilers, the 123-MW Unit 1, the 188-MW Unit 2, and the 396-MW Unit 3, which have previously been retired, and will provide power in the Electric Reliability of Council of Texas (ERCOT) market. To the extent practicable, the proposed Project will make use of existing plant infrastructure, including the existing cooling water system.

The proposed Project will consist of two natural gas-fired combustion turbines, each exhausting to its respective heat recovery steam generator (HRSG), served with duct firing, to produce steam to drive a shared steam turbine. Two combustion turbine models are being considered: the General Electric 7FA.05, with a nominal baseload electric power output of approximately 210 MW at ISO conditions, and the Siemens SGT6-5000F(5)ee, with a nominal baseload electric power output of approximately 231 MW at ISO conditions. The nominal electric power output from the steam turbine will be approximately 310 MW for the GE configuration and 350 MW for the Siemens configuration. Final selection of the turbine model will likely not to be made until after the permit is issued.

The state and Non-Attainment New Source Review (NNSR)/PSD air permit application for non-GHG pollutants was received by the Texas Commission on Environmental Quality (TCEQ) on January 27, 2014.

On June 3, 2010, the EPA published final rules for permitting sources of GHGs under the PSD and Title V air permitting programs, known as the GHG Tailoring Rule.[1] Under the Tailoring Rule, after July 1, 2011, new sources with the potential to emit more than 100,000 tons/yr of GHGs and modifications increasing GHG emissions more than 75,000 tons/yr on a carbon dioxide equivalent (CO_2e) basis at existing major sources are subject to GHG PSD review, regardless of whether PSD was triggered for other pollutants.

Under the Tailoring Rule, the EMPC project for construction of the combined cycle combustion turbine units triggers PSD review for GHG regulated pollutants because the potential to emit from the Project exceeds 100,000 tons/yr of GHG emissions. This application includes a Project scope description, GHG emissions calculations, and a GHG Best Available Control Technology (BACT) analysis.

[1] 75 FR 31514 (June 3, 2010).

In a June 23, 2014 opinion, the U.S. Supreme Court ruled that aspects of the Tailoring Rule are not authorized by the Clean Air Act (UARG decision). Since then, EPA has provided some preliminary guidance pertaining to the changes warranted by the UARG decision but is continuing to evaluate how to address GHG BACT decision-making in furtherance of this decision. EMPC began preparation of this application prior to the UARG decision affecting the Tailoring Rule that, prior to the Court's ruling, established applicability requirements for PSD permitting of GHG emissions. Recognizing that changes to the EPA GHG permitting requirements are probable but also understanding that the full import and implications of the UARG decision for EMPC's proposed Project are still uncertain, EMPC has elected to submit this application without substantive revisions that might be appropriate following the UARG decision. To move forward with the permitting of the Project during this time of legal uncertainty, this application may contain information that is reflective of EPA requirements regarding EMPC GHG permitting obligations that were in place prior to the UARG decision (but are now altered by that decision), or information that now proves to be superfluous. In any case, this application requesting GHG BACT review for the EMPC project is consistent with guidance issued by the EPA to date.

Texas Commission on Environmental Quality
Form PI-1 General Application for Air Preconstruction Permit and Amendment

Important Note: The agency requires that a Core Data Form be submitted on all incoming applications unless a Regulated Entity and Customer Reference Number have been issued and no core data information has changed. For more information regarding the Core Data Form, call (512) 239-5175 or go to www.tceq.texas.gov/permitting/central_registry/guidance.html.

I. Applicant Information		
A. Company or Other Legal Name: Eagle Mountain Power Company LLC		
Texas Secretary of State Charter/Registration Number (if applicable):		
B. Company Official Contact Name: David P. Duncan		
Title: Director, Environmental Generation		
Mailing Address: 1601 Bryan Street		
City: Dallas	State: TX	ZIP Code: 75201
Telephone No.: 214-875-8647	Fax No.: 214-875-8699	E-mail Address: david.duncan@luminant.com
C. Technical Contact Name: Paul Coon		
Title: Air Permitting Manager, Environmental Services		
Company Name: Luminant Generation Company LLC		
Mailing Address: 1601 Bryan Street		
City: Dallas	State: TX	ZIP Code: 75201
Telephone No.: 214-875-8376	Fax No.: 214-875-8699	E-mail Address: paul.coon@luminant.com
D. Site Name: Eagle Mountain Steam Electric Station		
E. Area Name/Type of Facility: Electric Utility		☒ Permanent ☐ Portable
F. Principal Company Product or Business: Electric Generation		
Principal Standard Industrial Classification Code (SIC): 4911		
Principal North American Industry Classification System (NAICS): 221112		
G. Projected Start of Construction Date: 01/01/2015		
Projected Start of Operation Date: 06/01/2017		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: 10029 Morris Dido Newark Road		
City/Town: Fort Worth	County: Tarrant	ZIP Code: 76179
Latitude (nearest second): 32°54'24.33"N	Longitude (nearest second): 97°28'49.31"W	

I.	**Applicant Information (continued)**	
I.	Account Identification Number (leave blank if new site or facility): TA-0352-I	
J.	Core Data Form.	
Is the Core Data Form (Form 10400) attached? If No, provide customer reference number and regulated entity number (complete K and L).		☐ YES ☒ NO
K.	Customer Reference Number (CN): CN604515361	
L.	Regulated Entity Number (RN): RN100693308	
II.	**General Information**	
A.	Is confidential information submitted with this application? If Yes, mark each confidential page confidential in large red letters at the bottom of each page.	☐ YES ☒ NO
B.	Is this application in response to an investigation, notice of violation, or enforcement action? If Yes, attach a copy of any correspondence from the agency and provide the RN in section I.L. above.	☐ YES ☒ NO
C.	Number of New Jobs: Approximately 30	
D.	Provide the name of the State Senator and State Representative and district numbers for this facility site:	
State Senator: Jane Nelson		District No.: 12
State Representative: Charlie Geren		District No.: 99
III.	**Type of Permit Action Requested**	
A.	Mark the appropriate box indicating what type of action is requested.	
☒ Initial ☐ Amendment ☐ Revision (30 TAC 116.116(e) ☐ Change of Location ☐ Relocation		
B.	Permit Number (if existing):	
C.	Permit Type: Mark the appropriate box indicating what type of permit is requested. *(check all that apply, skip for change of location)*	
☐ Construction ☐ Flexible ☐ Multiple Plant ☐ Nonattainment ☐ Plant-Wide Applicability Limit		
☒ Prevention of Significant Deterioration ☐ Hazardous Air Pollutant Major Source		
☐ Other:		
D.	Is a permit renewal application being submitted in conjunction with this amendment in accordance with 30 TAC 116.315(c).	☐ YES ☒ NO

Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment

III. Type of Permit Action Requested *(continued)*		
E. Is this application for a change of location of previously permitted facilities? If Yes, complete III.E.1 - III.E.4.0		☐ YES ☒ NO
1. Current Location of Facility (If no street address, provide clear driving directions to the site in writing.):		
Street Address:		
City:	County:	ZIP Code:
2. Proposed Location of Facility (If no street address, provide clear driving directions to the site in writing.):		
Street Address:		
City:	County:	ZIP Code:
3. Will the proposed facility, site, and plot plan meet all current technical requirements of the permit special conditions? If "NO", attach detailed information.		☐ YES ☐ NO
4. Is the site where the facility is moving considered a major source of criteria pollutants or HAPs?		☐ YES ☐ NO
F. Consolidation into this Permit: List any standard permits, exemptions or permits by rule to be consolidated into this permit including those for planned maintenance, startup, and shutdown.		
List: none		
G. Are you permitting planned maintenance, startup, and shutdown emissions? If Yes, attach information on any changes to emissions under this application as specified in VII and VIII.		☒ YES ☐ NO
H. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) Is this facility located at a site required to obtain a federal operating permit? If Yes, list all associated permit number(s), attach pages as needed).		☐ YES ☐ NO ☒ To be determined
Associated Permit No (s.):		
1. Identify the requirements of 30 TAC Chapter 122 that will be triggered if this application is approved.		
☐ FOP Significant Revision	☐ FOP Minor	☐ Application for an FOP Revision
☐ Operational Flexibility/Off-Permit Notification		☐ Streamlined Revision for GOP
☒ To be Determined		☐ None

Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment

III. Type of Permit Action Requested *(continued)*		
H. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) *(continued)*		
2. Identify the type(s) of FOP(s) issued and/or FOP application(s) submitted/pending for the site. ***(check all that apply)***		
☐ GOP Issued	☐ GOP application/revision application submitted or under APD review	
☐ SOP Issued	☐ SOP application/revision application submitted or under APD review	
IV. Public Notice Applicability		
A. Is this a new permit application or a change of location application?		☒ YES ☐ NO
B. Is this application for a concrete batch plant? If Yes, complete V.C.1 – V.C.2.		☐ YES ☒ NO
C. Is this an application for a major modification of a PSD, nonattainment, FCAA 112(g) permit, or exceedance of a PAL permit?		☐ YES ☒ NO
D. Is this application for a PSD or major modification of a PSD located within 100 kilometers or less of an affected state or Class I Area?		☐ YES ☒ NO
If Yes, list the affected state(s) and/or Class I Area(s).		
List:		
E. Is this a state permit amendment application? If Yes, complete IV.E.1. – IV.E.3.		
1. Is there any change in character of emissions in this application?		☐ YES ☐ NO
2. Is there a new air contaminant in this application?		☐ YES ☐ NO
3. Do the facilities handle, load, unload, dry, manufacture, or process grain, seed, legumes, or vegetables fibers (agricultural facilities)?		☐ YES ☐ NO
F. List the total annual emission increases associated with the application ***(List all that apply and attach additional sheets as needed):***		
Volatile Organic Compounds (VOC):		
Sulfur Dioxide (SO2):		
Carbon Monoxide (CO):		
Nitrogen Oxides (NOx):		
Particulate Matter (PM):		
PM 10 microns or less (PM10):		
PM 2.5 microns or less (PM2.5):		
Lead (Pb):		
Hazardous Air Pollutants (HAPs):		
Other speciated air contaminants not listed above: CO2e: 3,038,547 tpy		

Texas Commission on Environmental Quality
Form PI-1 General Application for Air Preconstruction Permit and Amendment

TCEQ

V. Public Notice Information *(complete if applicable)*		
A. Public Notice Contact Name: Paul Coon		
Title: Air Permitting Manager, Environmental Services		
Mailing Address: 1601 Bryan St.		
City: Dallas	State: TX	ZIP Code: 75201
B. Name of the Public Place: N/A		
Physical Address *(No P.O. Boxes)*:		
City:	County:	ZIP Code:
The public place has granted authorization to place the application for public viewing and copying.		☐ YES ☐ NO
The public place has internet access available for the public.		☐ YES ☐ NO
C. Concrete Batch Plants, PSD, and Nonattainment Permits		
1. County Judge Information (For Concrete Batch Plants and PSD and/or Nonattainment Permits) for this facility site.		
The Honorable: B. Glen Whitley		
Mailing Address: 100 E. Weatherford, Ste. 501		
City: Fort Worth	State: TX	ZIP Code: 76196
2. Is the facility located in a municipality or an extraterritorial jurisdiction of a municipality? ***(For Concrete Batch Plants)***		☐ YES ☐ NO
Presiding Officers Name(s):		
Title:		
Mailing Address:		
City:	State:	ZIP Code:
3. Provide the name, mailing address of the chief executive and Indian Governing Body; and identify the Federal Land Manager(s) for the location where the facility is or will be located.		
Chief Executive: Betsy Price, Mayor of Fort Worth		
Mailing Address: 1000 Throckmorton St.		
City: Fort Worth	State: TX	ZIP Code: 76102
Name of the Indian Governing Body: N/A		
Mailing Address:		
City:	State:	ZIP Code:

Texas Commission on Environmental Quality
Form PI-1 General Application for Air Preconstruction Permit and Amendment

V.	**Public Notice Information *(complete if applicable) (continued)***	
C.	Concrete Batch Plants, PSD, and Nonattainment Permits	
3.	Provide the name, mailing address of the chief executive and Indian Governing Body; and identify the Federal Land Manager(s) for the location where the facility is or will be located. *(continued)*	
Name of the Federal Land Manager(s):		
D.	Bilingual Notice N/A	
Is a bilingual program required by the Texas Education Code in the School District?		☐ YES ☐ NO
Are the children who attend either the elementary school or the middle school closest to your facility eligible to be enrolled in a bilingual program provided by the district?		☐ YES ☐ NO
If Yes, list which languages are required by the bilingual program?		
VI.	**Small Business Classification *(Required)***	
A.	Does this company (including parent companies and subsidiary companies) have fewer than 100 employees or less than $6 million in annual gross receipts?	☐ YES ☒ NO
B.	Is the site a major stationary source for federal air quality permitting?	☒ YES ☐ NO
C.	Are the site emissions of any regulated air pollutant greater than or equal to 50 tpy?	☒ YES ☐ NO
D.	Are the site emissions of all regulated air pollutants combined less than 75 tpy?	☐ YES ☒ NO
VII.	**Technical Information**	
A.	The following information must be submitted with your Form PI-1 ***(this is just a checklist to make sure you have included everything)***	
1.	☒ Current Area Map	
2.	☒ Plot Plan	
3.	☐ Existing Authorizations	
4.	☒ Process Flow Diagram	
5.	☒ Process Description	
6.	☒ Maximum Emissions Data and Calculations	
7.	☐ Air Permit Application Tables	
a.	☐ Table 1(a) (Form 10153) entitled, Emission Point Summary	
b.	☐ Table 2 (Form 10155) entitled, Material Balance	
c.	☐ Other equipment, process or control device tables	
B.	Are any schools located within 3,000 feet of this facility? N/A	☐ YES ☐ NO

Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment

VII.	**Technical Information**			
C.	Maximum Operating Schedule:			
Hour(s): 24 hrs/day	Day(s): 7 days/wk	Week(s): 52 wks/year	Year(s):	
Seasonal Operation? If Yes, please describe in the space provide below.				☐ YES ☒ NO
D.	Have the planned MSS emissions been previously submitted as part of an emissions inventory?			☐ YES ☒ NO
Provide a list of each planned MSS facility or related activity and indicate which years the MSS activities have been included in the emissions inventories. Attach pages as needed.				
E.	Does this application involve any air contaminants for which a disaster review is required?			☐ YES ☒ NO
F.	Does this application include a pollutant of concern on the Air Pollutant Watch List (APWL)?			☐ YES ☒ NO
VIII.	**State Regulatory Requirements** **Applicants must demonstrate compliance with all applicable state regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify state regulations; show how requirements are met; and include compliance demonstrations.*			
A.	Will the emissions from the proposed facility protect public health and welfare, and comply with all rules and regulations of the TCEQ?			☒ YES ☐ NO
B.	Will emissions of significant air contaminants from the facility be measured?			☒ YES ☐ NO
C.	Is the Best Available Control Technology (BACT) demonstration attached?			☒ YES ☐ NO
D.	Will the proposed facilities achieve the performance represented in the permit application as demonstrated through recordkeeping, monitoring, stack testing, or other applicable methods?			☒ YES ☐ NO
IX.	**Federal Regulatory Requirements** **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.*			
A.	Does Title 40 Code of Federal Regulations Part 60, (40 CFR Part 60) New Source Performance Standard (NSPS) apply to a facility in this application?			☒ YES ☐ NO
B.	Does 40 CFR Part 61, National Emissions Standard for Hazardous Air Pollutants (NESHAP) apply to a facility in this application?			☐ YES ☒ NO

IX.	**Federal Regulatory Requirements** **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.*	
C.	Does 40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard apply to a facility in this application?	☒ YES ☐ NO
D.	Do nonattainment permitting requirements apply to this application? N/A for GHG	☐ YES ☐ NO
E.	Do prevention of significant deterioration permitting requirements apply to this application?	☒ YES ☐ NO
F.	Do Hazardous Air Pollutant Major Source [FCAA 112(g)] requirements apply to this application?	☐ YES ☒ NO
G.	Is a Plant-wide Applicability Limit permit being requested?	☐ YES ☒ NO
X.	**Professional Engineer (P.E.) Seal**	
Is the estimated capital cost of the project greater than $2 million dollars? N/A		☐ YES ☐ NO
If Yes, submit the application under the seal of a Texas licensed P.E.		
XI.	**Permit Fee Information**	
Check, Money Order, Transaction Number ,ePay Voucher Number:		Fee Amount: N/A
Paid online? N/A		☐ YES ☐ NO
Company name on check: N/A		
Is a copy of the check or money order attached to the original submittal of this application?		☐ YES ☐ NO ☒ N/A
Is a Table 30 (Form 10196) entitled, Estimated Capital Cost and Fee Verification, attached?		☐ YES ☐ NO ☒ N/A

XII. Delinquent Fees and Penalties
This form will not be processed until all delinquent fees and/or penalties owed to the TCEQ or the Office of the Attorney General on behalf of the TCEQ is paid in accordance with the Delinquent Fee and Penalty Protocol. For more information regarding Delinquent Fees and Penalties, go to the TCEQ Web site at: www.tceq.texas.gov/agency/delin/index.html.
XIII. Signature
The signature below confirms that I have knowledge of the facts included in this application and that these facts are true and correct to the best of my knowledge and belief. I further state that to the best of my knowledge and belief, the project for which application is made will not in any way violate any provision of the Texas Water Code (TWC), Chapter 7, Texas Clean Air Act (TCAA), as amended, or any of the air quality rules and regulations of the Texas Commission on Environmental Quality or any local governmental ordinance or resolution enacted pursuant to the TCAA I further state that I understand my signature indicates that this application meets all applicable nonattainment, prevention of significant deterioration, or major source of hazardous air pollutant permitting requirements. The signature further signifies awareness that intentionally or knowingly making or causing to be made false material statements or representations in the application is a criminal offense subject to criminal penalties.
Name: David P. Duncan
Signature: David P. Duncan *Original Signature Required*
Date: September 10, 2014

2.0 PROJECT OVERVIEW AND DESCRIPTION

2.1 INTRODUCTION

With this application, EMPC is seeking greenhouse gas (GHG) emissions BACT review and authorization for a combined cycle electric generating project at EMSES. The power generating equipment and ancillary equipment that will be constructed as part of the Project and that are sources of GHG emissions at the site are summarized below:

- Two of the same model combined cycle, natural gas-fired combustion turbines equipped with dry low-NO_x (DLN) combustors
- Two natural gas-fired duct burner systems serving the two heat recovery steam generators (HRSGs) associated with the two combustion turbines
- Natural gas piping and handling and metering equipment
- A natural gas-fired auxiliary boiler
- A diesel fuel-fired emergency generator engine
- A diesel fuel-fired firewater pump engine
- Electrical equipment insulated with sulfur hexafluoride (SF_6).

A process flow diagram is included at the end of this section.

Pipeline natural gas is chosen as the only fuel for the combustion turbines and duct burner systems due to local availability of fuel and infrastructure to support delivery of the fuel to the facility in adequate volume and pressure.

2.2 COMBUSTION TURBINE GENERATORS AND HEAT RECOVERY STEAM GENERATORS

The combustion turbine generators (CTGs) will burn pipeline-quality natural gas to drive electrical generators. The main components of each CTG turbine consist of a compressor, combustor, turbine, and generator. The compressor pressurizes the inlet combustion air to the combustor where the fuel is mixed with the combustion air and burned. Hot exhaust gases then enter an expansion turbine section where the gases expand across the turbine blade, which produces torque that drives a shaft to power an electric generator. The temperature of the inlet air to the CTGs proposed for the Project may occasionally be lowered using evaporative cooling to increase the mass air flow through the turbines and achieve additional turbine power output on days with warm to hot ambient conditions.

One of two CTG models will be selected for the Project: the General Electric (GE) 7FA.05 design or the Siemens SGT6-5000F(5)ee design. The GE turbine has a nominal baseload electric power output of approximately 210 MW at ISO conditions, and the Siemens turbine has a nominal baseload electric power output of approximately 231 MW at ISO conditions. The final selection of the combustion turbine model will likely not be made until after the permit is issued. The exhaust gases from each combustion turbine train will be directed through their respective

HRSG, supplemented with a set of natural gas-fired duct burners. Each set of duct burners will have a maximum heat input capacity of approximately 349 MMBtu/hr higher heating value (HHV) in the GE configuration and 500 MMBtu/hr HHV in the Siemens configuration. The exhaust gases from the two HRSGs will be routed to the respective exhaust stacks (EPNs: EM-CT1S and EM-CT2S).

Steam produced by each of the two HRSGs will be routed to a single common steam turbine generator (STG), with a nominal electric power output of 310 MW for the GE configuration and 350 MW for the Siemens configuration. Electric power produced by the two combustion turbines and the common steam turbine will be sold on to the ERCOT power grid. The steam piping associated with each HRSG will include steam turbine bypass capability that facilitates faster combustion turbine and HRSG startup capability. Although the intended use of the proposed generating units is, primarily, to provide baseload power, the units may operate at reduced load, and operate for short periods of time, to respond to changes in electrical grid power requirements and/or stability.

2.3 CTG/HRSG STARTUP/SHUTDOWN ACTIVITIES

Planned startup and shutdown of the proposed combined cycle units (i.e., either or both of the two combustion turbines and their associated HRSG) will be part of the routine operations at the facility. The Project will consist of an optimized design for reducing the time required to ramp up the CT to a temperature where the DLN combustor and post-combustion control devices will be effective. The steam piping design includes bypass piping around the steam turbine for use during startup, which allows the HRSG to accommodate a more rapid combustion turbine startup and heat release, thereby reducing startup time. An auxiliary boiler will also supply auxiliary steam and will help facilitate shorter startups.

A planned startup for a combustion turbine is defined as the period beginning when the combustion turbine receives a "turbine start" signal and an initial flame detection signal is recorded in the plant's control system and ending when the combustion turbine output achieves steady operation in the low NO_X operating mode and the selective catalytic reduction and oxidation catalyst have achieved steady state operation, thereby achieving emissions compliance.

A planned shutdown period will begin when a combustion turbine receives a shutdown command and the combustion turbine operating level drops below its minimum sustainable load. A combustion turbine planned shutdown will end when a flame detection signal is no longer recorded in the plant's control system.

2.4 AUXILIARY BOILER

A natural gas-fired auxiliary boiler, rated at 73.3 MMBtu/hr, will be operated to provide auxiliary steam during brief periods of time between routine shutdowns/startups to allow for shorter startup duration, and during startups to provide steam to the steam turbine seals, the steam jet air ejector/hogging jets, the condenser deaerator spargers, and the HRSG steam spargers. In addition, the auxiliary boiler will provide auxiliary steam to prevent freezing of the sparging headers and the condenser deaerator in the event that HRSGs are not operating for extended durations during cold weather conditions.

Emissions from the auxiliary boiler will be exhausted through the stack, EPN: EM-ABS.

2.5 DIESEL-FIRED EMERGENCY EQUIPMENT

The site will be equipped with one nominally rated 1,340-hp diesel-fired emergency generator (EPN: EM-EDGV) to provide electricity to the facility in case of power failure. In addition, a nominally rated 282-hp diesel-fired water pump (EPN: EM-DFPV) will be installed at the site to provide water in the event of a fire. Each emergency engine will be limited to 100 hours of non-emergency operation per year for purposes of maintenance checks and readiness testing.

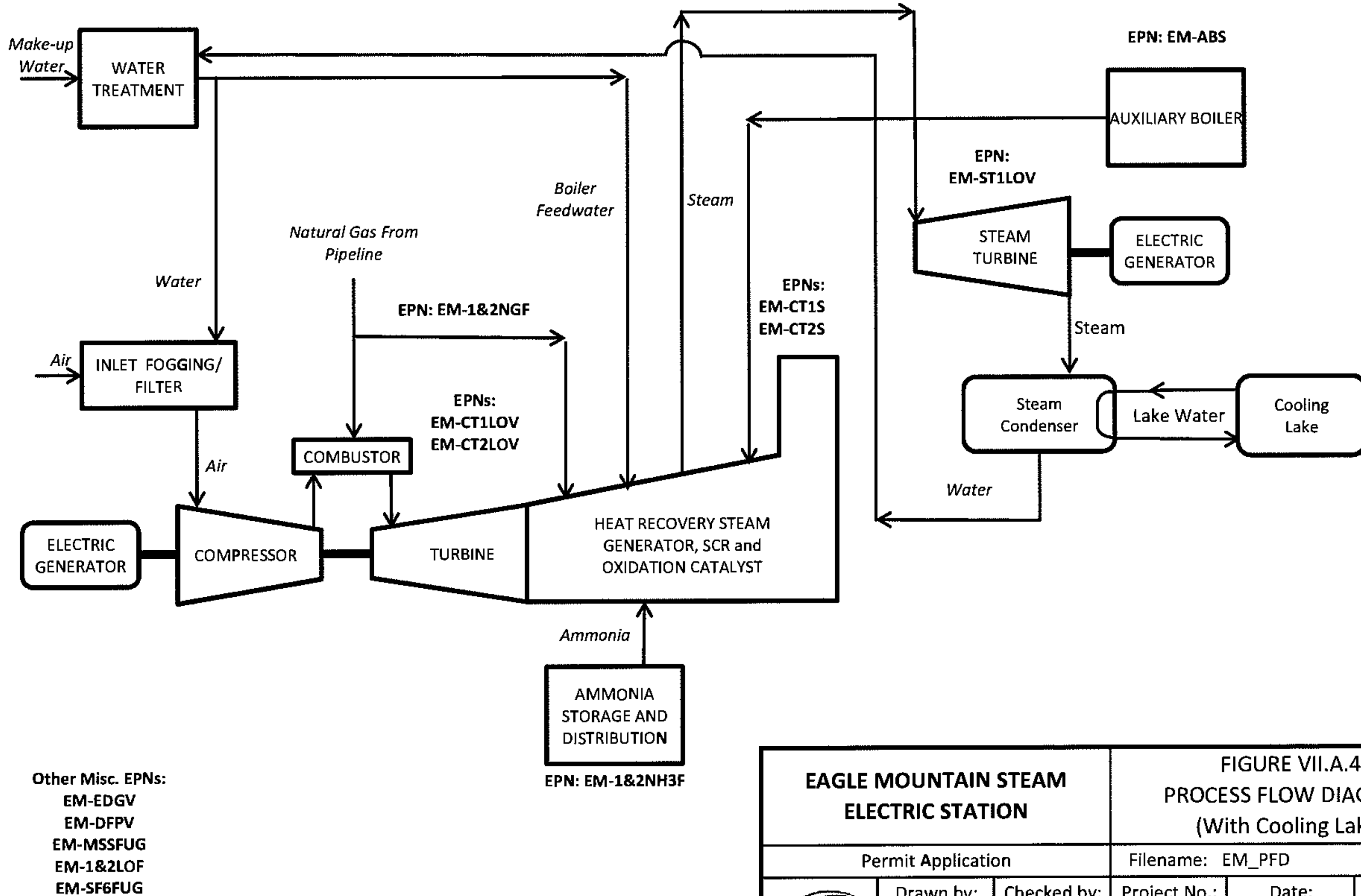
2.6 NATURAL GAS PIPING FUGITIVES

Natural gas is delivered to the site via pipeline. Gas will be metered and piped to the new combustion turbines and duct burners. Project fugitive emissions from the natural gas piping components associated with the new CTG/HRSG units will include emissions of methane (CH_4) and carbon dioxide (CO_2). Emissions from the natural gas piping are designated as EPN EM-1&2NGF.

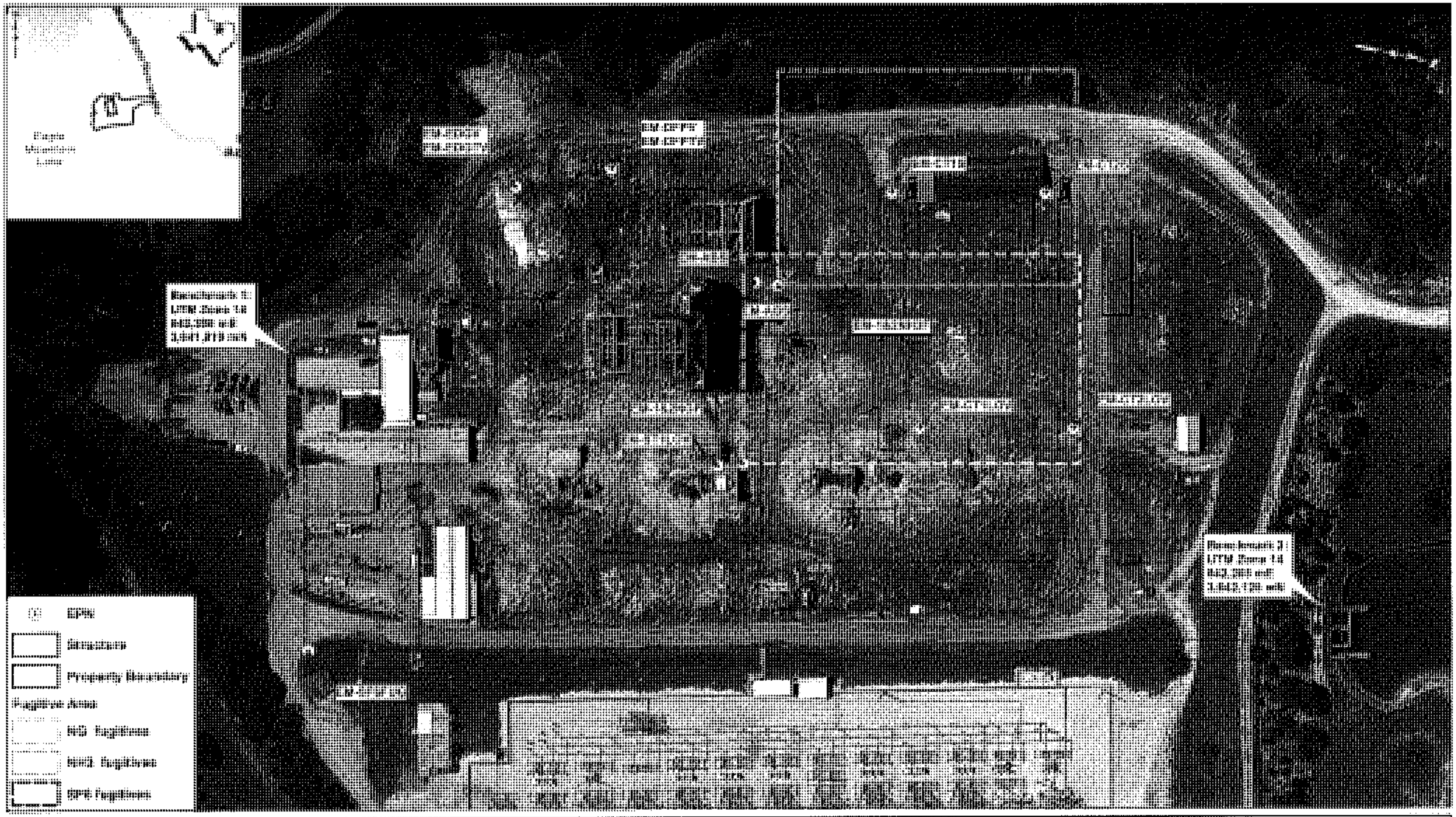
2.7 ELECTRICAL EQUIPMENT INSULATED WITH SULFUR HEXAFLUORIDE (SF_6)

The generator circuit breakers associated with the proposed units will be insulated with SF_6. SF_6 is a colorless, odorless, non-flammable gas. It is a fluorinated compound that has an extremely stable molecular structure. The unique chemical properties of SF_6 make it an efficient electrical insulator. The gas is used for electrical insulation, arc quenching, and current interruption in high-voltage electrical equipment. SF_6 is only used in sealed and safe systems which under normal circumstances do not leak gas. The capacity of the circuit breakers associated with the proposed plant is estimated to be 410 lbs of SF_6. Fugitive emissions of SF_6 are designated as EPN EM-SF6FUG.

The proposed circuit breakers will have a low pressure alarm and a low pressure lockout. The alarm will alert operating personnel of any leakage in the system and the lockout prevents any operation of the breaker in the event there is a lack of "quenching and cooling" SF_6 gas.



EAGLE MOUNTAIN STEAM ELECTRIC STATION			FIGURE VII.A.4 PROCESS FLOW DIAGRAM (With Cooling Lake)		
Permit Application			Filename: EM_PFD		
zephyr	Drawn by: Z Trieff	Checked by: L Moon	Project No.: 13354	Date: 9/8/2014	Sheet: 1 of 1



Map Sources:
Google Earth Pro
Imagery 04.10.13;
ESRI Streets Basemap
Datum: NAD83
UTM Zone 14

0 50 100 Meters

0 150 300 Feet

N

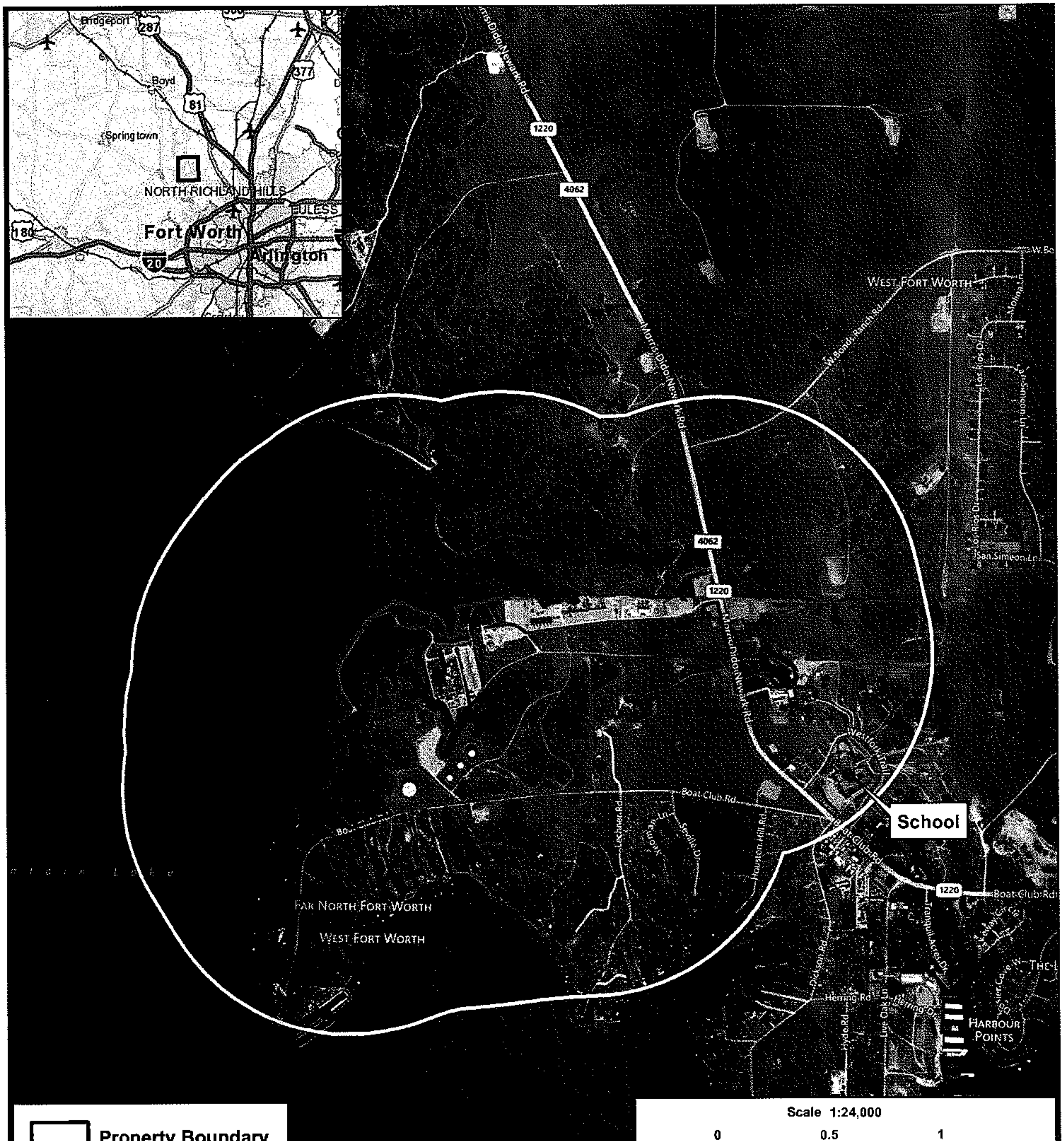
zephyr

PLOT PLAN - GHG

Eagle Mountain Steam Electric Station
Tarrant County, Texas

Document Path: H:\Luminant\013354 Eagle Mountain Combined-Cycle Permits\GIS\ArcMap\GHG Plot Plan- Eagle Mountain.mxd

Drafted By: J. Knowles	Reviewed By: L Moon	Project No.: 013354.001	Date: 9/9/2014



Datum: GCS NAD 1983
UTM Zone 14
Map Sources: ESRI-BING
Hybrid & Streets Basemaps

SITE LOCATION

zephyr

AREA MAP

Eagle Mountain Steam Electric Station

Eagle Mountain Power Company LLC

Tarrant County, Texas

H:\Luminant\013354 Eagle Mountain Combined-Cycle Permits\GIS\ArcMap

Drafted By:	Reviewed By:	Project No.:	Date:
J. Knowles	L. Moon	013354.001	01.13.2014

3.0 GHG EMISSION CALCULATIONS

3.1 GHG EMISSIONS FROM COMBINED CYCLE COMBUSTION TURBINES

GHG emissions from the combustion turbines and the HRSGs are calculated in accordance with the procedures in the Mandatory Greenhouse Reporting Rules, Subpart D – Electric Generation.[2] Annual CO_2 emissions are calculated using the methodology in equation G-4 of the Acid Rain Rules.[3]

$$W_{CO_2} = \left(\frac{F_C \times H \times U_f \times MW_{CO_2}}{2000} \right) \qquad (Eq.\ G\text{-}4)$$

Where:

W_{CO2} = CO_2 emitted from combustion, tons/yr

MW_{CO2} = Molecular weight of carbon dioxide, 44.0 lb/lb-mole

F_c = Carbon based F-factor, 1,040 scf/MMBtu for natural gas

H = Annual heat input in MMBtu

U_f = 1/385 scf CO_2/lb-mole at 14.7 psia and 68 °F.

Annual methane (CH_4) and nitrous oxide (N_2O) emissions are calculated using the emission factors (kg/MMBtu) for natural gas combustion from Table C-2 of the Mandatory Greenhouse Gas Reporting Rules.[4] A summary of the site-wide total GHG emissions is provided in Table 3-1. The global warming potential factors used to calculate carbon dioxide equivalent (CO_2e) emissions are based on Table A-1 of the Mandatory Greenhouse Gas Reporting Rules.

A separate set of turbine/HRSG calculations is provided for each of the two models being considered: the General Electric 7FA.05 and the Siemens SGT6-5000F(5)ee. Calculations of GHG emissions from the combined cycle turbines are presented on Tables 3-2 and 3-3.

The emissions of CO_2, CH_4, and N_2O from the combustion turbines/HRSGs will be directly proportional to the firing rate of natural gas. During a typical startup, there will be no duct burner firing and the firing rate of natural gas to the combustion turbine will be less than the firing rate

[2] 40 CFR 98, Subpart D – *Electricity Generation*

[3] 40 CFR 75, Appendix G – *Determination of CO_2 Emissions*

[4] *Default CH_4 and N_2O Emission Factors for Various Types of Fuel*, 40 CFR 98, Subpt. C, Tbl. C-2

at baseload. Therefore, GHG emissions during startup will be less than GHG emissions at baseload conditions.

3.2 AUXILIARY BOILER

CO_2 emissions from the natural-gas-fired auxiliary boiler are calculated using the emission factors (kg/MMBtu) for natural gas from Table C-1 of the Mandatory Greenhouse Gas Reporting Rules.[5] CH_4 and N_2O emissions from the auxiliary boiler are calculated using the emission factors (kg/MMBtu) for natural gas from Table C-2 of the Mandatory Greenhouse Gas Reporting Rules.[6] The "global warming potential factors" used to calculate CO_2e emissions are based on Table A-1 of the Mandatory Greenhouse Gas Reporting Rules.[7]

Calculations of GHG emissions from the auxiliary boiler are presented on Table 3-4.

3.3 GHG EMISSIONS FROM NATURAL GAS PIPING FUGITIVES AND NATURAL GAS MAINTENANCE AND STARTUP/SHUTDOWN RELATED RELEASES

GHG emission calculations for natural gas/fuel gas piping component fugitive emissions are based on emission factors from Table W-1A of Mandatory Greenhouse Gas Reporting Rules.[8] The concentrations of CH_4 and CO_2 in the natural gas are based on a typical natural gas analysis. Since the CH_4 and CO_2 content of natural gas is variable, the concentrations of CH_4 and CO_2 from the typical natural gas analysis are used when determining the worst-case mass emission rate estimate. The "global warming potential factors" used to calculate CO_2e emissions are based on Table A-1 of the Mandatory Greenhouse Gas Reporting Rules.[9]

GHG emission calculations for releases of natural gas related to piping maintenance and turbine startup/shutdowns are calculated using the same CH_4 and CO_2 concentrations as natural gas/fuel gas piping fugitives.

Calculations of GHG emissions from natural gas piping fugitives are presented on Table 3-5. Calculations of GHG emissions from releases of natural gas related to piping maintenance and turbine maintenance and startup/shutdown activities are presented on Table 3-6.

[5] *Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel,* 40 CFR 98, Subpt. C, Tbl. C-1

[6] *Default CH_4 and N_2O Emission Factors for Various Types of Fuel,* 40 CFR 98, Subpt. C, Tbl. C-2

[7] *Global Warming Potentials,* 40 C.F.R. Pt. 98, Subpt. A, Tbl. A-1.

[8] Default Whole Gas Emission Factors for Onshore Petroleum and Natural Gas Production, 40 CFR 98, Subpt. W, Tbl. W-1A

[9] *Global Warming Potentials,* 40 CFR Pt. 98, Subpt. A, Tbl. A-1.

3.4 GHG EMISSIONS FROM DIESEL-FIRED EMERGENCY ENGINES

CO_2 emissions from the diesel-fired emergency generator and fire pump engine are calculated using the emission factors (kg/MMBtu) for Distillate Fuel Oil No. 2 from Table C-1 of the Mandatory Greenhouse Gas Reporting Rules.[10] CH_4 and N_2O emissions from the diesel-fired engines are calculated using the emission factors (kg/MMBtu) for Petroleum from Table C-2 of the Mandatory Greenhouse Gas Reporting Rules.[11] The global warming potential factors used to calculate CO_2e emissions are based on Table A-1 of the Mandatory Greenhouse Gas Reporting Rules.[12]

Calculations of GHG emissions from the emergency engines are presented on Table 3-7.

3.5 GHG EMISSIONS FROM ELECTRICAL EQUIPMENT INSULATED WITH SF_6

SF_6 emissions from the SF_6 circuit breakers associated with the proposed units are calculated using a predicted SF_6 annual leak rate of 0.5% by weight. The "global warming potential factors" used to calculate CO_2e emissions are based on Table A-1 of the Mandatory Greenhouse Gas Reporting Rules.[13]

Calculations of GHG emissions from electrical equipment insulated with SF_6 are presented on Table 3-8.

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[10] *Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel*, 40 CFR 98, Subpt. C, Tbl. C-1

[11] *Default CH_4 and N_2O Emission Factors for Various Types of Fuel*, 40 CFR 98, Subpt. C, Tbl. C-2

[12] *Global Warming Potentials*, 40 CFR Pt. 98, Subpt. A, Tbl. A-1.

[13] *Global Warming Potentials*, 40 CFR Pt. 98, Subpt. A, Tbl. A-1.

Table 3-1
Project GHG Emission Summary
Eagle Mountain Steam Electric Station
Eagle Mountain Power Company LLC

Name	EPN	CO_2 ton/yr	CH_4 ton/yr	N_2O ton/yr	SF_6 ton/yr	Total GHG Mass Emissions ton/yr	Total CO_2e ton/yr
Unit 1 (GE 7FA.05)	EM-CT1S	1,283,747.4	23.8	2.4		1,283,773.6	1,285,052.3
Unit 2 (GE 7FA.05)	EM-CT2S	1,283,747.4	23.8	2.4		1,283,773.6	1,285,052.3
Unit 1 (Siemens SGT6-5000F5ee)	EM-CT1S	1,498,890.4	27.8	2.8		1,498,920.9	1,500,413.9
Unit 2 (Siemens SGT6-5000F5ee)	EM-CT2S	1,498,890.4	27.8	2.8		1,498,920.9	1,500,413.9
Auxiliary Boiler	EM-ABS	37,527.3	0.7	0.1		37,528.1	37,566.1
Natural Gas Fugitives	EM-1&2NGF	0.1	1.3			1.4	33.4
Gas Venting	EM-MSSFUG	0.008	0.10			0.11	2.6
Emergency Generator	EM-EDGV	77.0	0.0031	0.0006		77.0	77.3
Fire Water Pump	EM-DFPV	16.2	0.00066	0.00013		16.2	16.2
SF_6 Insulated Equipment	EM-SF6FUG				0.00103	0.00103	23.4
Sitewide Emissions[1]		3,035,401.4	57.7	5.6	0.00103	3,035,464.7	3,038,546.8

1. The project emissions total uses the higher GHG emissions from the two gas turbine options.

Table 3-2

GHG Annual Emission Calculations - GE 7FA.05 Combined Cycle Combustion Turbines

Eagle Mountain Steam Electric Station

Eagle Mountain Power Company LLC

EPN	Average Heat Input[1] (MMBtu/hr)	Annual Heat Input[2] (MMBtu/yr)	Pollutant	Emission Factor (lb/MMBtu)[3]	GHG Mass Emissions[4] (tpy)	Global Warming Potential[5]	CO_2e (tpy)
EM-CT1S (GE 7FA.05)	2,466	21,601,519	CO_2	118.86	1,283,747.4	1	1,283,747.4
			CH_4	2.2E-03	23.8	25	595.3
			N_2O	2.2E-04	2.4	298	709.6
				Total:	**1,283,773.6**		**1,285,052.3**
EM-CT2S (GE 7FA.05)	2,466	21,601,519	CO_2	118.86	1,283,747.4	1	1,283,747.4
			CH_4	2.2E-03	23.8	25	595.3
			N_2O	2.2E-04	2.4	298	709.6
				Total:	**1,283,773.6**		**1,285,052.3**
				Total for 2 Turbines:	***2,567,547.2***		***2,570,104.5***

Note

1. *The average heat input for the GE 7FA.05 scenario is based on the HHV heat input at 100% load, with duct burner firing, at 59 °F ambient temperature (Operating Case 1-4)*
2. *Annual heat input based on 8,760 hours per year operation.*
3. *CH_4 and N_2O GHG factors based on Table C-2 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*
4. *CO_2 emissions based on 40 CFR Part 75, Appendix G, Equation G-4*

$W_{CO2} = (F_c \times H \times U_f \times MW_{CO2})/2000$

W_{CO2} = CO_2 *emitted from combustion, tons/yr*

F_c = *Carbon based F-factor, 1040 scf/MMBtu*

H = Heat Input (MMBtu/yr)

U_f = *1/385 scf CO_2/lbmole at 14.7 psia and 68 °F*

MW_{CO2} = *Molecule weight of CO_2, 44.0 lb/lb-mole*

5. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

Table 3-3

GHG Emission Calculations - Siemens SGT6-5000F(5)ee Combined Cycle Combustion Turbines

Eagle Mountain Steam Electric Station

Eagle Mountain Power Company LLC

EPN	Average Heat Input[1] (MMBtu/hr)	Annual Heat Input[2] (MMBtu/yr)	Pollutant	Emission Factor (lb/MMBtu)[3]	GHG Mass Emissions[4] (tpy)	Global Warming Potential[5]	CO_2e (tpy)
EM-CT1S (Siemens SGT6-5000F5ee)	2,879	25,221,713	CO_2	118.86	1,498,890.4	1	1,498,890.4
			CH_4	2.2E-03	27.8	25	695.0
			N_2O	2.2E-04	2.8	298	828.5
				Total:	**1,498,920.9**		**1,500,413.9**
EM-CT2S (Siemens SGT6-5000F5ee)	2,879	25,221,713	CO_2	118.86	1,498,890.4	1	1,498,890.4
			CH_4	2.2E-03	27.8	25	695.0
			N_2O	2.2E-04	2.8	298	828.5
				Total:	**1,498,920.9**		**1,500,413.9**
				Total for 2 Turbines:	***2,997,841.9***		***3,000,827.8***

<u>*Note*</u>

1. *The average heat input for the Siemens scenarios are based on the HHV heat input at 100% load, with duct burner firing, at 59 °F ambient temperature (Operating Case 1-4).*
2. *Annual heat input based on 8,760 hours per year operation.*
3. *CH_4 and N_2O GHG factors based on Table C-2 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*
4. *CO_2 emissions based on 40 CFR Part 75, Appendix G, Equation G-4*

$W_{CO2} = (F_c \times H \times U_f \times MW_{CO2})/2000$

W_{CO2} = CO_2 emitted from combustion, tons/yr

F_c = Carbon based F-factor, 1040 scf/MMBtu

H = Heat Input (MMBtu/yr)

U_f = 1/385 scf CO_2/lbmole at 14.7 psia and 68 °F

MW_{CO2} = Molecule weight of CO_2, 44.0 lb/lb-mole

5. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

Table 3-4
GHG Emission Calculations - Auxiliary Boiler
Eagle Mountain Steam Electric Station
Eagle Mountain Power Company LLC

GHG Potential To Emit Emissions From Natural Gas-Fired Auxiliary Boiler

EPN	Maximum Heat Input[1] (MMBtu/yr)	Pollutant	Emission Factor (lb/MMBtu)[2]	GHG Mass Emissions (tpy)	Global Warming Potential[3]	CO_2e (tpy)
EM-ABS	642,108	CO_2	116.89	37,527.3	1	37,527.3
		CH_4	2.2E-03	0.71	25	17.7
		N_2O	2.2E-04	0.071	298	21.1
			Total:	**37,528.1**		**37,566.1**

Note
1. *Annual fuel use and heating value of natural gas from Table A-9 State/PSD air permit application*
2. *Factors based on Table C-1 and C-2 of 40 CFR Part 98, Mandatory Greenhouse Gas Reporting.*
3. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

Table 3-5
GHG Emission Calculations - Natural Gas Piping Fugitives
Eagle Mountain Steam Electric Station
Eagle Mountain Power Company LLC

GHG Emissions Contribution From Fugitive Natural Gas Piping Components

EPN	Source Type	Fluid State	Count	Emission Factor[1] (scf/hr/comp)	CO_2[2] (tpy)	Methane[3] (tpy)	**Total (tpy)**
EM-1&2NGF	Valves	Gas/Vapor	36	0.121	0.055	0.742	
	Flanges	Gas/Vapor	90	0.017	0.019	0.261	
	Relief Valves	Gas/Vapor	10	0.193	0.024	0.329	
GHG Mass-Based Emissions					0.099	1.33	**1.4**
Global Warming Potential[4]					1	25	
CO_2e Emissions					0.099	33.27	**33.4**

Note

1. *Emission factors from Table W-1A of 40 CFR 98 Mandatory Greenhouse Gas Reporting Rules*
2. *CO_2 emissions based on vol% of CO_2 in natural gas* 2.52%
3. *CH_4 emissions based on vol% of CH_4 in natural gas* 93.31%
4. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

Example calculation:

36 valves	0.121 scf gas	0.0252 scf CO2	lbmole	44 lb CO_2	8760 hr	ton =	0.055 ton/yr
	hr * valve	scf gas	385 scf	lbmole	yr	2000 lb	

TABLE 3-6

Gaseous Fuel Venting During Turbine Shutdown/Maintenance and Small Equipment and Fugitive Component Repair/Replacement Eagle Mountain Steam Electric Station Eagle Mountain Power Company LLC

Location	Initial Conditions			Final Conditions			Annual Emissions		**Total**
	Volume[1] (ft^3)	Press. (psig)	Temp. (°F)	Press. (psig)	Temp. (°F)	Volume[2] (scf)	CO_2[3] (tpy)	CH_4[4] (tpy)	**(tpy)**
Turbine Fuel Line Shutdown/Maintenance	1,146	50	50	0	68	5,275	0.0076	0.10	
Small Equipment/Fugitive Component Repair/Replacement	6.7	50	50	0	68	31	0.00004	0.00060	
GHG Mass-Based Emissions							0.0076	0.1029	**0.11**
Global Warming Potential[5]							1	25	
CO_2e Emissions							0.0076	2.6	**2.6**

1. Initial volume is calculated by multpilying the crossectional area by the length of pipe using the following formula:
   V_i = pi * [(diameter in inches/12)/2]^2 * length in feet = ft^3
2. Final volume calculated using ideal gas law $[(PV/ZT)_i = (PV/ZT)_f]$. $V_f = V_i\ (P_i/P_f)\ (T_f/T_i)\ (Z_f/Z_i)$, where Z is estimated using the following equation: $Z = 0.9994 - 0.0002P + 3E\text{-}08P^2$.
3. CO_2 emissions based on vol% of CO_2 in natural gas — 2.52% from natural gas analysis
4. *CH_4 emissions based on vol% of CH_4 in natural gas* — 93.3% from natural gas analysis
5. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

Example calculation:

5275 scf Nat Gas	0.025 scf CO2	lbmole	44 lb CO_2	ton =	=	0.0076 ton/yr CO_2
yr	scf Nat Gas	385 scf	lbmole	2000 lb		

Table 3-7
GHG Emission Calculations - Emergency Engines
Eagle Mountain Steam Electric Station
Eagle Mountain Power Company LLC

GHG Emissions Contribution From Diesel Combustion In Emergency Engines

Assumptions:

	Generator	Fire Water Pump	
Annual Operating Schedule:	100	100	hours/year
Power Rating:	1,340	282	hp
Max Hourly Fuel Use:	68.5	14.4	gal/hr
Heating Value of No. 2 Fuel Oil[1]:	0.138	0.138	MMBtu/gal
Max Hourly Heat Input:	9.4	2.0	MMBtu/hr
Annual Heat Input:	944.9	198.9	MMBtu/yr

EPN	Heat Input (MMBtu/yr)	Pollutant	Emission Factor (kg/MMBtu)[2]	GHG Mass Emissions (tpy)	Global Warming Potential[3]	CO_2e (tpy)
EM-EDGV	944.9	CO_2	73.96	77.0	1	77.0
		CH_4	3.0E-03	0.0031	25	0.1
		N_2O	6.0E-04	0.0006	298	0.2
			Total:	**77.04**		**77.3**
EM-DFPV	198.9	CO_2	73.96	16.2	1	16.2
		CH_4	3.0E-03	0.0007	25	0.0
		N_2O	6.0E-04	0.0001	298	0.0
			Total:	**16.18**		**16.2**

Calculation Procedure

Annual Emission Rate = annual heat Input X Emission Factor X 2.2 lbs/kg X Global Warming Potential / 2,000 lbs/ton

Note

1. *Default high heat value based on Table C-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*
2. *GHG factors based on Tables C-1 and C-2 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*
3. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

Table 3-8

GHG Emission Calculations - Electrical Equipment Insulated With SF_6

Eagle Mountain Steam Electric Station

Eagle Mountain Power Company LLC

Assumptions

Insulated circuit breaker SF_6 capacity:	410	lb
Estimated annual SF_6 leak rate:	0.5%	by weight
Estimated annual SF_6 mass emission rate:	0.0010	ton/yr
Global Warming Potential[1]:	22,800	
Estimated annual CO_2e emission rate:	23.4	ton/yr

Note

Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.

4.0 PREVENTION OF SIGNIFICANT DETERIORATION (PSD) APPLICABILITY

The proposed Project will constitute a major source under 40 CFR §52.21; thus, PSD review is required for all PSD-regulated contaminants for which the Project will be a significant source of emissions. Because the GHG emissions increase and GHG net emissions increase associated with the proposed Project will be greater than 75,000 tons/yr of CO_2e, and because EPA is continuing to consider PSD BACT review for GHG emissions on this basis following the UARG decision, EPMC is seeking EPA review and approval of the proposed Project. Table 1F: Air Quality Application Supplement and Table 2F: Project Emission Increase for each of the turbine options follow in this Section.

TABLE 1F
AIR QUALITY APPLICATION SUPPLEMENT

Permit No.: PSD-TX-1390-GHG		Application Submittal Date:	
Company	Eagle Mountain Power Company LLC		
RN:	RN100693308	Facility Location:	10029 Morris Dido Newark Road
City	Fort Worth	County:	Tarrant
Permit Unit I.D.:	EM-CT1S & EM-CT2S (GE 7FA.05)	Permit Name:	Eagle Mountain Steam Electric Station
Permit Activity:	☑ New Major Source	☐ Modification	
Project or Process Description:	Construction of a combined cycle power plant (2 x 1 configuration)		

Complete for all pollutants with a project emission increase.	POLLUTANTS						
	Ozone		CO	SO_2	PM	GHG	CO_2e
	NOx	VOC					
Nonattainment? (yes or no)						No	No
Existing site PTE (tpy)	This form for GHG only					0	0
Proposed project increases (tpy from 2F)[3]						2,605,170	2,607,824
Is the existing site a major source? If not, is the project a major source by itself? (yes or no)						Yes	Yes
If site is major, is project increase significant? (yes or no)						Yes	Yes
If netting required, estimated start of construction:	N/A						
5 years prior to start of construction:	N/A	Contemporaneous					
estimated start of operation:	N/A	Period					
Net contemporaneous change, including proposed project, from Table 3F (tpy)						2,605,170	2,607,824
FNSR applicable? (yes or no)						Yes	Yes

1. Other PSD pollutants
2. Nonattainment major source is defined in Table 1 in 30 TAC 116.12(11) by pollutant and county. PSD thresholds are found in 40 CFR §51.166(b)(1).
3. Sum of proposed emissions minus baseline emissions, increases only. Nonattainment thresholds are found in Table 1 in 30 TAC 116.12(11) and PSD thresholds in 40 CFR §51.166(b)(23).
4. Since there are no contemporaneous decreases which would potentially affect PSD applicability and an impacts analysis is not required for GHG emissions, contemporaneous emission changes are not included on this table.

The presentations made above and on the accompanying tables are true and correct to the best of my knowledge.

David P. Duncan — Director, Environmental Generation — 09/10/2014

Signature — Title — Date

TCEQ

TABLE 2F
PROJECT EMISSION INCREASE
(GE 7FA.05)

Pollutant[1]:	GHG	Permit:	PSD-TX-1390-GHG
Baseline Period:	N/A to N/A		

	Affected or Modified Facilities[2] FIN	EPN	Permit No.	Actual Emissions[3]	A Baseline Emissions[4]	B Proposed Emissions[5]	Projected Actual Emissions	Difference (B - A)[6]	Correction[7]	Project Increase[8]
1	EM-CT1	EM-CT1S	PSD-TX-1390-GHG	0.00	0.00	1,283,774		1,283,774		1,283,774
2	EM-CT2	EM-CT2S	PSD-TX-1390-GHG	0.00	0.00	1,283,774		1,283,774		1,283,774
3	EM-AB	EM-ABS	PSD-TX-1390-GHG	0.00	0.00	37,528		37,528		37,528
4	EM-1&2NG	EM-1&2NGF	PSD-TX-1390-GHG	0.00	0.00	1.4		1.4		1.4
5	EM-MSSFUG	EM-MSSFUG	PSD-TX-1390-GHG	0.00	0.00	0.1		0.1		0.1
6	EM-EDG	EM-EDGV	PSD-TX-1390-GHG	0.00	0.00	77		77		77
7	EM-DFP	EM-DFPV	PSD-TX-1390-GHG	0.00	0.00	16		16		16
8	EM-SF6FUG	EM-SF6FUG	PSD-TX-1390-GHG	0.00	0.00	0.0010		0.0010		0.0010
9										
10										
11										
12										
14										
15										
							Page Subtotal[9]			2,605,170

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TABLE 2F
PROJECT EMISSION INCREASE
(GE 7FA.05)

Pollutant[1]:	CO_2e	**Permit:**	PSD-TX-1390-GHG
Baseline Period:	N/A to N/A		

	Affected or Modified Facilities[2] FIN	**EPN**	**Permit No.**	**Actual Emissions[3]**	A **Baseline Emissions[4]**	B **Proposed Emissions[5]**	**Projected Actual Emissions**	**Difference (B - A)[6]**	**Correction[7]**	**Project Increase[8]**
1	EM-CT1	EM-CT1S	PSD-TX-1390-GHG	0.00	0.00	1,285,052		1,285,052		1,285,052
2	EM-CT2	EM-CT2S	PSD-TX-1390-GHG	0.00	0.00	1,285,052		1,285,052		1,285,052
3	EM-AB	EM-ABS	PSD-TX-1390-GHG	0.00	0.00	37,566		37,566		37,566
4	EM-1&2NG	EM-1&2NGF	PSD-TX-1390-GHG	0.00	0.00	33		33		33
5	EM-MSSFUG	EM-MSSFUG	PSD-TX-1390-GHG	0.00	0.00	3		3		3
6	EM-EDG	EM-EDGV	PSD-TX-1390-GHG	0.00	0.00	77		77		77
7	EM-DFP	EM-DFPV	PSD-TX-1390-GHG	0.00	0.00	16		16		16
8	TH-SF6FUG	EM-SF6FUG	PSD-TX-1390-GHG	0.00	0.00	23		23		23
9										
10										
11										
12										
13										
14										
15										
							Page Subtotal[9]			2,607,824

All emissions must be listed in tons per year (tpy). The same baseline period must apply for all facilities for a given NSR pollutant.

1. Individual Table 2F's should be used to summarize the project emission increase for each criteria pollutant.
2. Emission Point Number as designated in NSR Permit or Emissions Inventory.
3. All records and calculations for these values must be available npon request.
4. Correct actual emissions for currently applicable rule or permit requirements, and periods of non-compliance. These corrections, as well as any MSS previously demonstrated under 30 TAC 101, should be explained in the Table 2F supplement.
5. If projected actual emission is used it must be noted in the next column and the basis for the projection identified in the Table 2F supplement.
6. Proposed Emissions (column B) Baseline Emissions (column A).
7. Correction made to emission increase for what portion could have been accommodated during the baseline period. The justification and basis for this estimate must be provided in the Table 2F supplement.
8. Obtained by subtracting the correction from the difference. Must be a positive number.
9. Sum all values for this page.

9/9/2014

TCEQ

TABLE 1F
AIR QUALITY APPLICATION SUPPLEMENT

Permit No.: PSD-TX-1390-GHG		Application Submittal Date:	
Company	Eagle Mountain Power Company LLC		
RN:	RN100693308	Facility Location:	10029 Morris Dido Newark Road
City	Fort Worth	County:	Tarrant
Permit Unit I.D.:	EM-CT1S & EM-CT2S [Siemens SGT6-5000F(5)ee]	Permit Name:	Eagle Mountain Steam Electric Station
Permit Activity:	☑ New Major Source	☐ Modification	
Project or Process Description:	Construction of a combined cycle power plant (2 x 1 configuration)		

Complete for all pollutants with a project emission increase.	POLLUTANTS						
	Ozone		CO	SO_2	PM	GHG	CO_2e
	NOx	VOC					
Nonattainment? (yes or no)						No	No
Existing site PTE (tpy)	This form for GHG only					0	0
Proposed project increases (tpy from 2F)[3]						3,035,465	3,038,547
Is the existing site a major source? If not, is the project a major source by itself? (yes or no)						Yes	Yes
If site is major, is project increase significant? (yes or no)						Yes	Yes
If netting required, estimated start of construction:		N/A					
5 years prior to start of construction:		N/A	Contemporaneous				
estimated start of operation:		N/A	Period				
Net contemporaneous change, including proposed project, from Table 3F (tpy)						3,035,465	3,038,547
FNSR applicable? (yes or no)						Yes	Yes

1. Other PSD pollutants
2. Nonattainment major source is defined in Table 1 in 30 TAC 116.12(11) by pollutant and county. PSD thresholds are found in 40 CFR §51.166(b)(1).
3. Sum of proposed emissions minus baseline emissions, increases only. Nonattainment thresholds are found in Table 1 in 30 TAC 116.12(11) and PSD thresholds in 40 CFR §51.166(b)(23).
4. Since there are no contemporaneous decreases which would potentially affect PSD applicability and an impacts analysis is not required for GHG emissions, contemporaneous emission changes are not included on this table.

The presentations made above and on the accompanying tables are true and correct to the best of my knowledge.

David P. Duncan   Director, Environmental Generation   09/10/2014

Signature   Title   Date

TCEQ

TABLE 2F
PROJECT EMISSION INCREASE
[Siemens SGT6-5000F(5)ee]

Pollutant[1]:	GHG			**Permit:**	PSD-TX-1390-GHG
Baseline Period:	N/A	to	N/A		

	Affected or Modified Facilities[2] FIN	EPN	Permit No.	Actual Emissions[3]	A Baseline Emissions[4]	B Proposed Emissions[5]	Projected Actual Emissions	Difference (B - A)[6]	Correction[7]	Project Increase[8]
1	EM-CT1	EM-CT1S	PSD-TX-1390-GHG	0.00	0.00	1,498,921		1,498,921		1,498,921
2	EM-CT2	EM-CT2S	PSD-TX-1390-GHG	0.00	0.00	1,498,921		1,498,921		1,498,921
3	EM-AB	EM-ABS	PSD-TX-1390-GHG	0.00	0.00	37,528		37,528		37,528
4	EM-1&2NG	EM-1&2NGF	PSD-TX-1390-GHG	0.00	0.00	1		1		1
5	EM-MSSFUG	EM-MSSFUG	PSD-TX-1390-GHG	0.00	0.00	0.11		0		0
6	EM-EDG	EM-EDGV	PSD-TX-1390-GHG	0.00	0.00	77		77		77
7	EM-DFP	EM-DFPV	PSD-TX-1390-GHG	0.00	0.00	16		16		16
8	EM-SF6FUG	EM-SF6FUG	PSD-TX-1390-GHG	0.00	0.00	0.0010		0.0010		0.0010
9										
10										
11										
12										
14										
15										
							Page Subtotal[9]			3,035,465

TCEQ

TABLE 2F
PROJECT EMISSION INCREASE
[Siemens SGT6-5000F(5)ee]

Pollutant[(1)]:	CO_2e	**Permit:**	PSD-TX-1390-GHG
Baseline Period:	N/A to N/A		

				A	B				
Affected or Modified Facilities[(2)]	**FIN**	**EPN**	**Permit No.**	**Actual Emissions**[(3)]	**Baseline Emissions**[(4)]	**Proposed Emissions**[(5)]	**Projected Actual Emissions**	**Difference (B - A)**[(6)]	**Correction**[(7)]	**Project Increase**[(8)]
1	EM-CT1	EM-CT1S	PSD-TX-1390-GHG	0.00	0.00	1,500,414		1,500,414		1,500,414
2	EM-CT2	EM-CT2S	PSD-TX-1390-GHG	0.00	0.00	1,500,414		1,500,414		1,500,414
3	EM-AB	EM-ABS	PSD-TX-1390-GHG	0.00	0.00	37,566		37,566		37,566
4	EM-1&2NG	EM-1&2NGF	PSD-TX-1390-GHG	0.00	0.00	33		33		33
5	EM-MSSFUG	EM-MSSFUG	PSD-TX-1390-GHG	0.00	0.00	3		3		3
6	EM-EDG	EM-EDGV	PSD-TX-1390-GHG	0.00	0.00	77		77		77
7	EM-DFP	EM-DFPV	PSD-TX-1390-GHG	0.00	0.00	16		16		16
8	EM-SF6FUG	EM-SF6FUG	PSD-TX-1390-GHG	0.00	0.00	23		23		23
9										
10										
11										
12										
13										
14										
15										
							Page Subtotal[(9)]			3,038,547

All emissions must be listed in tons per year (tpy). The same baseline period must apply for all facilities for a given NSR pollutant.

1. Individual Table 2F's should be used to summarize the project emission increase for each criteria pollutant.
2. Emission Point Number as desiguated in NSR Permit or Emissious Inventory.
3. All records and calculations for these values must be available upon request.
4. Correct actual emissions for currently applicable rule or permit requirements, and periods of non-compliance. These corrections, as well as any MSS previously demonstrated under 30 TAC 101, should be explained in the Table 2F supplement.
5. If projected actual emission is used it must be noted in the next column and the basis for the projection identified in the Table 2F supplement.
6. Proposed Emissions (column B) Baseline Emissions (column A).
7. Correction made to emission increase for what portion could have been accommodated during the baseline period. The justification and basis for this estimate must be provided in the Table 2F supplement.
8. Obtained by subtracting the correction from the difference. Must be a positive number.
9. Sum all values for this page.

5.0 BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

EPA's PSD rules define BACT as follows:

> *Best available control technology* means an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under [the] Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, 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. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.[14]

In the EPA guidance document titled *PSD and Title V Permitting Guidance for Greenhouse Gases*, EPA recommends the use of the Agency's five-step "top-down" BACT process to determine BACT for GHGs.[15] 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

[14] 40 CFR § 52.21(b)(12.)
[15] EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases*, p. 18 (Nov. 2010).

- Step 3: Rank remaining control technologies
- Step 4: Evaluate most effective controls and document results
- Step 5: Select the BACT.

5.1 BACT FOR THE COMBINED CYCLE COMBUSTION TURBINES

5.1.1 Step 1: Identify All Available Control Technologies

5.1.1.1 Inherently Lower-Emitting Processes/Practices/Designs

A summary of available, lower greenhouse gas emitting processes, practices, and designs for combustion turbine power generators is presented below. The proposed energy efficiency processes, practices and designs discussed in Step 1 will be the same for the two models of combustion turbines being considered for this site: the General Electric 7FA.05 and the Siemens SGT6-5000F(5)ee. The BACT limits proposed in Step 5 are specific to each turbine model.

5.1.1.1.1 Combustion Turbine Energy Efficiency Processes, Practices, and Designs

Combustion Turbine Design
CO_2 is a product of combustion of fuel containing carbon, which is inherent in any power generation technology using fossil fuel. It is not possible to reduce the amount of CO_2 generated from combustion, as CO_2 is the essential product of the chemical reaction between the fuel and the oxygen in which it burns, not a byproduct caused by imperfect combustion. As such, there is no technology available that can effectively reduce CO_2 generation by adjusting the conditions in which combustion takes place.

The only effective means to reduce the amount of CO_2 generated by a fuel-burning power plant is to generate as much electric power as possible per unit of fuel combusted, thereby reducing the amount of fuel needed to meet the Project's required power output. This result is obtained by using the most efficient generating technologies available, so that as much of the energy content of the fuel as possible goes into generating power.

The most efficient way to generate electricity from a natural gas fuel source is the use of a combined cycle design. For fossil fuel technologies, efficiency ranges from approximately 30-50% (higher heating value (HHV)). A typical Rankine cycle power plant has a baseload efficiency of approximately 30% (HHV), while a modern F-Class natural gas-fired combined cycle unit operating under optimal conditions has a baseload efficiency of approximately 50% (HHV).

Combined cycle units operate based on a combination of two thermodynamic cycles: the Brayton and the Rankine cycles. A combustion turbine operates on the Brayton cycle and the

HRSG and steam turbine operate on the Rankine cycle. The combination of the two thermodynamic cycles allows for the high efficiency associated with combined cycle plants.

In addition to the high-efficiency primary components of a combustion turbine, there are a number of other design features employed within the turbine that can improve the overall efficiency of the machine. These additional features include those summarized below.

Periodic Burner Tuning
Modern F-Class combustion turbines have regularly scheduled routine maintenance programs. These maintenance programs are important for the reliable operation of the unit, as well as to maintain optimal efficiency. As the combustion turbine is operated, the unit experiences degradation and loss in performance. The combustion turbine maintenance program helps restore lost performance. The maintenance program schedule is determined by the number of hours of operation and/or turbine starts. There are three basic maintenance levels, commonly referred to as combustion inspections, hot gas path inspections, and major overhauls. Combustion inspections are the most frequent of the maintenance cycles. As part of this maintenance activity, the combustors are tuned to restore efficiency to the combustion turbines.

Reduction in Heat Loss
Modern F-Class combustion turbines have high operating temperatures. The high operating temperatures are a result of the heat of compression in the compressor along with the fuel combustion in the burners. To minimize heat loss from the combustion turbine and protect the personnel and equipment around the machine, insulation blankets are applied to the combustion turbine casing. These blankets minimize the heat loss through the combustion turbine shell and help improve the overall efficiency of the machine.

Instrumentation and Controls
Modern F-Class combustion turbines have sophisticated instrumentation and controls to automatically control the operation of the combustion turbine. The control system is a digital-type and is supplied with the combustion turbine. The distributed control system (DCS) controls all aspects of the turbine's operation, including the fuel feed and burner operations, to achieve efficient low-NO_X combustion. The control system monitors the operation of the unit and modulates the fuel flow and turbine operation to achieve optimal performance for full-load and part-load conditions, thereby minimizing emissions of greenhouse gases.

5.1.1.1.2 Heat Recovery Steam Generator Energy Efficiency Processes, Practices, and Designs

The HRSG takes waste heat from the combustion turbine exhaust and uses the waste heat to convert boiler feed water to steam. Duct burning involves burning additional natural gas in the ducts to the heat recovery boiler, which increases the temperature of the exhaust coming from the combustion turbines and thereby creates additional steam for the steam turbine. The duct burner firing provides additional power generation capacity during periods of high electrical demand.

The modern large combustion turbine-based combined cycle HRSG is generally a horizontal, natural circulation, drum-type heat exchanger designed with three pressure levels of steam generation, reheat, split superheater sections with interstage attemperation, post-combustion emissions control equipment, and condensate recirculation. The HRSG is designed to maximize the conversion of the combustion turbine exhaust gas waste heat to steam for all plant ambient and load conditions. Maximizing steam generation will increase the steam turbine's power generation, which maximizes plant efficiency.

Heat Exchanger Design Considerations
HRSGs are heat exchangers designed to capture as much thermal energy as possible from the combustion turbine exhaust gases. This is performed at multiple pressure levels. For a drum-type configuration, each pressure level incorporates an economizer section(s), evaporator section, and superheater section(s). These heat transfer sections are made up of many thin-walled tubes to provide surface area to maximize the transfer of heat to the working fluid. Most of the tubes also include extended surfaces (e.g., fins). The extended surface optimizes the heat transfer, while minimizing the overall size of the HRSG. Additionally, flow guides are used to distribute the flow evenly through the HRSG to allow for efficient use of the heat transfer surfaces and post-combustion emissions control components. Low-temperature economizer sections employ recirculation systems to minimize cold-end corrosion, and stack dampers are used for cycling operation to conserve the thermal energy within the HRSG when the unit is off line.

Insulation
HRSGs take waste heat from the combustion turbine exhaust gas and use that waste heat to convert boiler feed water to steam. As such, the temperatures inside the HRSG are nearly equivalent to the exhaust gas temperatures of the turbine. For modern large combustion turbines, these temperatures can approach 1,200°F. HRSGs are designed to maximize the conversion of the waste heat to steam. One aspect of the HRSG design in maximizing this waste heat conversion is the use of insulation. Insulation minimizes heat loss to the surrounding air, thereby improving the overall efficiency of the HRSG. Insulation is applied to the HRSG panels that make up the shell of the unit, to the high-temperature steam and water lines, and typically to the bottom portion of the stack.

Minimizing Fouling of Heat Exchange Surfaces
HRSGs are made up of a number of tubes within the shell of the unit that are used to generate steam from the combustion turbine exhaust gas waste heat. To maximize this heat transfer, the tubes and their extended surfaces need to be as clean as possible. Fouling of the tube surfaces impedes the transfer of heat. Fouling occurs from the constituents within the exhaust gas stream. To minimize fouling, filtration of the inlet air to the combustion turbine is performed. Additionally, cleaning of the tubes is performed during periodic outages. By reducing the fouling, the efficiency of the unit is maintained.

Minimizing Vented Steam and Repair of Steam Leaks

As with all steam-generated power facilities, minimization of steam vents and repair of steam leaks is important in maintaining the plant's efficiency. A combined cycle facility has just a few locations where steam is vented from the system, including at the deaerator vents, blowdown tank vents, and vacuum pumps/steam jet air ejectors. These vents are necessary to improve the overall heat transfer within the HRSG and condenser by removing solids and air that potentially blankets the heat transfer surfaces lowering the equipment's performance. Additionally, power plant operators are concerned with overall efficiency of their facilities. Therefore, steam leaks are repaired as soon as possible to maintain facility performance. Minimization of vented steam and repair of steam leaks will be performed for the Project.

5.1.1.1.3 Steam Turbine Energy Efficiency Processes, Practices, and Designs

The steam turbine for the Project will be a modern, high-efficiency, reheat, condensing unit. Steam turbines have been in operation for over a century, and are generally classified as impulse or reaction. However, most modern turbines employ both impulse and reaction blading. The overall efficiency of the unit is affected by a number of items, including the inlet steam conditions, the exhaust steam conditions, the blading design, the turbine seals, and the generator efficiency.

Use of Reheat Cycles

The efficiency of a steam turbine is directly related to the steam conditions entering the turbine. The higher the steam temperature and pressure, the higher the overall efficiency. To achieve the higher temperatures, reheat cycles are employed. This is necessary to minimize the condensed moisture content of the exhaust steam exiting a turbine stage. If the moisture content of the exhaust steam is too high, erosion of the last-stage turbine blades occurs. A typical reheat cycle reheats partially expanded steam from the steam turbine. For a modern combined cycle facility, the high-pressure inlet and intermediate-pressure inlet steam temperatures typically are 1,050°F and above, and the high-pressure steam turbine inlet pressure is typically in the range of 1,800-2,400 psig.

Use of Exhaust Steam Condenser

Steam turbine efficiency is also improved by lowering the exhaust steam conditions of the unit. The lower the exhaust pressure, the higher the overall turbine efficiency. For high-efficiency units, the exhaust steam is saturated under vacuum conditions. This is accomplished by the use of a condenser. The condenser is typically a shell and tube heat exchanger with cooling water flowing through the tubes and the turbine exhaust steam condensing in the shell. The condensing steam creates a vacuum in the condenser, which increases steam turbine efficiency. This vacuum is dependent on the temperature of the cooling water. As the temperature of the cooling water is lowered, the absolute vacuum attainable is lowered and the steam turbine is more efficient.

Efficient Blading Design
Blading design also affects the overall efficiency of the turbine. As noted earlier, steam turbines have been used to generate power for over a century, and are either impulse or reaction design. The blade design has evolved for high-efficiency transfer of the energy in the steam to power generation. Additionally, 3-D computer-aided design technology is also employed to provide the highest efficiency blade design. Blade materials are also important components in blade design, which allow for high-temperature and large exhaust areas to improve performance.

Turbine seals are also important in the overall performance of the steam turbine. The high-pressure steam will leak to the atmosphere along the turbine shaft, as well as bypass the turbine stages if sealing is not employed. The steam turbine designers have multiple steam seal designs to obtain the highest efficiency from the steam turbine.

Efficient Steam Turbine Generator Design
The steam turbine generator is also a key element in the overall performance of the steam turbine. The modern generator is a high-efficiency unit. The generator for modern steam turbines is typically cooled by one of three methods. These methods are open-air cooling, totally enclosed water to air cooling or hydrogen cooling. These cooling methods allow for the highest efficiency of the generator, resulting in an overall high-efficiency steam turbine. According to Siemens representatives, there is no energy penalty between the three cooling methods. The cooling method for the EMPC steam turbine will be either totally enclosed water to air cooling or hydrogen cooling. The selection of the cooling method will be made by the equipment provider based on atmospheric conditions for the particular site.

5.1.1.1.4 Additional Energy Efficiency Processes, Practices, and Designs

There are a number of other components within the combined cycle plant that help improve overall efficiency, including:

- *Fuel gas preheating* – The overall efficiency of the combustion turbine is increased with increased fuel inlet temperature.
- *Drain operation* – Drains are required to allow for draining the equipment for maintenance (i.e., maintenance drains), and also to allow condensate to be removed from the steam piping and drains for operation (i.e., operation drains). Operation drains are generally controlled to minimize the loss of energy from the cycle. This is accomplished by closing the drains as soon as the appropriate steam conditions are achieved.
- *Multiple combustion turbine/HRSG trains* – Multiple combustion turbine/HRSG trains help with part-load operation. The multiple trains allow the unit to achieve higher overall plant part-load efficiency by shutting down a train operating at less efficient part-load conditions and ramping up the remaining train to high-efficiency full-load operation.

- *Boiler feed pump fluid drives* – The boiler feed pumps are used as the means to impart high pressure on the working fluid. The pumps require considerable power. To minimize the power consumption at part-loads, the use of fluid drives or variable-frequency drives can be employed. For the Project, fluid drives are being used to minimize power consumption at part-load, improving the facility's overall efficiency.

5.1.1.2 Add-On Controls

In addition to power generation process technology options discussed above, it is appropriate to consider whether add-on technologies are possible ways to capture GHG emissions that are emitted from natural gas combustion in the proposed Project's CTG/HRSG units and to prevent them from entering the atmosphere. These emerging carbon capture and storage (CCS) technologies generally consist of processes that separate CO_2 from combustion process flue gas, and then inject it into geologic formations such as oil and gas reservoirs, unmineable coal seams, and underground saline formations. Of the emerging CO_2 capture technologies that have been identified, only amine absorption is currently commercially used for state-of-the-art CO_2 separation processes. Amine absorption has been applied to processes in the petroleum refining and natural gas processing industries and for exhausts from gas-fired industrial boilers. Other potential absorption and membrane technologies are currently considered developmental.

The U.S. Department of Energy's National Energy Technology Laboratory (DOE-NETL) provides the following brief description of state-of-the-art post-combustion CO_2 capture technology and related implementation challenges:

> "...In the future, emerging R&D will provide numerous cost-effective technologies for capturing CO_2 from power plants. At present, however, state-of-the-art technologies for existing power plants are essentially limited to amine absorbents. Such amines are used extensively in the petroleum refining and natural gas processing industries... Amine solvents are effective at absorbing CO_2 from power plant exhaust streams—about 90 percent removal—but the highly energy-intensive process of regenerating the solvents decreases plant electricity output..."[16]

The DOE-NETL adds:

> "...Separating CO_2 from flue gas streams is challenging for several reasons:

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[16] DOE-NETL, *Carbon Sequestration: FAQ Information Portal*, http://extsearch1.netl.doe.gov/search?q=cache:e0yvzjAh22cJ:www.netl.doe.gov/technologies/carbon_seq/FAQs/tech-status.html+emerging+R%26D&access=p&output=xml_no_dtd&ie=UTF-8&client=default_frontend&site=default_collection&proxystylesheet=default_frontend&oe=ISO-8859-1 (last visited Feb. 27, 2012).

- CO_2 is present at dilute concentrations (13-15 volume percent in coal-fired systems and 3-4 volume percent in gas-fired turbines) and at low pressure (15-25 pounds per square inch absolute [psia]), which dictates that a high volume of gas be treated.
- Trace impurities (particulate matter, sulfur dioxide, nitrogen oxides) in the flue gas can degrade sorbents and reduce the effectiveness of certain CO_2 capture processes.
- Compressing captured or separated CO_2 from atmospheric pressure to pipeline pressure (about 2,000 psia) represents a large auxiliary power load on the overall power plant system…"[17]

For the combustion turbines being considered for the Project, the CO_2 stack concentration at baseload and ISO conditions for the General Electric 7FA.05 is 3.93 vol% without duct burner firing and 4.44 vol% with duct burner firing, and for the Siemens SGT6-5000F(5)ee is 3.96 vol% without duct burner firing and 4.72 vol% with duct burner firing.

If CO_2 capture can be achieved at a power plant, it would need to be routed to a geologic formation capable of long-term storage. The long-term storage potential for a formation is a function of the volumetric capacity of a geologic formation and CO_2 trapping mechanisms within the formation, including dissolution in brine, reactions with minerals to form solid carbonates, and/or adsorption in porous rock. The DOE-NETL describes the geologic formations that could potentially serve as CO_2 storage sites as follows:

> "Geologic carbon dioxide (CO_2) storage involves the injection of supercritical CO_2 into deep geologic formations (injection zones) overlain by competent sealing formations and geologic traps that will prevent the CO_2 from escaping. Current research and field studies are focused on developing better understanding of 11 major types of geologic storage reservoir classes, each having their own unique opportunities and challenges. Understanding these different storage classes provides insight into how the systems influence fluids flow within these systems today, and how CO_2 in geologic storage would be anticipated to flow in the future. The different storage formation classes include: deltaic, coal/shale, fluvial, alluvial, strandplain, turbidite, eolian, lacustrine, clastic shelf, carbonate shallow shelf, and reef. Basaltic interflow zones are also being considered as potential reservoirs. These storage reservoirs contain fluids that may include natural gas, oil, or saline water; any of which may impact CO_2 storage differently…"[18]

5.1.2 Step 2: Eliminate Technically Infeasible Options

Amine absorption technology for CO_2 capture has been applied to processes in the petroleum refining and natural gas processing industries, so it has been postulated that it is technically

[17] *Id.*
[18] DOE-NETL, *Carbon Sequestration: Geologic Storage Focus Area,* http://www.netl.doe.gov/technologies/carbon_seq/corerd/storage.html

feasible to apply that technology to exhausts for power plants. However, that technology has not been commercially available to power plants gas turbine exhausts, which have considerably larger flow volumes and considerably lower CO_2 concentrations. The high energy demand, high water demand, technical difficulties and economic costs associated with CCS are addressed in Step 4 of this section.

5.1.3 Step 3: Rank Remaining Control Technologies

As documented in Step 4 below, as all of the energy efficiency related processes, practices, and designs discussed in Section 5.1.1.1 of this application are being proposed for the Project, a ranking of the control technologies is not necessary for this application.

5.1.4 Step 4: Evaluate Most Effective Controls and Document Results

As all of the energy efficiency related processes, practices, and designs discussed in Section 5.1.1.1 of this application are being proposed for the Project, an examination of the energy, environmental, and economic impacts of the efficiency designs is not necessary for this application.

In this section, EMPC addresses the potential energy, environmental, and economic feasibility of implementing CCS technology as BACT for GHG emissions from the proposed Project's gas turbine/HRSG trains. Each component of CCS technology (i.e., capture and compression, transport, and storage) is discussed separately.

5.1.4.1 CO_2 Capture and Compression

Though amine absorption technology for CO_2 capture has been applied to processes in the petroleum refining and natural gas processing industries and to exhausts from gas-fired industrial boilers, it is more difficult to apply to power plant gas turbine exhausts, which have considerably larger flow volumes and considerably lower CO_2 concentrations. The Obama Administration's Interagency Task Force on Carbon Capture and Storage confirms this in its recently completed report on the current status of development of CCS systems:

> "Current technologies could be used to capture CO_2 from new and existing fossil energy power plants; however, they are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant application. Since the CO_2 capture capacities used in current industrial processes are generally much smaller than the capacity required for the purposes of GHG emissions mitigation at a typical power plant, there is considerable uncertainty associated with capacities at volumes necessary for commercial deployment."[19]

[19] *Report of the Interagency Task Force on Carbon Capture and Storage* at 50 (Aug. 2010).

In its current CCS research program plans, the DOE-NETL confirms that commercial CO_2 capture technology for large-scale power plants is not yet available and suggests that it may not be available until at least 2020:

> "The overall objective of the Carbon Sequestration Program is to develop and advance CCS technologies that will be ready for widespread commercial deployment by 2020. To accomplish widespread deployment, four program goals have been established:
>
> (1) Develop technologies that can separate, capture, transport, and store CO_2 using either direct or indirect systems that result in a less than 10 percent increase in the cost of energy by 2015;
>
> (2) Develop technologies that will support industries' ability to predict CO_2 storage capacity in geologic formations to within ±30 percent by 2015;
>
> (3) Develop technologies to demonstrate that 99 percent of injected CO_2 remains in the injection zones by 2015;
>
> (4) Complete Best Practices Manuals (BPMs) for site selection, characterization, site operations, and closure practices by 2020. Only by accomplishing these goals will CCS technologies be ready for safe, effective commercial deployment both domestically and abroad beginning in 2020 and through the next several decades."[20A]

Another challenge of CO_2 capture is conservation of water resources. A modern natural gas-fired combined cycle facility requires four to five million gallons of water per day for condenser cooling and boiler make-up service. This amount will vary based on ambient temperature and humidity as well as the level of duct firing in the HRSG. Adding CO_2 separation facilities and compression equipment would significantly increases the cooling water requirements of a generating station. Studies have indicated that employing CCS on a natural gas-fired combined cycle facility could increase water consumption by more than 90%. Texas is currently experiencing widespread drought conditions and increased water consumption for electricity generation is not practical or economical, and may not be possible for the foreseeable future.

5.1.4.2 CO_2 Transport

Even if it is assumed that CO_2 capture and compression could feasibly be achieved for the proposed Project, the high-volume CO_2 stream generated would need to be transported to a facility capable of storing it. Potential geologic storage sites in Texas, Louisiana, and Mississippi to which CO_2 could be transported (if a supporting pipeline was constructed) are delineated on the map found at the end of Section 5.[21] The potential length of such a CO_2

[20] DOE-NETL, *Carbon Sequestration Program: Technical Program Plan,* at 10 (Feb. 2011).

[21] Susan Hovorka, University of Texas at Austin, Bureau of Economic Geology, Gulf Coast Carbon Center, *New Developments: Solved and Unsolved Questions Regarding Geologic Sequestration of CO_2 as a Greenhouse Gas Reduction Method* (GCCC Digital Publication #08-13) at slide 4 (Apr. 2008), available at: http://www.beg.utexas.edu/gccc/forum/codexdownloadpdf.php?ID=100(last visited Feb. 27, 2012).

transport pipeline is uncertain due to the uncertainty of identifying a site(s) that is suitable for large-scale, long-term CO_2 storage. The hypothetical minimum length required for any such pipeline(s) is the distance to the closest site with recognized potential for some geological storage of CO_2, which is a Pennsylvanian Oil Play Enhanced Oil Recovery (EOR) candidate reservoir site located approximately 20 miles from the Project site.

However, none of the north-central Texas EOR reservoir or other geologic formation sites have yet been technically demonstrated for large-scale, long-term CO_2 storage, as discussed further in Section 5.1.4.3.

In comparison, the closest site that is currently being field-tested to demonstrate its capacity for large-scale geological storage of CO_2 is the Scurry Area Canyon Reef Operators Committee (SACROC) oilfield site, located in Scurry County, Texas, approximately 200 miles west of the Project site (see the map at the end of Section 5 for the test site location). Therefore, to access this potentially large-scale storage capacity site, and assuming that it is eventually demonstrated capable of indefinitely storing a substantial portion of the large volume of CO_2 generated by the proposed Project, a very long and sizable pipeline would need to be constructed to transport the large volume of high-pressure CO_2 from EMSES to the storage facility, thereby rendering implementation of a CO_2 transport system infeasible due to the complexities and cost of doing so.

5.1.4.3 CO_2 Storage

Even if it is assumed that CO_2 capture and compression could feasibly be achieved for the proposed Project and that the CO_2 could be transported economically, the feasibility of CCS technology would still depend on the availability of a suitable sequestration site. The suitability of potential storage sites is a function of volumetric capacity of their geologic formations, CO_2 trapping mechanisms within formations (including dissolution in brine, reactions with minerals to form solid carbonates, and/or adsorption in porous rock), and potential environmental impacts resulting from injection of CO_2 into the formations. Potential environmental impacts resulting from CO_2 injection that still require assessment before CCS technology can be considered feasible include:

- Uncertainty concerning the significance of dissolution of CO_2 into brine,
- Risks of brine displacement resulting from large-scale CO_2 injection, including a pressure leakage risk for brine into underground drinking water sources and/or surface water,
- Risks to fresh water as a result of leakage of CO_2, including the possibility for damage to the biosphere, underground drinking water sources, and/or surface water,[22] and
- Potential effects on wildlife.

[22] *Id.*

Potentially suitable storage sites, including EOR sites and saline formations, exist in Texas, Louisiana, and Mississippi. In fact, sites with some potential for geological storage of CO_2 are located approximately 20 miles west-northwest of the proposed Project, but such sites have not yet been technically demonstrated with respect to all of the suitability factors described above. In comparison, the closest site that is being field-tested to demonstrate its capacity for geological storage of the volume of CO_2 that would be generated by the proposed power unit is the aforementioned SACROC oilfield site, located approximately 200 miles west-northwest of the Project site. It should be noted that, based on the suitability factors described above, the suitability of the SACROC oilfield site or any other test site to store a substantial portion of the large volume of CO_2 generated by the proposed Project has yet to be demonstrated.

Based on the reasons provided above, EMPC concludes that CCS technology should be eliminated from further consideration as a potential feasible control technology for purposes of this BACT analysis. However, to answer possible questions that the public or the EPA may have concerning the relative costs of implementing hypothetical CCS systems, EMPC has estimated such costs. Construction of a carbon capture system at the EMSES site would require, at a minimum, installation of the following major pieces of equipment:

- Two Amine Scrubber Vessels
- Two CO_2 Strippers
- Four Amine Transfer Pumps
- Four Flue Gas Fans
- Four CO_2 Gas Compressors
- One Amine Storage Tank.

The estimated costs associated with implementation of a carbon capture system for the Project are shown in the table below. A control cost for implementing CCS in terms of \$/ton of CO_2 sequestered was calculated using the "cost of electricity" methodology outlined in the U.S. Department of Energy document "Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity", Revision2a, September 2013, DOE/NETL-2010/1397. Most of the inputs into this table were the default values from the DOE/NETL document except for the distance to the CCS storage site. This distance was increased from 100 km to 322 km. The calculated costs for CCS were still very comparable to the DOE/NETL results.

Summary of Estimated CCS Implementation Costs

	Two Combustion Turbines and One Steam Turbine Without CCS	Two Combustion Turbines and One Steam Turbine With CCS
Cost-of-Electricity (COE) (\$/MWh) @ 85% capacity factor	57.3 \$/MWh	97.40 \$/MWh
CO_2 Emissions (Siemens SGT6-5000F(5)ee)	2,997,842 tons/yr	299,784 tons/yr
Cost of CO_2 Avoided		\$89.11/ton CO_2

In addition to the high construction and operating costs associated with CCS, the carbon capture equipment requires a substantial amount of energy to operate, thereby reducing the net electrical output of the plant. Operation of carbon capture equipment at a typical natural gas-fired combined cycle plant is estimated to reduce the net energy efficiency of the plant from approximately 50% (HHV) to approximately 42.9% (HHV).[23] Furthermore, the additional costs associated with CCS would be expected to result in reduced annual utilization in the competitive Texas power market relative to a combined cycle plant without CCS. Therefore, the cost per ton removed would be expected to exceed that shown in the table above approximately in proportion to the reduced utilization.

5.1.5 Step 5: Select BACT

EMPC proposes the following energy efficiency processes, practices, and designs as BACT for the proposed combined cycle combustion turbines:

- Use of Combined cycle Power Generation Technology
- Combustion Turbine Energy Efficiency Processes, Practices, and Designs
    - Efficient turbine design
    - Turbine inlet air cooling
    - Periodic turbine burner tuning
    - Reduction in heat loss
    - Instrumentation and controls
- HRSG Energy Efficiency Processes, Practices, and Designs
    - Efficient heat exchanger design
    - Insulation of HRSG
    - Minimizing Fouling of heat exchange surfaces
    - Minimizing vented steam and repair of steam leaks
- Steam Turbine Energy Efficiency Processes, Practices, and Designs
    - Use of Reheat Cycles
    - Use of Exhaust Steam Condenser
    - Efficient Blading Design
    - Efficient Generator Design
- Additional Energy Efficiency Processes, Practices, and Designs
    - Fuel gas preheating
    - Drain operation
    - Multiple combustion turbine/HRSG trains
    - Boiler feed pump fluid drive design.

To determine the appropriate heat-input efficiency limit, EMPC started with the turbine's design baseload gross heat rate for combined cycle operation and then calculated a compliance margin

[23] U.S. Department of Energy, National Energy Technology Laboratory, "Costs and Performance Baseline For Fossil Energy Plants, Volume 1 - Bituminous Coal and Natural Gas to Energy", Revision 2a, September 2013

based upon reasonable degradation factors that may foreseeably reduce efficiency under real-world conditions. The design baseload gross heat rate for the combustion turbines being considered for the Project are as follows: the General Electric 7FA.05 design baseload gross heat rate is 6400 Btu/kWh (HHV) without duct burner firing and 6575 Btu/kWh (HHV) with duct burner firing; and the Siemens SGT6-5000F(5)ee design baseload gross heat rate is 6522 Btu/kWh (HHV) without duct burner firing and 6836 Btu/kWh (HHV) with duct burner firing.

To determine an appropriate heat rate limit for the permit, the following compliance margins are added to the base heat rate limit:

- A 3.3% design margin reflecting the possibility that the constructed facility will not be able to achieve the design heat rate.
- A 6% degradation margin reflecting efficiency losses due to equipment degradation prior to maintenance overhauls.
- A 3% performance margin reflecting the variability in operation of auxiliary plant equipment due to use over time.

Design and construction of a combined cycle power plant involves many assumptions about anticipated performance of the many elements of the plant, which are often imprecise or not reflective of conditions once installed at the site. As a consequence, the facility also calculates an "Installed Base Heat Rate", which represents a design margin of 3.3% to address such items as equipment underperformance and short-term degradation.

To establish an enforceable BACT condition that can be achieved over the life of the facility, the permit limit must also account for anticipated degradation of the equipment over time between regular maintenance cycles. The manufacturer's degradation curves project anticipated degradation rate of 5% within the first 48,000 hours of the gas turbine's useful life; they do not reflect any potential increase in this rate which might be expected after the first major overhaul and/or as the equipment approaches the end of its useful life. Further, the projected 5% degradation rate represents the average, and not the maximum or guaranteed, rate of degradation for the gas turbines. Therefore, EMPC proposes that, for purposes of deriving an enforceable BACT limitation on the proposed facility's heat rate, gas turbine degradation may reasonably be estimated at 6% of the facility's heat rate.

Finally, in addition to the heat rate degradation from normal wear and tear on the combustion turbines, EMPC is also providing a reasonable performance margin of 3% based on potential degradation in other elements of the combined cycle plant that would cause the overall plant heat rate to rise (*i.e.*, cause efficiency to fall). Degradation in the performance of the heat recovery steam generator, steam turbine, heat transfer, and ancillary equipment such as pumps and motors is also expected to occur over the course of a major maintenance cycle. The calculation of the gross heat rate and the equivalent lb CO_2/MWhr is provided on Tables 5-1 and 5-2 of this application.

EMPC is proposing the following BACT limits for the Project:

Turbine Model	Gross Heat Rate (Btu/kWh) (HHV)	Output Based Emission Limit (lb CO_2/MWh) gross
General Electric 7FA.05 (with duct burner firing)	7415	881.4
Siemens SGT6-5000F(5)ee (with duct burner firing)	7710	916.4

The proposed BACT limits vary by 3.8% between the two turbine variants. While energy efficiency will be a consideration for final selection of a turbine, other considerations will include the capacity of the turbine, cost, reliability, and predicted longevity of the turbines. Since the plant heat rate varies according to turbine operating load and the amount of duct burner firing, EMPC proposes to demonstrate compliance with the proposed heat rate utilizing a 12-month rolling average compliance period. This compliance period is necessary to accommodate conditions where there may be extended periods of operation at low loads and the potential for high use of duct burners.

On January 8, 2014, EPA published in the Federal Register its proposed new source performance standard for emissions of carbon dioxide for new affected fossil fuel-fired electric utility generating units. EPA proposed two options for codifying the requirements: (1) amend existing NSPS Subparts Da (Standards of Performance for Electric Utility Steam Generating Units) and KKKK (Standards of Performance for Stationary Combustion Turbines), or (2) create new NSPS Subpart TTTT (Standards of Performance for Greenhouse Gas Emissions for Electric Utility Generating Units). The proposed rule would apply to new fossil-fuel-fired steam electric generating units that begin construction after the effective date of the final published rule and sell more than one-third of their potential output and more than 219,000 MWh net electrical output to the grid on an annual basis. The EPA proposed that new combustion turbines with a design heat input greater than 850 MMBtu/hr meet an annual average output based standard of 1,000 lb CO_2/MWh gross. The proposed CO_2 emission rates from the EMPC combined cycle turbines are within the emission limit in the proposed NSPS Subpart KKKK or TTTT.

EMPC performed a search of the EPA's RACT/BACT/LAER Clearinghouse (RBLC) for natural gas-fired combustion turbine generators and found numerous entries which address BACT for GHG emissions. The results of the RBLC search are included in Table 5-3 of this application. This table presents a summary of the type(s) of units at these facilities and their proposed or permitted BACT limits.

Although there are differences in the technologies proposed by each plant, as well as differences in the basis of the proposed limits (i.e. net vs. gross output basis, with or without duct burners, mass emission rate limits or not, etc.), the summary presented above demonstrates that the limits proposed by EMPC are comparable to recently issued permits.

Therefore, EMPC concludes that the combination of the ton per year and output-based limits proposed in this application are BACT for the Project.

5.2 BACT FOR SF_6 INSULATED ELECTRICAL EQUIPMENT

5.2.1 Step 1: Identify All Available Control Technologies

Step 1 of the Top-Down BACT analysis is to identify all available control technologies. An available technology is the use of state-of-the-art SF_6 technology with leak detection to limit fugitive emissions. In comparison to older SF_6 circuit breakers, modern breakers are designed as a totally enclosed-pressure system with far lower potential for SF_6 emissions. In addition, the effectiveness of leak-tight closed systems can be enhanced by equipping them with a density alarm that provides a warning when 10% of the SF_6 (by weight) has escaped. The use of an alarm identifies potential leak problems before the bulk of the SF_6 has escaped, so that it can be addressed proactively in order to prevent further release of the gas.

Another available technology that was considered in this analysis is to substitute another, non-GHG substance for SF_6 as the dielectric material in the breakers. Potential alternatives to SF_6 were addressed in the National Institute of Standards and Technology (NTIS) Technical Note 1425, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF_6.*[24]

5.2.2 Step 2: Eliminate Technically Infeasible Options

According to the report NTIS Technical Note 1425, SF_6 is a superior dielectric gas for nearly all high voltage applications.[25] It is easy to use, exhibits exceptional insulation and arc-interruption properties, and has proven its performance by many years of use and investigation. It is clearly superior in performance to the air and oil insulated equipment used prior to the development of SF_6-insulated equipment. The report concluded that although "...various gas mixtures show considerable promise for use in new equipment, particularly if the equipment is designed specifically for use with a gas mixture... it is clear that a significant amount of research must be performed for any new gas or gas mixture to be used in electrical equipment." Therefore substituting another, non-GHG substance for SF_6 as the dielectric material in the breakers is not technically feasible.

5.2.3 Step 3: Rank Remaining Control Technologies

The use of state-of-the-art SF_6 technology with leak detection to limit fugitive emissions is the only control technology that is technically feasible for this application.

[24] Christophorous, L.G., J.K. Olthoff, and D.S. Green, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF_6,* NIST Technical Note 1425, Nov.1997.
[25] *Id.* at 28 – 29.

5.2.4 Step 4: Evaluate Most Effective Controls and Document Results

Energy, environmental, or economic impacts were not addressed in this analysis because the use of alternative, non-GHG substance for SF_6 as the dielectric material in the breakers is not technically feasible.

5.2.5 Step 5: Select BACT

Based on this top-down analysis, EMPC concludes that using state-of-the-art enclosed-pressure SF_6 circuit breakers with leak detection is BACT. The circuit breakers will be designed to meet the latest American National Standards Institute (ANSI) C37.013 standard for high voltage circuit breakers.[26] The proposed SF_6 circuit breakers will each have a low pressure alarm and a low pressure lockout. This alarm will function as an early leak detector that will bring potential fugitive SF_6 emissions leaks to the attention of the operations/maintenance staff before a substantial portion of the SF_6 escapes. The lockout prevents any operation of the breaker due to lack of "quenching and cooling" SF_6 gas.

EMPC will monitor emissions annually in accordance with the requirements of the Mandatory Greenhouse Gas Reporting rules for Electrical Transmission and Distribution Equipment Use.[27] Annual SF_6 emissions will be calculated according to the mass balance approach in Equation DD-1 of Subpart DD.

5.3 BACT FOR AUXILIARY BOILER

One nominally rated 73.3-MMBtu/hr auxiliary boiler will be utilized to facilitate startup of the combined cycle units.

5.3.1 Step 1: Identify All Available Control Technologies

Step 1 of the Top-Down BACT analysis is to identify all available control technologies. The following technologies were identified as potential control options for boilers:

- Carbon capture and sequestration
- Use of low carbon fuels
- Use of good operating and maintenance practices
- Energy efficient design

As stated in the combustion turbine BACT discussion above, CCS was eliminated as possible BACT. The economics of applying such technology to the auxiliary boiler is even more

[26] ANSI Standard C37.013, *Standard for AC High-Voltage Generator Circuit Breakers on a Symmetrical Current.*
[27] *See* 40 CFR Pt. 98, Subpt. DD.

exacerbated due to the intermittent operations of the auxiliary boiler as well as its low CO_2 concentration in the flue gas. As such, CCS will not be further evaluated as BACT for the auxiliary boiler.

The auxiliary boiler will utilize natural gas which is the lowest carbon fuel available at the EMSES site. Therefore, formation of CO_2 from combustion of the fuel will be minimized.

Good operating and maintenance practices for the boiler include following the manufacturer's recommended operating and maintenance procedures; maintaining good fuel mixing in the combustion zone; and maintaining the proper air/fuel ratio so that sufficient oxygen is provided to provide complete combustion of the fuel while at the same time preventing introduction of more air than is necessary into the boiler.

The energy efficient design of the boiler includes insulation to retain heat within the boiler and a computerized process control system that will optimize the fuel/air mixture and limit excess air in the boiler.

5.3.2 Step 2: Eliminate Technically Infeasible Options

CCS was discussed above for the combined cycle unit, and it was determined that it is technically infeasible for application on a commercial scale power plant at this time. The same holds true for the auxiliary boiler.

5.3.3 Step 3: Rank Remaining Control Technologies

As discussed above, the only potential post-combustion options for GHG removal are all technically infeasible for application on the auxiliary boiler at this time. This leaves efficient combustion, processes, practices, and designs as the only available control option.

5.3.4 Step 4: Evaluate Most Effective Controls and Document Results

Efficient processes, practices, and design considerations are the only remaining control options for the auxiliary boiler.

5.3.5 Step 5: Select BACT

Based on this top-down analysis, EMPC concludes that the use of natural gas as a low carbon fuel; good operating and maintenance practices and the energy efficient design are selected as BACT for the auxiliary boiler.

EMPC performed a search of the EPA's RBLC and GHG permits issued by EPA Region 6 for natural gas-fired steam boilers and a summary of GHG BACT limits for natural gas-fired boilers less than or equal to 100 MMBtu/hr is provided in attached Table 5-4. For six of the seven GHG Permits for boilers, BACT consisted of an annual CO_2e emission limit and good combustion practices. One of the boilers, St. Joseph Energy Center, included a requirement that the boiler be designed to meet 80% thermal efficiency, as demonstrated with a one-time initial performance test, in addition to an annual CO_2e emission limit. The BACT for the auxiliary boiler proposed for this application is comparable to recently issued permits for similar sized natural-gas fired boilers.

5.4 BACT FOR EMERGENCY ENGINES

The EMPC project will include one nominally rated 1,340-hp diesel-fired emergency generator to provide electricity to the facility in case of power failure and one nominally rated 282-hp diesel-fired water pump to provide water in the event of a fire.

5.4.1 Step 1: Identify All Available Control Technologies

Step 1 of the Top-Down BACT analysis is to identify all available control technologies. The following technologies were identified as potential control options for emergency engines:

- Use of low carbon fuel
- Use of good operating and maintenance practices
- Low annual capacity factor.

Engine options include engines powered with electricity, natural gas, or liquid fuel, such as gasoline or fuel oil.

Good operating and maintenance practices for the engines include the following:

- Operating with recommended fuel to air ratio recommended by the manufacturer and
- Appropriate maintenance of equipment, such as periodic readiness testing.

Each emergency engine will be limited to 100 hours of non-emergency operation per year for purposes of maintenance checks and readiness testing.

5.4.2 Step 2: Eliminate Technically Infeasible Options

This step of the top-down BACT analysis eliminates any control technology that is not considered technically feasible. The purpose of the engines is to provide a power source during emergencies, which includes outages of the combustion turbines, natural gas supply outages, and natural disasters, such as floods and hurricanes. As such, the engines must be available during emergencies. Electricity and natural gas may not be available during an emergency and therefore cannot be used as an energy source for the emergency engines.

The engines must be powered by a liquid fuel that can be stored on-site in a tank and supplied to the engines on demand, such as gasoline or diesel fuels. The default CO_2 emission factors for gasoline and diesel are very similar, 70.22 kg/MMBtu for gasoline and 73.96 kg/MMBtu for diesel. Diesel fuel has a much lower volatility than gasoline and can be stored for longer periods of time. Therefore, diesel is typically the chosen fuel for emergency engines.

Because of the need to store the emergency engine fuel on-site and the ability to store diesel for longer periods of time than gasoline, it is technically infeasible to utilize a lower carbon fuel than diesel.

The use of good operating and maintenance practices is technically feasible for the emergency engines. Also, a low annual capacity factor for the engines is technically feasible since the engines will only be operated either for readiness testing or for actual emergencies.

5.4.3 Step 3: Rank Remaining Control Technologies

Since the remaining technically feasible processes, practices, and designs discussed in Section 5.4.1 of this application for the emergency engines are being proposed for the engines, a ranking of the control technologies is not necessary for this application.

5.4.4 Step 4: Evaluate Most Effective Controls and Document Results

Since the remaining technically feasible processes, practices, and designs discussed in Section 5.4.1 of this application for the emergency engines are being proposed for the engines, an evaluation of the most effective controls is not necessary for this application.

5.4.5 Step 5: Select BACT

As a result of this analysis, appropriate operation of the engines through proper fuel to air ratios and maintenance based on recommended readiness testing and low annual hours of operation are selected as BACT for the proposed engines.

From the RBLC, several facilities had GHG BACT items stated for diesel fuel-fired emergency engines. All of the RBLC results for diesel fuel-fired emergency engines included an annual GHG emission limits and annual operating hour limits. The BACT for the diesel fuel-fired emergency engines proposed for this application is comparable to recently issued permits for similar diesel fuel fired emergency engines.

5.5 BACT FOR NATURAL GAS FUGITIVES

The proposed Project will include natural gas piping components. These components are potential sources of methane and CO_2 emissions due to emissions from rotary shaft seals, connection interfaces, valve stems, and similar points.

5.5.1 Step 1: Identify All Available Control Technologies

Step 1 of the Top-Down BACT analysis is to identify all feasible control technologies. The following technologies were identified as potential control options for piping fugitives:

- Implementation of leak detection and repair (LDAR) program using a hand held analyzer
- Implementation of alternative monitoring using a remote sensing technology such as infrared cameras
- Implementation of audio/visual/olfactory (AVO) leak detection program.

5.5.2 Step 2: Eliminate Technically Infeasible Options

This step of the top-down BACT analysis eliminates any control technology that is not considered technically feasible. The use of instrument LDAR and remote sensing technologies are technically feasible. Since pipeline natural gas is odorized with a small amount of mercaptan, an AVO leak detection program for natural gas piping components is technically feasible.

5.5.3 Step 3: Rank Remaining Control Technologies

The use of a LDAR program with a portable gas analyzer meeting the requirements of 40 CFR 60, Appendix A, Method 21, can be effective for identifying leaking methane. Quarterly instrument monitoring with a leak definition of 10,000 part per million by volume (ppmv) (TCEQ 28M LDAR Program) is generally assigned a control efficiency of 75% for valves, relief valves, sampling connections, and compressors and 30% for flanges.[28] Quarterly instrument monitoring with a leak definition of 500 ppmv (TCEQ 28VHP LDAR Program) is generally assigned a control efficiency of 97% for valves, relief valves, and sampling connections, 85% for compressors, and 30% for flanges.[29] The U.S. EPA has allowed the use of an optical gas imaging instrument as an alternative work practice for a Method 21 portable analyzer for monitoring equipment for leaks in 40 CFR 60.18(g). For components containing inorganic or odorous compounds, periodic AVO walk-through inspections provide predicted control efficiencies of 97% control for valves, flanges, relief valves, and sampling connections, and 95% for compressors.[30]

[28] Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, TCEQ, Oct. 2000
[29] Id. at page 52.
[30] Id. at page 52.

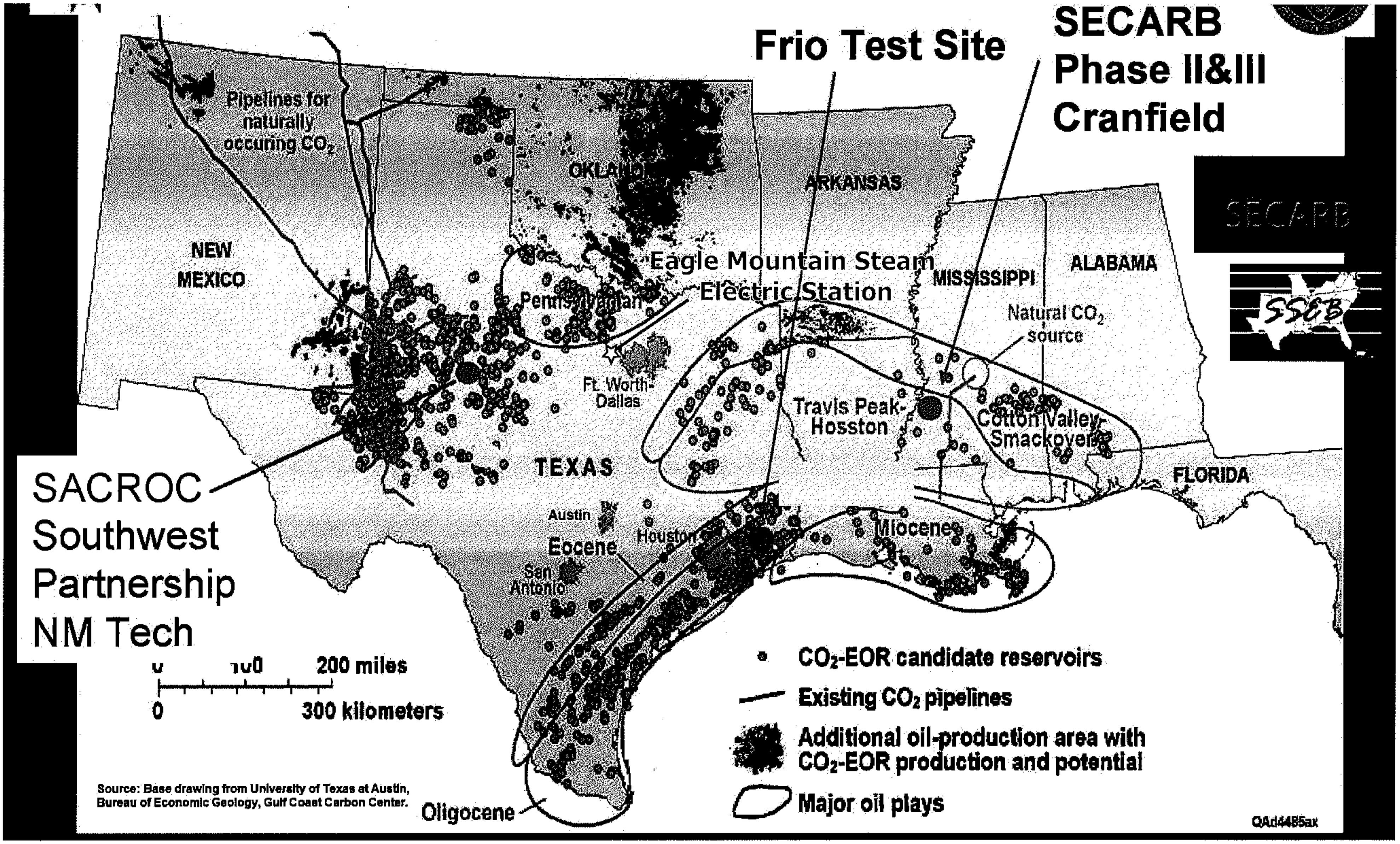
5.5.4 Step 4: Evaluate Most Effective Controls and Document Results

The frequency of inspection and the low odor threshold of mercaptans in natural gas make AVO inspections an effective means of detecting leaking components in natural gas service. As discussed in Section 5.5.3, the predicted emission control efficiency is comparable to the LDAR programs using Method 21 portable analyzers.

5.5.5 Step 5: Select BACT

Due to the very low volatile organic compound (VOC) content of natural gas, the Project will not be subject to any VOC leak detection programs by way of its State/PSD air permit, TCEQ Chapter 115 – Control of Air Pollution from Volatile Organic Compounds, New Source Performance Standards (40 CFR Part 60), National Emission Standard for Hazardous Air Pollutants (40 CFR Part 61); or National Emission Standard for Hazardous Air Pollutants for Source Categories (40 CFR Part 63). Therefore, any leak detection program implemented will be solely due to potential greenhouse emissions. Since the uncontrolled CO_2e emissions from the natural gas piping represent approximately 0.01% of the total site wide CO_2e emissions, any emission control techniques applied to the piping fugitives will provide minimal CO_2e emission reductions.

Based on this top-down analysis, EMPC concludes that a daily AVO inspection program is BACT for piping components in natural gas service.



Distance to nearest CO2-EOR candidate reservoir ~ 11 miles
Distance to SACROC Southwest Parntership NM Tech ~ 173 miles

Table 5-1
GHG Emission Calculations - Calculation of Design Heat Rate and Output Limits for GE 7FA.05
Eagle Mountain Steam Electric Station
Eagle Mountain Power Company LLC

Without Duct Burner Firing

	Gross Output Basis	
Base Heat Rate:	**6,400**	Btu/kWh (HHV)
Design Margin:	3.3%	
CTG Degradation Margin:	6.0%	
Plant Degradation Margin:	3.0%	
Adjusted Base Heat Rate with Compliance Margins:	**7,218**	Btu/kWh (HHV)

EPN	Base Heat Rate (Btu/kWhr)	Electrical Output Basis	Heat Input Required to Produce 1 MW (MMBtu/MWhr)	Pollutant	Emission Factor (lb/MMBtu)[1]	lb GHG/MWhr[2]	Global Warming Potential[3]	lb CO_2e/MWhr[4]
EM-CT1S & EM-CT2S	7,218	Gross	7.22	CO_2	118.86	857.92	1	857.92
				CH_4	2.2E-03	1.59E-02	25	3.98E-01
				N_2O	2.2E-04	1.59E-03	298	4.74E-01
					Total:	**857.9**		**858.8**

With Duct Burner Firing

	Gross Output Basis	
Base Heat Rate:	**6,575**	Btu/kWh (HHV)
Design Margin:	3.3%	
CTG Degradation Margin:	6.0%	
Plant Degradation Margin:	3.0%	
Adjusted Base Heat Rate with Compliance Margins:	**7,415**	Btu/kWh (HHV)

EPN	Base Heat Rate (Btu/kWhr)	Electrical Output Basis	Heat Input Required to Produce 1 MW (MMBtu/MWhr)	Pollutant	Emission Factor (lb/MMBtu)[1]	lb GHG/MWhr[2]	Global Warming Potential[3]	lb CO_2e/MWhr[4]
EM-CT1S & EM-CT2S	7,415	Gross	7.42	CO_2	118.86	881.38	1	881.38
				CH_4	2.2E-03	1.63E-02	25	4.09E-01
				N_2O	2.2E-04	1.63E-03	298	4.87E-01
					Total:	**881.4**		**882.3**

Note

1. CH_4 and N_2O GHG factors based on Table C-2 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.
2. *CO_2 emissions based on 40 CFR Part 75, Appendix G, Equation G-4*

$W_{CO2} = (F_c \times H \times U_f \times MW_{CO2})/2000$

W_{CO2} = CO_2 emitted from combustion, tons/yr

F_c = Carbon based F-factor, 1040 scf/MMBtu

H = Heat Input (MMBtu/yr)

MW_{CO2} = Molecule weight of CO_2, 44.0 lb/lbmole

3. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*
4. *Example calculation: GHG emissions (lbs) x Global Warming Potential / 1 MW = lb CO_2e/MWhr*

Table 5-2
GHG Emission Calculations - Calculation of Design Heat Rate and Output Limits for Siemens SGT6-5000F(5)ee
Eagle Mountain Steam Electric Station
Eagle Mountain Power Company LLC

Without Duct Burner Firing

	Gross Output Basis	
Base Heat Rate:	**6,522**	Btu/kWh (HHV)
Design Margin:	3.3%	
CTG Degradation Margin:	6.0%	
Plant Degradation Margin:	3.0%	
Adjusted Base Heat Rate with Compliance Margins:	**7,356**	Btu/kWh (HHV)

EPN	Base Heat Rate (Btu/kWhr)	Electrical Output Basis	Heat Input Required to Produce 1 MW (MMBtu/MWhr)	Pollutant	Emission Factor (lb/MMBtu)[1]	lb GHG/MWhr[2]	Global Warming Potential[3]	lb CO_2e/MWhr[4]
EM-CT1S & EM-CT2S	7,356	Gross	7.36	CO_2	118.86	874.28	1	874.28
				CH_4	2.2E-03	1.62E-02	25	4.05E-01
				N_2O	2.2E-04	1.62E-03	298	4.83E-01
					Total:	**874.3**		**875.2**

With Duct Burner Firing

	Gross Output Basis	
Base Heat Rate:	**6,836**	Btu/kWh (HHV)
Design Margin:	3.3%	
CTG Degradation Margin:	6.0%	
Plant Degradation Margin:	3.0%	
Adjusted Base Heat Rate with Compliance Margins:	**7,710**	Btu/kWh (HHV)

EPN	Base Heat Rate (Btu/kWhr)	Electrical Output Basis	Heat Input Required to Produce 1 MW (MMBtu/MWhr)	Pollutant	Emission Factor (lb/MMBtu)[1]	lb GHG/MWhr[2]	Global Warming Potential[3]	lb CO_2e/MWhr[4]
EM-CT1S & EM-CT2S	7,710	Gross	7.71	CO_2	118.86	916.37	1	916.37
				CH_4	2.2E-03	1.70E-02	25	4.25E-01
				N_2O	2.2E-04	1.70E-03	298	5.07E-01
					Total:	**916.4**		**917.3**

Note
1. CH_4 and N_2O GHG factors based on Table C-2 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.
2. *CO_2 emissions based on 40 CFR Part 75, Appendix G, Equation G-4*
$W_{CO2} = (F_c \times H \times U_f \times MW_{CO2})/2000$
W_{CO2} = CO_2 emitted from combustion, tons/yr
H = Heat Input (MMBtu/yr)
U_f = 1/385 scf CO_2/lbmole at 14.7 psia and 68 °F
MW_{CO2} = Molecule weight of CO_2, 44.0 lb/lbmole
3. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*
4. *Example calculation: GHG emissions (lbs) x Global Warming Potential / 1 MW = lb CO_2e/MWhr*

Table 5-3
Natural Gas Fired Combustion Turbine GHG BACT Summary Table
Eagle Mountain Steam Electric Station
Eagle Mountain Power Company LLC

Facility Name	Permit Date	Permit Number	Location	Plant Type	Type(s) of Units	Output-Based GHG Emission Limit	Heat Rate Limit	Averaging Period
Russell City Energy Center	02/03/10	15487	Hayward, CA	Natural gas fired combined cycle plant	Siemens/Westinghouse 501F with 200 MMBtu/hr duct burners (2 on 1 configuration)		7730 Btu (HHV)/kWh (net) without duct firing (ISO Conditions)	Annual heat rate performance test at maximum load
Sumpter Power Plant	11/17/11	81-11	Wayne County, MI	Natural gas fired combined cycle plant	Proposed project is to convert Unit 4 to a combined-cycle combustion turbine by adding a non-fired heat recovery steam generator (HRSG).	954 lb CO2/MW-hr (gross)		12 month rolling average
Gateway Cogeneration 1, LLC-Smart Water Project	08/27/12	52375-002	Prince George County, VA	Natural gas fired combined cycle plant	Combined cycle electrical power generating facility (160 MW), consisting of two combustion turbines (Rolls Royce Trent 60 WLE) with associated HRSG and no duct burning.	1050 LB CO2/MWH	8,983 Btu/kWh (HHV gross)	12 operating month average
Deer Park Energy Center	11/29/12	PSD-TX-979-GHG	Deer Park, TX	Natural Gas/Refinery Gas Fired Cogeneration unit added to existing power plant.	One Siemens FD-2 501F with 725 MMBtu/hr Duct Burners in Phase 1, upgraded to Siemens FD-3 501F in Phase 2 (5 on 1 configuration + provide steam to neighboring plant)	0.460 ton (920 lb) CO2/MWh (net)	7730 Btu(HHV)/kWh net (ISO conditions, without duct firing)	30-day rolling average
Channel Energy Center	11/29/12	PSD-TX-955-GHG	Pasadena, TX	Natural Gas/Refinery Gas Fired Cogeneration unit added to existing power plant.	One Siemens FD-2 501F with 475 MMBtu/hr duct burners in Phase 1, upgraded to Siemens FD-3 501F in Phase 2 (3 on 1 configuration + provided steam to neighboring plant)	0.460 ton (920 lb) CO2/MWh (net)	7730 Btu(HHV)/kWh net (ISO conditions, without duct firing)	30-day rolling average
St. Joseph Energy Center	12/03/12	141-31003-00579	St. Joseph County, IN	Natural gas fired combined cycle plant	Four (4) natural gas-fired combined cycle combustion turbines with natural gas fired duct burners		7,646 Btu/kW-hr (HHV-net) ISO conditions, baseload operation without duct firing or inlet evaporative cooling, and not accounting for transformer losses	
GARRISON ENERGY CENTER, LLC/ CALPINE CORPORATION	01/30/13	APC-2012/0098	Kent County, DE	Natural gas fired combined cycle plant	309 MW GE Combined Cycle Combustion Turbine Generating system fired principally on Natural Gas,	The RBLC only lists a ton/yr limit for CO_2e.		
Virginia Electric And Power Company, Brunswick County Power Station	02/12/13	6/22	Brunswick County, VA	Natural gas fired combined cycle plant	Three Gas Turbines (Mitsubishi M501 GAC combustion turbine generator with HRSG duct burner)	920 lbs CO2/MWh (net HHV)	7,500 Btu/kWh net (HHV) output	12 operating month average
Pioneer Valley Energy Center	04/12/13	052-042-MA15	Westfield, MA	New Natural Gas Fired Combined Cycle	One Mitsubishi M501G Turbine without duct firing (1 on 1 Configuration)	825 lb CO_2e/MWh_{grid}, (initial limit) and 895 lb CO_2e/MWh_{grid} (rolling average)		365-day rolling average
Midland Cogeneration Venture	04/23/13	103-12	Midland County, MI	Natural gas fueled (including propane and liquified petroleum gas) combined cycle combustion turbine generators	Two Gas Turbines with 249 MMBtu/hr duct burners (3 possible turbine models: GE 7FA, Siemens SGT6-5000F(4) or SGT6-5000F(5)). (2 on 1 configuration)	995.0 lb CO2/MW-hr gross energy output without duct firing; 1,071.0 lb/MW-hr gross energy output with duct firing		12 operating month average
Hickory Run Energy Station	04/23/13	37-337A	Lawrence County, PA	Natural gas fired combined cycle plant	Two Gas Turbines with 750 MMBtu/hr duct burners (four possible turbine models: 1. General Electric 7FA (GE 7FA) 2. Siemens SGT6-5000F (Siemens F) 3. Mitsubishi M501G (Mitsubishi G) 4. Siemens SGT6-8000H (Siemens H))	1,000 lb CO2 / MW-hr (gross)		12 operating month average

Table 5-3
Natural Gas Fired Combustion Turbine GHG BACT Summary Table
Eagle Mountain Steam Electric Station
Eagle Mountain Power Company LLC

Arcadis, US, INC., Oregon Clean Energy Center	06/18/13	P0110840	Lucas, OH	Natural gas fired combined cycle plant	Either 2 Mitsubishi M501 GAC units or 2 Siemens SGT-8000H units, not both; with 300 MMBtu/hr duct fired heat recovery steam generators (HRSG), steam turbine generator, and electric generator.	840 lb CO2/MWh (gross) carbon dioxide equivalent (CO2e)		12 operating month average
Consumers Energy Company	07/25/13	191-12	enesee County, N	Natural gas fired combined cycle plant	Four natural gas fired combustion turbines with duct burners	TPY limit for CO2e only		
Cricket Valley Energy Center	09/12/13	3-1326-00275/00004	Dover, NY	New Natural gas fired combined cycle	Three GE 7FA turbines with 596.8 MMBtu/hr duct burners) (3 on 3 configuration)	None	The permit states the facility is subject to a CO2 Budget Trading Program but there is no heat rate limit in permit. Applicant proposed 7605 Btu/kWh (HHV) (ISO conditions and no Duct Burner-firing) in application. The application does not specify whether it is on a gross electrical output basis or net electrical output basis.	
Palmdale Hybrid Power Project	10/11/13	SE-09-01	Palmdale, CA	New Natural gas fired combined cycle	Two GE 7FA turbines with 500 MMBtu/hr duct burners. (2 combustion turbine on 1 steam turbine configuration)	774 lb CO_2/MWh (net)	7319 Btu (HHV)/kWh (net)	365-day rolling average
LCRA Ferguson Plan	11/11/13	PSD-TX-1244-GHG	Marble Falls, TX	New Natural gas fired combined cycle	Two GE 7FA turbines (without duct burners) (2 on 1 configuration)	0.459 ton (918 lbs)CO_2/MWh (net)	7720 Btu (HHV)/kWh (net)	365-day rolling average
La Paloma Energy Center	11/16/13	PSD-TX-1288-GHG	Harlingen, TX	Natural gas fired combined cycle plant	Two Gas Turbines with 750 MMBtu/hr duct burners (3 possible turbine models: GE 7FA, Siemens SGT6-5000F(4) or SGT6-5000F(5)). (2 on 1 configuration)	Output-Based Limits (excludes startup hours): 934.5 lb CO_2/MWh (gross) with Duct Firing [GE 7FA]; 909.2 lb CO_2/MWh (gross) with Duct Firing [SGT6-5000F(4); 912.7 lb CO_2/MWh (gross) with Duct Firing [SGT6-5000F(5);	Heat Rates in Draft Permit (excludes startup hours): 7,861.8 Btu (HHV)/kWh (gross) with duct firing [GE 7FA] 7,649.0 Btu (HHV)/kWh (gross) with duct firing [SGT6-5000F(4) 7,679.0 Btu (HHV)/kWh (gross) with duct firing [SGT6-5000F(5)	12 operating month average
Interstate Power and Light	04/14/14	13-A-499-P	Marshall County, IA	Natural gas fired combined cycle plant	Addition of two combined cycle Siemens SGT6-5000F turbines without duct burning	951.0000 LB/MW-H		12 month rolling average
Pinecrest Energy Center	08/01/14	PSD-TX-1298-GHG	Lufkin, TX	Natural gas fired combined cycle plant	Two Gas Turbines with 750 MMBtu/hr duct burners (3 possible turbine models: GE 7FA, Siemens SGT6-5000F(4) or SGT6-5000F(5)). (2 on 1 configuration)	Output-Based Limits (excludes startup hours): 942.0 lb CO_2/MWh (gross) with Duct Firing [GE 7FA]; 909.2 lb CO_2/MWh (gross) with Duct Firing [SGT6-5000F(4); 912.7 lb CO_2/MWh (gross) with Duct Firing [SGT6-5000F(5);	Heat Rates (excludes startup hours): 7,925.0 Btu (HHV)/kWh (gross) with duct firing [GE 7FA] 7,649.0 Btu (HHV)/kWh (gross) with duct firing [SGT6-5000F(4) 7,679.0 Btu (HHV)/kWh (gross) with duct firing [SGT6-5000F(5)	12 operating month average

Table 5-4
Natural Gas Fired Boiler $\leq$ 100 MMBtu/hr GHG BACT Comparison Table
Eagle Mountain Steam Electric Station
Eagle Mountain Power Company LLC

Facility Name	Permit Date	Permit Number	Location	Type(s) of Units	Output-Based GHG Emission Limit	Averaging Period
Hickory Run Energy Center	4/23/2013	37-337A	Lawrence Cty, PA	40.0 MMBtu/hr Natural Gas Fired Aux Boiler (estimated 5,850 hrs/yr based on annual TPY Limit)	TPY limit only	12 month rolling average
Consumers Energy Company	07/25/13	191-12	Genesee County, MI	100 MMBtu/hr Natural Gas Fired Aux Boiler; limited to 416.3 MMscf natural gas firing per year	TPY limit only	12 month rolling average
St. Joseph Energy Center	12/3/2013	141-31003-00579	St. Joseph Cty, IN	Two Natural Gas Fired 80 MMBtu/hr Aux Boilers (8,760 hr/yr)	TPY limit; Boiler designed for 80% efficiency as determined by initial performance test	12 month rolling average
Berks Hollow Energy	12/17/2013	06-05150A	Berks Cty, PA	40.0 MMBtu/hr Natural Gas Fired Aux Boiler (estimated 5,270 hrs/yr based on annual TPY Limit)	TPY limit only	12 month rolling average
Interstate Power and Light, Marshalltown Generating Station	4/14/2014	13-A-499-P	Marshall Cty., IA	60.1 MMBtu/hr Natural Gas Fired Aux Boiler; limited to 288.7 MMScf natural gas firing per year	TPY limit only	12 month rolling average
Arcadis, US, Inc, Oregon Clean Energy Center	6/18/2014	P0110840	Lucas Cty., PA	99.0 MMBtu/hr Natural Gas Fired Aux Boiler (Limited to 2,000 hr/yr)	TPY limit plus 2000 hour run-time limit	12 month rolling average
Black Hills Power Inc., Cheyenne Power Generating Station	07/16/14	MD-16173	Laramie County, WY	25.06 MMBtu/hr Auxiliary Boiler (8,760 hr/yr)	TPY limit only plus good combustion practices and energy efficiency	12 month rolling average

6.0 OTHER PSD REQUIREMENTS

6.1 IMPACTS ANALYSIS

An impacts analysis is not being provided with this application in accordance with EPA's recommendations:

> *Since there are no NAAQS or PSD increments for GHGs, the requirements in sections 52.21(k) and 51.166(k) of EPA's regulations to demonstrate that a source does not cause contribute to a violation of the NAAQS are not applicable to GHGs. Therefore, there is no requirement to conduct dispersion modeling or ambient monitoring for CO_2 or GHGs.*[31]

An impacts analysis for non-GHG emissions is being submitted in association with the Criteria Pollutant state/PSD/Nonattainment permit application submitted to the TCEQ.

6.2 GHG PRECONSTRUCTION MONITORING

A pre-construction monitoring analysis for GHG is not being provided with this application in accordance with EPA's recommendations:

> *EPA does not consider it necessary for applicants to gather monitoring data to assess ambient air quality for GHGs under section 52.21(m)(1)(ii), section 51.166(m)(1)(ii), or similar provisions that may be contained in state rules based on EPA's rules. GHGs do not affect "ambient air quality" in the sense that EPA intended when these parts of EPA's rules were initially drafted. Considering the nature of GHG emissions and their global impacts, EPA does not believe it is practical or appropriate to expect permitting authorities to collect monitoring data for purpose of assessing ambient air impacts of GHGs.*[32]

A pre-construction monitoring analysis for non-GHG emissions is being submitted with the State/PSD/Nonattainment permit application submitted to the TCEQ.

6.3 ADDITIONAL IMPACTS ANALYSIS

A PSD additional impacts analysis is not being provided with this application in accordance with EPA's recommendations:

> *Furthermore, consistent with EPA's statement in the Tailoring Rule, EPA believes it is not necessary for applicants or permitting authorities to assess impacts from GHGs in*

[31] EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases* at 47-49.
[32] *Id.* at 48.

> *the context of the additional impacts analysis or Class I area provisions of the PSD regulations for the following policy reasons. Although it is clear that GHG emissions contribute to global warming and other climate changes that result in impacts on the environment, including impacts on Class I areas and soils and vegetation due to the global scope of the problem, climate change modeling and evaluations of risks and impacts of GHG emissions is typically conducted for changes in emissions 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 with current climate change modeling. Given these considerations, GHG emissions would serve as the more appropriate and credible proxy for assessing the impact of a given facility. Thus, EPA believes that the most practical way to address the considerations reflected in the Class I area and additional impacts analysis is to focus on reducing GHG emissions to the maximum extent. In light of these analytical challenges, compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs.*[33]

An additional impacts analysis for non-GHG emissions is being submitted with the State/PSD/Nonattainment application submitted to the TCEQ. There are no Class I areas within 100 kilometers of the EMSES. The nearest Class I area is the Wichita Mountains National Wildlife Refuge, which is approximately 215 kilometers from the EMSES site.

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[33] *Id.* at 48.

7.0 PROPOSED GHG MONITORING PROVISIONS

EMPC proposes to monitor CO_2 emissions by monitoring the quantity of fuel combusted in the turbines and HRSGs and performing periodic fuel sampling as specified in 40 CFR 75.10(3)(ii) (refer to procedure below). Results of the fuel sampling will be used to calculate a site-specific Fc factor, and that factor will be used in the equation below to calculate CO_2 mass emissions.

The EMPC natural gas-fired turbines will comply with the fuel flow metering and Gross Calorific Value (GCV) sampling requirements of 40 CFR Part 75, Appendix D. The site-specific Fc factor will be determined using the ultimate analysis and Gross Calorific Value in equation F-7b of 40 CFR 75, Appendix F. The site-specific Fc factor will be re-determined annually in accordance with 40 CFR 75, Appendix F, §3.3.6.

The procedure for estimating CO_2 Emissions specified in 40 CFR 75.10(3)(ii) is as follows:

Affected gas-fired and oil-fired units may use the following equation:

$$W_{CO2} = (F_c \times H \times U_f \times MW_{CO2})/2{,}000$$

Where:

W_{CO2} = *CO_2 emitted from combustion, tons/hr*

MW_{CO2} = *molecular weight of CO_2, 44.0 lb/lbmole*

F_c = *Carbon based F-factor, (1,040 scf/MMBtu for natural gas <u>or a site-specific F_c factor</u>)*

H = Hourly heat input in MMBtu, as calculated using the procedure in 40 CFR 75, Appendix F, §5)

U_f = *1/385 scf CO_2/lb-mole at 14.7 psia and 68 °F*

The requirements for fuel flow monitoring and quality assurance in 40 CFR 75 Appendix D are as follows:

Fuel flow meter: meet an accuracy of 2.0 %, required to be tested once each calendar quarter (40 CFR 75, Appendix D, §2.1.5 and §2.1.6(a))

Gross Calorific Value (GCV): determine the GCV of pipeline natural gas at least once per calendar month (40 CFR 75, Appendix D, §2.3.4.1)

This monitoring approach is consistent with the CO_2 reporting requirements of the GHG Mandatory Reporting Rule for Electricity Generation (40 CFR 98, Subpart D). Subpart D requires electric generating sources that report CO_2 emissions under 40 CFR 75 to report CO_2 under 40 CFR 98 by converting CO_2 tons reported under Part 75 to metric tons.

In addition, the recently proposed new source performance standards for emissions of CO_2 for new affected fossil fuel-fired electric utility generating units would allow electric generating units firing gaseous fuel and liquid fuel oil to determine CO_2 mass emissions by monitoring fuel combusted in the affected Electric Generating Unit and using either a default Fc factor listed in 40 CFR 75, Appendix G or a site specific Fc factor determined in accordance with 40 CFR 75, Appendix F. Therefore, EMPC's proposed CO_2 monitoring method would be consistent with the proposed NSPS for emissions of CO_2 for new affected fossil fuel-fired electric utility generating units.