CORONADO
VENTURES
4401 West Plano Parkway, Suite 128
Plano, TX 75093

April 26, 2012

Mr. Jeff Robinson
Chief, Air Permits Section
U.S. EPA Region 6, 6PD
1445 Ross Avenue, Suite 1200
Dallas, TX 75202-2733

RE: Application for a Prevention of Significant Deterioration Air Quality Permit for Greenhouse Gas Emissions
La Paloma Energy Center, LLC
Harlingen, Cameron County, Texas

Mr. Robinson:

La Paloma Energy Center, LLC is hereby submitting this application for a Prevention of Significant Deterioration (PSD) air quality permit for greenhouse gas emissions for the construction of a new natural gas fired combined cycle electric generating plant, La Paloma Energy Center, to be located near Harlingen, Cameron County, Texas. The state/PSD application for non-greenhouse gas emissions was submitted to the Texas Commission on Environmental Quality (TCEQ) on March 15, 2012.

General information for the application is provided on the TCEQ Form PI-1 - General Application for Air Preconstruction Permit and Amendments. The U.S. Environmental Protection Agency's (EPA) document entitled "*PSD and Title V Permitting Guidance For Greenhouse Gases", dated November 2010 and March 2011*, was utilized as a guide for preparation of the attached application.

La Paloma Energy Center is committed to working closely with EPA Region 6 to get the application review completed as expeditiously as possible. We will be contacting your staff soon after submittal of this application to arrange a meeting to review the application and answer any questions that your team may have developed after initially reading our application.

Should you have any questions regarding this application, please contact La Paloma Energy Center's technical contact for this application, Kathleen Smith, at ksmith@coronado-ventures.com or by telephone at 281-253-4385.

Sincerely,

Kathleen Smith

Enclosure

cc: Mr. Mike Wilson, P.E., Director, Air Permits Division, TCEQ
Mr. Larry Moon, P.E., Zephyr Environmental Corporation

# PREVENTION OF SIGNIFICANT DETERIORATION GREENHOUSE GAS PERMIT APPLICATION FOR A COMBINED CYCLE POWER PLANT AT THE LA PALOMA ENERGY CENTER CAMERON COUNTY, TEXAS

*SUBMITTED TO:*

**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:*

**LA PALOMA ENERGY CENTER, LLC**
**4011 WEST PLANO PARKWAY, SUITE 128**
**PLANO, TEXAS 75093**

4-26-2012

Zephyr Environmental Corporation
STATE OF TEXAS
LARRY A. MOON
69515
LICENSED
PROFESSIONAL ENGINEER
F-102

*PREPARED BY:*


**ZEPHYR ENVIRONMENTAL CORPORATION**
**2600 VIA FORTUNA, SUITE 450**
**AUSTIN, TEXAS 78746**


Larry A. Moon

**APRIL, 2012**

zephyr

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## APPENDICES

# 1.0 INTRODUCTION

La Paloma Energy Center, LLC (La Paloma) is hereby submitting this application for a Greenhouse Gas (GHG) Prevention of Significant Deterioration (PSD) air quality permit for the construction of a new combined cycle electric generating plant, La Paloma Energy Center (LPEC), in Cameron County, Texas. LPEC will consist of two natural gas-fired combustion turbines, each exhausting to a fired heat recovery steam generator (HRSG) to produce steam to drive a shared steam turbine. Three models of combustion turbines are being considered for this site: the General Electric 7FA, the Siemens SGT6-5000F(4), and the Siemens SGT6-5000F(5). The final selection of the combustion turbine model will not be made until after the permit is issued. The State and PSD air permit application for non-GHG pollutants was submitted to the Texas Commission on Environmental Quality (TCEQ) on March 15, 2012.

The General Electric 7FA combustion turbine has a maximum base-load electric power output of approximately 183 MW, the Siemens SGT6-5000F(4) is approximately 205 MW, and the Siemens SGT6-5000F(5) is approximately 232 MW. The maximum electric power output from the steam turbine is approximately 271 MW for both the GE and Siemens configurations. All three combustion turbines are F-Class turbines.

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] After July 1, 2011, new sources having 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.

On December 23, 2010, EPA issued a Federal Implementation Plan (FIP) authorizing EPA to issue PSD permits in Texas for GHG sources until Texas submits the required SIP revision for GHG permitting and it is approved by EPA.[2]

The LPEC project for construction of two combined cycle power plant units triggers PSD review for GHG regulated pollutants because the project will increase GHG emissions by more than 100,000 tons/yr. Included in this application are a project scope description, GHG emissions calculations, GHG netting analysis, and a GHG Best Available Control Technology (BACT) analysis.

[1] 75 FR 31514 (June 3, 2010).
[2] 75 FR 81874 (Dec. 29, 2010).

# 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: La Paloma Energy Center, LLC | | |
| Texas Secretary of State Charter/Registration Number (*if applicable*): 5108003 | | |
| **B.** Company Official Contact Name: Gary Neus | | |
| Title: EVP | | |
| Mailing Address: 4011 West Plano Parkway, Suite 128 | | |
| City: Plano | State: TX | ZIP Code: 75093 |
| Telephone No.: 281-682-8448 | Fax No.: 972-964-0807 | E-mail Address: gneus@coronado-ventures.com |
| **C.** Technical Contact Name: Gary Neus | | |
| Title: EVP | | |
| Company Name: La Paloma Energy Center, LLC | | |
| Mailing Address: 4011 West Plano Parkway, Suite 128 | | |
| City: Plano | State: TX | ZIP Code: 75093 |
| Telephone No.: 281-682-8448 | Fax No.: 972-964-0807 | E-mail Address:gneus@coronado-ventures.com |
| **D.** Site Name: La Paloma Energy Center | | |
| **E.** Area Name/Type of Facility: Electric Generating Facility | | ☒ Permanent ☐ Portable |
| **F.** Principal Company Product or Business: Generation of Electricity | | |
| Principal Standard Industrial Classification Code (SIC): 4911 | | |
| Principal North American Industry Classification System (NAICS): 221112 | | |
| **G.** Projected Start of Construction Date: 06/01/2013 | | |
| Projected Start of Operation Date: 10/01/2015 | | |
| **H.** Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.): | | |
| Street Address: 24684 FM 1595 | | |
| | | |
| City/Town: Harlingen | County: Cameron | ZIP Code: 78550 |
| Latitude (nearest second): 26 12 58.9 | Longitude (nearest second): 97 37 41.02 | |

| | |
|---|---|
| **I. Applicant Information (continued)** | |
| **I.** Account Identification Number (leave blank if new site or facility): | |
| **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): | |
| **L.** Regulated Entity Number (RN): | |
| **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 or enforcement action? If *Yes*, attach a copy of any correspondence from the agency. | ☐ YES ☒ NO |
| **C.** Number of New Jobs: 50 | |
| **D.** Provide the name of the State Senator and State Representative and district numbers for this facility site: | |
| Senator: Eddy Lucio | District No.: 27 |
| Representative: J. M. Lozano | District No.: 38 |
| **III. Type of Permit Action Requested** | |
| **A.** Mark the appropriate box indicating what type of action is requested.<br>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)*<br>Construction ☒ Flexible ☐ Multiple Plant ☐ Nonattainment ☐ Prevention of Significant Deterioration ☒<br>Hazardous Air Pollutant Major Source ☐ Plant-Wide Applicability Limit ☐<br>Other:__________ | |
| **D.** Is a permit renewal application being submitted in conjunction with this amendment in accordance with 30 TAC 116.315(c). | ☐ YES ☒ NO |

| 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. | | | ☐ 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.<br>FOP Significant Revision ☐ FOP Minor ☐ Application for an FOP Revision ☐ To Be Determined ☒<br>Operational Flexibility/Off-Permit Notification ☐ Streamlined Revision for GOP ☐ None ☐ | | | |

| | | |
|---|---|---|
| **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 of an affected state? | ☐ YES ☒ NO |
| If *Yes*, list the affected state(s). | | |
| **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): 155.9 ton/yr | | |
| Sulfur Dioxide ($SO_2$): 15.7 ton/yr | | |
| Carbon Monoxide (CO): 420.7 ton/yr | | |
| Nitrogen Oxides ($NO_x$): 263.3 ton/yr | | |
| Particulate Matter (PM): 278.5 ton/yr | | |
| PM $_{10}$ microns or less ($PM_{10}$): 247.1 ton/yr | | |
| PM $_{2.5}$ microns or less ($PM_{2.5}$): 240.2 ton/yr | | |
| Lead (Pb): | | |
| Hazardous Air Pollutants (HAPs): < 10 tons/yr for individual HAP and < 25 ton/yr for all HAPs | | |
| Other speciated air contaminants **not** listed above: 261.1 ton/yr NH3; 7.9 ton/yr HSO4;10.7 ton/yr (NH4)2SO4 | | |

| | | | |
|---|---|---|---|
| **V. Public Notice Information (complete if applicable)** | | | |
| **A.** Public Notice Contact Name: Gary Neus | | | |
| Title: EVP | | | |
| Mailing Address: 4011 West Plano Parkway, Suite 128 | | | |
| City: Plano | State: TX | ZIP Code: 75093 | |
| **B.** Name of the Public Place: Harlingen Public Library | | | |
| Physical Address (No P.O. Boxes): 410 76 Drive | | | |
| City: Harlingen | County: Cameron | ZIP Code: 78550 | |
| 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: Carlos H. Cascos | | | |
| Mailing Address: 1100 E. Monroe St., Dancy Building, Second Floor | | | |
| City: Harlingen | State: Texas | ZIP Code: 78520 | |
| 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 executives of the city and county, Federal Land Manager, or Indian Governing Body for the location where the facility is or will be located. | | | |
| Chief Executive: Mayor Chris Boswell | | | |
| Mailing Address: 515 E. Harrison, Ste. A | | | |
| City: Harlingen | State: Texas | ZIP Code: 78550 | |
| Name of the Federal Land Manager: N/A | | | |
| Title: | | | |
| Mailing Address: | | | |
| City: | State: | ZIP Code: | |

| | |
|---|---|
| **V. Public Notice Information (complete if applicable) (continued)** | |
| 3. Provide the name, mailing address of the chief executives of the city and county, State, Federal Land Manager, or Indian Governing Body for the location where the facility is or will be located. *(continued)* | |
| Name of the Indian Governing Body: N/A | |
| Title: | |
| Mailing Address: | |
| City: / State: / ZIP Code: | |
| **D.** Bilingual Notice | |
| 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? Spanish | |
| **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 ☒ | |

| **VII. Technical Information** | | | |
|---|---|---|---|
| **B.** Are any schools located within 3,000 feet of this facility? | | | ☐ YES ☒ NO |
| **C.** Maximum Operating Schedule: | | | |
| Hours: 24 hr/day | Day(s): 7 day/week | Week(s): 52 week/year | Year(s): 8,760 hr/year |
| 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. | | | |
| MSS activities are listed on Tables A-16 and A-17 of the attached application. | | | |
| This is a new site and there have been no previous emission inventories. | | | |
| **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 |
| **C.** Does 40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard 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.*** | | |
| **D.** Do nonattainment permitting requirements apply to this application? | | ☐ 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? | | ☒ 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: 1007 | Fee Amount: $75,000 | |
| Company name on check: Coronado Power Investments 1 LLC | Paid online?: ☐ YES ☐ NO | |
| 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 | |

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

| |
|---|
| **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:** Gary Neus |
| **Signature:** Gary Neus *Original Signature Required* |
| **Date:** 3/15/2012 |

# 2.0 PROJECT SCOPE

## 2.1 INTRODUCTION

With this application, La Paloma is seeking authorization to construct a new combined cycle electric generating plant, LPEC, in Cameron County, Texas. The power generating equipment, as well as ancillary equipment that will be sources of GHG emissions at the site, are listed below:

- Two natural gas-fired combustion turbines equipped with lean pre-mix low-$NO_x$ combustors
- Two natural gas-fired duct burner systems
- Natural gas piping and metering
- One diesel fuel-fired emergency electrical generator engine
- One diesel fuel-fired fire water pump engine
- One natural gas-fired auxiliary boiler
- Electrical equipment insulated with sulfur hexafluoride ($SF_6$)

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

The business purpose of the LPEC is to generate 637 - 735 megawatts (MW), of gross electrical power near the City of Harlingen in an efficient manner while increasing the reliability of the electrical supply for the State of Texas. One of the factors in siting the plant is the availability of reclaimed water from the City of Harlingen to be used as cooling water at the plant. 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 GENERATOR

The plant will consist of two identical natural gas-fired combustion turbine generators (CTGs), with three models being considered: the General Electric 7FA, the Siemens SGT6-5000F(4), and the Siemens SGT6-5000F(5). The final selection of the combustion turbine model will likely be made after the permit is issued. Each combustion turbine will exhaust to an HRSG. Emission point numbers (EPNs) for the combustion turbine/HRSG units are identified as U1-STK and U2-STK.

The combustion turbine will burn pipeline natural gas to rotate an electrical generator to generate electricity. The main components of a combustion turbine generator consist of a compressor, combustor, turbine, and generator. The compressor pressurizes combustion air to the combustor where the fuel is mixed with the combustion air and burned. Hot exhaust gases then enter the turbine where the gases expand across the turbine blades, driving a shaft to power an electric generator. The exhaust gas will exit the combustion turbine and be routed to the HRSG for steam production.

## 2.3 HEAT RECOVERY STEAM GENERATOR

Heat recovered in the HRSG will be utilized to produce steam. Steam generated within the HRSG will be utilized to drive a steam turbine and associated electrical generator. The HRSG will be equipped with duct burners for supplemental steam production. The duct burners will be fired with pipeline-quality natural gas. The duct burners have a maximum heat input capacity of 750 MMBtu/hr per unit. The exhaust gases from the unit, including emissions from the CT and the duct burners, will exit through a stack to the atmosphere.

The normal duct burner operation will vary from 0 to 100 percent of the maximum capacity. Duct burners will be located in the HRSG prior to the selective catalytic reduction system.

Steam produced by each of the two HRSGs will be routed to the steam turbine (FIN STG-1). The two combustion turbines and one steam turbine will be coupled to electric generators to produce electricity for sale to the Electric Reliability Council of Texas power grid. Each GE combustion turbine model has a maximum base-load electric power output of approximately 183 MW, the Siemens SGT6-5000F(4) is approximately 205 MW, and the Siemens SGT6-5000F(5) is approximately 232 MW. The maximum electric power output from the steam turbine is approximately 271 MW for both the GE and Siemens configurations.

The units may operate at reduced load to respond to changes in system power requirements and/or stability.

## 2.4 AUXILIARY BOILER

One auxiliary boiler (EPN AUXBLR) will be available to facilitate startup of the combined cycle units. The auxiliary boiler will have a maximum heat input of 150 MMBtu/hr and will burn pipeline natural gas. The auxiliary boiler could operate up to 876 hours per year.

## 2.5 DIESEL FIRED EMERGENCY EQUIPMENT

The site will be equipped with one nominally rated 1,072-hp diesel-fired emergency generator (EPN: EMGEN1-STK) to provide electricity to the facility in case of power failure. A nominally rated 500-hp diesel-fired pump (EPN: ENG-FWMAIN) will be installed at the site to provide water in the event of a fire. Four nominally rated 100-hp diesel-fired pumps (EPN: FWP1-STK) will be installed at the site to serve as a fire water booster pumps. Each emergency engine will be limited to 100 hours operation per year for purposes of maintenance checks and readiness testing.

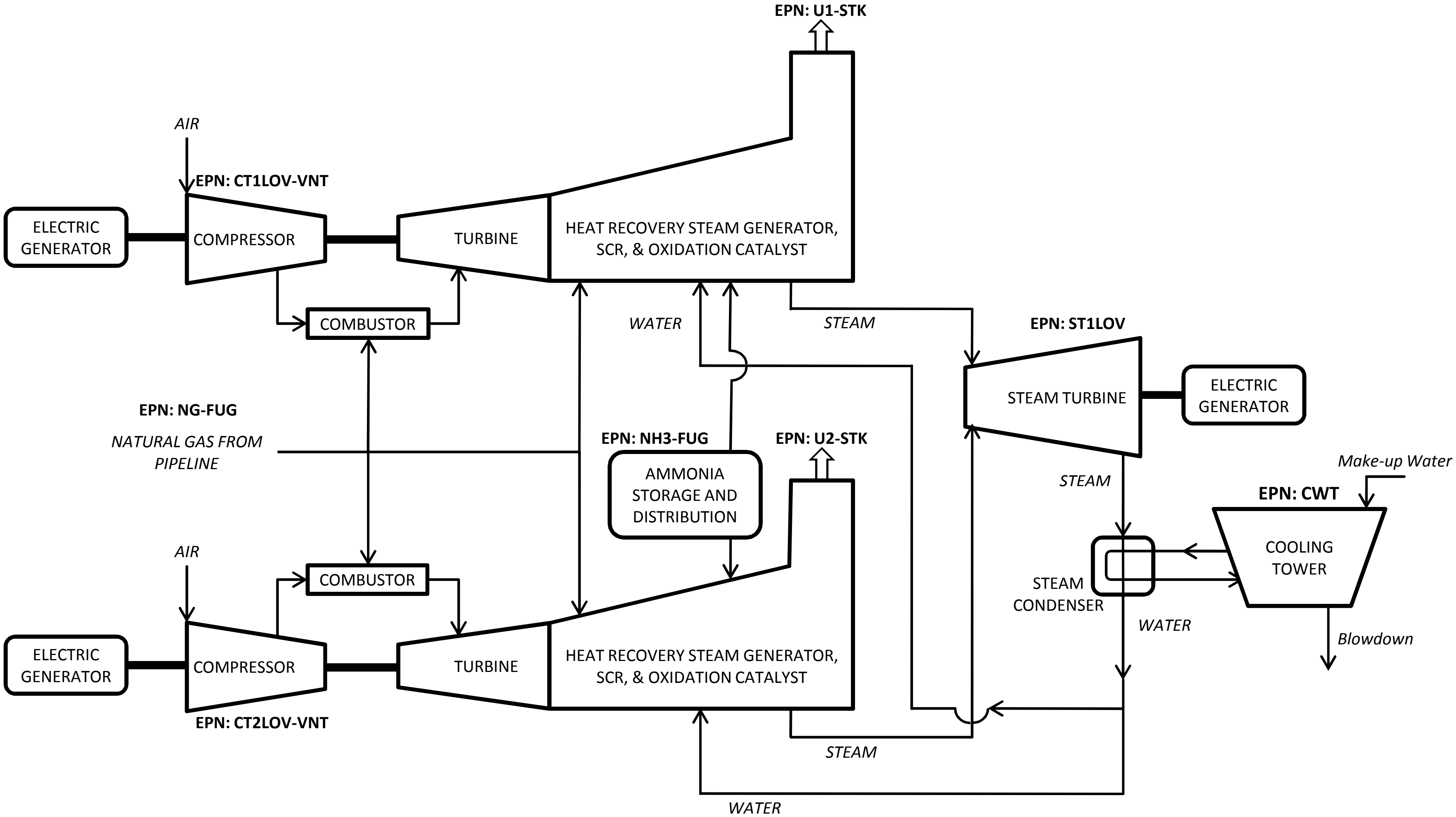
## 2.6 NATURAL GAS/FUEL GAS PIPING

Natural gas will be 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 gas piping components associated with the new CTG/HRSG units will include emissions of methane ($CH_4$) and carbon dioxide ($CO_2$). The natural gas piping is designated as EPN NG-FUG.

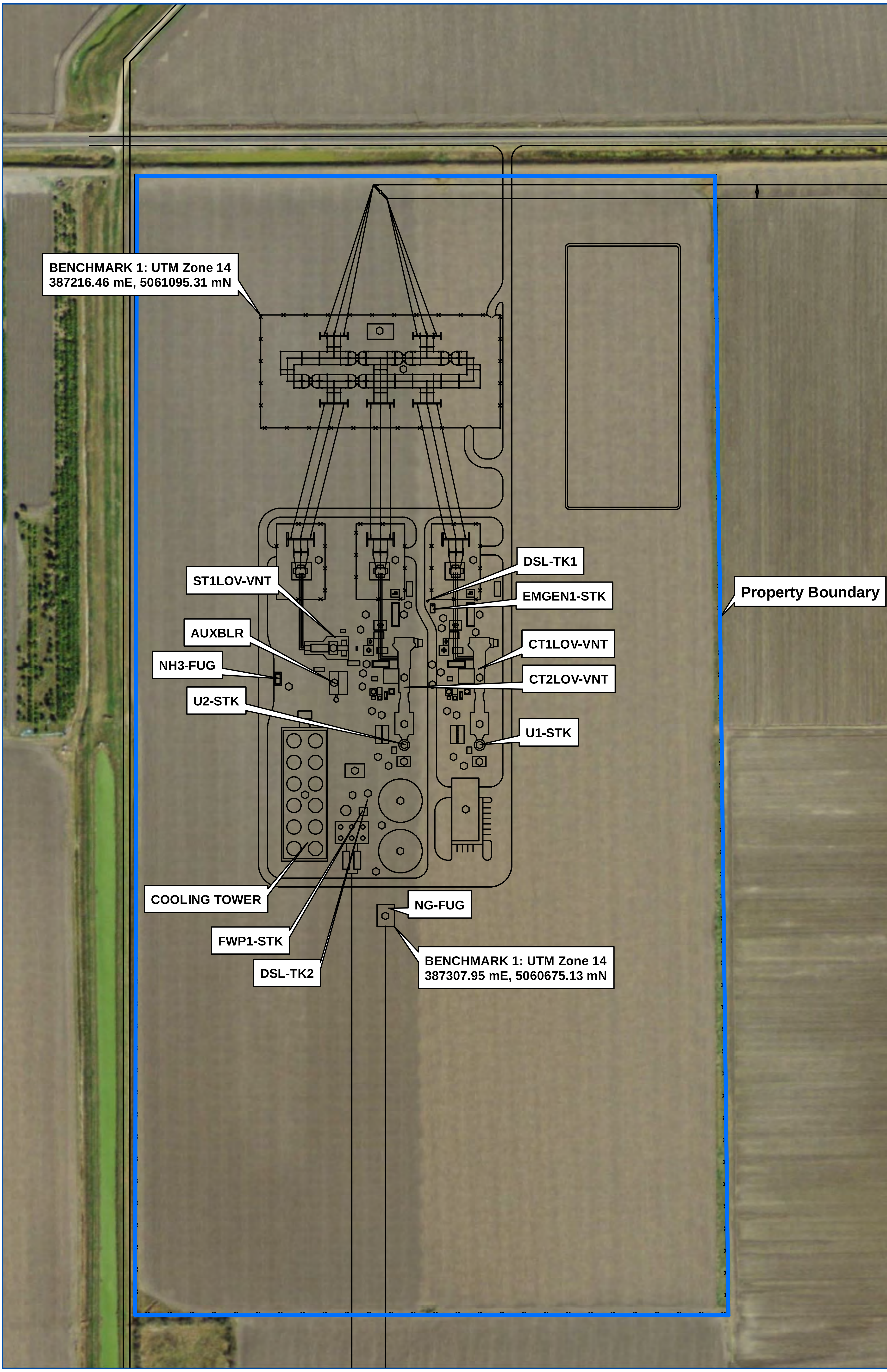
## 2.7 ELECTRICAL EQUIPMENT INSULATED WITH SULFUR HEXAFLUORIDE ($SF_6$)

The generator circuit breakers associated with the proposed units will be insulated with $SF_6$. $SF_6$ is a colorless, odorless, non-flammable, and non-toxic synthetic 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 currently estimated to be 400 lb of $SF_6$.

The proposed circuit breaker at the generator output 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 due to lack of “quenching and cooling” $SF_6$ gas.




| | | | | | |
|---|---|---|---|---|---|
| **LA PALOMA ENERGY CENTER** | | | PROCESS FLOW DIAGRAM | | |
| Permit Application | | | Filename: PFD 2012-03-14.xls | | |
| zephyr | Drawn by: E Rapier | Checked by: L Moon | Project No.: 011368 | Date: 3/14/2012 | Sheet: 1 of 1 |




Data Sources:
ESRI i-cubed imagery; Coronado Ventures
Coordinate System:
NAD83 SP TX South FIPS 4205 Feet

N

Scale 1:2,500 1 in = 208 ft

0 75 150 Meters

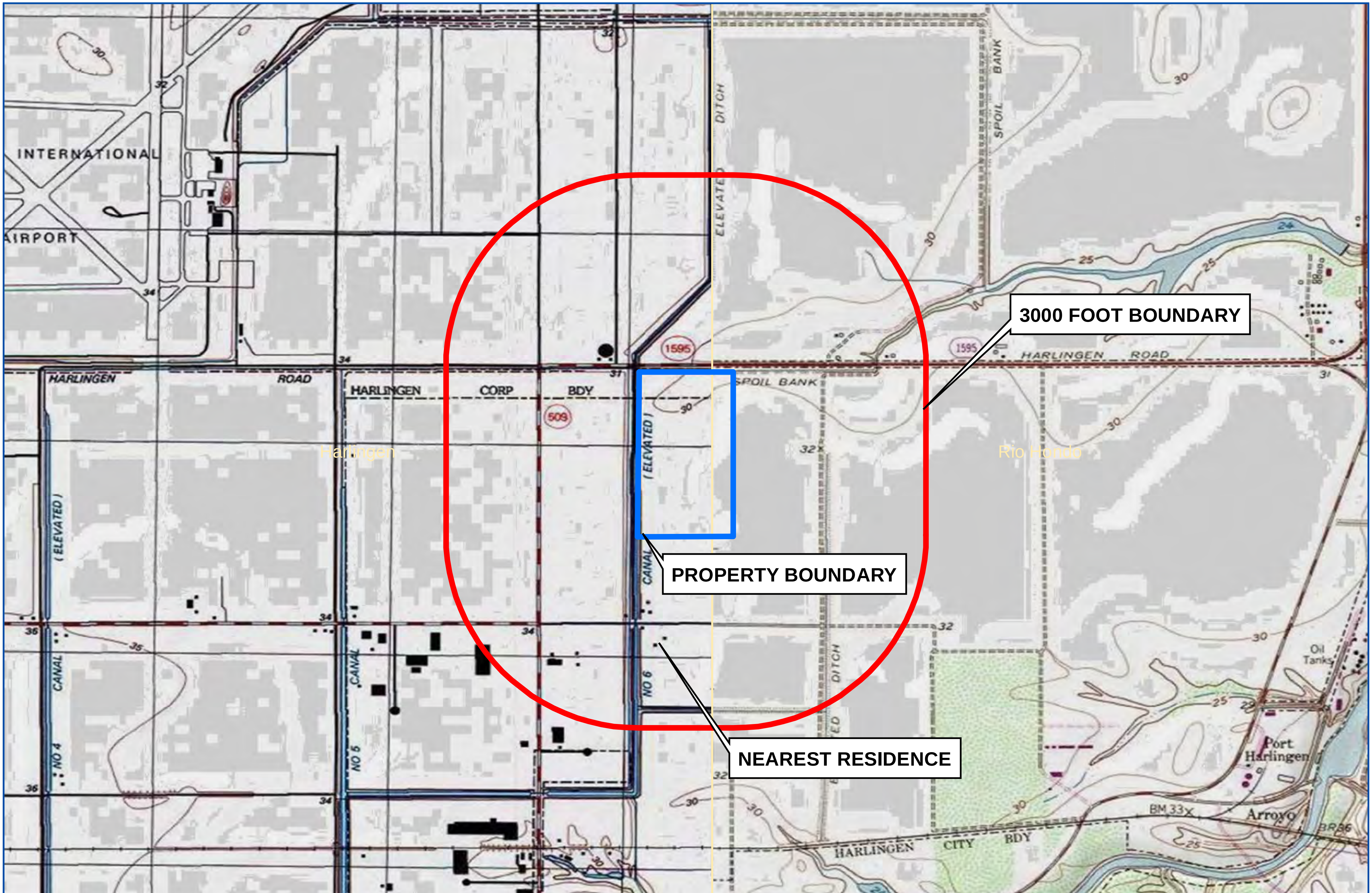
0 250 500 Feet

zephyr

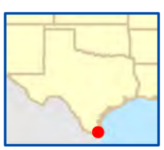
# PLOT PLAN
## La Paloma Energy Center
## Harlingen, TX

H:\Coronado Ventures\011368 Harlingen NSR Application\Graphics\Plot Plan

| Drafted by: | Reviewed by: | Project No.: | Date: |
|---|---|---|---|
| J. Knowles | L. Moon | 11368 | 03/09/2012 |




Data Sources: Coronado Ventures; ESRI - National Geographic TOPO



Scale 1:24,000 1 inch = 2,000 feet

0 0.5 1 Kilometers

0 0.5 1 Miles

N

zephyr

# AREA MAP

## La Paloma Energy Center - Harlingen,Texas

H:\Coronado Ventures\011368 Harlingen NSR Application\Graphics\Area Map

| Drafted By: | Reviewed by: | Project No.: | Date: |
|---|---|---|---|
| J. Knowles | E. Rapier | 11368.001 | 03/06/2012 |

# 3.0 GHG EMISSION CALCULATIONS

## 3.1 GHG EMISSIONS FROM COMBINED CYCLE COMBUSTION TURBINE

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

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

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, 1040 scf/MMBtu for natural gas.

H = Annual heat input in MMBtu.

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

Emissions of $CH_4$ and nitrous oxide ($N_2O$) are calculated using the emission factors (kg/MMBtu) for natural gas combustion from Table C-2 of the Mandatory Greenhouse Gas Reporting Rules.[5] 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 three models being considered: the General Electric 7FA, the Siemens SGT6-5000F(4), and the Siemens SGT6-5000F(5). Calculations of GHG emissions from the combined cycle turbines are presented on Tables 3-2, 3-3, and 3-4.

## 3.2 AUXILIARY BOILER

$CO_2$ emissions from the natural-gas-fired auxiliary boilers are calculated using the emission factors (kg/MMBtu) for natural gas from Table C-1 of the Mandatory Greenhouse Gas Reporting Rules.[6] $CH_4$ and $N_2O$ emissions from the auxiliary boilers are calculated using the emission

[3] 40 C.F.R. 98, Subpart D – *Electricity Generation*

[4] 40 C.F.R. 75, Appendix G – *Determination of $CO_2$ Emissions*

[5] *Default $CH_4$ and $N_2O$ Emission Factors for Various Types of Fuel*, 40 C.F.R. 98, Subpt. C, Tbl. C-2

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

factors (kg/MMBtu) for natural gas from Table C-2 of the Mandatory Greenhouse Gas Reporting Rules.[7] The global warming potential factors used to calculate $CO_2$e emissions are based on Table A-1 of the Mandatory Greenhouse Gas Reporting Rules.[8]

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

## 3.3 GHG EMISSIONS FROM NATURAL GAS/FUEL GAS PIPING FUGITIVES AND NATURAL GAS/FUEL 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 the Mandatory Greenhouse Gas Reporting Rules.[9] 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 as a worst case estimate. The global warming potential factors used to calculate $CO_2$e emissions are based on Table A-1 of the Mandatory Greenhouse Gas Reporting Rules.[10]

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

## 3.4 GHG EMISSIONS FROM DIESEL FIRED EMERGENCY ENGINES

$CO_2$ emission calculations 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.[11] $CH_4$ and $N_2O$ emission calculations 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.[12] The global warming potential factors used to calculate $CO_2$e emissions are based on Table A-1 of the Mandatory Greenhouse Gas Reporting Rules.[13]

---

[7] *Default $CH_4$ and $N_2O$ Emission Factors for Various Types of Fuel*, 40 C.F.R. 98, Subpt. C, Tbl. C-2

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

[9] *Default Whole Gas Emission Factors for Onshore Petroleum and Natural Gas Production*, 40 C.F.R. Pt. 98, Subpt. W, Tbl. W-1A.

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

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

[12] *Default $CH_4$ and $N_2O$ Emission Factors for Various Types of Fuel*, 40 C.F.R. 98, Subpt. C, Tbl. C-2

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

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 new generator circuit breaker and yard breaker 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.[14]

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



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

**Table 3-1**
**Plantwide GHG Emission Summary**
**La Paloma Energy Center**

| Name | EPN | GHG Mass Emissions ton/yr | $CO_2e$ ton/yr |
|---|---|---|---|
| Unit 1 (GE F7FA) | U1-STK | 1,299,449 | 1,300,674 |
| Unit 2 (GE F7FA) | U2-STK | 1,299,449 | 1,300,674 |
| Unit 1 (Siemens SGT6-5000F(4)) | U1-STK | 1,450,405 | 1,451,772 |
| Unit 2 (Siemens SGT6-5000F(4)) | U2-STK | 1,450,405 | 1,451,772 |
| Unit 1 (Siemens SGT6-5000F(5)) | U1-STK | 1,640,771 | 1,642,317 |
| Unit 2 (Siemens SGT6-5000F(5)) | U2-STK | 1,640,771 | 1,642,317 |
| Auxiliary Boiler | AUXBLR | 7,680 | 7,687 |
| Natural Gas Fugitives | NG-FUG | 497 | 10,046 |
| Gas Venting | TRB-MSS | 0.11 | 2 |
| Emergency Generator | EMGEN1-STK | 64 | 65 |
| Fire Water Pump | FWP1-STK | 28 | 28 |
| $SF_6$ Insulated Equipment | SF6-FUG | 0.001 | 24 |
| Sitewide Emissions[1] | | 3,289,810 | 3,302,485 |

1. The sitewide emissions total uses the higher GHG emissions from the three gas turbine options.

**Table 3-2**

**GHG Annual Emission Calculations - GE F7FA Combined Cycle Combustion Turbines**

**La Paloma Energy Center**

**GHG Emissions Contribution From Natural Gas Fired Combustion Turbines**

| EPN | Average Heat Input[1] (MMBtu/hr) | Annual Heat Input[2] (MMBtu/yr) | Pollutant | Emission Factor (kg/MMBtu)[3] | GHG Mass Emissions[4] (tpy) | Global Warming Potential[5] | $CO_2$e (tpy) |
|---|---|---|---|---|---|---|---|
| U1-STK (GE F7FA) | 2,496 | 21,865,290 | $CO_2$ | | 1,299,423.0 | 1 | 1,299,423.0 |
| | | | $CH_4$ | 1.0E-03 | 24.1 | 21 | 505.1 |
| | | | $N_2O$ | 1.0E-04 | 2.4 | 310 | 745.6 |
| | | | | **Totals** | **1,299,449.4** | | **1,300,673.7** |
| | | | | | | | |
| U2-STK (GE F7FA) | 2,496 | 21,865,290 | $CO_2$ | | 1,299,423.0 | 1 | 1,299,423.0 |
| | | | $CH_4$ | 1.0E-03 | 24.1 | 21 | 505.1 |
| | | | $N_2O$ | 1.0E-04 | 2.4 | 310 | 745.6 |
| | | | | **Totals** | ***1,299,449.4*** | | **1,300,673.7** |
| Total for 2 Turbines | | | | | ***2,598,898.8*** | | ***2,601,347.3*** |

*Note*

1. *The average heat input for the GE F7FA scenario is based on the HHV heat input at 100% load, with maximum duct firing, at 69 $^oF$ ambient temperature.*
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*

*$W_{CO2}$ = (Fc x H x $U_f$ X $MW_{CO2}$)/2000*

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

*Fc = 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 $^oF$*

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

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

## Table 3-3
## Startup GHG Emission Calculations - GE F7FA Turbines
## La Paloma Energy Center

**Max Hourly GHG Emissions From GE F7FA Turbine**

| EPN | Max Hourly Heat Input[1] (MMBtu/hr) | Pollutant | Emission Factor (kg/MMBtu)[2] | GHG Mass Emissions[3] (ton/hr) | Global Warming Potential[4] | $CO_2e$ (ton/hr) |
|---|---|---|---|---|---|---|
| U1-STK | 2,654.0 | $CO_2$ | | 158 | 1 | 158 |
| | | $CH_4$ | 1.0E-03 | 0.0029 | 21 | 0.0614 |
| | | $N_2O$ | 1.0E-04 | 0.0003 | 310 | 0.0907 |
| | | | **Totals** | **158** | | **158** |

**Startup/Shutdown Hourly GHG Emissions From GE F7FA Turbine**

| EPN | Heat Input During Startup[1] (MMBtu/hr) | Pollutant | Emission Factor (kg/MMBtu)[2] | GHG Mass Emissions[3] (ton/hr) | Global Warming Potential[4] | $CO_2e$ (ton/hr) |
|---|---|---|---|---|---|---|
| U1-STK | 1,230.6 | $CO_2$ | | 73 | 1 | 73 |
| | | $CH_4$ | 1.0E-03 | 0.0014 | 21 | 0.0285 |
| | | $N_2O$ | 1.0E-04 | 0.0001 | 310 | 0.0420 |
| AUXBLR | 150.0 | $CO_2$ | | 9 | 1 | 9 |
| | | $CH_4$ | 1.0E-03 | 0.0002 | 21 | 0.0035 |
| | | $N_2O$ | 1.0E-04 | 0.0000 | 310 | 0.0051 |
| | | | **Totals** | **82** | | **82** |

*Note*

1. *The following hourly firing rates Information is from Table A-3, in Appendix A of the PSD application submitted to TCEQ on 03/15/2012.*

| | Operating Mode | CTG Data Case Number | Turbine Heat Input MMBtu/hr | Duct Burner Heat Input MMBtu/hr | Total Hourly Heat Input MMBtu/hr |
|---|---|---|---|---|---|
| Maximum Hourly Heat Input | Base Load, 20 °F Ambient, Max Duct Burner Firing | 6b | 1,904.0 | 750 | 2,654.0 |
| Maximum Hourly Heat Input During Startup | 50% Load, 20 °F Ambient, no Duct Burner Firing | 8b | 1,230.6 | 0 | 1,230.6 |

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

*$W_{CO2}$ = (Fc x H x $U_f$ X $MW_{CO2}$)/2000*

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

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

*H = Heat Input (MMBtu/hr)*

*$U_f$ = 1/385 scf $CO_2$/lbmole at 14.7 psia and 68 $^oF$*

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

4. *Global Warming Potential factors from Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

**Table 3-4**

**GHG Annual Emission Calculations - Siemens SGT6-5000F(4) Combined Cycle Combustion Turbines**

**La Paloma Energy Center**

| EPN | Average Heat Input[1] (MMBtu/hr) | Annual Heat Input[2] (MMBtu/yr) | Pollutant | Emission Factor (kg/MMBtu)[3] | GHG Mass Emissions[4] (tpy) | Global Warming Potential[5] | $CO_2$e (tpy) |
|---|---|---|---|---|---|---|---|
| U1-STK (Siemens SGT6-5000F(4)) | 2,786 | 24,405,360 | $CO_2$ | | 1,450,375.7 | 1 | 1,450,375.7 |
| | | | $CH_4$ | 1.0E-03 | 26.8 | 21 | 563.8 |
| | | | $N_2O$ | 1.0E-04 | 2.7 | 310 | 832.2 |
| | | | | Totals | **1,450,405.2** | | **1,451,771.7** |
| | | | | | | | |
| U2-STK (Siemens SGT6-5000F(4)) | 2,786 | 24,405,360 | $CO_2$ | | 1,450,375.7 | 1 | 1,450,375.7 |
| | | | $CH_4$ | 1.0E-03 | 26.8 | 21 | 563.8 |
| | | | $N_2O$ | 1.0E-04 | 2.7 | 310 | 832.2 |
| | | | | ***Totals*** | ***1,450,405.2*** | | **1,451,771.7** |
| Total for 2 Turbines | | | | | ***2,900,810.4*** | | ***2,903,543.3*** |

*Note*

1. *The average heat input for the Siemens scenarios are based on the HHV heat input at 100% load, with maximum duct firing, at 59 $^oF$ ambient temperature.*
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*

*$W_{CO2}$ = (Fc x H x $U_f$ X $MW_{CO2}$)/2000*

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

*Fc = 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 $^oF$*

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

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

## Table 3-5
## Startup GHG Emission Calculations - Siemens SGT6-5000F(4) Turbines
## La Paloma Energy Center

**Max Hourly GHG Emissions From Siemens SGT6-5000F(4)**

| EPN | Max Hourly Heat Input[1] (MMBtu/hr) | Pollutant | Emission Factor (kg/MMBtu)[2] | GHG Mass Emissions[3] (ton/hr) | Global Warming Potential[4] | $CO_2e$ (ton/hr) |
|---|---|---|---|---|---|---|
| U1-STK | 2,997.0 | $CO_2$ | | 178 | 1 | 178 |
| | | $CH_4$ | 1.0E-03 | 0.0033 | 21 | 0.0694 |
| | | $N_2O$ | 1.0E-04 | 0.0003 | 310 | 0.1024 |
| | | | **Totals** | **178** | | **178** |

**Startup/Shutdown Hourly GHG Emissions From Siemens SGT6-5000F(4)**

| EPN | Heat Input During Startup[1] (MMBtu/hr) | Pollutant | Emission Factor (kg/MMBtu)[2] | GHG Mass Emissions[3] (ton/hr) | Global Warming Potential[4] | $CO_2e$ (ton/hr) |
|---|---|---|---|---|---|---|
| U1-STK | 1,626.0 | $CO_2$ | | 97 | 1 | 97 |
| | | $CH_4$ | 1.0E-03 | 0.0018 | 21 | 0.0376 |
| | | $N_2O$ | 1.0E-04 | 0.0002 | 310 | 0.0556 |
| AUXBLR | 150.0 | $CO_2$ | | 9 | 1 | 9 |
| | | $CH_4$ | 1.0E-03 | 0.0002 | 21 | 0.0035 |
| | | $N_2O$ | 1.0E-04 | 0.0000 | 310 | 0.0051 |
| | | | **Totals** | **106** | | **106** |

Note

1. *The following hourly firing rates Information is from Table A-3, in Appendix A of the PSD application submitted to TCEQ on 03/15/2012.*

| | Operating Mode | CTG Data Case Number | Turbine Heat Input MMBtu/hr | Duct Burner Heat Input MMBtu/hr | Total Hourly Heat Input MMBtu/hr |
|---|---|---|---|---|---|
| Maximum Hourly Heat Input | Base Load, 10 °F Ambient, Max Duct Burner Firing | 5 | 2,247.0 | 750 | 2,997.0 |
| Maximum Hourly Heat Input During Startup | 60% Load, 10 °F Ambient, no Duct Burner Firing | 8 | 1,626.0 | 0 | 1,626.0 |

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

*$W_{CO2}$ = (Fc x H x $U_f$ X $MW_{CO2}$)/2000*

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

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

*H = Heat Input (MMBtu/hr)*

*$U_f$ = 1/385 scf $CO_2$/lbmole at 14.7 psia and 68 $^oF$*

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

4. *Global Warming Potential factors from Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

**Table 3-6**

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

**La Paloma Energy Center**

| EPN | Average Heat Input[1] (MMBtu/hr) | Annual Heat Input[2] (MMBtu/yr) | Pollutant | Emission Factor (kg/MMBtu)[3] | GHG Mass Emissions[4] (tpy) | Global Warming Potential[5] | $CO_2e$ (tpy) |
|---|---|---|---|---|---|---|---|
| U1-STK (Siemens SGT6-5000F(5)) | 3,152 | 27,608,561 | $CO_2$ | | 1,640,737.4 | 1 | 1,640,737.4 |
| | | | $CH_4$ | 1.0E-03 | 30.4 | 21 | 637.8 |
| | | | $N_2O$ | 1.0E-04 | 3.0 | 310 | 941.5 |
| | | | | Totals | **1,640,770.8** | | **1,642,316.6** |
| | | | | | | | |
| U2-STK (Siemens SGT6-5000F(5)) | 3,152 | 27,608,561 | $CO_2$ | | 1,640,737.4 | 1 | 1,640,737.4 |
| | | | $CH_4$ | 1.0E-03 | 30.4 | 21 | 637.8 |
| | | | $N_2O$ | 1.0E-04 | 3.0 | 310 | 941.5 |
| | | | | ***Totals*** | ***1,640,770.8*** | | **1,642,316.6** |
| Total for 2 Turbines | | | | | ***3,281,541.6*** | | ***3,284,633.2*** |

*Note*

1. *The average heat input for the Siemens scenarios are based on the HHV heat input at 100% load, with maximum duct firing, at 59 °F ambient temperature.*
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*

*$W_{CO2}$ = (Fc x H x $U_f$ X $MW_{CO2}$)/2000*

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

*Fc = 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/lbmole*

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

# Table 3-7
# Startup GHG Emission Calculations - Siemens SGT6-5000F(5) Turbines
# La Paloma Energy Center

**Max Hourly GHG Emissions From Siemens SGT6-5000F(5)**

| EPN | Max Hourly Heat Input[1] (MMBtu/hr) | Pollutant | Emission Factor (kg/MMBtu)[2] | GHG Mass Emissions[3] (ton/hr) | Global Warming Potential[4] | $CO_2e$ (ton/hr) |
|---|---|---|---|---|---|---|
| U1-STK | 3,151.7 | $CO_2$ | | 187 | 1 | 187 |
| | | $CH_4$ | 1.0E-03 | 0.0035 | 21 | 0.0730 |
| | | $N_2O$ | 1.0E-04 | 0.0003 | 310 | 0.1077 |
| | | | **Totals** | **187** | | **187** |

**Startup/Shutdown Hourly GHG Emissions From Siemens SGT6-5000F(5)**

| EPN | Heat Input During Startup[1] (MMBtu/hr) | Pollutant | Emission Factor (kg/MMBtu)[2] | GHG Mass Emissions[3] (ton/hr) | Global Warming Potential[4] | $CO_2e$ (ton/hr) |
|---|---|---|---|---|---|---|
| U1-STK | 1,584.2 | $CO_2$ | | 94 | 1 | 94 |
| | | $CH_4$ | 1.0E-03 | 0.0017 | 21 | 0.0367 |
| | | $N_2O$ | 1.0E-04 | 0.0002 | 310 | 0.0541 |
| AUXBLR | 150.0 | $CO_2$ | | 9 | 1 | 9 |
| | | $CH_4$ | 1.0E-03 | 0.0002 | 21 | 0.0035 |
| | | $N_2O$ | 1.0E-04 | 0.0000 | 310 | 0.0051 |
| | | | **Totals** | **103** | | **103** |

*Note*

1. *The following hourly firing rates Information is from Table A-3, in Appendix A of the PSD application submitted to TCEQ on 03/15/2012.*

| | Operating Mode | CTG Data Case Number | Turbine Heat Input MMBtu/hr | Duct Burner Heat Input MMBtu/hr | Total Hourly Heat Input MMBtu/hr |
|---|---|---|---|---|---|
| Maximum Hourly Heat Input | Base Load, 59 °F Ambient, Max Duct Burner Firing | 7 | 2,401.7 | 750 | 3,151.7 |
| Maximum Hourly Heat Input During Startup | 60% Load, 10 °F Ambient, no Duct Burner Firing | 11 | 1,584.2 | 0 | 1,584.2 |

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

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

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

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

*H = Heat Input (MMBtu/hr)*

*$U_f$ = 1/385 scf $CO_2$/lbmole at 14.7 psia and 68 $^oF$*

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

4. *Global Warming Potential factors from Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

**Table 3-8**
**GHG Emission Calculations - Auxilliary Boiler**
**La Paloma Energy Center**

**GHG Potential To Emit Emissions From Natural Gas Fired Auxilliary Boiler**

| EPN | Maximum Heat Input[1] (MMBtu/yr) | Pollutant | Emission Factor (kg/MMBtu)[2] | GHG Mass Emissions (tpy) | Global Warming Potential[3] | $CO_2e$ (tpy) |
|---|---|---|---|---|---|---|
| AUXBLR | 131,400 | $CO_2$ | 53.02 | 7,679.53 | 1 | 7,679.5 |
| | | $CH_4$ | 1.0E-03 | 0.14 | 21 | 3.0 |
| | | $N_2O$ | 1.0E-04 | 0.01 | 310 | 4.5 |
| | | | **Totals** | **7,679.7** | | **7,687.1** |

*Note*
1. *Annual fuel use and heating value of natural gas from Table A-10 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 3-9**

**GHG Emission Calculations - Natural Gas Piping**

**La Paloma Energy Center**

**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) |
|---|---|---|---|---|---|---|---|
| NG-FUG | Valves | Gas/Vapor | 600 | 2.903 | 12.26 | 305.45 | |
| | Flanges | Gas/Vapor | 2400 | 0.396 | 6.69 | 166.67 | |
| | Relief Valves | Gas/Vapor | 5 | 4.631 | 0.163 | 4.06 | |
| | Sampling Connections | Gas/Vapor | 10 | 0.748 | 0.0526 | 1.312 | |
| | Compressors | Gas/Vapor | 3 | 0.002 | 0.000042 | 0.0011 | |
| GHG Mass-Based Emissions | | | | | 19.16 | 477.49 | ***496.6*** |
| Global Warming Potential[4] | | | | | 1 | 21 | |
| $CO_2$e Emissions | | | | | 19.16 | 10,027.3 | ***10,046.5*** |

*Note*

1. *Emission factors from Table W-1A of 40 CFR 98 Mandatory Greenhouse Gas Reporting*
2. *$CO_2$ emissions based on vol% of $CO_2$ in natural gas* *1.41%*
3. *$CH_4$ emissions based on vol% of $CH_4$ in natural gas* *96.10%*
4. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

*Example calculation:*

$$600 \text{ valves} \times \frac{0.123 \text{ scf gas}}{\text{hr * valve}} \times \frac{0.0141 \text{ scf CO2}}{\text{scf gas}} \times \frac{\text{lbmole}}{385 \text{ scf}} \times \frac{44 \text{ lb } CO_2}{\text{lbmole}} \times \frac{8760 \text{ hr}}{\text{yr}} \times \frac{\text{ton}}{2000 \text{ lb}} = 12.26 \text{ ton/yr}$$

## TABLE 3-10

**Gaseous Fuel Venting During Turbine Shutdown/Maintenance and Small Equipment and Fugitive Component Repair/Replacement**

**La Paloma Energy Center**

| Location | Initial Conditions | | | Final Conditions | | | $CO_2$ [3] | $CH_4$ [4] | Total |
|---|---|---|---|---|---|---|---|---|---|
| | Volume[1] ($ft^3$) | Press. (psig) | Temp. (°F) | Press. (psig) | Temp. (°F) | Volume[2] (scf) | Annual (tpy) | Annual (tpy) | Annual (tpy) |
| Turbine Fuel Line Shutdown/Maintenance | 1,146 | **50** | **50** | 0 | 68 | 5,277 | 0.0042 | 0.11 | |
| Small Equipment/Fugitive Component Repair/Replacement | 6.7 | **50** | **50** | 0 | 68 | 31 | 0.00002 | 0.00061 | |
| GHG Mass-Based Emissions | | | | | | | 0.0043 | 0.1060 | 0.11 |
| Global Warming Potential[5] | | | | | | | 1 | 21 | |
| $CO_2$e Emissions | | | | | | | 0.0043 | 2.2 | 2.2 |

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* — 1.41% from natural gas analysis
4. *$CH_4$ emissions based on vol% of $CH_4$ in natural gas* — 96.1% from natural gas analysis
5. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

*Example calculation:*

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 5277 scf Nat Gas | 0.014 scf CO2 | lbmole | 44 lb $CO_2$ | ton = | = | 0.0042 | ton/yr $CO_2$ |
| yr | scf Nat Gas | 385 scf | lbmole | 2000 lb | | | |

**Table 3-11**

**GHG Emission Calculations - Emergency Engines**

**La Paloma Energy Center**

**GHG Emissions Contribution From Diesel Combustion In Emergency Engines**

| **Assumptions** | **Generator** | **Fire Water Pump** | |
|---|---|---|---|
| Ann.Operating Schedule | 100 | 100 | hours/year |
| Power Rating | 1,072 | 500 | hp |
| Max Fuel Combustion | 57.3 | 24.7 | gal/hr |
| Heating Value of No. 2 Fuel Oil[1] | 0.138 | 0.138 | MMBtu/gal |
| Max Hourly Heat Input | 7.9 | 3.4 | MMBtu/hr |
| Annual Heat Input | 790.7 | 340.9 | MMBtu/yr |

| **EPN** | **Heat Input** (MMBtu/yr) | **Pollutant** | **Emission Factor** (kg/MMBtu)[2] | **GHG Mass Emissions** (tpy) | **Global Warming Potential**[3] | **$CO_2e$** (tpy) |
|---|---|---|---|---|---|---|
| EMGEN1-STK | 790.7 | $CO_2$ | 73.96 | 64.3 | 1 | 64.3 |
| | | $CH_4$ | 3.0E-03 | 0.0026 | 21 | 0.1 |
| | | $N_2O$ | 6.0E-04 | 0.0005 | 310 | 0.2 |
| | | | | **64.33** | | **64.5** |
| | | | | | | |
| FWP1-STK | 340.9 | $CO_2$ | 73.96 | 27.7 | 1 | 27.7 |
| | | $CH_4$ | 3.0E-03 | 0.0011 | 21 | 0.0 |
| | | $N_2O$ | 6.0E-04 | 0.0002 | 310 | 0.1 |
| | | | ***Totals*** | ***27.73*** | | **27.8** |

*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 3-12**

**GHG Emission Calculations - Electrical Equipment Insulated With $SF_6$**

**La Paloma Energy Center**

**Assumptions**

| | | |
|---|---|---|
| Insulated circuit breaker $SF_6$ capacity | 400 | lb |
| | | |
| Estimated annual $SF_6$ leak rate | 0.5% | by weight |
| Estimated annual $SF_6$ mass emission rate | 0.001 | ton/yr |
| Global Warming Potential[1] | 23,900 | |
| Estimated annual $CO_2$e emission rate | 23.9 | ton/yr |

*Note*

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

# 4.0 PREVENTION OF SIGNIFICANT DETERIORATION APPLICABILITY

Because the project emissions increase of GHG is greater than 100,000 ton/yr of $CO_2e$, PSD is triggered for GHG emissions. The emissions netting analysis is documented on the attached TCEQ PSD netting tables: Table 1F and Table 2F. Note that this is a new Greenfield site and, as such, there are no contemporaneous emission changes associated with the project. Also included in Appendix A is the "The GHG PSD APPLICABILITY FLOWCHART – NEW SOURCES" from the *PSD and Title V Permitting Guidance for Greenhouse Gases.*

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**TABLE 1F**
**AIR QUALITY APPLICATION SUPPLEMENT**

TCEQ

| | | | |
|---|---|---|---|
| Permit No.: | 101542, PSD-TX-1288 | Application Submittal Date: | |
| Company | La Paloma Energy Center LLC | | |
| RN: | RN100213107 | Facility Location: | 24684 FM 1595 |
| City | Harlingen | County: | Cameron |
| Permit Unit I.D.: | GTG/HRSG1 and GTG/HRSG2 | Permit Name: | Las Paloma Energy Center |
| Permit Activity: | ☑ New Major Source | ☐ Modification | |
| Project or Process Description: | Construction of new combined cycle electric generating plant | | |

| 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] | | | | | | 3,289,810 | 3,302,433 |
| Is the existing site a major source? If not, is the project a major source by itself? (yes or no) | Yes | | | | | | |
| If site is major, is project increase significant? (yes or no) | | | | | | Yes | Yes |
| If netting required, estimated start of construction: | | 6/1/13 | | | | | |
| 5 years prior to start of construction: | | 6/1/08 | Contemporaneous | | | | |
| estimated start of operation: | | 10/1/15 | Period | | | | |
| Net contemporaneous change, including proposed project, from Table 3F (tpy) | | | | | | 3,289,810 | 3,302,433 |
| 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.

Smith — PRESIDENT — 4-26-12

Signature — Title — Date

TCEQ

**TABLE 2F**
**PROJECT EMISSION INCREASE**

| | | | |
|---|---|---|---|
| **Pollutant[1]:** GHG | | **Permit:** | 101542 |
| **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 | CTG1/HRSG1 | U1-STK | 101542 | 0.00 | 0.00 | 1,640,771 | | 1,640,771 | | 1,640,771 |
| 2 | CTG2/HRSG2 | U2-STK | 101542 | 0.00 | 0.00 | 1,640,771 | | 1,640,771 | | 1,640,771 |
| 3 | AUXBLR | AUXBLR | 101542 | 0.00 | 0.00 | 7,680 | | 7,680 | | 7,680 |
| 4 | NG-FUG | NG-FUG | 101542 | 0.00 | 0.00 | 497 | | 497 | | 497 |
| 5 | TRB-MSS | TRB-MSS | 101542 | 0.00 | 0.00 | 0.11 | | 0 | | 0 |
| 6 | EMGEN1 | EMGEN1-STK | 101542 | 0.00 | 0.00 | 64 | | 64 | | 64 |
| 7 | FWP1 | FWP1-STK | 101542 | 0.00 | 0.00 | 28 | | 28 | | 28 |
| 8 | SF6-FUG | SF6-FUG | 101542 | 0.00 | 0.00 | 0.0010 | | 0.0010 | | 0.0010 |
| 9 | | | | | | | | | | |
| 10 | | | | | | | | | | |
| 11 | | | | | | | | | | |
| 12 | | | | | | | | | | |
| 14 | | | | | | | | | | |
| 15 | | | | | | | | | | |
| | | | | | | | Page Subotal[9] | | | 3,289,810 |

TCEQ

# TABLE 2F
## PROJECT EMISSION INCREASE

| | | | |
|---|---|---|---|
| **Pollutant[1]:** | $CO_2e$ | **Permit:** | 101542 |
| **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 | CTG1/HRSG1 | U1-STK | 101542 | 0.00 | 0.00 | 1,642,317 | | 1,642,317 | | 1,642,317 |
| 2 | CTG2/HRSG2 | U2-STK | 101542 | 0.00 | 0.00 | 1,642,317 | | 1,642,317 | | 1,642,317 |
| 3 | AUXBLR | AUXBLR | 101542 | 0.00 | 0.00 | 7,687 | | 7,687 | | 7,687 |
| 4 | NG-FUG | NG-FUG | 101542 | 0.00 | 0.00 | 10,046 | | 10,046 | | 10,046 |
| 5 | TRB-MSS | TRB-MSS | 101542 | 0.00 | 0.00 | 2 | | 2 | | 2 |
| 6 | EMGEN1 | EMGEN1-STK | 101542 | 0.00 | 0.00 | 65 | | 65 | | 65 |
| 7 | FWP1 | FWP1-STK | 101542 | | | | | | | |
| 8 | | | | | | | | | | |
| 9 | | | | | | | | | | |
| 10 | | | | | | | | | | |
| 11 | | | | | | | | | | |
| 12 | | | | | | | | | | |
| 13 | | | | | | | | | | |
| 14 | | | | | | | | | | |
| 15 | | | | | | | | | | |
| | | | | | | | Page Subotal[9] | | | 3,302,433 |

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 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)

The PSD rules define BACT as:

> *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.[15]

In the EPA guidance document titled *PSD and Title V Permitting Guidance for Greenhouse Gases*, EPA recommended the use of the Agency's five-step "top-down" BACT process to determine BACT for GHGs.[16] In brief, the top-down process calls for all available control technologies for a given pollutant to be identified and ranked in descending order of control effectiveness. The permit applicant should first examine the highest-ranked ("top") option. The top-ranked options should be established as BACT unless the permit applicant demonstrates to the satisfaction of the permitting authority that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the top ranked technology is not "achievable" in that case. If the most effective control strategy is eliminated in this fashion, then the next most effective alternative should be evaluated, and so on, until an option is selected as BACT.

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

**Step 1: Identify all available control technologies.**
**Step 2: Eliminate technically infeasible options.**
**Step 3: Rank remaining control technologies.**

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[15] 40 C.F.R. § 52.21(b)(12.)

[16] EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases*, p. 18 (Nov. 2010).

**Step 4: Evaluate most effective controls and document results.**
**Step 5: Select the BACT.**

## 5.1 BACT FOR THE COMBINED CYCLE COMBUSTION TURBINE

### 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.

##### 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 from the combustion, thereby reducing the amount of fuel needed to meet the plant'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 coal-fired Rankine cycle power plant has a base load efficiency of approximately 30% (HHV), while a modern F-Class natural gas fired combined cycle unit operating under optimal conditions has a base load 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 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 the recoverable 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 highly efficient low-emission operation.

**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 high-efficiency low-emission performance for full-load and part-load conditions.

#### 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 F-Class 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 uses 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 F-Class 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 this project.

#### 5.1.1.1.3 Steam Turbine Energy Efficiency Processes, Practices, and Designs

The steam turbine for this 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 moisture content of the exhaust steam. If the moisture content of the exhaust steam is too high, erosion of the last-stage turbine blades occurs. This 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. The steam turbine for this project will either be totally enclosed water to air-cooled or hydrogen-cooled. These cooling methods allow for the highest efficiency of the generator, resulting in an overall high-efficiency steam turbine.

#### 5.1.1.1.4 Plant-wide 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 temperatures. For the F-Class combustion turbine based combined cycle, the fuel gas is generally heated with high temperature water from the HRSG. This improves the efficiency of the combustion turbine.
- **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 this 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 add-on technologies as 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…"[17]

The DOE-NETL adds:

> "…Separating $CO_2$ from flue gas streams is challenging for several reasons:
>
> - $CO_2$ 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…"[18]

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

[17] 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).

[18] *Id.*

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…"[19]

### 5.1.2 Step 2: Eliminate Technically Infeasible Options

In this section, LPEC addresses the potential 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.

#### *5.1.2.1 $CO_2$ 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."[20]

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[19] DOE-NETL, *Carbon Sequestration: Geologic Storage Focus Area,* http://www.netl.doe.gov/technologies/carbon_seq/corerd/storage.html (last visited Feb. 27, 2012)

[20] *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."[21A]

To corroborate that commercial availability of $CO_2$ capture technology for large-scale power plant projects will not occur for several more years, Alstom, one of the major developers of commercial $CO_2$ capture technology using post-combustion amine absorption, post-combustion chilled ammonia absorption, and oxy-combustion, states on its web site that its $CO_2$ capture technology will become commercially available in 2015.[22B] However, it should be noted that in committing to this timeframe, the company does not indicate whether such technology will be able to handle the volume of $CO_2$ emissions generated by a project of the size of LPEC.

### *5.1.2.2 $CO_2$ 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 pipeline was constructed are delineated on the map found at the end of Section 5.[23] The potential length of such a $CO_2$ transport pipeline is uncertain due to the uncertainty of identifying a site(s) that is suitable for large-scale, long-term

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

[22] Alstom, *Alstom's Carbon Capture Technology Commercially "Ready to Go" by 2015*, Nov.30, 2010, http://www.alstom.com/australia/news-and-events/pr/ccs2015/ (last visited Sept.28, 2011).

[23] 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).

$CO_2$ 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 an enhanced oil recovery (EOR) reservoir site located within 15 miles of the proposed project.

However, none of the South and Southeast Texas EOR reservoir or other geologic formation sites have yet been technically demonstrated for large-scale, long-term $CO_2$ storage.

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 Southwest Regional Partnership on Carbon Sequestration's (SWP) SACROC test site, which is located in Scurry County, Texas approximately 490 miles away (see the map at the end of Section 5 for the test site location). Therefore, to access this potentially large-scale storage capacity site, assuming that it is eventually demonstrated to indefinitely store 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 the plant to the storage facility, thereby rendering implementation of a $CO_2$ transport system infeasible.

### *5.1.2.3 $CO_2$ 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,[24] and
- Potential effects on wildlife.

Potentially suitable storage sites, including EOR sites and saline formations, exist in Texas, Louisiana, and Mississippi. In fact, sites with such recognized potential for some geological storage of $CO_2$ are located within 15 miles of the proposed project, but such nearby sites have not yet been technically demonstrated with respect to all of the suitability factors described above. In comparison, the closest site that is currently being field-tested to demonstrate its capacity for geological storage of the volume of $CO_2$ that would be generated by the proposed

[24] *Id.*

power unit, i.e., SWP's SACROC test site, is located in Scurry County, Texas approximately 490 miles away. It should be noted that, based on the suitability factors described above, currently the suitability of the SACROC 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 fully demonstrated.

Based on the reasons provided above, LPEC believes 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, LPEC has estimated such costs. Those cost estimates are presented on Table 5-1 at the end of Section 5.

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 42.8% (HHV).[25]

### 5.1.3 Step 3: Rank Remaining Control Technologies

As documented above, implementation of CCS technology is currently infeasible, leaving energy efficiency measures as the only technically feasible emission control options. As all of the energy efficiency related processes, practices, and designs discussed in Section 5.1.1 of this application are being proposed for this 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 of this application are being proposed for this project, an examination of the energy, environmental, and economic impacts of the efficiency designs is not necessary for this application. Because the CCS add-on control option discussed in Section 5.1.2 was determined to be technically infeasible, an examination of the energy, environmental, and economic impacts of that option is not necessary for this application. However, at the request of EPA Region 6, LPEC is including estimated costs for implementation of CCS.

### 5.1.5 Step 5: Select BACT

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

- Use of Combined Cycle Power Generation Technology
- Combustion Turbine Energy Efficiency Processes, Practices, and Designs

[25] US 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 2, November 2010

  - 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
- Plant-wide 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, LPEC started with the turbine's design base load net heat rate for combined cycle operation and then calculated a compliance margin based upon reasonable degradation factors that may foreseeably reduce efficiency under real-world conditions. The design base load net heat rate for the project is 6,845 Btu/kWhr (HHV) without duct firing at 100% load and 7,050 Btu/kWhr (HHV) with maximum duct firing at 100% load. Note that this rate reflects the facility's "net" power production, meaning the denominator is the amount of power provided to the grid; it does not reflect the total amount of energy produced by the plant, which also includes auxiliary load consumed by operation of the plant. To be consistent with other recent GHG BACT determinations, the net heat rate without duct firing is used to calculate the heat-input efficiency limit.

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% performance margin reflecting efficiency losses due to equipment degradation prior to maintenance overhauls.
- A 3% degradation 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, LPEC 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, LPEC is also providing a reasonable compliance margin 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, cooling tower, and ancillary equipment such as pumps and motors is also expected to occur over the course of a major maintenance cycle.

As a result of these adjustments, LPEC is proposing an annual average net heat rate for the Project of 7,720 Btu/kWh (HHV), without duct burner firing. This heat rate limit is equivalent to an output based GHG BACT limit of 919 lb $CO_2$e/MWhr (net). The calculation of the net heat rate and the equivalent lb $CO_2$e/MWhr is provided on Table 5-2 of this application. Since the plant heat rate varies according to turbine operating load and the amount of duct burner firing, LPEC proposes to demonstrate compliance with the 7,720 Btu/kWh (HHV) heat rate with an annual compliance test, at 100% load, corrected to ISO conditions.

On March 27, 2012, the EPA proposed New Source Performance Standard (NSPS), Subpart TTTT, that would control GHG emissions from new power plants.[26] The proposed rule would apply to fossil-fuel fired electric generating units that generate electricity for sale and are larger than 25 MW. The EPA proposed that new power plants meet an annual average output based standard of 1,000 lb $CO_2$/MWh gross. The proposed emission rate for the LPEC on a net electrical output basis is 918 lb $CO_2$/MWh without duct burner firing and 945 lb/MWh with maximum duct burner firing. The LPEC lb $CO_2$/MWh emission rates on a gross electrical output basis will be approximately 2% lower than the proposed rates on a net electrical output basis. The proposed $CO_2$ emission rates from the LPEC combined cycle turbines are well without the emission limit in proposed NSPS Subpart TTTT.

[26] Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, 77 Fed Reg 22392, April 13, 2012

LPEC performed a search of the EPA's RACT/BACT/LAER Clearinghouse for natural gas fired combustion turbine generators and found no entries which address BACT for GHG emissions. Although not listed in the RACT/BACT/LAER Clearinghouse, a GHG BACT analysis was performed by the following natural gas fired power generation facilities: Russell City Energy Center, Palmdale Hybrid Power Plant, Lower Colorado River Authority Ferguson Plant, Cricket Valley Energy Center, Pioneer Valley Energy Center, Deer Park Energy Center, and Channel Energy Center. A discussion of the LPEC's proposed BACT as compared to those projects is provided below:

**Palmdale Hybrid Power Project**

The application for the Palmdale Hybrid Power Project (PHPP) was submitted in May 2011 and a final permit was issued by the Antelope Valley Air Quality Management District on October 18, 2011. The permit authorizes the construction of two natural-gas-fired GE 7FA combustion turbine generators, with 500 MMBtu/hr duct fired heat recovery steam generators, and one steam turbine generator to be located in Palmdale, California. The project included a 50 MW, 251 acre solar thermal array field with a solar steam boiler on the 333 acre site. The permit listed a GHG BACT limit of 774 lb $CO_2$/MW-hr source-wide net output and 7,319 Btu/kWhr source wide net heat rate, 365 rolling average.

The application submitted by PHPP represented as BACT, a heat rate of 6,970 Btu/kWh, based on the higher heating value (HHV) of natural gas with two CTGs operating at 100% with no solar input and with no duct firing.[27] The PHPP application did not state whether the 6,970 Btu/kWh heat rate represented as BACT, is on a gross electrical output basis or a net electrical output basis. A $CO_2$ emission rate of 0.408 short tons of $CO_2$/MW-hr was derived from the heat rate of 6,970 Btu/Kw-hr, based on a $CO_2$ emission factor of 53.06 kg $CO_2$/MMBtu. 0.408 short tons of $CO_2$/MW-hr equates to 816 lb $CO_2$/MW-hr.

The BACT representations in the Palmdale permit and the application cannot be directly compared to the representations for the LPEC for the following reasons:

1. The permit limit of 774 lb $CO_2$/MW-hr does not correspond to the representations in the PHPP application. PHPP represented a $CO_2$ emission rate of 0.408 short tons $CO_2$/MW-hr (816 lb $CO_2$/MW-hr) for the two combustion turbines, without duct burner firing which was derived from the represented design heat rate of 6,970 Btu/kW-hr. The $CO_2$ emission rate associated with the permit heat rate limit of 7,319 Btu/kW-hr would be 856.9 lb $CO_2$/MW-hr. The basis of the 774 lb $CO_2$/MWhr permit limit is unclear.

2. The U.S. EPA, Region 9, in its response to comments, stated that the BACT limit was being set at 7,319 Btu/kWh to account for "a variety of factors that can affect heat rate, including seasonal variations (i.e. temperature, humidity) and equipment degradation".[28]

[27] AECOM Memorandum to Lisa Bingham and Joe Lapka, Response to EPA Comments on PHPP GHG BACT Analysis, July 15, 2011.

[28] U.S. Environmental Protection Agency, Region 9, "Responses to Public Comments on the Proposed Prevention of Significant Deterioration Permit for the Palmdale Hybrid Power Project", Oct. 2011.

The 7,319 Btu/kWh limit provides only a 5% compliance margin over the represented "design" heat rate of 6,970 Btu/kWh. This is not consistent with the Cricket Valley Energy Center, Pioneer Valley Energy Center, Lower Colorado River Authority Ferguson Plant, Deer Park Energy, and Channel Energy Center GHG permits discussed below. The Palmdale permit does not account for the design margin of the equipment or degradation of supporting equipment.

3. The "design" heat rate proposed by PHPP was for two CTGs operating at 100% load. The 365 day rolling average permit limit of 7,319 Btu/kW-hr does not account for lower efficiencies at reduced loads. LPEC is proposing an annual heat rate based on expected heat rates at an annual average load of 70%.

**Lower Colorado River Authority Ferguson Plant**

The application for the LCRA Ferguson Plant was submitted in March 2011. The application included two natural-gas-fired GE 7FA combustion turbines, heat recovery steam generators without no additional duct firing, and one steam turbine generator to be located in Marble Falls, Texas. The permit, issued November 10, 2011, included BACT limits of 0.459 ton $CO_2$/MWh (net) on a 365 day rolling average and an average net heat rate of 7,720 Btu/kWh (HHV) on a 365 day rolling average.

For comparison purposes, LPEC's application proposes a heat rate of 7,720 Btu/kWh (HHV, net basis), which accounts for design margins, performance margins, and degradation margins and an emission rate of 0.459 ton $CO_2$/MW-hr (net) [0.460 ton $CO_2$e/MW-hr (net)].

**Cricket Valley Energy Center**

The Cricket Valley Energy Center (CVEC) air permit application proposed the construction of three natural-gas-fired GE 7FA combustion turbines, with 596.8 MMBtu/hr duct fired heat recovery steam generators, and three steam turbine generators to be located in Dover, New York. The CVEC application represented that the GE 7FA turbines operating in combined cycle mode have a design base heat rate of 6,742 Btu/kW-hr at ISO conditions with no duct firing (based on net output). Based upon the design efficiency, and adding a reasonable margin of compliance, CVEC proposed a limit of 7,605 Btu/kW-hr (ISO conditions without duct firing) as BACT for the proposed project. The draft permit specifies that the facility is required conduct a thermal efficiency test on a minimum of one combustion turbine annually.

For comparison purposes, LPEC proposes a heat rate of 7,720 Btu/kWh (HHV, net basis), which accounts for design margins, performance margins, and degradation margins, which is within 1.6% of the proposed CVEC proposed limit. The efficiencies from two similarly sized combined cycle electric generating units will not be identical due to differences in the properties and variability of the natural gas; the geographic location - higher combustion turbine efficiencies are achieved at lower elevations and at cooler ambient temperatures due to denser ambient air; differences in combustion turbine designs, heat recovery steam generator designs and steam turbine designs; and electric generating unit load generation flexibility requirements -

operating an electric generating unit as a base load unit is more efficient than operating as a load cycling unit to respond to fluctuations in customer electricity or steam demands.

**Pioneer Valley Energy Center**

The Pioneer Valley Energy Center (PVEC) air permit application proposed the construction of a 431 MW natural-gas-fired combined cycle turbine generator to be located in Westfield, Massachusetts. The PVEC air application proposed to construct a Mitsubishi M501G combined cycle turbine. The air permit for the project was issued April 12, 2012. The permit contained an initial GHG limit of 825 lbs of $CO_2e/MWh_{grid}$ to be demonstrated during initial performance test and a 365-day rolling average limit of 895 lbs of $CO_2e/MWh_{grid}$.

For comparison purposes, LPEC proposes a $CO_2e$ emission rate of 918 lb CO2e/MWh, net basis, which accounts for design margins, performance margins, and degradation margins, which is within 2.6% of the proposed PVEC limit. The efficiencies from two similarly sized combined cycle electric generating units will not be identical due to differences in the properties and variability of the natural gas; the geographic location - higher combustion turbine efficiencies are achieved at lower elevations and at cooler ambient temperatures due to denser ambient air; differences in combustion turbine designs, heat recovery steam generator designs and steam turbine designs; and electric generating unit load generation flexibility requirements - operating an electric generating unit as a base load unit is more efficient than operating as a load cycling unit to respond to fluctuations in customer electricity or steam demands.

**Deer Park Energy Center**

The application for the Calpine Deer Park Energy Center was submitted in September 2011 and a draft permit has not yet been issued. The application proposed to authorize a fifth Siemens 501F CTG/HRSG train and ancillary equipment at the existing Deer Park Energy Center located in Deer Park, Texas. The Deer Park application represented a BACT net heat rate for the Project of 7,730 Btu/kWh (HHV), corrected to ISO conditions.

For comparison purposes, LPEC proposes a heat rate of 7,720 Btu/kWh (HHV, net basis), which accounts for design margins, performance margins, and degradation margins.

**Channel Energy Center**

The application for the Calpine Channel Energy Center was submitted in October 2011 and a draft permit has not yet been issued. The application proposed to authorize a third Siemens 501F CTG/HRSG train and ancillary equipment at the existing Channel Energy Center located in Pasadena, Texas. The Channel Energy application represented a BACT net heat rate for the Project of 7,730 Btu/kWh (HHV), corrected to ISO conditions.

For comparison purposes, LPEC proposes a heat rate of 7,720 Btu/kWh (HHV, net basis), which accounts for design margins, performance margins, and degradation margins.

## 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 feasible control technologies. One 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.

One alternative 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 $SF_6$.*[29]

### 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.[30] 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 there are currently no technically feasible options besides use of $SF_6$.

### 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 highest ranked control technology that is technically feasible for this application.

[29] 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.
[30] *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-greenhouse-gas 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, LPEC concludes that using state-of-the-art enclosed-pressure $SF_6$ circuit breakers with leak detection would be the BACT control technology option. The circuit breakers will be designed to meet the latest of the American National Standards Institute (ANSI) C37.013 standard for high voltage circuit breakers.[31] The proposed circuit breaker at the generator output will 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 problems to light 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.

LPEC will monitor emissions annually in accordance with the requirements of the Mandatory Greenhouse Gas Reporting rules for Electrical Transmission and Distribution Equipment Use.[32] 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 150 MMBtu/hr auxiliary boiler (EPNs AUX-BOIL1 and AUX-BOILL2) will be utilized to facilitate startup of the combined cycle units. Each auxiliary boiler will be limited to 876 hours of operation per year.

The calculated GHG emissions from the auxiliary boiler represent less than 0.2% of the total proposed GHG emissions from the site. LBEC proposes as BACT for this project, to follow manufacturer's recommended operating and maintenance procedures.

Among other recently issued or currently pending GHG permits, the Wolverine Power Supply Cooperative permit and the Palmdale Hybrid Power Project permit included BACT determinations for limited use, auxiliary boilers and heaters. The Wolverine Permit included a 72.4 MMBtu/hr diesel-fired auxiliary boiler, limited to 4,000 hours operation per year. The Permit listed BACT for GHG for the auxiliary boiler to incorporate energy efficient equipment wherever practical in the design of the auxiliary boiler. The Wolverine Permit did not include an output based BACT limit for the auxiliary boiler.

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[31] ANSI Standard C37.013, *Standard for AC High-Voltage Generator Circuit Breakers on a Symmetrical Current*.

[32] *See* 40 C.F.R. Pt. 98, Subpt. DD.

The application for the Palmdale Hybrid Power Project (PHPP) was submitted in May 2011 and a draft permit was issued by the Antelope Valley Air Quality Management District in August 2011. The PHPP application proposed the construction of a power plant utilizing natural-gas-fired combustion turbine combined cycle generators located in Palmdale, California. The project also included a 110 MMBtu/hr natural-gas-fired auxiliary boiler, limited to 500 hours per year operation, and a 40 MMBtu/hr natural-gas-fired heater, limited to 1,000 hours per year operation. The Palmdale Permit listed BACT for GHG for the auxiliary boiler and heater as annual tune-ups. The Palmdale Permit did not include an output based BACT limit for the auxiliary boiler or heater.

## 5.4 BACT FOR EMERGENCY ENGINES

The proposed project will include installation of a new, high efficiency, fire pump engine and emergency generator. The use of diesel is being used as fuel for the emergency engines in the event of unavailability of a natural gas supply. Use of these engines for purpose of maintenance checks and readiness testing will be limited to 100 hours per year each. The new engines will be subject to the New Source Performance Standard for Stationary Compression Ignition Internal Combustion Engines.[33] As such, the engines will be required to meet specific emission standards based on engine size, model year, and end use.

The use of engines with a low annual capacity factor and performance of routine maintenance is proposed as BACT for GHG emissions.

[33] *See* 40 C.F.R. Pt. 60, Subpt. IIII.

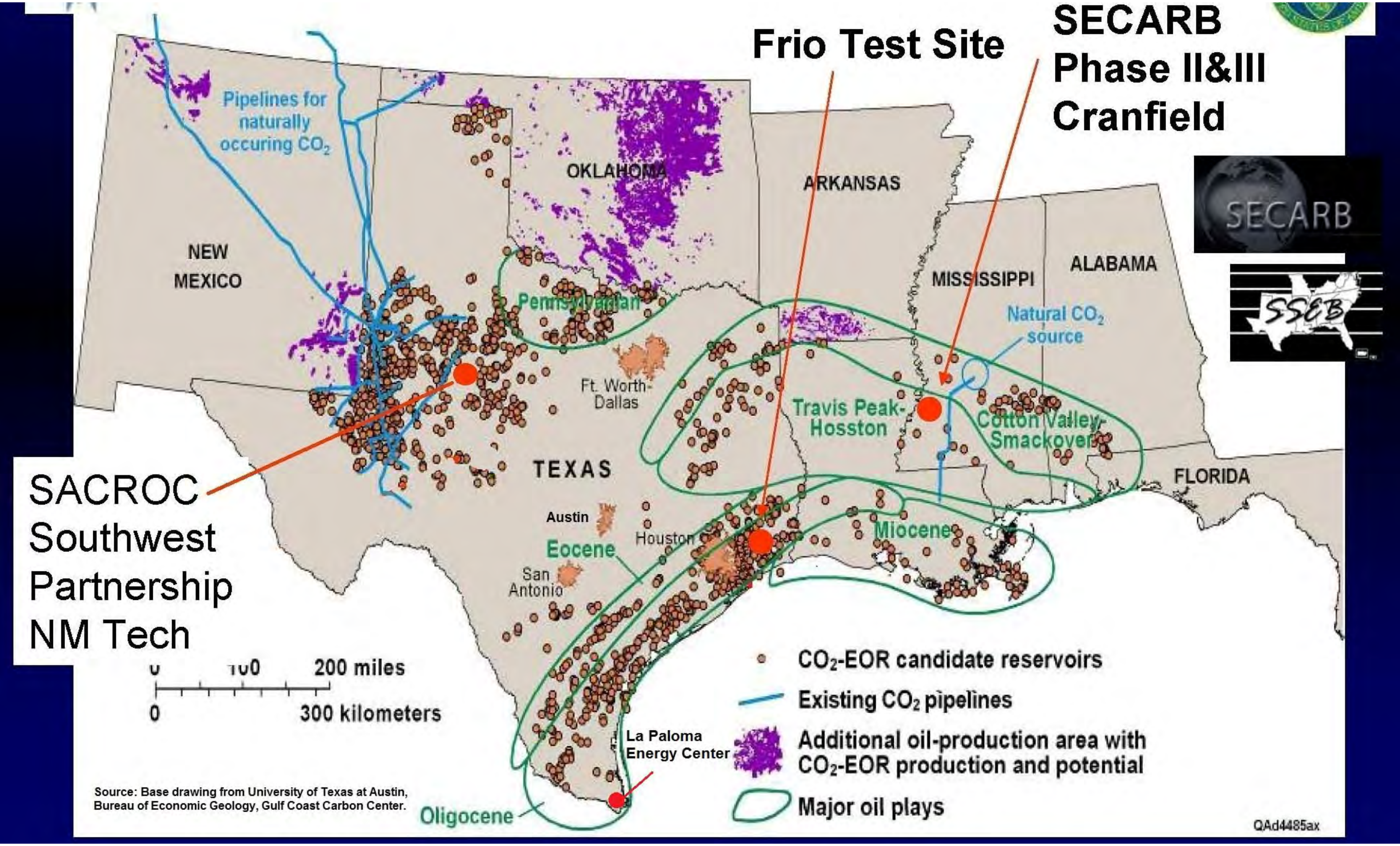

Frio Test Site
SECARB
Phase II&III
Cranfield
SECARB
SSEB
Pipelines for
naturally
occuring $CO_2$
OKLAHOMA
ARKANSAS
NEW
MEXICO
MISSISSIPPI
ALABAMA
Pennsylvanian
Natural $CO_2$
source
Ft. Worth-
Dallas
Travis Peak-
Hosston
Cotton Valley
Smackover
TEXAS
FLORIDA
SACROC
Southwest
Partnership
NM Tech
Austin
Houston
Miocene
Eocene
San
Antonio
0 100 200 miles
0 300 kilometers
$CO_2$-EOR candidate reservoirs
Existing $CO_2$ pipelines
Additional oil-production area with
$CO_2$-EOR production and potential
Major oil plays
La Paloma
Energy Center
Source: Base drawing from University of Texas at Austin,
Bureau of Economic Geology, Gulf Coast Carbon Center.
Oligocene
QAd4485ax

**Table 5-1**
**Range of Approximate Annual Costs for Installation and Operation of Capture, Transport, and Storage Systems for Control of $CO_2$ Emissions from the Two Proposed Electric Generating Units at La Paloma Energy Center, Cameron County, Texas**

| Carbon Capture and Storage (CCS) Component System | Factors for Approximate Costs for CCS Systems | Annual System $CO_2$ Throughput (tons of $CO_2$ captured, transported, and stored) [1] | Pipeline Length for $CO_2$ Transport System (km $CO_2$ transported) [5] | Range of Approximate Annual Costs for CCS Systems ($) |
|---|---|---|---|---|
| **Post-Combustion $CO_2$ Capture and Compression System** | | | | |
| Minimum Cost | $44.11 / ton of $CO_2$ avoided [2] | 2,953,327 | | $130,271,268 |
| Maximum Cost | $103.42 / ton of $CO_2$ avoided [3] | 2,953,327 | | $305,430,323 |
| Average Cost | $73.76 / ton of $CO_2$ avoided [4] | 2,953,327 | | $217,850,795 |
| **$CO_2$ Transport System** | | | | |
| Minimum Cost | $0.91 / ton of $CO_2$ transported per 100 km [3] | 2,953,327 | 19 | $517,722 |
| Maximum Cost | $2.72 / ton of $CO_2$ transported per 100 km [3] | 2,953,327 | 19 | $1,553,167 |
| Average Cost | $1.81 / ton of $CO_2$ transported per 100 km [4] | 2,953,327 | 19 | $1,035,445 |
| **$CO_2$ Storage System** | | | | |
| Minimum Cost | $0.51 / ton of $CO_2$ stored [3, 6] | 2,953,327 | | $1,500,359 |
| Maximum Cost | $18.14 / ton of $CO_2$ stored [3, 6] | 2,953,327 | | $53,584,267 |
| Average Cost | $9.33 / ton of $CO_2$ stored [4] | 2,953,327 | | $27,542,313 |
| **Total Cost for $CO_2$ Capture, Transport, and Storage Systems** | | | | |
| Minimum Cost | $44.79 / ton of $CO_2$ removed | 2,953,327 | | $132,289,350 |
| Maximum Cost | $122.09 / ton of $CO_2$ removed | 2,953,327 | | $360,567,757 |
| Average Cost | $83.44 / ton of $CO_2$ removed [4] | 2,953,327 | | $246,428,554 |

[1] Assumes the maximum possible annual $CO_2$ emissions scenario of the three proposed combustion turbine options, i.e., operating two Siemens SGT6-5000F(5)) turbines, and assumes that a capture system would be able to capture 90% of the total $CO_2$ emissions generated by the combustion turbines.

[2] This cost factor is the minimum found for implementation/operation of $CO_2$ capture systems within the cost-related information reviewed for CCS technology. The factor is from the on the "Properties" spreadsheet of the *Greenhouse Gas Mitigation Strategies Database* (Apr. 2010) (http://ghg.ie.unc.edu:8080/GHGMDB/#data), which was obtained through the EPA GHG web site (http://www.epa.gov/nsr/ghgpermitting.html). The factor is based on the increased cost of electricity (COE; in $/MW-h) resulting from implementation and operation at a $CO_2$ capture system on a natural gas-fired combined cycle power plant. The factor accounts for annualized capital costs, fixed operating costs, variable operating costs, and fuel costs.

[3] These cost factors are from *Report of the Interagency Task Force on Carbon Capture and Storage* , pp.33, 34, 37, and 44 (Aug. 2010) (http://www.epa.gov/climatechange/policy/ccs_task_force.html). The factors from the report in the form of $/tonne of $CO_2$ avoided, transported, or stored and have been converted to $/ton. Per the report, the factors are based on the increased cost of electricity (COE; in $/kW-h) of an "energy -generating system, including all the costs over its lifetime: initial investment, operations and maintenance, cost of fuel, and cost of capital".

[4] The average cost factors were calculated as the arithmetic mean of the minimum and maximum factors for each CCS component system and for all systems combined.

[5] The length of the pipeline was assumed to be the distance to the closest potential geologic storage site, as identified by the University of Texas at Austin, Bureau of Economic Geology, Gulf Coast Carbon Center, available at: http://www.beg.utexas.edu/gccc/graphics/Basemap_state_lands_fp_lg.jpg (last visited Feb. 27, 2012).

[6] "Cost estimates [for geologic storage of $CO_2$] are limited to capital and operational costs, and do not include potential costs associated with long-term liability." (from the *Report of the Interagency Task Force on Carbon Capture and Storage* , p. 44)

**Table 5-2**
**GHG Emission Calculations - Calculation of Design Heat Rate Limit**
**La Paloma Energy Center**

| | | |
|---|---|---|
| **Base Net Heat Rate** | **6,845** | **Btu/kWH (HHV) (Without Duct Firing)** |
| | **3.3%** | **Design Margin** |
| | **6.0%** | **Performance Margin** |
| | **3.0%** | **Degradation Margin** |
| **Calculated Base Net Heat Rate with Compliance Margins** | 7720.0 | **Btu/kWH (HHV) (Without Duct Firing)** |

**Calculate of lb CO2e/MWhr Heat Rate Limit**

| EPN | Base Heat Rate (Btu/kWhr) | Heat Input Required to Produce 1 MW (MMBtu/MWhr) | Pollutant | Emission Factor (kg/MMBtu)[1] | lb GHG/MWhr[2] | Global Warming Potential[3] | lb $CO_2$e/MWhr |
|---|---|---|---|---|---|---|---|
| CTG/HRSG3 | 7720.0 | 7.72 | $CO_2$ | | 917.576 | 1 | 917.576 |
| | | | $CH_4$ | 1.0E-03 | 1.70E-02 | 21 | 3.57E-01 |
| | | | $N_2O$ | 1.0E-04 | 1.70E-03 | 310 | 5.28E-01 |
| | | | | **Totals** | **917.6** | | **918.5** |

*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*

*$W_{CO2}$ = (Fc x H x $U_f$ X $MW_{CO2}$)/2000*

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

*Fc = 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 $^oF$*

*$MW_{CO2}$ = 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.*

# 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.*[34]

An impacts analysis for non-GHG emissions is being submitted with the State/PSD/Non-attainment 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.*[35]

A pre-construction monitoring analysis for non-GHG emissions is being submitted with the State/PSD/Nonattainment 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 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*

[34] EPA, *PSD and Title V Permitting Guidance For Greenhouse Gases* at 48-49.

[35] *Id.* at 49.

> *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.*[36]

A PSD additional impacts analysis for non-GHG emissions is being submitted with the State/PSD/Nonattainment application submitted to the TCEQ.

[36] *Id.*

# 7.0 PROPOSED GHG MONITORING PROVISIONS

LPEC proposes to monitor $CO_2$ emissions by monitoring the quantity of fuel combusted in the turbines and heat recovery steam generators 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 LPEC 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:*

$W_{CO2} = (Fc \times H \times Uf \times MW_{CO2})/2000$

*Where:*

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

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

*Fc = Carbon Based Fc-Factor, (1040 scf/MMBtu for natural gas <u>or a site-specific Fc factor</u>)*

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

*Uf = 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)*

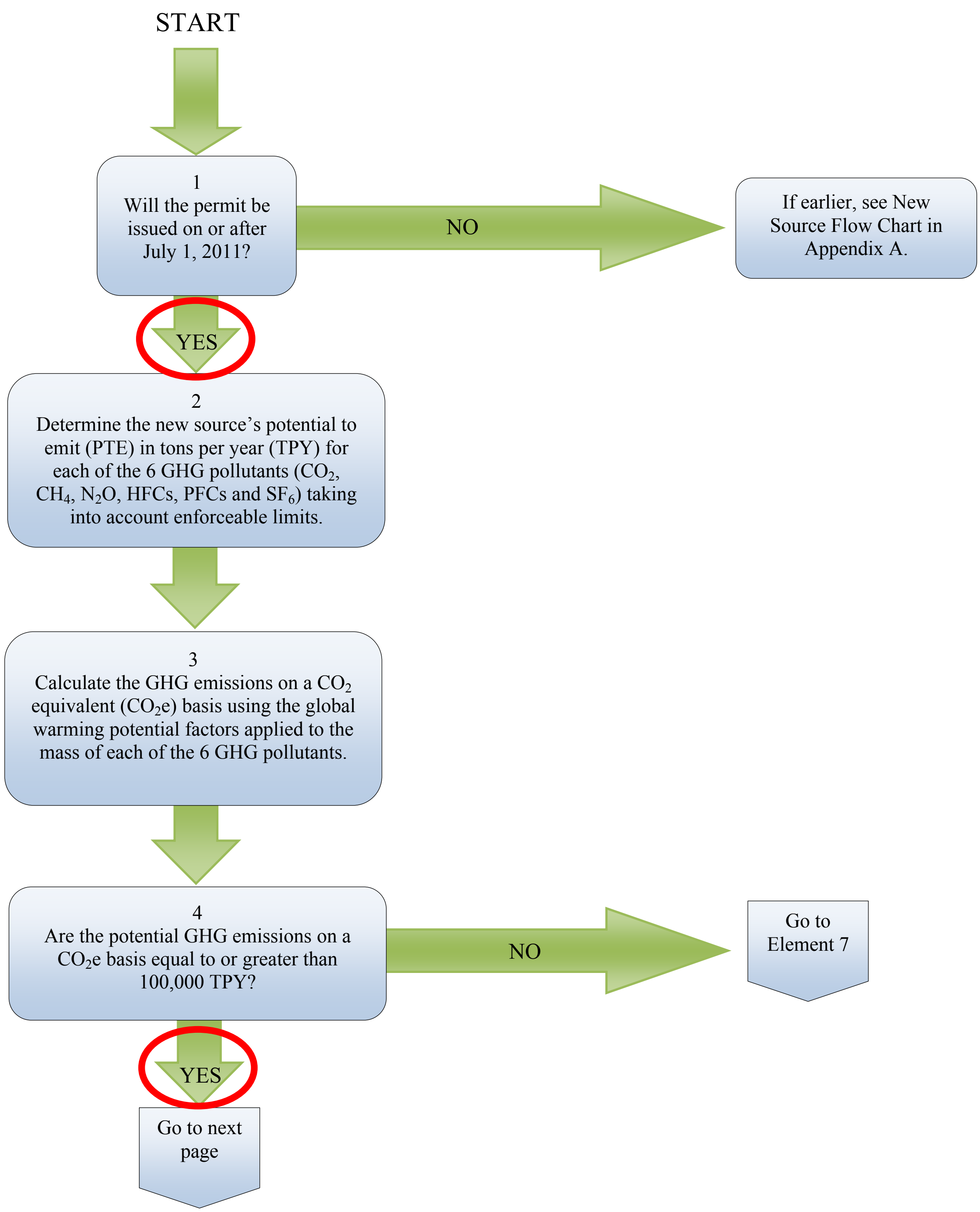
This monitoring approach is consistent with the $CO_2$ reporting requirements of the GHG Mandatory Reporting Rule for Electricity Generation (40 CFR 98, Subpart D). Subpart D requires electric generating sources that report $CO_2$ emissions under 40 CFR 75 to report $CO_2$ under 40 CFR 98 by converting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

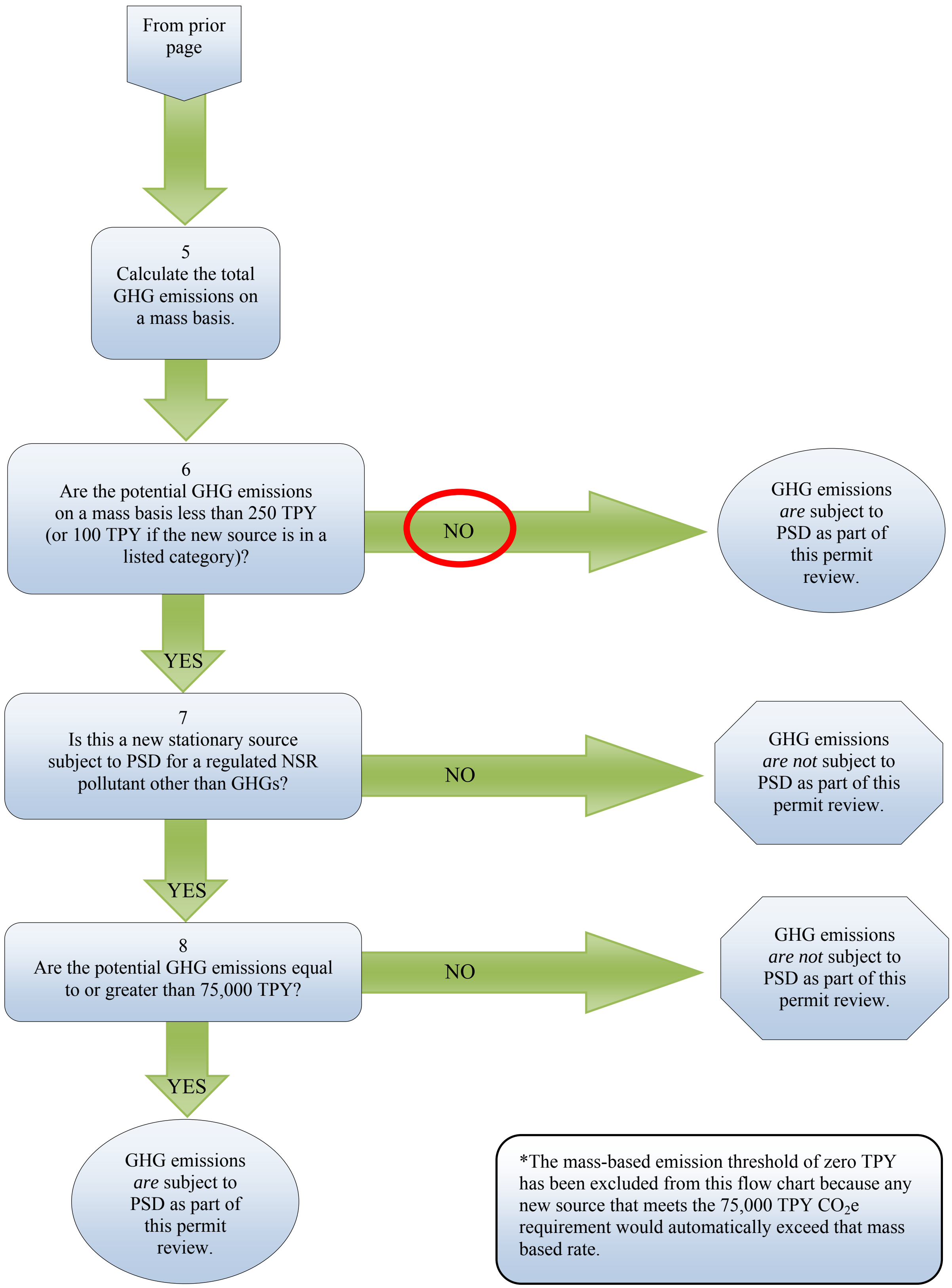
Also, the recently proposed NSPS Subpart TTTT –Standards of Performance for Greenhouse Gas Emissions for Electric Utility Generating Units ((40 CFR §60.5535(c)) allows electric generating units firing gaseous fuel and liquid fuel oil to determine $CO_2$ mass emissions by monitoring fuel combusted in the affected Electric Generating Unit and using a site specific Fc factor determined in accordance with 40 CFR 75, Appendix F. Therefore, LPEC's proposed $CO_2$ monitoring method is consistent with the proposed NSPS Subpart TTTT.

# APPENDIX A

# GHG PSD APPLICABILITY FLOWCHART – NEW SOURCES

## *Appendix A - GHG Applicability Flow Chart – New Sources (On or after July 1, 2011)*




From prior page
5
Calculate the total GHG emissions on a mass basis.
6
Are the potential GHG emissions on a mass basis less than 250 TPY (or 100 TPY if the new source is in a listed category)?
NO
GHG emissions *are* subject to PSD as part of this permit review.
YES
7
Is this a new stationary source subject to PSD for a regulated NSR pollutant other than GHGs?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
8
Are the potential GHG emissions equal to or greater than 75,000 TPY?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
GHG emissions *are* subject to PSD as part of this permit review.
*The mass-based emission threshold of zero TPY has been excluded from this flow chart because any new source that meets the 75,000 TPY $CO_2e$ requirement would automatically exceed that mass based rate.