Statement of Basis

Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit
for Invenergy Thermal Development, LLC

Permit Number: PSD-TX-1366-GHG

April 2014

This document serves as the statement of basis for the above-referenced draft permit, as required by 40 CFR 124.7. This document sets forth the legal and factual basis for the draft permit conditions and provides references to the statutory or regulatory provisions, including provisions under 40 CFR 52.21, that would apply if the permit is finalized. This document is intended for use by all parties interested in the permit.

I. Executive Summary

On June 26, 2013, Invenergy Thermal Development, LLC (Invenergy), submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions. In connection with the same proposed project, Invenergy submitted a PSD permit application for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on May 13, 2013.

Invenergy proposes to construct a 330 MW peak power plant (known as the Ector County Energy Center Plant (ECEC)), located in Goldsmith, Ector County, Texas. With this proposed project, Invenergy plans to construct two natural gas-fired simple-cycle turbines, General Electric (GE) Model 7FA.03, and associated equipment, a fire water pump engine, a natural gas-fired dew-point heater, and two circuit breakers. For the purposes of this proposed permitting action, GHG emissions are permitted for the two turbines, the fire water pump engine, the natural gas-fired dew-point heater, and the circuit breakers, as well as for fugitive emissions, and maintenance, startup and shutdown emissions. The remaining units are not considered to be potential GHG emission sources. After reviewing the application and supplemental information provided by Invenergy, EPA Region 6 has prepared the following Statement of Basis (SOB) and draft air permit to authorize construction of air emission sources at the ECEC.

This SOB documents the information and analysis EPA used to support the decisions EPA made in drafting the air permit. It includes a description of the proposed facility, the applicable air requirements, and an analysis showing how the applicant complied with the requirements.

EPA Region 6 concludes that Invenergy's application is complete and provides the necessary information to demonstrate that the proposed project meets the applicable air permit regulations.

EPA's conclusions rely upon information provided in the permit application, supplemental information Invenergy provided at EPA's request, and EPA's own technical analysis. EPA is making all this information available as part of the public record.

II. Applicant

Invenergy Thermal Development, LLC
1 South Wacker Drive, Suite 1900
Chicago, IL 60606

Facility Physical Address:
Ector County Energy Center
SW 3601 West of Holt
Goldsmith, TX 79741

Contact:
Mr. Jim Shield
Vice President, Thermal Development
1 South Wacker Drive, Suite 1900
Chicago, IL 60606
(312) 582-1440

III. Permitting Authority

On May 3, 2011, EPA published a federal implementation plan that makes EPA Region 6 the PSD permitting authority for the pollutant GHGs. 75 FR 25178 (promulgating 40 CFR § 52.2305). Texas is the PSD permitting authority for pollutants that were subject to regulation before January 2, 2011, i.e., regulated NSR pollutants other than GHGs.

The GHG PSD Permitting Authority for the State of Texas is:

EPA, Region 6
1445 Ross Avenue
Dallas, TX 75202

The EPA, Region 6 Permit Writer is:
Anna Milburn
Air Permitting Section (6PD-R)
1445 Ross Avenue
Dallas, TX 75202
(214) 665-8348

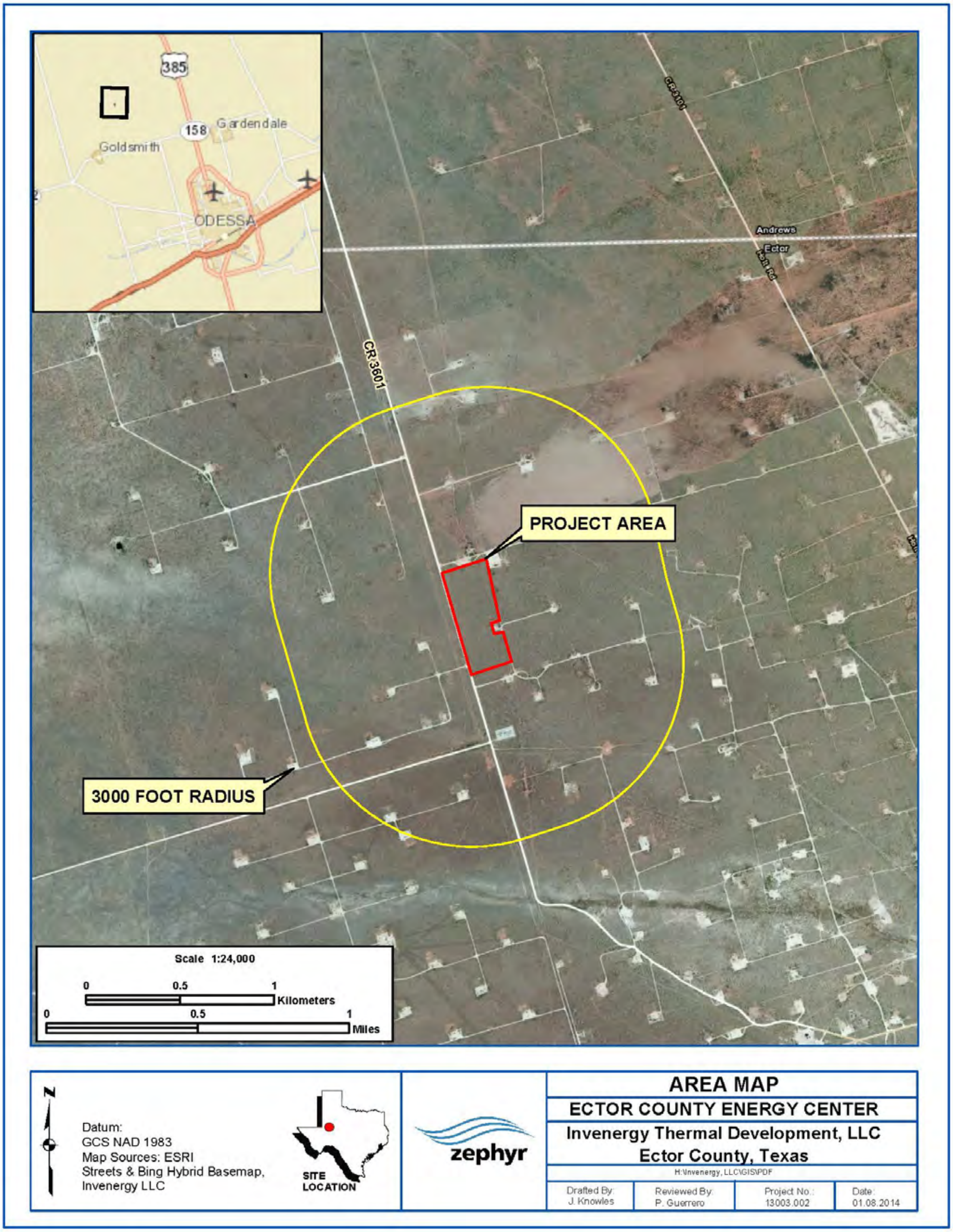
IV. Facility Location

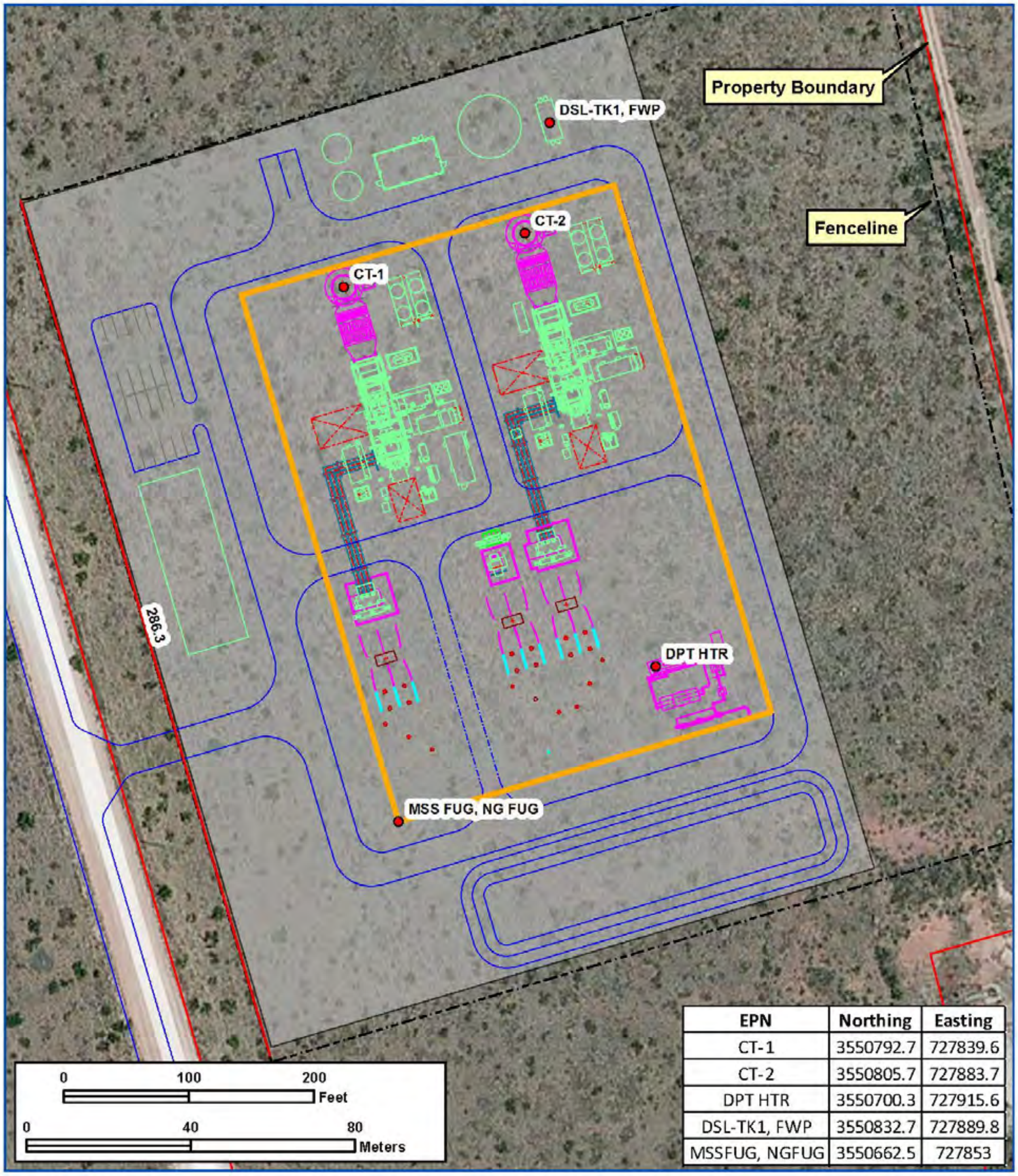
ECEC is located in Ector County, Texas. Ector County is currently designated attainment for all criteria pollutants. The ECEC plant site development is to be located on an undeveloped tract of land approximately 3 miles west of Holt Road, on the north side of SW 3601. This property is located near Goldsmith, Texas.

The geographic coordinates for this facility are planned to be as follows:

Latitude: 32° 04' 10" N
Longitude: 102° 35' 08" W

The following figures illustrate the ECEC facility location and the proposed site layout for this draft permit.


385
158
Gardendale
Goldsmith
ODESSA
CR-3101
Andrews
Ector
CR-3601
PROJECT AREA
3000 FOOT RADIUS
Scale 1:24,000
0
0.5
1
Kilometers
0
0.5
1
Miles
N
Datum:
GCS NAD 1983
Map Sources: ESRI
Streets & Bing Hybrid Basemap,
Invenergy LLC
SITE
LOCATION
zephyr
AREA MAP
ECTOR COUNTY ENERGY CENTER
Invenergy Thermal Development, LLC
Ector County, Texas
H:\Invenergy, LLC\GIS\PDF
Drafted By:
J. Knowles
Reviewed By:
P. Guerrero
Project No.:
13003.002
Date:
01.08.2014



EPN	Northing	Easting
CT-1	3550792.7	727839.6
CT-2	3550805.7	727883.7
DPT HTR	3550700.3	727915.6
DSL-TK1, FWP	3550832.7	727889.8
MSSFUG, NGFUG	3550662.5	727853

N

Datum:
GCS NAD 1983
Map Sources: ESRI
Bing Hybrid Basemap,
Invenergy LLC

zephyr

PLOT PLAN

ECTOR COUNTY ENERGY CENTER

Invenergy Thermal Development, LLC
Ector County, Texas

H:\Invenergy, LLC\GIS\PDF

Drafted By:	Reviewed By:	Project No.:	Date:
J. Knowles	P. Guerrero	13003.002	01.09.2014

V. Applicability of Prevention of Significant Deterioration (PSD) Regulations

EPA concludes that Invenergy's application is subject to PSD review for the pollutant GHGs because the facility will be a new major stationary source for nitrogen oxides (NOx) and carbon monoxide (CO) and also will emit or has a potential to emit 75,000 tons per year (tpy) CO_2e or more, as described at 40 CFR § 52.21(b)(49)(iv)(*a*).

EPA Region 6 implements a GHG PSD FIP for Texas under the provisions of 40 CFR § 52.21 (except paragraph (a)(1)). See 40 CFR § 52.2305. Invenergy represents that TCEQ, the permitting authority for regulated NSR pollutants other than GHGs, will determine that the ECEC is also subject to PSD review for increases of nitrogen oxides (NOx) and carbon monoxide (CO). Accordingly, under the circumstances of this project, the TCEQ will issue the non-GHG portion of the permit, and EPA will issue the GHG portion.[1]

EPA Region 6 applies the policies and practices reflected in the EPA document entitled "PSD and Title V Permitting Guidance for Greenhouse Gases" (March 2011). Consistent with that guidance, we have neither required the applicant to model or conduct ambient monitoring for GHGs, nor have we required any assessment of impacts of GHGs in the context of the additional impacts analysis or Class I area provisions. Instead, EPA has determined that 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. We note again, however, that the project has triggered review for regulated NSR pollutants that are non-GHG pollutants under the PSD permit sought from TCEQ. Thus, TCEQ's PSD permit that will address regulated NSR pollutants other than GHGs should address the additional impacts analysis and Class I area requirements for other pollutants as appropriate.

VI. Project Description

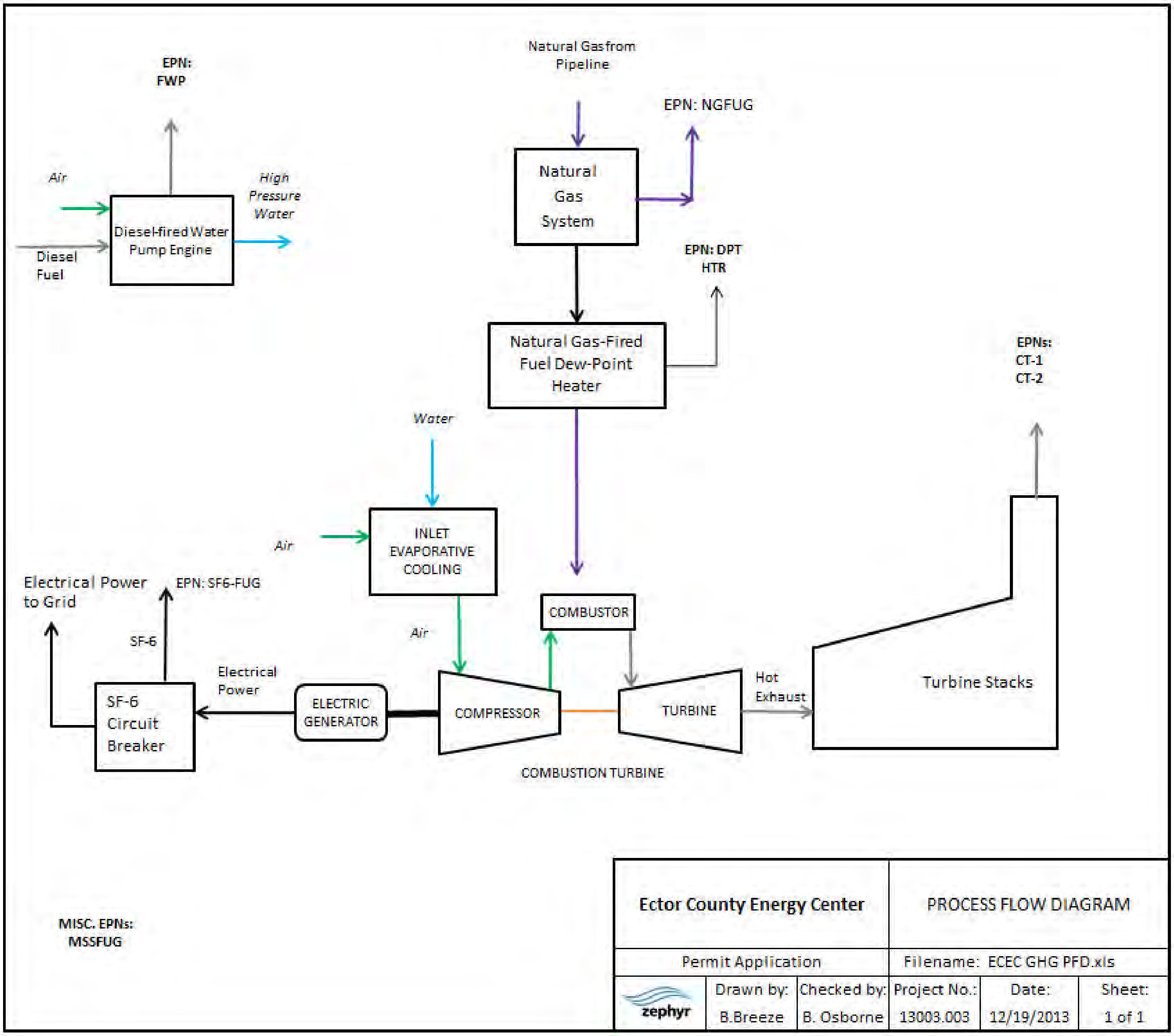
Invenergy proposes to construct a peaking power facility on a Greenfield site, located near Goldsmith, Texas. To meet the anticipated need for peak power demand, Invenergy proposes to construct two (2) identical natural gas-fired F-class simple-cycle combustion turbines with associated support equipment. The two new combustion turbine generators (CTG) are GEFA7.03 simple-cycle turbines, each with a maximum base-load electric power output of approximately 165 megawatts (MW, nominal). This project also proposes to install one natural gas-fired dew-point heater, one firewater pump engine, and other auxiliary equipment. GHG emissions will result from the following emission units:

- Two Simple-Cycle Combustion Turbines (EPNs: CTG-1 and CTG-2);
- One Natural Gas-Fired Dew-Point Heater (EPN: DPT HRT-3);
- One Fire Water Pump Engine (EPN: FWP-4);
- Fugitive Emissions from SF_6 Circuit Breakers (EPN: SF6-FUG); and,
- Fugitive Emissions from Piping Components (EPN: NG-FUG)

[1] *See* EPA, Question and Answer Document: Issuing Permits for Sources with Dual PSD Permitting Authorities, April 19, 2011, http://www.epa.gov/nsr/ghgdocs/ghgissuedualpermitting.pdf

<u>Process Description and Process Flow</u>

The following presents a process flow diagram for the two simple-cycle combustion turbines at ECEC, Each power block will have the potential to generate a nominal 165 MW of electricity.



Peak Load Operation Using Two Simple-Cycle CTGs

Invenergy is a public utility holding company engaged in, among other things, the generation of electric energy, and the transmission, distribution, and sale of electricity and natural gas through its subsidiaries.

As a member of the Electric Reliability Council of Texas (ERCOT), Invenergy is responsible for meeting the requirements and standards for reliable and adequate bulk power transmission by the National Electric Reliability Corporation (NERC) and ERCOT. NERC is the entity certified by the Federal Energy Regulatory Commission (FERC) to establish and enforce reliability standards for the bulk power system. In an agreement between NERC and ERCOT, the ERCOT provides the coordination and promotion of electric system reliability for a region that covers a majority of Texas. In 1999, the Texas Legislature restructured the Texas electric market by unbundling the investor-owned utilities and created a retail customer choice for service areas. ERCOT has the following responsibilities: system reliability, open access to transmission, retail switching process for customer choice, and wholesale market settlement for electricity production and delivery. As a member of ERCOT, Invenergy has agreed to provide reliable operation of a portion of the bulk electric system for the Texas service area. In addition, Invenergy has mandatory and enforceable standards from NERC to ensure the reliable operation of the bulk electric system.

Invenergy is proposing to add two identical natural gas-fired simple-cycle CTGs to meet a demand for peak power in the ERCOT service area. The company documented the design and efficiency considerations for its selection of a turbine model by providing comparative analysis of several simple–cycle CTG models. While the BACT requirement does not necessarily dictate the selection of any particular turbine model, particularly when each model is reflective of the efficiency upgrades attained in the last several years, an applicant's study or discussion of multiple models can be helpful in delineating the design and feasibility considerations that are crucial for meeting the project's business purpose. Both CTGs will burn pipeline natural gas to rotate an electrical generator to produce electricity. The main components of a CTG 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. To reduce the heat level from the turbine compressor and allow for a higher mass flow of combustion air, the GEFA7.03 proposed by Invenergy offers an option of two types of intercoolers, a wet system or a dry system. Invenergy is proposing to use the wet system intercooler. The wet system will require two evaporative cooling towers. The cooling towers are not a source of GHG emissions.

In 2012, renewable energy resources (other than hydroelectric) accounted for approximately 5 percent of the electricity generated by electric utilities.[2] Because the use of solar and wind power are not typically utilized to provide peaking power to the grid due to interruptible service, renewable resources were not addressed in the BACT analysis because these interruptible sources are not suited for the primary purpose serving as peaking power project.

[2] U.S. Department of Energy, Energy Information Administration, *Frequently Asked Questions*. See http://www.eia.gov/tools/faqs/faq.cfm?id=427&t=3, September 30, 2010 .

Fire Water Pump Engine

The site will be equipped with one nominally rated 250-hp diesel-fired firewater pump engine to provide water in the event of a fire. The fire water pump engine will operate on low-sulfur (0.0015%) fuel and will be limited to 100 hours per year of non-emergency operation for purposes of maintenance checks and readiness testing. The fire water pump engine will meet Tier 3 standards for off-road diesel engines under 40 CFR Part 89.

Natural Gas-Fired Dew-Point Heater

The project will include a 9 MMBtu/hr gas-fired dew-point heater. The heater will be fired with natural gas, and will be limited to annual operations of 5,000 hours per year. This equates to the operational limit on the turbines of 5000 hours on a rolling 12-month basis.

Electrical Equipment Insulated with Sulfur Hexafluoride (SF_6)

The circuit breakers associated with the proposed units and associated equipment 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 total capacity of the circuit breakers associated with the proposed plant is currently estimated not to exceed 240 lb SF_6. The proposed circuit breakers will have a low-pressure alarm and a low-pressure lockout. The alarm will alert personnel of any leakage in the system and the lockout prevents any operation of the breaker due to lack of “quenching and cooling” of SF_6 gas.

Fugitive Emissions from Piping Components

Emissions from piping components (valves and flanges) associated with this project consist of methane (CH_4) and carbon dioxide (CO_2). Because a majority of the GHG fugitives comes from CH_4 and the GWP is higher for CH_4, a conservative estimate was done to assume that all piping components are in a rich-CH_4 stream. The CO_2e from fugitive emissions account for less than 0.001% of the project’s total CO_2e emissions.

VII. General Format of the BACT Analysis

The BACT analyses for this draft permit were conducted in accordance with EPA’s *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011), which outlines the steps for conducting a “top-down” BACT analysis. Those steps are listed below.

(1) Identify all available control options;
(2) Eliminate technically infeasible control options;
(3) Rank remaining control options;

(4) Evaluate the most effective controls (taking into account the energy, environmental, and economic impacts) and document the results; and
(5) Select BACT.

VIII. Natural Gas-Fired Simple-Cycle Combustion Turbines BACT Analysis (EPNs: CTG-1 and CTG-2)

Step 1 – Identify all available control technologies

The first step in the top-down BACT process is to identify all "available" control options. In general, if a control option has been demonstrated in practice on a range of exhaust gases with similar physical and chemical characteristics and does not have a significant negative impact on process operations, product quality, or the control of other emissions; it may be considered as potentially feasible for application to another process.

- *Carbon Capture and Storage (CCS)* - CCS is classified as an add-on pollution control technology, which involves the separation and capture of CO_2 from flue gas, pressurizing of the captured CO_2 into a pipeline for transport, and injection/storage within a geologic formation. CCS is generally applied to "facilities emitting CO_2 in large concentrations, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing)."[3]

  CCS contains three major components: carbon capture, transport, and storage. With respect to carbon capture, CCS systems involve the use of adsorption or absorption processes to remove CO_2 from flue gas, with subsequent desorption to produce a concentrated CO_2 stream. The three main capture technologies for CCS are pre-combustion capture, post-combustion capture, and oxyfuel combustion (IPCC, 2005). Of these approaches, pre-combustion capture is used primarily in gasification plants, where solid fuel such as coal is converted into gaseous components by applying heat under pressure in the presence of steam and oxygen (U.S. Department of Energy, 2011). At this time, oxyfuel combustion has not yet reached a commercial stage of deployment for gas turbine applications and still requires the development of oxy-fuel combustors and other components with higher temperature tolerances (IPCC, 2005). Accordingly, pre-combustion capture and oxyfuel combustion have no practical application for this proposed gas turbine facility. The third approach, post-combustion capture, is applicable to gas turbines.

  With respect to post-combustion capture, a number of methods may potentially be used for separating the CO_2 from the exhaust gas stream, including adsorption, physical absorption,

[3]U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, *PSD and Title V Permitting Guidance for Greenhouse Gases*, March 2011, <http:/www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf> (March 2011)

chemical absorption, cryogenic separation, and membrane separation (Wang et al., 2011). Many of these methods are either still in development or are not suitable for treating power plant flue gas due to the characteristics of the exhaust stream (Wang, 2011; IPCC, 2005). Of the potentially applicable technologies, post-combustion capture with an amine solvent such as monoethanolamine (MEA) is currently the preferred option because it is the most mature and well-documented technology (Kvamsdal et al., 2011), and because it offers high capture efficiency, high selectivity, and the lowest energy use compared to the other existing processes (IPCC, 2005). Post-combustion capture using MEA is also the only process known to have been previously demonstrated in practice on gas turbines (Reddy, Scherffius, Freguia, & Roberts, 2003). As such, post-combustion capture is the sole carbon capture technology considered in this BACT analysis.

Once CO_2 is captured from the flue gas, the captured CO_2 is compressed to 100 atmospheres (atm) or higher for ease of transport (usually by pipeline). The CO_2 would then be transported to an appropriate location for underground injection into a suitable geological storage reservoir, such as a deep saline aquifer or depleted coal seam, or used in crude oil production for enhanced oil recovery (EOR), if available. There is a large body of ongoing research and field studies focused on developing better understanding of the science and technologies for CO_2 storage.

- *Generating technologies, such as combined-cycle CTGs* – As stated in the *PSD and Title V Permitting Guidance for Greenhouse Gases*, combined-cycle CTGs should be listed as an option for proposed natural gas-fired projects. However, the guidance also recognizes that this option may be evaluated under the redefining-the-source framework and excluded from Step 1 on a case-by-case basis if it can be shown that application of this control technology would disrupt the applicant's basic or fundamental business purpose for the proposed facility.[4] The applicant's project is conceived as a peaking power provider operating no more than 2,500 hours per year, and is designed to provide power quickly when dispatched by the grid operator, to respond to varying needs of the electric grid and to expeditiously shut down when no longer needed. Simple-cycle turbines, such as the CTGs selected by the applicant, are well suited for peaking power supply due to their ability to rapidly respond to immediate needs for additional power generation and quickly cease operation when these additional power needs are satisfied.

  Combined-cycle turbines generally have higher efficiencies than simple-cycle turbines; however, while combined cycle units are well suited to operate as baseload-power electric generating units, EPA has not concluded at this time that combined-cycle turbines can provide the rapid response and shutdown required of a peaking power source with limited hours of operation, while continuing to produce reasonably priced power to sell in a deregulated market. The start-up sequence for a combined-cycle plant includes three phases: 1) purging of the heat recovery

[4] U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, *PSD and Title V Permitting Guidance for Greenhouse Gases*, at 29-30, March 2011, <http:/www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf.

steam generator (HRSG); 2) gas turbine speed-up, synchronization, and loading; and 3) steam turbine speed-up, synchronization, and loading. The third phase of this process is dependent on the amount of time that the plant has been shut down prior to being restarted because the HRSG and steam turbine contain parts that can be damaged by thermal stress and require time to heat up and prepare for normal operation. For this reason, the complete startup time for a combined-cycle plant is longer than that of a similarly sized simple-cycle plant.[5] Fast-start technology is capable of enabling startup of a combined-cycle turbine within 30 minutes; however, this technology requires that the unit be maintained in a state allowing warm or hot startup. Cold startup of a combined-cycle turbine with fast-start technology may take as long as 90 minutes. To keep the HRSG and the steam turbine seals and auxiliary equipment at a sufficiently high temperature to allow for quick startup of the combustion turbine, the facility would have to continuously operate an auxiliary boiler. An additional concern with the use of a combined-cycle configuration is the thermal mechanical fatigue due to the large numbers of startups and shutdowns.

In supplemental information provided to EPA,[6] Invenergy noted that the low capital cost for a simple-cycle project can accommodate the intended utilization of limited, flexible, and on-demand operations. Invenergy's application is based on a business plan where it believes market indicators point towards a need for peaking power plant in the west Texas area. Therefore, based on the defined business purpose of the proposed project and for the reasons discussed herein, EPA has determined that the use of combined-cycle turbines would result in a redefinition of the source for this specific project and therefore are excluded from Step 1 of this BACT analysis.

- *Combustion Turbine Generator (CTG) Design Efficiency* – A key factor in minimizing GHG emissions is to maximize the efficiency of electricity production. Older, more inefficient turbines consume more fuel to generate the same amount of electricity as newer, more efficient turbines. This is due to equipment wear and tear, improved design in newer models, as well as the use of higher quality metallurgy. EPA evaluated the turbines proposed for this project using available resources such as the Gas Turbine World (2012) handbook and concludes that the proposed model, the GE7FA.03, is a modern and efficient combustion turbine.

  Invenergy currently has two GE7FA.03 combustion turbines in their unused turbine inventory and is proposing to use them on the ECEC project. Invenergy's business model indicates the need to generate approximately 300 MWs of peaking capacity to respond to the peaking power demands in Texas, and the existing 7FA simple cycle frame turbines already owned by ECEC fit the business purpose of the project.

[5] U.S. Environmental Protect Agency, Region 9. Fact Sheet and Ambient Air Quality Impact Report for the Proposed Prevention of Significant Deterioration Permit, Pio Pico Energy Center.
[6] Email from M. Thornton to A. Milburn, February 27, 2014.

- *Fuel Selection* – In 2008, approximately 70% of the electricity used in the United States was generated by burning fossil fuels (coal, natural gas, petroleum liquids). Fuels vary in the amount of carbon per Btu, which in turn affects the quantity of CO_2 emissions generated per unit of heat input. In assessing CO2 emissions for the three potential fuel types, natural gas combustion results in lower GHG emissions (119 lbs CO_2e/mmBtu) than distillate oil (163 lbs CO_2e/mmBtu) or coal (243 lbs CO_2e/mmBtu).

- *Good Combustion, Operating, and Maintenance Practices* –Good combustion, operating, and maintenance practices are a control option for improving the fuel efficiency of the combustion turbine. Natural gas-fired combustion turbines typically operate in a lean pre-mix mode to ensure effective staging of air/fuel ratios in the turbine, thus maximizing fuel efficiency and minimizing incomplete combustion. Furthermore, the turbine's operation is automated to ensure optimal fuel combustion and efficient operation, leaving virtually no operator ability to further tune these aspects of operation. Good combustion practices also include proper maintenance and tune-up of the combustion turbine system at least twice annually per the manufacturer's specifications.

- Modern 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 control system monitors the operation of the unit and modulates the fuel flow and turbine operation to achieve optimal high-efficiency, low-emissions performance.

Use of Evaporative Cooling – Chilling the incoming air increases the thermal and power efficiency of the CTG. An evaporative cooling system will be used to cool the incoming combustion turbine air (to approximately 60^oF) in order to increase the combustion air mass flow. Chilling the incoming air in this way increases the thermal efficiency and power gain of the combustion turbine, thus reducing GHG emissions.

There are three commercial systems for cooling the inlet air to a combustion turbine:

a. Foggers –Atomized, demineralized water is sprayed into the inlet air of the combustion turbine. The cooling effect is created by the evaporation of the water droplets. This process has been used in many installed combustion turbines, and has proven to very efficient especially in very dry desert like areas. However turbine suppliers are discouraging power plant operators from using these systems due to many reported incidents of droplet impingement damage to the air compressor section of the gas turbine. General Electric does not recommend inlet fogging for their combustion turbines due to erosion concerns for the first stage of compressor blades. Furthermore air foggers require the installation of costly demineralized water treatment systems.
b. Refrigeration Units – Coils carrying a cooled aqueous solution of glycol are placed in the inlet structure of a gas turbine to cool the incoming air. These systems have become more popular in humid regions of the world where the effect of evaporative cooling is

very limited. However the refrigeration systems are very costly to install and have a substantial parasitic load with their operation.

c. Evaporative Coolers - A film of water is distributed downward through a plastic media. The inlet air of the gas turbine passes through the media and the water is evaporated causing a drop in the air temperature. This effect is similar to the foggers as described above. The difference between the systems is that in the case of evaporative coolers, demineralized water is not necessary, and in many cases only filtration is required as pretreatment of the water. Weighing in the capital cost of the evaporation systems, the cost of water treatment, and the cooling efficiency of the systems, the use of evaporative coolers is the technology of choice for this project.

Step 2 **–** Elimination of Technically Infeasible Alternatives

Carbon Capture and Storage: In a typical MEA absorption process, the flue gas is cooled before it is contacted counter-currently with the lean solvent in a reactor vessel. The scrubbed flue gas is cleaned of solvent and vented to the atmosphere, while the rich solvent is sent to a separate stripper where it is regenerated at elevated temperatures and then returned to the absorber for re-use. Fluor's Econamine FG Plus process operates in this manner, and it uses an MEA-based solvent that has been specially designed to recover CO_2 from oxygen-containing streams with low CO_2 concentrations typical of gas turbine exhaust (Fluor, 2009). Post-combustion capture using MEA is also the only process known to have previously demonstrated in practice on at least part of the exhaust gas stream of a combustion turbine (Reddy, Scherffius, Freguia, & Roberts, 2003).This process has been used successfully to capture 365 tons per day of CO_2 from the exhaust of a natural gas combined-cycle plant previously owned by Florida Power and Light in Bellingham, Massachusetts. The CO_2 capture plant was maintained in continuous operation from 1991 to 2005 (Reddy, Scherffius, Freguia, & Roberts, 2003).

As identified by the August 2010 Report of the Interagency Task Force on Carbon Capture and Storage (co-chaired by US EPA and US Department of Energy), while amine- or ammonia-based CO_2 capture technologies are commercially available, they have not been demonstrated in practice on a simple-cycle electric generating unit that operates as a peaking power provider. Peaking units frequently cycle their operation, with multiple starts and stops, to respond to electricity demand dispatch requirements. Because a CCS system is unable to operate in cycling mode, we conclude that carbon capture is not applicable to the proposed peaking power project. Therefore, because CCS has not been demonstrated in practice for simple-cycle peaking units and cannot be applied to systems that involve frequent cycling of operations, CCS is not technically feasible at this facility.

Because CCS has been eliminated in Step 2 of the BACT analysis, EPA need not include a cost analysis in its evaluation of this option and is not addressing a cost analysis in Step 4 of the BACT analysis. However, Invenergy submitted a cost analysis for CCS as part of the application, and that analysis has been included in the administrative record.

Combustion Turbine Design Efficiency: The applicant documented its considerations in selecting particular turbine models for this facility, while weighing in operational variables such as project size, project purpose, fuel use, technical feasibility, and ambient conditions. The turbine models selected by Invenergy are considered efficient, modern simple-cycle turbines. Operation of these turbines has been demonstrated in practice, thus making this a technically feasible option.

Aside from CCS, the remaining control options identified in Step 1 are considered technically feasible and are being proposed for Step 3 analysis.

Step 3 – Ranking of Remaining Control Technologies Based on Effectiveness

- Efficient Turbine Design,
- Fuel Selection,
- Good Combustion, Operating, and Maintenance Practices,
- Use of Evaporative Cooling

Efficient turbine design is considered the most effective control technology in this analysis. Fuel selection; good combustion, operating, and maintenance practices; and the use of evaporative cooling are all considered effective and have a range of efficiency improvements which cannot be directly quantified. Therefore, ranking of those control technologies based on effectiveness is not possible.

Step 4 – Evaluation of Control Technologies with Consideration of Economic, Energy and Environmental Impacts

Efficient Combustion Turbine Design

The applicant assessed various turbines operating in a simple-cycle configuration for economic purposes, but is proposing to utilize new unused turbines already owned by the company that are currently in storage. A high efficiency turbine rating does not necessarily translate directly to low GHG emissions for a particular project because some operating parameters, such as fuel type, operating loads, and operating hours, will affect the total GHG emissions. The GE7FA.03 turbine proposed by the applicant meets the technical requirements of the project and is considered a modern and efficient design for this project. In addition, the utilization of the GE7FA.03 turbines already owned by the company eliminates the need to purchase new turbines.

Fuel Selection

The combustion of a fossil fuel to generate electricity can be either: 1) in a steam generating unit (also referred to simply as a "boiler") to feed a steam turbine that spins an electric generator; or 2) in a combustion turbine or a reciprocating internal combustion engine that directly drives the generator.[7]

EPA concludes that natural gas is the appropriate fuel for this source because it is the lowest source of CO_2e from combustion and best fits the project's purpose and design considerations.

Good Combustion, Operating, and Maintenance Practices

Good combustion, operating, and maintenance practices are a control option for improving the fuel efficiency of the combustion turbine. Natural gas-fired combustion turbines typically operate in a lean pre-mix mode to ensure effective staging of air/fuel ratios in the turbine, thus maximizing fuel efficiency and minimizing incomplete combustion. Furthermore, the turbine's operation is automated to ensure optimal fuel combustion and efficient operation, leaving virtually no operator ability to further tune these aspects of operation. Good combustion practices also include proper maintenance and tune-up of the combustion turbine system at least twice annually per the manufacturer's specifications.

Modern 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 control system monitors the operation of the unit and modulates the fuel flow and turbine operation to achieve optimal high-efficiency, low-emissions performance.

EPA concludes that no economic, energy, or environmental impacts warrant elimination of this control option.

Use of Evaporative Cooling

Weighing in the capital cost of the evaporation systems, the cost of water treatment, the cooling efficiency of the systems, and the energy consumed by the technologies, EPA is eliminating foggers and refrigeration units. Evaporative coolers represent the most energy efficient means of cooling inlet air to a simple-cycle combustion turbine because refrigeration units have a very high parasitic load and inlet fogging requires demineralized water, which also requires additional energy consumption. Therefore, EPA concludes that foggers and refrigeration units are eliminated as BACT. For evaporative coolers, EPA concludes that no economic, energy, or environmental impacts warrant elimination of this control option.

[7] "Available and Emerging Technologies for Reducing Greenhouse Gas Emissions From Coal-Fired Electric Generating Units". EPA, OAR. October 2010

Step 5 – Selection of BACT

To date, other similar peak power facilities with a GHG BACT limit are summarized in the table below:

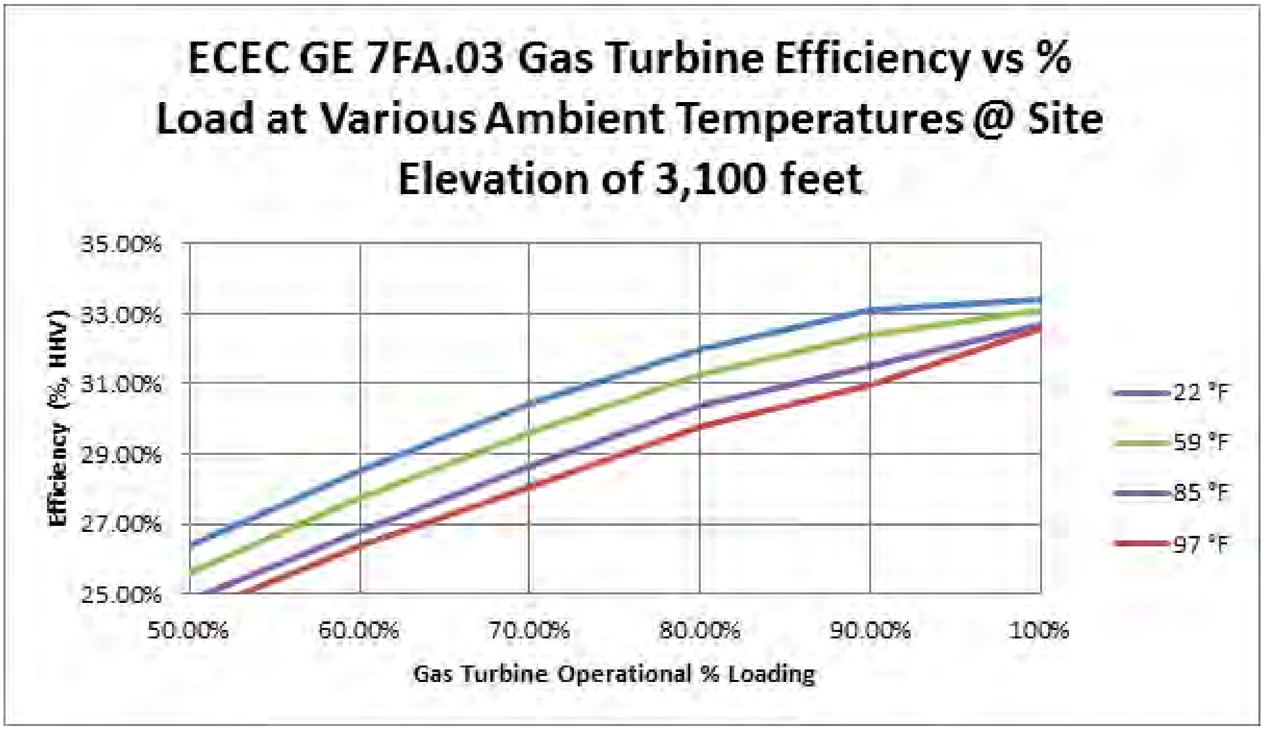
Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
Puget Sound Energy Fredonia Generating Station Mt. Vernon, Washington	Peak Power, simple-cycle combustion turbine, to provide an additional 181-207 MW	Energy Efficiency/ Good Design & Combustion Practices	GE7FA.05 Option: 1,299 lb CO_2e/MWhr (net) 311,382 tpy CO_2e GE7FA.04 Option: 1,310 lb CO_2e/MWhr (net) 274,496 tpy CO_2e SGT5000F4 Option: 1,278 lb CO_2e/MWhr (net) 301,819 tpy CO_2e GELMS100 Option: 1,138 lb CO_2e/MWhr (net) 327,577 tpy CO_2e	2013	PSD-11-05
EFS Shady Hills LLC EPA Region 4	Simple-cycle combustion turbine to provide an additional 436 MW	Energy Efficiency/ Good Design & Combustion Practices	GE7FA.05: 1,377 lb CO_2e/MWhr (gross) when firing natural gas	2014	PSD-EPA-R4013

From this analysis, EPA has concluded that GHG BACT for Invenergy is the use of modern, natural gas-fired, thermally efficient, simple-cycle combustion turbines combined with evaporative cooling and good combustion and maintenance practices to maintain optimum efficiency. EPA believes that the applicant's proposal to use the GE FA7.03 is consistent with the BACT requirement for the specific goal of this project. Based on these factors and data provided to Invenergy from GE, EPA is also proposing an emission limit of 1,393 lb CO_2/MWhr gross output for the GE7FA.03 combustion turbine to be utilized for this project. Each combustion turbine is limited to 2,500 operational hours on a rolling basis, plus 500 startup and shutdown events on a 12–month rolling average. Until the 2,500 operational hour basis has been established, Invenergy should utilize the performance testing data to establish a plan whereby Invenergy may operate the emission unit in a manner that will not exceed the permitted CO_{2e} emissions limits. Invenergy is responsible for demonstrating compliance with the permitted emission limits and should evaluate its actual emissions and verify actual compliance from recorded operational data. The operating scenario provided by the applicant (2,500 hours at 100% load per year) was used to calculate the worst-case emission rates from the facility. To account for the additional hours of operation associated with the startup and shutdowns, each turbine is limited by fuel use associated with the 2,500 hours of operation per year. Limiting the fuel use achieves the same objective as limiting the number of hours of operation of each turbine to 2,500 hours. The fuel use limit for each combustion turbine that corresponds to the 2,500 hours of operation per 365 day basis is 4,028,700 MMBtu (HHV) on a 12-month rolling basis for the GE7FA.03 combustion turbine. The recently issued Puget Sound Energy, Fredonia Generation Station permit contains a GHG BACT limit of 1,299 lb CO2e/MWhr (net) for the GE7FA.05 combustion turbine, and the EFS Shady Hills LLC permit contains a GHG BACT limit of 1,377 lb CO_2e/MWhr (gross) for the GE7FA.05 combustion turbine. As noted earlier, Invenergy is proposing to utilize existing unused GE7FA.03 turbines already owned by Invenergy, and it has proposed a GHG BACT limit calculated at 1,393 lbs CO_2/MWhr (gross). When comparing the gross based BACT limit for Shady Hills LLC and ECEC, the Shady Hills project has a 1 percent lower (more stringent) gross output based BACT limit for the newer GE7FA.05 combustion turbine.

Figure 1 of this document shows the GE7FA.03 anticipated site-specific efficiency versus load percent at the various ambient conditions of Goldsmith, Texas. Variations in elevation and ambient temperature will affect a CTG's operation performance and are an important consideration in the comparison of various CTGs in different locations. In a discussion of CTG efficiency, it is important to note that the calculated gross CTG power and efficiency are as "measured" across the electric generator terminals at ISO (International Organization for Standardization) site conditions without allowances for inlet filter and duct losses, exhaust stack and silencer losses, gearbox efficiency, or any auxiliary mechanical and electrical systems parasitic power consumption. ISO design ratings are typically provided to be 59°F and sea level. However, to assess site-specific CTG performance, correction factors should be applied. Invenergy has provided an efficiency curve, shown in Figure 1, to estimate the anticipated actual operational scenario for a simple-cycle CTG located in Ector County, Texas.[8] The efficiency has been corrected to represent the output at the site-specific elevation of 3100 ft and the various ambient temperatures.

[8] Email from M. Thorton, to A. Milburn, U.S. EPA, Region 6, on March 24, 2014.

Figure 1: Site Specific Load versus Efficiency Curve for GE 7FA.03



Within the calculations for CTGs, a design margin of 2.3 percent, a degradation margin of 4% and a performance margin of 5.0 percent were included. To allow for variations in manufacturing tolerances and test uncertainties, equipment manufacturers frequently rely on design margins to accommodate the small variation in turbine performance. These differences are mere fractions of the total calculated emissions and the 2.3 percent is comparable to other recently permitted projects. The performance margin used in this analysis, 5 percent, is also comparable to other recently permitted projects and is also within the 2 to 6 percent range provided in the Gas Turbine World (2012) handbook.

BACT During Startup and Shutdown

BACT applies during all periods of turbine operation, including startup and shutdown. MSS emissions are limited to 10,502 CO_2e per year and each start up and shut down event is limited to 21 tons of CO_2e. The number of startups and shutdowns is based on the number of operational hours per year (2,500 service hours per year per turbine). All startups and shutdowns are limited to 60 minutes in duration per event. A startup of each turbine is defined as the period that begins when there is measureable fuel flow to the turbine and ends when the turbine load reaches 60 percent. A shutdown of each turbine is defined as the time period that begins when the combustion turbine drops out of the normal operating low-NOx combustion mode (which equates to approximately 60% combustion turbine load) following an instruction to shut down, and ends when flame is no longer detected in the combustion turbine combustors. The proposed ECEC project is proposing 500 startups/shutdowns in addition to 2,500 operational hours per year per turbine. BACT for startup/shutdown is the work practice standard to utilize good pollution control practices, safe operating practices, and protection of the facility. The startup /shutdown activities shall be minimized by limiting the duration of operation in startup/shutdown mode as follows:

- Startups and shutdowns are limited to no more than 60 minutes per event. Each start up and shutdown shall not exceed 21 tons of CO_2e per event.
- No more than 500 startup and shutdown events per turbine on a 12-month rolling basis.
- The maximum heat input during startup shall be limited to 1,320 MMBtu/hr.
- No more than one of the two simple-cycle turbines will undergo a startup and/or shutdown in any 30 minute period, except that simultaneous startups of multiple turbines within a 30 minute period may occur 52 times on a 12-month rolling basis.

BACT Compliance:

Proposed BACT for this project is the use of new, natural gas-fired, thermally efficient, simple-cycle combustion turbines combined with evaporative cooling and good combustion and maintenance practices to maintain optimum efficiency for each combustion turbine, with an output-based limit of 1,393 lb CO_2/MWhr (gross), except during start up and shut down. Compliance will be based on a 2,500 operational hour rolling basis, calculated daily for each turbine. Invenergy will maintain records of tune-ups, burner tip maintenance, O_2 analyzer calibrations and maintenance for each combustion turbine. In addition, records of fuel temperature, ambient temperature, and stack exhaust temperature will be maintained for each CTG. For each CTG, the parameters that will be measured are natural gas flow rate using an operational non-resettable elapsed flow meter, total amount of fuel combusted on a hourly basis, fuel gross calorific value (GCV) on a high heat value (HHV), carbon content, combustion temperature, exhaust temperature, and gross hourly energy output (MWhr).

Invenergy will demonstrate compliance with the CO_2 limit for each CTG by using non-resettable elapsed fuel flow meters to monitor the quantity of fuel combusted in the electric generating unit and performing periodic scheduled fuel sampling pursuant to 40 CFR 75.10(3)(ii) and the procedures listed in 40 CFR 75, Appendix G. 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 proposed permit also includes an alternative compliance demonstration method in which ECEC may install, calibrate, and operate a CO_2 Continuous Emission Monitoring System (CEMS) and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording CO_2 emissions. The measured hourly CO_2 emissions from each combustion turbine are divided by the measured gross energy output of the combustion turbine (MWhr). The quotient of the hourly measurement (lb CO_2/MWhr, gross) is added to the 2,500 operational hour rolling average and the calculations shall be completed on a daily basis to determine compliance with the BACT limit.

Invenergy proposes to determine a site-specific Fc factor using the analysis and GCV 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 equation for estimating CO_2 emissions as specified in 40 CFR 75.10(3)(ii) is as follows:

$$W_{CO_2} = (Fc \times H \times Uf \times MW_{CO_2})/2000$$

Where:

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

MW_{CO2} = molecular weight of CO_2, 44.0 lbs/mole

Fc = Carbon-based Fc-Factor, 1040 scf/MMBtu for natural gas or site-specific Fc factor

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

Invenergy is subject to all applicable requirements for fuel flow monitoring and quality assurance pursuant to 40 CFR 75, Appendix D, which include:

- Fuel flow meter- meets an accuracy of 2.0%, required to be tested once each calendar quarter pursuant to 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 pursuant to 40 CFR 75, Appendix D, § 2.3.4.1

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Table C-2 and the actual heat input (HHV). Comparatively, the emissions from CO_2 contribute the most (greater than 99%) to the overall emissions from the heaters and additional analysis is not required for CH_4 and N_2O. To calculate the CO_2e emissions, the draft permit requires calculation of the emissions based on the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1. Records of the calculations would be required to be kept to demonstrate compliance with the emission limits on a 2,500 operational hour average, calculated daily. The demonstration of compliance with the BACT emission limit includes periods of startup and shutdown. The permittee shall also demonstrate compliance with the startup and shutdown work practice standard by maintaining a copy of the vendor recommendations and maintaining documentation on-site to show that each startup and shutdown event does not exceed the 60-minute duration or 500 events on a 12-month rolling basis.

An initial stack test demonstration will be required for CO_2 emissions from each emission unit. An initial stack test demonstration for CH_4 and N_2O emissions are not required because the CH_4 and N_2O emission are less than 0.01% of the total CO_2e emissions from the CTGs and are considered a *de minimis* level in comparison to the CO_2 emissions.

IX. Natural Gas-Fired Dew-Point Heater (EPN: DPT HTR-3)

The proposed project will be equipped with one new natural gas-fired dew-point heater. The heater will have a capacity of 9 MMBtu/hr (HHV) and will be operated no more than 5,000 hours per year. This heater will serve to preheat the natural-gas feed into the combustion turbines to maximize combustion efficiency. The pipeline heater represents 0.01% of the facility-wide GHG emissions.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Periodic Tune-up* – Periodically tune-up the heaters to maintain optimal thermal efficiency.
- *Heater Design* – Good heater design to maximize thermal efficiency.
- *Heater Air/Fuel Control* – Monitoring of oxygen concentration in the flue gas to be used to control air to fuel ratio on a continuous basis for optimal efficiency.
- *Waste Heat Recovery* – Use of heat recovery from the heater exhausts to preheat the heater combustion air or process streams in the unit.
- *Use of Low Carbon Fuels* – Fuels vary in the amount of carbon per Btu, which in turn affects the quantity of CO_2 emissions generated per unit of heat input. Selecting low carbon fuels is a viable method of reducing GHG emissions.

Step 2 – Elimination of Technically Infeasible Alternatives

Use of low carbon fuels, heater design, heater air/fuel control, and periodic tune-ups are considered technically feasible. Waste heat recovery is not applicable to intermittently operated combustion units, and is therefore rejected as technically infeasible for the heaters. CCS was determined to be technically infeasible in section VIII of this SOB.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- Use of low carbon fuels (up to 100% for fuels containing no carbon)
- Heater design (up to 10%)
- Periodic tune-up
- Heater air/fuel control

Virtually all GHG emissions from fuel combustion result from the conversion of carbon in the fuel to CO_2. Fuels used in industrial processes and power generation are typically coal, fuel oil, natural gas, and process fuel gas. Of these, natural gas is typically the lowest carbon fuel that can be burned, with a CO_2

emissions factor in lb/MMBtu, about 55% of the emissions from subbituminous coal. Process-fuel gas is a byproduct of chemical processes that typically contain a higher fraction of longer-chain carbon compounds than natural gas and thus results in more CO_2 emissions. Some processes produce significant quantities of hydrogen, which produces no CO_2 emissions when burned. Thus, use of a completely carbon-free fuel, such as 100% hydrogen, has the potential of reducing CO_2 emissions by 100%. Hydrogen is not readily available at the ECEC site, and therefore is not a viable fuel for the proposed heater. Natural gas is the lowest carbon fuel available for use in the proposed heater.

Good heater design, periodic tune-ups, and heater air/fuel control have a range of efficiency improvements which cannot be directly quantified. Therefore, the above ranking is approximate only.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Use of Low Carbon Fuel

Natural gas is the lowest carbon fuel available for use in the proposed heaters. Natural gas is readily available at the ECEC site and is currently considered a very cost-effective fuel alternative. Natural gas is also a very clean burning fuel with respect to criteria pollutants and thus has minimal environmental impact compared to other fuels. Natural gas is the fuel choice for most industrial facilities, especially natural-gas processing facilities, in addition to being the lowest carbon fuel available.

Heater Design

New heaters can be designed with efficient burners and state-of-the art refractory and insulation materials in the heater walls, floor, and other surfaces to minimize heat loss and increase overall thermal efficiency. Due to the very low energy consumption of these small intermittently used heaters, only basic heater efficiency features are practical for consideration in the heater design.

Periodic Heater Tune-ups

Periodic tune-ups of the heater includes:

- Preventative maintenance check of gas flow meters,
- Preventative maintenance check of oxygen control analyzers,
- Cleaning of burner tips on an as-needed basis, and
- Cleaning of convection section tubes on an as-needed basis.

These activities insure maximum thermal efficiency is maintained; however, it is not possible to quantify an efficiency improvement, although convection cleaning has shown improvements in the 0.5

to 1.5% range. Due to the minimal use of these heaters, regularly scheduled tune-ups and inspections are not warranted.

<u>Heater Air/Fuel Controls</u>

Manual controls of the air/fuel ratio enable the heaters to operate under optimal conditions ensuring heater efficiency.

Step 5 – Selection of BACT

ECEC proposes to use efficient heater design, use of natural gas, and tune-ups performed as needed as BACT for the heater. The following specific BACT practices are proposed for the heater:

- Use of low carbon fuel (natural gas). Natural gas will be the only fuel fired in the proposed heaters. It is the lowest carbon fuel available for heaters of this size in intermittent service.
- Good heater design and operation to maximize thermal efficiency and reduce heat loss to the extent practical for heaters of this size in intermittent service.
- Use of manual air/fuel controls to maximize combustion efficiency.
- Clean and inspect heater burner tips and perform tune-ups are needed and per vendor recommendations.
- Limit the operational use of the heaters to no more than 5000 hours per year per heater on a 12 month rolling basis.

Use of these practices corresponds with a permit emission limit of 2,633 tpy CO_2e for the heater. Compliance with this limit will be determined by calculating the emissions on a monthly basis, and keeping a rolling total of hours of operation.

X. Fire Water Pump Engine BACT Analysis (EPN: FWP-4)

ECEC will be equipped with one, nominally rated, 250-hp, diesel-fired, fire water pump engine to provide water in the event of a fire. The fire water pump will operate a maximum of 100 hours of non-emergency operation on a 12-month rolling basis for testing and maintenance. The fire water pump engine emissions represent 0.003% of the total facility-wide GHG emissions.

Step 1 – Identification of Potential Control Technologies for GHGs

- Selection of Fuel Efficient Engine;
- Fuel Selection; and
- Good Combustion Practices, Operating, and Maintenance Practices

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible except fuel selection.

The only technically feasible fuel for the fire water pump engine is diesel fuel. While natural gas-fueled engines may provide lower GHG emissions per unit of power output, natural gas is not considered a technically feasible fuel for the fire water pump engine because it will be used in the event of facility-wide power outage, when natural gas supplies may be interrupted.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The selection of fuel efficient engines and good combustion, operating, and maintenance practices are potentially equally effective but their case-by-case effectiveness cannot be quantified to allow ranking.

Step 4 – Evaluation of Control Technologies, with Consideration of Economic, Energy, and Environmental Impacts

<u>Efficient Engine Design</u>

Invenergy will install a new fire water pump engine. It is anticipated that this equipment will be designed for optimal combustion efficiency. EPA concludes that no economic, energy, or environmental impacts warrant elimination of this control option.

<u>Good Combustion, Operating and Maintenance Practices</u>

Good combustion and operating practices are a potential control option for maintaining the combustion efficiency of the emergency equipment. Good combustion practices include proper maintenance and tune-up of the fire water pump engine at least annually or per the manufacturer's specifications. EPA concludes that no economic, energy, or environmental impacts warrant elimination of this control option.

Step 5 – Selection of BACT

Invenergy proposes to use both remaining identified control options to minimize GHG emissions from the fire water pump engine. The following specific BACT practices are proposed for the emergency diesel generator:

- *Selection of Fuel Efficient Engine* - Invenergy will purchase a fire water pump internal combustion engine (ICE) certified by the manufacturer to meet applicable emission standards at the time of installation and the applicable requirements of 40 CFR Part 60 Subpart IIII, "Standards of Performance for Stationary Compression Ignition Internal Combustion Engines."
- *Good Combustion, Operating, and Maintenance Practices* - Invenergy will implement good combustion, operating, and maintenance practices for the fire water pump engine.

BACT for the fire water pump engine will be to limit operation to no more than 100 hours of non-emergency operation per year for the purpose of maintenance, testing, and inspection. Invenergy will also monitor hours of operation for the purpose of maintenance, testing, and inspection for each engine on a monthly basis. Compliance will be based on runtime hour meter readings on a 12-month rolling basis.

XI. Fugitive Emissions from SF_6 Circuit Breakers BACT Analysis (EPN: SF6FUG)

The circuit breakers associated with the proposed units will be insulated with SF_6. The capacity of the circuit breakers associated with the proposed plant expansion is currently estimated to be two (2) breakers with 240 lb SF_6 each.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Circuit Breaker Design Efficiency* - In comparison to older SF_6 circuit breakers, modern circuit 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.

- *Alternative Dielectric Material* – Because SF_6 has a high GWP, 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 (NIST) Technical note 1425, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF_6.*[9] The alternatives considered include mixtures of SF_6 and nitrogen, various gases and mixtures, and potential gases for which little experimental data are available.

Step 2 – Elimination of Technically Infeasible Alternatives

- *Circuit Breaker Design Efficiency* – Considered technically feasible and is carried forward for Step 3 analysis.

- *Alternative Dielectric Material* - According to the report NIST Technical Note 1425, among the alternatives examined in the report, SF_6 is a superior dielectric gas for nearly all high voltage applications. 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

[9] 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. Available at http://www.epa.gov/electricpower-sf6/documents/new_report_final.pdf

performance to the air and oil-insulated equipment used prior to the development of SF_6-insulated equipment. The mixture of SF_6 and nitrogen is noted to need further development and may only be applicable in limited installations. The second alternative of various gases and mixtures needs additional systematic study before the alternative could be considered technically feasible. The third alternative of potential gases has not been demonstrated in practice, and there is little experimental data available to examine applicability. Therefore, based on the information contained in this report, "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." Consequently, because the alternative dielectric material options have not been demonstrated in practice for this project's circuit breakers and there is insufficient data to determine whether they are commercially available or applicable to the circuit breakers, this alternative is considered technically infeasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The use of efficient circuit breaker design (including state-of-the-art SF_6 technology with leak detection to limit fugitive emissions) is the highest ranked control technology that is feasible for this application.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Because the only remaining technically feasible alternative from Step 1 is the circuit breaker design efficiency, an evaluation of the most effective controls is not necessary.

Step 5 – Selection of BACT

State-of-the-art, enclosed-pressure, SF_6 circuit breakers with leak detection is the BACT control technology option. The circuit breakers will be designed to meet the latest of the American National Standards Institute (ANSI) C37.06 and C37.010 standard for high voltage circuit breakers.[10] 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 the lack of "quenching and cooling" SF_6 gas.

BACT compliance will be demonstrated by ECEC through annual monitoring emissions in accordance with the requirements of the Mandatory Greenhouse Gas Reporting rules for Electrical Transmissions and Distribution Equipment Use.[11] Annual SF_6 emissions will be calculated according to the mass balance approach in Equation DD-1 of Subpart DD.

---

[10] ANSI Standard C37.06, *Standard for AC High-Voltage Generator Circuit Breakers on a Symmetrical Current Basis* and ANSI Standard C37.010, *Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis*.
[11] See 40 CFR Part 98 Subpart DD.

XII. Fugitive Emissions from Piping Components BACT Analysis (EPN: NGFUG)

Emissions from piping components (valves and flanges) associated with this project consist of CH_4 and CO_2. Because a majority of the GHG fugitives comes from CH_4, which has a higher GWP, a conservative estimate was made to assume that all piping components are in a rich-CH_4 stream.

Step 1 – Identification of Potential Control Technologies

- *Leakless/Sealless Technology*
- *Instrument Leak Detection and Repair (LDAR) Programs*
- *Remote Sensing*
- *Auditory/Visual/ Olfactory (AVO) Monitoring*
- *Use of High Quality Components and Materials*

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Leakless technologies are effective in eliminating fugitive emissions from valve stems and flanges, though there are still some areas where fugitive emissions can occur (e.g. relief valves).

Instrument monitoring (LDAR) is effective for identifying leaking components and is an accepted practice by EPA. Quarterly monitoring with an instrument and a leak definition of 500 ppm is assigned as a control effectiveness of 97%. Texas' LDAR program, 28LAER, provides for 97% control credit for valves, flanges, and connectors.

Remote sensing using infrared imaging has proven effective in identifying leaks, especially for components in difficult to monitor areas. LDAR programs and remote sensing using an infrared camera have been determined by EPA to be equivalent methods of piping fugitive controls.[12]

AVO monitoring is effective due to the frequency of observation opportunities, but it is not very effective for low leak rates. It is not preferred for identifying large leaks of odorless gases such as CH_4. However, because pipeline natural gas is odorized with very small quantities of mercaptan, AVO observation is a very effective method for identifying and correcting leaks in natural-gas systems. Due to the pressure and other physical properties of plant fuel gas, AVO observations of potential fugitive leaks are likewise moderately effective.

The use of high quality components is also effective relative to the use of lower quality components.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

[12] 73 FR 78199-78219, December 22, 2008.

Although the use of leakless components, instrument LDAR and/or remote sensing of piping fugitive emission in natural gas service may be somewhat more effective than as-observed AVO methods, the incremental GHG emissions controlled by implementation of the TCEQ 28 LAER LDAR program or a comparable remote sensing program is considered a *de minimis* level in comparison to the total project's proposed CO_2e emissions. Accordingly, given the costs of implementing 28 LAER or a comparable remote sensing program when not otherwise required, these methods are not economically practicable for GHG control from components in natural gas service. Given that GHG fugitives are conservatively estimated to be little more than 2 tons per year CH_4, there is, in any case, a negligible difference in emissions between the considered control alternatives.

Step 5 – Selection of BACT

Based on the economic impracticability of instrument monitoring and remote sensing for natural gas components, EPEC proposes to incorporate as-observed AVO as BACT for the natural gas piping components. The proposed permit contains a condition to implement AVO inspections on a daily basis.

XIII. Endangered Species Act

Pursuant to Section 7(a)(2) of the Endangered Species Act (ESA) (16 U.S.C. 1536) and its implementing regulations at 50 CFR Part 402, EPA is required to insure that any action authorized, funded, or carried out by EPA is not likely to jeopardize the continued existence of any federally-listed endangered or threatened species or result in the destruction or adverse modification of such species' designated critical habitat.

Endangered Species Act

Pursuant to Section 7(a)(2) of the Endangered Species Act (ESA) (16 U.S.C. 1536) and its implementing regulations at 50 CFR Part 402, EPA is required to insure that any action authorized, funded, or carried out by EPA is not likely to jeopardize the continued existence of any federally-listed endangered or threatened species or result in the destruction or adverse modification of such species' designated critical habitat.

To meet the requirements of Section 7, EPA is relying on a Biological Assessment (BA) prepared by the applicant, Invenergy and its consultant, Zephyr Environmental Corporation, (Zephyr), and adopted by EPA.

A draft BA has identified three (3) species listed as federally endangered or threatened in Ector County, Texas:

Federally Listed Species for Ector County by the U.S. Fish and Wildlife Service (USFWS) and the Texas Parks and Wildlife Department (TPWD)	**Scientific Name**
Birds	
Northern aplomado falcon	*Falco femoralis septentrionalis*
Mammals	
Black-footed ferret	*Mustela nigripes*
Gray Wolf	*Canis lupus*

EPA has determined that issuance of the proposed permit will have no effect on any of the three listed species, as there are no records of occurrence, no designated critical habitat, nor potential suitable habitat for any of these species within the action area.

Because of EPA's "no effect" determination, no further consultation with the USFWS is needed.

Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on listed species. The final draft biological assessment can be found at EPA's Region 6 Air Permits website at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

National Historic Preservation Act

Section 106 of the NHPA requires EPA to consider the effects of this permit action on properties eligible for inclusion in the National Register of Historic Places. To make this determination, EPA relied on and adopted a cultural resource report prepared by Horizon Environmental Services, Inc. (Horizon) on behalf of Zephyr submitted in May, 2013.

For purposes of the NHPA review, the Area of Potential Effect (APE) was determined to be 25.3 acres which includes the location of the project site of the Ector County Energy Center and construction laydown area. Horizon conducted a desktop review within a 1.0-mile radius area of potential effect (APE). The desktop review included an archaeological background and historical records review using the Texas Historical Commission's online Texas Archaeological Site Atlas (TASA) and the National Park Service's National Register of Historic Places (NRHP). Based on the desktop review and field survey, including shovel testing, within the APE, no recorded historical or archaeological sites were identified.

EPA Region 6 determines that because no historic properties are located within the APE and that a potential for the location of archaeological resources within the construction footprint itself is low, issuance of the permit to Invenergy will not affect properties potentially eligible for listing on the National Register.

On January 21, 2014, EPA sent letters to Indian tribes identified by the Texas Historical Commission as having historical interests in Texas to inquire if any of the tribes have historical interest in the particular location of the project and to inquire whether any of the tribes wished to consult with EPA in the Section 106 process. EPA received no requests from any tribe to consult on this proposed permit. EPA will provide a copy of the report to the State Historic Preservation Officer for consultation and concurrence with its determination. Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on historic properties. A copy of the report may be found at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XIV. Environmental Justice (EJ)

Executive Order (EO) 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive branch policy on environmental justice. Based on this Executive Order, the EPA's Environmental Appeals Board (EAB) has held that environmental justice issues must be considered in connection with the issuance of federal Prevention of Significant Deterioration (PSD) permits issued by EPA Regional Offices [See, e.g., *In re Prairie State Generating Company*, 13 E.A.D. 1, 123 (EAB 2006); *In re Knauf Fiber Glass*, Gmbh, 8 E.A.D. 121, 174-75 (EAB 1999)]. This permitting action, if finalized, authorizes emissions of GHG, controlled by what we have determined is the Best Available Control Technology for those emissions. It does not select environmental controls for any other pollutants. Unlike the criteria pollutants for which EPA has historically issued PSD permits, there is no National Ambient Air Quality Standard (NAAQS) for GHGs. The global climate-change inducing effects of GHG emissions, according to the "Endangerment and Cause or Contribute Finding", are far-reaching and multi-dimensional (75 FR 66497). Climate change modeling and evaluations of risks and impacts are typically conducted for changes in emissions that are orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible [PSD and Title V Permitting Guidance for GHGS at 48]. Thus, we conclude it would not be meaningful to evaluate impacts of GHG emissions on a local community in the context of a single permit. Accordingly, we have determined an environmental justice analysis is not necessary for the permitting record.

XV. Conclusion and Proposed Action

Based on the information supplied by Invenergy, our review of the analyses contained in the TCEQ PSD Permit Application and the GHG PSD Permit Application, and our independent evaluation of the information contained in our Administrative Record, it is our determination that the proposed facility would employ BACT for GHGs under the terms contained in the draft permit. Therefore, EPA is proposing to issue Invenergy a PSD permit for GHGs for the facility, subject to the PSD permit conditions specified therein. This permit is subject to review and comments. A final decision on issuance of the permit will be made by EPA after considering comments received during the public comment period.

Appendix

Table 1. Annual Emission Limit – GE 7FA.03 CT

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[1,2]	BACT Requirements
				TPY		
CTG-1 CTG-2	CTG-1 CTG-2	Natural Gas Fired-Simple Cycle Turbine	CO_2	239,420[3]	239,649[3]	- BACT limit of 1,393 lb CO_2/MW-hr (gross) on a 2,500 operational hour rolling basis, rolling daily, each turbine. -Not to exceed 2,500 hours of operation on a 12-month rolling basis per turbine. -See permit condition III.A.2.a. through d.
			CH_4	4.4[3]		
			N_2O	0.4[3]		
CTG-1 CTG-2	CTG-1 CTG-2	Natural Gas Fired-Simple Cycle Turbine – MSS[4]	CO_2	10,500[4]	10,502[4]	-Each event limited to 21 tons CO_2e. -Limit of 500 events on a 12-month rolling total. -Maximum heat input during startup limited to 1,320 MMBtu/hr. -See Special Condition III.A.4.c. through e.
			CH_4	0.06[4]		
			N_2O	No Numerical Limit Established[5]		
DPT HTR-3	DPT HTR-3	Natural Gas-Fired Dew-Point Heater	CO_2	2,630	2,631	-Not to exceed 5,000 hours per year on a 12-month rolling basis
			CH_4	0.05		
			N_2O	No Numerical Limit Established[5]		
FWP-4	FWP-4	Firewater Pump Engine	CO_2	5.44	5	- Not to exceed 100 hours of non-emergency operation on a 12-month rolling basis - Use of Good Combustion Practices. See permit condition III.B.
			CH_4	No Numerical Limit Established[5]		
			N_2O	No Numerical Limit Established[5]		

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[1,2]	BACT Requirements
				TPY		
SF6FUG	SF6-FUG	Fugitive SF_6 Circuit Breaker Emissions	SF_6	No Numerical Limit Established[6]	No Numerical Limit Established[6]	Work Practices. See permit condition III.C.
NGFUG	NG-FUG	Components Fugitive Leak Emissions	CH_4	No Numerical Limit Established[7]	No Numerical Limit Established[7]	Implementation of AVO Program. See permit condition III.D.
Totals[8]			CO_2	502,475	**503,204 CO_2e**	
			CH_4	19		
			N_2O	0.8		
			SF_6	.0006		

1. The TPY emission limits specified in this table are not to be exceeded for this facility and include emissions from the facility during all operations and include MSS activities.
2. Global Warming Potentials (GWP): CO_2=1, CH_4 = 25, N_2O = 310, SF_6=22,800
3. The GHG Mass Basis TPY limit and the CO_2e TPY limit for the natural gas fired simple cycle turbines applies to each turbine and is not a combined limit.
4. The GHG Mass Basis TPY limit and the CO_2e TPY limit for the natural gas fired simple cycle turbines – MSS includes emissions associated with gaseous fuel venting of the fuel lines during a turbine shutdown or maintenance and applies to each turbine and is not a combined limit.
5. These values indicated as “No Numerical Limit Established” are less than 0.01 TPY with appropriate rounding. The emission limit will be a design/work practice standard as specified in the permit.
6. Fugitive Leak Emissions from SF6-FUG are estimated to be 0.0006 TPY SF_6 and 13.7 TPY CO_2e. In lieu of an emission limit, the emissions will be limited by implementing a design/work practice standard as specified in the permit.
7. Fugitive Leak Emissions from NG-FUG are estimated to be 0.134TPY CO_2, 10.08 TPY CH_4, and 252.25 TPY CO_2e. In lieu of an emission limit, the emissions will be limited by implementing a design/work practice standard as specified in the permit.
8. Total emissions include the PTE for fugitive emissions. Totals are given for informational purposes only and do not constitute emission limits.