**Statement of Basis**
Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit
for FGE Power, LLC

Permit Number: PSD-TX-1364-GHG

March 2014

This document serves as the Statement of Basis (SOB) 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 will apply if the permit is finalized. This document is intended for use by all parties interested in the permit.

## I. Executive Summary

On May 6, 2013, FGE Power, LLC (FGE), submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions for a proposed construction project. On January 17, 2014, FGE submitted additional information for inclusion into the application. In connection with the same proposed construction project, FGE submitted an application for a PSD permit for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on May 6, 2013. The project proposes to construct a natural gas fired combined cycle electric generating plant, known as the FGE Texas Project (FGETP), to be located near Westbrook, Mitchell County, Texas. The FGETP will consist of two combined cycle power blocks, each in a 2-on-1 configuration consisting of two combustion turbines (CTGs), two supplementally fired (duct burners) heat recovery steam generators (HRSGs) and one steam turbine. After reviewing the application, EPA Region 6 prepared the following SOB and draft air permit to authorize construction of air emission sources at the FGETP.

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 permit requirements, and an analysis showing how the applicant complied with the requirements.

EPA Region 6 concludes that FGE’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 requested by EPA and provided by FGE, and EPA's own technical analysis. EPA is making all this information available as part of the public record.

## II. Applicant

FGE Power, LLC
21 Waterway Avenue
Suite 300
The Woodlands, TX 77380

Facility Physical Address:
3.5 miles south southwest of the intersection of Interstate 20 and Main Street
Westbrook, TX 79565

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CEO and President
FGE Power, LLC
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## III. Permitting Authority

On May 3, 2011, EPA published a federal implementation plan (FIP) that makes EPA Region 6 the PSD permitting authority for the pollutant GHGs. See 75 FR 25178 (promulgating 40 CFR § 52.2305).

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:
Aimee Wilson
Air Permitting Section (6PD-R)
(214) 665-7596

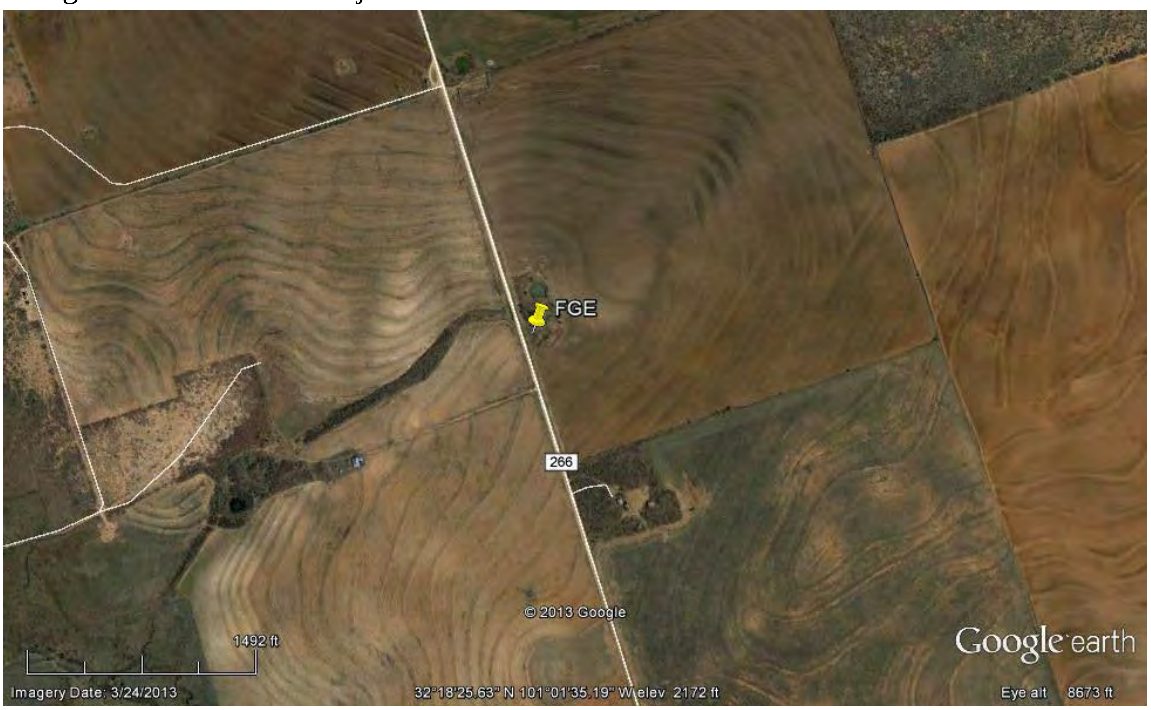
## IV. Facility Location

FGETP will be located in Mitchell County, Texas, and this area is currently designated "attainment" for all criteria pollutants. The nearest Class 1 area is the Carlsbad Caverns National Park, which is located over 100 miles from the site. The geographic coordinates for this proposed facility site are as follows:

Latitude: 30º 18' 30" North
Longitude: -101º 01'23" West

Below, Figure 1 illustrates the proposed facility location for this draft permit.

Figure 1. FGE Texas Project



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

EPA concludes that FGE's application is subject to PSD review for GHGs, because the project will constitute a new stationary source that will emit or have the potential to emit (PTE) 100,000 tons per year (TPY) $CO_2e$, as described at 40 CFR § 52.21(b)(49)(v)(*a*), and greater than 100/250 TPY on a mass basis (FGE calculates $CO_2e$ emissions of 5,889,434 TPY). EPA Region 6 implements a GHG PSD FIP for the State of Texas under the provisions of 40 CFR § 52.21 (except paragraph (a)(1)). See 40 CFR § 52.2305.

FGE represents that TCEQ, the permitting authority for regulated NSR pollutants other than GHGs, will determine that FGETP is also subject to PSD review for $NO_x$, CO, VOC, PM, $PM_{10}$, $PM_{2.5}$, and $H_2SO_4$. Accordingly, under the circumstances of this project, TCEQ will issue the non-GHG portion of the permit and EPA will issue the GHG portion.[1]

In evaluating this permit application, EPA Region 6 applies the policies and practices reflected in EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011). Consistent with that guidance, we have not 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 of 40 CFR § 52.21(o) and (p), respectively. Instead, EPA 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 regulated NSR pollutants that are non-GHG pollutants, which are addressed by the PSD permit to be issued by TCEQ. Air quality modeling or ambient monitoring may be required for TCEQ to issue the permit for the non-GHG pollutants.

## VI. Project Description

The proposed GHG PSD permit, if finalized, would authorize FGE to construct a new combined cycle electric generating plant (FGETP) in Mitchell County, Texas. FGETP will generate 1,620 megawatts (MW) of gross electrical power near the City of Westbrook. The gross electrical power output is based on four combustion turbines rated at nominal 230.7 MW each and two steam turbines with duct burner firing that are designed to produce an additional 336 MW each. FGE's rated output for a single power block is 810 MW of gross electrical output. FGETP will consist of the following sources of GHG emissions:

- Four natural gas-fired CTGs equipped with lean pre-mix low-$NO_x$ combustors;

[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

- Four natural gas-fired duct burner system equipped heat recovery steam generators (HRSGs);
- Natural gas piping and metering;
- Two diesel fuel-fired emergency electrical generator engines;
- Two diesel fuel-fired fire water pump engines; and
- Electrical equipment insulated with sulfur hexafluoride ($SF_6$).

Combustion Turbine Generator

The plant will consist of four identical Alstom GT24 natural gas-fired CTGs. The CTGs will burn pipeline quality natural gas to rotate an electrical generator to generate 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. The exhaust gas will exit the CTG and be routed to the heat recovery steam generator (HRSG) for steam production.

Heat Recovery Steam Generator (HRSG) with Duct Burners

Heat recovered in the HRSGs will be utilized to produce steam. Steam generated within the HRSGs will be utilized to drive a steam turbine and associated electrical generator. The HRSGs will be equipped with duct burners (DBs) for supplemental steam production. The DBs will be fired with pipeline quality natural gas. Each DB has a maximum heat input capacity of 409 million British thermal units per hour (MMBtu/hr). The exhaust gases from the unit, including emissions from the CTG and the DBs, will exit through a stack to the atmosphere.

The normal DB operation will vary from 0 to 100 percent of the maximum capacity. DBs are located prior to the HRSGs, selective catalytic reduction (SCR) system, and the oxidation catalyst (OC).

Generators Overall

Steam produced by each of the two HRSGs will be routed to the steam turbine. The two CTGs and one steam turbine will be coupled to electric generators to produce electricity for sale to the Electric Reliability Council of Texas (ERCOT) power grid. Each CTG has an approximate maximum base-load electric power output of 230.7 MW. The maximum electric power output from each steam turbine is approximately 336 MW. The units may operate at reduced load to respond to changes in system power requirements and/or stability.

Emergency Equipment

The site will be equipped with two diesel-fired emergency generators, each nominally rated at 900-hp, to provide electricity to the facility in case of power failure. Two diesel-fired fire water pumps, each nominally rated 389-hp, will be installed at the site to provide water in the event of a fire. Each emergency engine and fire water pump will be limited to 52 hours of operation per year for purposes of maintenance checks and readiness testing.

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 462 lbs 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 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.

## VII. General Format of the BACT Analysis

EPA conducted the BACT analyses for this draft permit by following the "top-down" BACT approach recommended in EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011) and earlier EPA guidance. The five steps in a top-down BACT process 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. Applicable Emission Units for BACT Analysis

The majority of the GHGs associated with the project are from emissions at combustion sources (i.e., combined cycle combustion turbines, duct burners, emergency engines, and fire water pumps). The project will have fugitive emissions from piping components which will account for 444 tpy of $CO_2e$, or less than 0.01% of the project's total $CO_2e$ emissions.

Stationary combustion sources primarily emit $CO_2$ and small amounts of $N_2O$, $CH_4$, and $SF_6$. The following equipment is included in this proposed GHG PSD permit:

- Combined Cycle Combustion Turbines (GT-1, GT-2, GT-3, and GT-4)
- Emergency Generators (EG-1 and EG-2)
- Fire Water Pumps (FWP-1 and FWP-2)
- Natural Gas Fugitives (FUG-NGAS)
- $SF_6$ Insulated Equipment (FUG -SF6)

## IX. Combined Cycle Combustion Turbines (EPNs: GT-1, GT-2, GT-3, and GT-4)

The four Alstom GT24 natural gas-fired combined cycle turbines (i.e., the combustion turbine, HRSG, and steam turbine) will be used for power generation. The BACT analysis for these turbines considered two types of GHG emission reduction alternatives: (1) energy efficiency processes, practices, and designs for the turbines and other facility components; and (2) carbon capture and storage (CCS).

As part of the PSD review, FGE provided in the GHG permit application a 5-step top-down BACT analysis for the combustion turbines. EPA has reviewed FGE'S BACT analysis for the combustion turbines, which is part of the record for this permit (including this Statement of Basis), and we also provide our own analysis in setting forth BACT for this proposed permit, as summarized below.

**Step 1 –** Identify All Available Control Options

<u>(1) **Energy Efficiency Processes, Practices, and Design**</u>

<u>Combustion Turbine:</u>

- *Combustion Turbine Design* – The most efficient way to generate electricity from a natural gas fuel source is the use of a combined cycle combustion turbine.
- *Periodic Burner Tuning* – Regularly scheduled combustion inspections involving tuning of the combustors are used to maintain optimal thermal efficiency and performance.
- *Reduction in Heat Loss* – Insulation blankets are applied to the combustion turbine casing to minimize heat loss to the environment. These blankets minimize the heat loss through the combustion turbine shell and help improve the overall efficiency of the machine.
- *Instrumentation and Controls* – Distributed digital system controls are used to automate processes for optimal operation.

Heat Recovery Steam Generator:

- *Heat Exchanger Design Considerations* – HRSGs are shell-and-tube style heat exchangers designed to maximize the contact surface between the turbine exhaust gas and the feed water.
- *Insulation* – The use of insulation prevents heat loss.
- *Minimizing Fouling of Heat Exchange Surfaces* – Fouling occurs when deposition of constituents in the exhaust gases occurs on heat transfer surfaces within the heat exchanger.
- *Minimizing Vented Steam and Repair of Steam Leaks* – Steam loss through venting and leakage reduces the efficiency of the heat exchanger. Restricting the venting outlets is used to maximize steam retention for power generation.

Steam Turbine:

- *Use of Reheat Cycles* – Steam turbine efficiency is dependent on the nature of the steam entering the turbine.
- *Use of Exhaust Steam Condenser* – Steam turbine efficiency is improved by lowering the exhaust pressure of the steam. Condensing units are utilized to lower the exhaust steam to the saturation point, which reduces the exhaust pressure.
- *Efficient Blading Design and Turbine Seals* – Blade design has evolved for high-efficiency transfer of the energy in the steam to power generation.
- *Efficient Steam Turbine Generator Design* – The generator for modern steam turbines is cooled allowing for the highest efficiency of the generator, resulting in an overall high-efficiency steam turbine.

Other Plant-wide Energy Efficiency Features

FGE has proposed a number of other measures that help improve overall energy efficiency of the facility (and thereby reducing GHG emissions from the emission units), including:

- *Multiple Combustion Turbine/HRSG Trains* – Part-load operation is improved through the use of multiple combustion turbine and HRSG trains. Optimum operating conditions are obtained through the automated shutting down/ramping up of less- and more-efficient operating trains.
- *Cooling Towers* – A closed-loop design, which includes a cooling tower to cool the water, will be utilized for the project.

(2) **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 general 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)."[2]

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 applicable primarily to 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 are not considered available control options 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, 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.

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

[2] U.S. EPA, Office of Air Quality Planning and Standards, PSD and Title V Permitting Guidance for Greenhouse Gases. March 2011. Available at: http://www.epa.gov/nsr/ghgdocs/ghgpermttingguidance.pdf.

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). 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 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).

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). 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.[3]

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

FGE's application examines the technical feasibility of CCS for this project and concludes that:

> While amine absorption technology for the capture of $CO_2$ has been applied to natural gas–fired processes in the petroleum industry and natural gas processing industry, and therefore it is technically feasible to apply the technology to that of power plant turbine exhaust streams. However, the technologies have not been proven to be reliable, nor are they ready for full-scale commercial deployment. Although numerous research pilot-scale projects for high-volume carbon sequestration are underway, these projects are still a few years from implementation. Furthermore, although a single natural gas–fired combined cycle combustion turbine project with $CO_2$ capture capabilities has been issued a standard permit by the TCEQ, this project has yet to be constructed. Although FGE questions whether it is feasible to implement CCS on a full-scale natural gas-fired combustion turbine project, an economic feasibility analysis for implementing CCS

[3] We note that EPA's recent proposed rule addressing *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units* rejected CCS as the best system of emission reduction for nation-wide standard for natural gas combined cycle (NGCC) turbines based on both "insufficient information to determine technical feasibility" and "adverse impact on electricity prices and the structure of the electric power sector." 79 Fed. Reg. at 1485 (Jan. 8, 2014). However, that proposal did not state that CCS was technically infeasible for individual NGCC sources and thus does not conflict with the type of case-by-case PSD BACT analysis (which separates the technical and cost issues) as presented here.

for control of the $CO_2$ emissions from the four combustion turbines is discussed in detail in Step 4 of this section.

FGE Application at 65. EPA's recent proposed rule addressing *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units* concluded that CCS was not the best system of emission reduction for a nation-wide standard for natural gas combined cycle (NGCC) turbines based on questions about whether full or partial capture CCS is technical feasible for the NGCC source category. 79 Fed. Reg. at 1485 (Jan. 8, 2014). Considering this, EPA is evaluating whether there is sufficient information to conclude that CCS is technically feasible at this specific NGCC source and will consider public comments on this issue. However, because the applicant has provided a basis to eliminate CCS on other grounds, we have assumed, for purposes of this specific permitting action, that potential technical or logistical barriers do not make CCS technically infeasible for this project and have addressed the economic feasibility issues in Step 4 of the BACT analysis in order to assess whether CCS is BACT for this project. In addition, the other control options identified in Step 1 are considered technically feasible for this project.

**Step 3 –** Ranking of Remaining Technologies Based on Effectiveness

Since all of the energy efficiency processes, practices, and designs discussed in Step 1 are proposed for this project, we will rank CCS and the suite of energy efficiency measures in BACT Step 4.

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

Carbon Capture and Storage

FGE developed an initial cost analysis for CCS that provided a total estimated capital cost for CCS as $1,508 million and stated that this would result in a more than 100% increase of the total capital cost of the proposed project. Based on these costs, FGE maintains that CCS is not economically feasible. While FGE provided some general information relating to this cost estimate that is provided in the record for this proposed permit (including more detailed cost information that is provided in Appendix B), FGE asserts that detailed capital cost information for this facility as a whole is protected as Confidential Business Information. Accordingly, to assess FGE's cost claims, EPA has summarized some of the publically available cost information FGE provided below and compared FGE's overall cost assertions with cost estimates for similar facility types developed by the Agency and by the U.S. Department of Energy (DOE).[4]

[4] *See* U.S. EPA, Air and Radiation, No. 450R13002, *Documentation for EPA Base Case v.5.13 Using the Integrated Planning Model* (Nov. 2013) (EPA Report), available at

Capital costs associated with CCS fall into two primary areas – $CO_2$ Capture and Compression Equipment and $CO_2$ Transport. The capture and compression equipment associated with CCS would have cost impacts based on the installation of the additional process equipment (e.g., amine units, cryogenic units, dehydration units, and compression facilities), while transport costs are associated with construction of a pipeline to transport the captured $CO_2$. FGE conducted an analysis of the capital cost impact of CCS capture and compression equipment on the FGETP using project specific data along with the methodology provided by the U.S. Department of Energy's *Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous and Natural Gas to Electricity*, DOE/2010/1397 (Revision 2, November 2010). These cost have been prepared based upon project specific criteria and have been updated to calendar year 2014 dollars. The estimated capital cost for post-combustion $CO_2$ capture and compression equipment was estimated to be $1,425 million. For transportation costs, FGE identified two possible options for transporting the captured $CO_2$ – building a pipeline to the nearest existing $CO_2$ pipeline (25 miles) or to build a separate line to the nearest enhanced oil recovery (EOR) market (100 miles) [5] – and estimated the cost for a 100 mile long 10 inch diameter pipeline at $83 million. Accordingly, FGE's total estimated capital cost for CCS at this facility is approximately $1,508 million.

Examining the proposed FGETP – a 1,610 MW Natural Gas Advanced Combined Cycle (CC) facility located in Mitchell County, TX – using the EPA and DOE cost estimates, EPA estimates that the capital costs of the entire facility without CCS would be approximately $1,500 million.[6] EPA estimates that the capital costs of the entire facility with CCS would be approximately $3,035 million.[7] These cost estimates are similar to the estimated CCS costs provided by FGE.[8] These estimates also support FGE's assertion that adding CCS to the

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http://www.epa.gov/airmarkt/progsregs/epa-ipm/docs/v513/Documentation.pdf, and U.S. Department of Energy, U.S. Energy Information Administration, *Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants* (April 2013) (DOE Report). *available at* *http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf*.

[5] The closest potential transportation route (an existing Kinder Morgan $CO_2$ pipeline) is approximately 25 miles to the north-northwest from the proposed FGE facility. In addition, based upon information FGE obtained from local exploration and production (E&P) companies, there is an absence of the market need for $CO_2$ for EOR activities in the immediate vicinity and the nearest enhanced oil recovery (EOR) market need is more than 100 miles to the west near Midland, Texas.

[6] *See* EPA Report at Table 4-13 (initial capital costs of $1,006/kW) and Table 4-15 (0.954 locality cost adjustment) and DOE Report at Table 1 (initial capital costs of $1,023/kW) and Table 4 (0.92 locality cost adjustment).

[7] *See* DOE Report at Table 1 (initial capital costs of $2,095/kW) and Table 4 (0.90 locality cost adjustment). The EPA Report does not contain similar CCS cost information in Table 4-13.

[8] It is unclear whether the CCS cost estimates provided in the DOE Report include pipeline costs, but EPA estimates that adding separate pipeline construction costs would increase the CCS costs estimates for this facility by 1-5% (based on a CCS costs of approximately $1,535 million). Based on the estimated $CO_2$ flow rate from the facility, EPA estimates that a 6-inch to 10-inch pipeline would be required to transport the captured $CO_2$ from FGETP, and that the cost associated to construct a pipeline of this size would be approximately $650,000 to $750,000 per mile. This would result in costs of approximately $16-75 million

proposed facility would increase of the total capital cost of the proposed project by more than 100%.[9]

*CCS Conclusion*

Based on the normalized control cost, comparison of total capital cost of control to project cost, and decrease in net power output due the additional power requirements for CCS, FGE maintains that CCS is not economically feasible. EPA has reviewed FGE's estimated CCS cost projections, and based upon the potential volume of $CO_2$ emissions from the project that would be available for capture and current estimates of CCS costs that would be associated with a project such as this, we believe FGE's estimated costs to install CCS add-on pollution controls for the facility are credible. Accordingly, we conclude that such costs would render the project economically unfeasible for FGETP and eliminate CCS as BACT for this facility.

<u>Energy Efficiency Processes, Practices, and Design</u>

There are no known adverse economic, energy, or environmental impacts associated with the control technologies identified in Step 1 for energy efficiency process, practices, and design. All these options are proposed for the facility as outlined below.

<u>Combustion Turbine:</u>

- *Combustion Turbine Design* –The Alstom turbine model under consideration for the FGETP facility has a sequential combustion design that allows the injection of fuel into two combustion systems in series. This design makes it is possible to increase output and cycle efficiency without significantly increasing emissions during normal and low load operations. The sequential combustion technology is unique in that it allows the turbines to meet current BACT during low load operations.
- *Periodic Burner Tuning* – Regularly scheduled combustion inspections involving tuning of the combustors are used to maintain optimal thermal efficiency and performance.

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dollars for a 25 to 100 mile pipeline. EPA's pipeline size estimate is based on distance transported of pure $CO_2$ gas flowing at 282,340 lb/hr, as obtained from SNC Lavalin on April 12, 2013. Pipeline capital costs are based on equations from DOE NETL analysis as described in $CO_2$ Transport, Storage & Monitoring Costs Quality Guidelines for Energy Systems Studies (March 2010) utilizing estimated pipeline length and diameter values. Calculations are included in Appendix B.

[9] This summary of cost estimates does not address costs associated with $CO_2$ storage. FGE's initial analysis discusses possible cost offsets that might occur by selling the captured $CO_2$ for EOR and taking advantage of limited tax credits for $CO_2$ sequestration, but any resulting cost reductions would relatively small in comparison to overall CCS costs and would still not result in costs that would make CCS economically feasible for this facility. Moreover, the cost estimates could increase if FGE had to pay for non-EOR geologic sequestration of the $CO_2$ emissions.

- *Reduction in Heat Loss* – Insulation blankets are applied to the combustion turbine casing to minimize heat loss to the environment. These blankets minimize the heat loss through the combustion turbine shell and help improve the overall efficiency of the machine.
- *Instrumentation and Controls* – Distributed digital system controls are used to automate processes for optimal operation. Higher efficiencies and lower emissions are obtained through automation and easy-to-read digital readouts, which simplify turbine operation.



Heat Recovery Steam Generator:

- *Heat Exchanger Design Considerations* – HRSGs are shell-and-tube style heat exchangers designed to maximize the contact surface between the turbine exhaust gas and the feed water. The heat transfer is carried out at multiple pressure levels within the HRSG, with fins used to extend heat transfer surfaces. In the low-pressure section, condensate is heated using the combustion turbine exhaust gas. Steam is further heated and pressured as it moves through the heat exchanger until the saturated high-pressure steam moves through the superheater section of the HRSG, where additional heat is added from duct-burners, as necessary. The expansion of the superheated, high-pressure steam then powers the turbine. Exhaust gas bypass systems and economizer sections are utilized during startup and shutdown to reduce startup and shutdown times, minimizing exhaust emissions and reducing cold-end corrosion.
- *Insulation* – HRSGs are designed to minimize waste heat from combustion by utilizing that waste heat to generate steam to power a steam turbine. The efficient transfer of this heat from the turbine exhaust gases and the minimization of heat losses to the environment is an integral part of HRSG design. The shell-side housing of the HRSG is well insulated to prevent unnecessary heat losses to the environment.
- *Minimizing Fouling of Heat Exchange Surfaces* – Fouling occurs when deposition of constituents in the exhaust gases occurs on heat transfer surfaces within the heat exchanger. This fouling "insulates" the heat exchange surfaces from heat transfer between the exhaust gases and the feed water, reducing heat transfer efficiency. Fouling is reduced through filtration of the inlet exhaust gases and periodic cleaning of heat exchange surfaces.
- *Minimizing Vented Steam and Repair of Steam Leaks* – Steam loss through venting and leakage reduces the efficiency of the heat exchanger. Venting operations are utilized in certain system areas, such as de-aerator vents, to improve operation. Restricting the venting outlets maximizes steam retention for power generation. If a leak is large enough, reduction in power generation efficiency is apparent and will be identified quickly through automatic

monitoring and low-pressure alarms. Smaller steam leaks are identified and repaired quickly through the proper implementation of operator SOPs requiring routine checks of the equipment.

Steam Turbine:

- *Use of Reheat Cycles* – Steam turbine efficiency is dependent on the nature of the steam entering the turbine. Reheat cycles are used to achieve higher steam temperatures and pressures and to reduce moisture content of the exhaust steam, increasing turbine efficiency.
- *Use of Exhaust Steam Condenser* – Steam turbine efficiency is improved by lowering the exhaust pressure of the steam. This lowering of the exhaust pressure creates a vacuum, creating a natural draw through the turbine and thus increasing turbine efficiency. Condensing units are utilized to lower the exhaust steam to the saturation point, which reduces the exhaust pressure.
- *Efficient Blading Design and Turbine Seals* – Blade design has evolved for high-efficiency transfer of the energy in the steam to power generation. Blade materials are also important components in blade design, which allow for high-temperature and large exhaust areas to improve performance. The steam turbines have a multiple steam seal design to obtain the highest efficiency from the steam turbine.
- *Efficient Steam Turbine Generator Design* – The generators for modern steam turbines are cooled, allowing for the highest efficiency of the generator and resulting in an overall high-efficiency steam turbine. The cooling method for the FGETP steam turbine will be either totally enclosed water-to-air cooling or hydrogen cooling.

Other Plant-wide Energy Efficiency Features

FGE has proposed a number of other measures that help improve overall energy efficiency of the facility (and thereby reducing GHG emissions from the emission units), including:

- *Multiple Combustion Turbine/HRSG Trains* – Part-load operation is improved through the use of multiple combustion turbine and HRSG trains. Optimum operating conditions are obtained through the automated shutting down/ramping up of less- and more-efficient operating trains.
- *Cooling Towers* – A closed-loop design, which includes a cooling tower to cool the water, will be utilized for the project. Closed-loop designs are either natural circulation or forced circulation. Both natural circulation and forced circulation designs require higher cooling water pump heads; therefore, increasing the pump's power consumption and reducing overall plant efficiency. Additionally,

to provide the forced circulation, fans are used for the forced circulation designs, which consume additional auxiliary power and reduce the plant's efficiency.

**Step 5 –** Selection of BACT

To date, other similar 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 |
|---|---|---|---|---|---|
| La Paloma Energy Center<br><br>Harlingen, TX | 183 MW<br><br>Combined cycle | Energy Efficiency Good Design & Combustion Practices | Annual Heat Input – 7,861 Btu/kWh<br><br>934 lb $CO_2$/MWh | 2013* | PSD-TX-1288-GHG |
| La Paloma Energy Center<br><br>Harlingen, TX | 265 MW<br><br>Combined cycle | Energy Efficiency Good Design & Combustion Practices | Annual Heat Input - 7,649 Btu/kWh<br><br>909 lb $CO_2$/MWh | 2013* | PSD-TX-1288-GHG |
| La Paloma Energy Center<br><br>Harlingen, TX | 271 MW<br><br>Combined cycle | Energy Efficiency Good Design & Combustion Practices | Annual Heat Input - 7,679 Btu/kWh<br><br>913 lb $CO_2$/MWh | 2013* | PSD-TX-1288-GHG |
| Calpine Deer Park Energy Center<br><br>Deer Park, TX | 168 MW/180 MW<br><br>Combustion Turbine (CT) / Duct Burner (DB) | Energy Efficiency Good Design & Combustion Practices | Annual Heat Input – 7,730 But/kWh<br><br>920 lb $CO_2$/MWh | 2012 | PSD-TX-979-GHG |
| Calpine Channel Energy Center<br><br>Pasadena, TX | 168 MW/180 MW<br><br>CT/DB | Energy Efficiency Good Design & Combustion Practices | Annual Heat Input – 7,730 Btu/kWh<br><br>920 lb $CO_2$/MWh | 2012 | PSD-TX-955-GHG |
| Pioneer Valley Energy Center<br><br>Westfield, MA | 431 MW<br><br>combined cycle | Energy Efficiency Good Design & Combustion Practices | 825 lb $CO_2e/MWh_{grid}$ (initial performance test)<br><br>895 lb $CO_2e/MWh_{grid}$ on a 365-day rolling average | 2012 | 052-042-MA15 |
| LCRA Thomas C. Ferguson Plant<br><br>Horseshoe Bay, TX | 195 MW<br><br>CTG/DB | Energy Efficiency Good Design & Combustion Practices | Annual Heat Rate - 7,720 Btu/kWh<br><br>920 lb $CO_2$/MWh | 2011 | PSD-TX-1244-GHG |
| Palmdale Hybrid Power Plant Project<br><br>Palmdale, CA | 195 MW<br><br>CTG/DB | Energy Efficiency Good Design & Combustion Practices | Annual Heat Rate - 7,319 Btu/kWh<br><br>774 lb $CO_2$/MWh | 2011** | SE 09-01 |

| Company / Location | Process Description | Control Device | BACT Emission Limit / Requirements | Year Issued | Reference |
|---|---|---|---|---|---|
| PacifiCorp Energy - Lake Side Power Plant<br><br>Vineyard, UT | 629 MW (without duct burning) combined cycle turbine | Energy Efficiency Good Design & Combustion Practices | 950 lb $CO_2e$/MWh (gross) | 2011 | DAQE-AN0130310010-11 |
| Calpine Russell City Energy<br><br>Hayward, CA | 600 MW combined cycle power plant | Energy Efficiency/ Good Design & Combustion Practices | Combustion Turbine Operational limit of 2,038.6 MMBtu/kWh | 2011 | 15487 |

**Permit currently under review by the EPA Environmental Appeals Board (EAB).*
***The Palmdale facility BACT limit is reduced due to the offset of emissions from the use of a 50 MW Solar-Thermal Plant that was part of the permitted project.*

The following specific BACT practices are proposed for the turbines:

- Use of Combined Cycle Power Generation Technology
- Combustion Turbine Energy Efficiency Processes, Practices, and Design
    - Highly Efficient Turbine Design
    - Turbine Inlet Air Cooling
    - Periodic Turbine Burner Tuning
    - Reduction in Heat Loss
    - Instrumentation and Controls
- HRSG Energy Efficiency Processes, Practices, and Design
    - 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 Design
    - Use of Reheat Cycles
    - Use of Exhaust Steam Condenser
    - Efficient Blading Design
    - Efficient Generator Design
- Plant-wide Energy Efficiency Processes, Practices, and Design
    - Multiple Combustion Turbine/HRSG Trains
    - Closed Loop Cooling Towers

BACT Limits and Compliance:

To determine the appropriate heat-input efficiency limit, FGE 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 gross heat rates for the combustion turbines being considered for this project are as follows:

- Alstom
  - 7,625 Btu/kWhr (HHV) without duct burner firing
  - 7,567 Btu/kWh (HHV) with duct burner firing

These rates reflect the facility's "gross" power production, meaning 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 gross heat rate without duct burner 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 Margin* - 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. Typically, the market for contracting the engineering and construction of combined cycle power plants has a design margin of 5% for the guaranteed net MW output and net heat rate. This is the condition for which the contractor has a "make right" obligation to continue tuning the facility's performance to achieve this minimum value. Therefore, the contractor must deliver a facility that is capable of generating 95% of the guaranteed MW and must have a heat rate that is no more than 105% of the guaranteed heat rate. Given FGE's confidence surrounding the expertise and experience of combined cycle power plant construction, FGE has elected to reduce the 5% design margin to 3.3%.

*Performance Margin on Combustion Turbine and Steam Turbine Generators* - The performance margin for equipment degradation relates to the combustion turbine and steam turbine generators. According to Figure 24 of the California Energy Commission publication CEC-200-2010-002, Cost of Generation Model Users Guide Version 2 (March 2010), the "sawtooth curve" indicates that the degradation will be limited to 2% between inspections and that 75% of that performance will be recovered, resulting in a 20-year degradation of 4.5%. According to the combustion turbine vendor (Alstom Power), typically, performance degradation during the first 36,000 hours (the normally recommended interval for inspection and maintenance) is 2.01% (heat rate degradation) to 2.64% (power output degradation). Alstom also indicated that, depending on the equivalent operating hours (EOH), approximately 28% to 44% of that performance will be recovered and would result in a 20-year degradation of approximately 2.23% and a 25-year degradation of approximately 2.32%. Considering the atmospheric conditions at the project location (e.g., high ambient temperature, humidity, and ~2,200 foot elevation, etc.); FGE has taken a slightly more conservative view of this degradation. FGE projects the potential degradation to be 3.5% between the 36,000 EOH inspections (considerably less than the potential 4.5% stated in the CEC publication) and, assuming a 44% performance recovery, FGE calculated a 20-year degradation of 6%.

*Degradation Margin for the Auxiliary Plant Equipment* - The degradation margin for the auxiliary plant equipment encompasses the HRSGs. This margin accounts for the scaling and corrosion of the boiler tubes over time as well as minor potential fouling of the heating surface of the tubes. Similar to the HRSGs, scaling and corrosion of the condenser tubes will also degrade the heat transfer characteristics, thus degrading the performance of the steam turbine generator. Because combustion turbine degradation accounts for the majority of the performance loss and as well as the large variation in operating parameters (fuels, temperatures, water treatment, cycling conditions, etc.), little operating data has been gathered and published that illustrate a clear performance degradation characteristic for this auxiliary plant equipment.

The following BACT limits are proposed:

| Turbine Model | Gross Heat Rate[1] (Btu/kWh) (HHV) | Output Based Emission Limit (lb $CO_2$/MWh) gross[1] |
|---|---|---|
| Alstom | 7,625 | 889 |

[1]BACT limits apply with or without duct burner firing.

The calculation of the gross heat rate and the equivalent lb $CO_2$/MWh is provided in Tables 7 and 8 of the supplemental information provided by FGE on January 17, 2014. The BACT limit will apply during startup conditions, shutdown and periods of maintenance (MSS will account for no more than 1,460 hours of operation a year). The BACT limit will apply to the turbines during all operational conditions, with and without duct burner firing. FGETP shall meet the BACT limit on a 12-month rolling average. Each combined MSS event is expected to not exceed 240 minutes (including cold startup and shutdown) during combined cycle operations. MSS events are estimated as follows: 180 minutes for a cold startup, 151 minutes for a warm startup, 56 minutes for a hot startup, and 60 minutes for a shutdown. The MSS emissions will also have a per event emission limit of 48 tons $CO_2$/hr during startup, 1,735 lb $CH_4$ per startup, 192 tons $CO_2$/hr during shutdown, and 510 lb $CH_4$ per shutdown.

Since the plant heat rate varies according to turbine operating load and amount of duct burner firing, FGETP proposes to demonstrate compliance with the proposed heat rate with an annual compliance test at 90% load, corrected to ISO conditions.

FGETP requested the BACT limit to be expressed in lb $CO_2$/MWh. When converting the BACT limits to tons $CO_2$/MWh, FGETP provides a value of 889 lb $CO_2$/MWh with or without duct burner firing. When compared to other BACT limits established for other combined cycle/heat recovery steam generating units, and when taking into account the mode of operation for the FGE facility, the proposed limits for FGETP are comparable to the limits established for LCRA, Calpine Deer Park, Calpine Channel Energy Center, Pioneer Valley Energy Center, and PacifiCorp Energy Lake Side Power Plant. The differences in BACT limits between La Paloma and LCRA and Cricket Valley Energy Center (CVEC) are related to the net heat rate for the turbines. The net heat rate of the turbines proposed by FGETP is higher than those at LCRA and CVEC. The BACT limit proposed for FGETP is higher than the limit proposed for Pioneer Valley Energy Center (PVEC). PVEC is more likely to operate at base load conditions, whereas FGETP will operate as a load cycling unit. The BACT for FGETP (889 lb $CO_2e$/MWh) is less than that established for both Calpine facilities (920 lb $CO_2e$/MWh).

On January 8, 2014, EPA proposed New Source Performance Standard (NSPS) 40 CFR Part 60 Subpart TTTT (Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, 77 FR 22392) that would control $CO_2$ emissions from new electric generating units (EGUs).[10] The proposed rule would apply to fossil-fuel fired EGUs that generate electricity for sale and are larger than 25 MW. EPA proposed that new EGUs meet an annual average output-based standard of 1,000 lb $CO_2$/MWh, on a gross basis. The proposed emission rate for the FGETP turbines on a gross electrical output basis is 889 lb $CO_2$/MWh with or without duct burner firing. The proposed $CO_2$ emission rates from the FGETP combined cycle turbines are well within the emission limit proposed in the NSPS at 40 CFR Part 60 Subpart TTTT.

The combined cycle combustion turbine unit will be designed with a number of features to improve the overall efficiency. The additional combustion turbine design features include:

- Inlet evaporative cooling to utilize water to cool the inlet air, thereby increasing the turbine's efficiency;

[10] Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, 79 Fed Reg 1430, January 8, 2014. Available at http://www.gpo.gov/fdsys/pkg/FR-2014-01-08/pdf/2013-28668.pdf

- Periodic burner tuning as part of a regularly scheduled maintenance program to help ensure more reliable operation of the unit and to maintain optimal efficiency;
- A Distributed Control System will control all aspects of the turbine's operation, including fuel feed and burner operations, to achieve optimal high-efficiency, low-emission performance for full-load and partial-load conditions;
- Insulation blankets are utilized to minimize the heat loss through the combustion turbine shell and help improve the overall efficiency of the machine; and
- Totally enclosed water to air cooling or hydrogen cooling will be used to cool the generators resulting in a lower electrical loss and higher unit efficiency.

The HRSG energy efficiency processes, practices, and designs considered include:

- Energy efficient heat exchanger design, including each pressure level incorporating an economizer section(s), evaporator section, and superheater section(s);
- Addition of insulation to the HRSG panels, high-temperature steam and water lines and to the bottom portion of the stack;
- Filtration of the inlet air to the combustion turbine and periodic cleaning of the tubes to minimize fouling; and
- Minimization of steam vents and repair of steam leaks.

Within the combined-cycle power plant, several plant-wide, overall energy efficiency processes, practices and designs are included as BACT requirements, because the additional operating conditions/practices help maintain the efficiency of the turbine. The requirements include:

- Multiple combustion turbine/HRSG trains. Multiple combustion turbine/HRSG trains help with part-load operation. A higher overall plant part-load efficiency is achieved by shutting down trains operating at less efficient part-load conditions and ramping up the remaining train(s) to high-efficiency full-load operation; and
- Cooling Towers. A closed-loop design, which includes a cooling tower to cool the water, will be utilized for the project. Closed-loop designs are either natural circulation or forced circulation. Both natural circulation and forced circulation designs require higher cooling water pump heads; therefore, increasing the pump's power consumption and reducing overall plant efficiency. Additionally, to provide the forced circulation, fans are used for the forced circulation designs, which consume additional auxiliary power and reduce the plant's efficiency.

FGE will demonstrate compliance with the $CO_2$ limit established as BACT by the use of a $CO_2$ continuous emission monitoring system (CEMS) and also by recording the heat input to and the net power output from the generating station to demonstrate on an ongoing basis the 7,625 Btu/kWh GHG BACT limit. FGE shall install, calibrate, and operate the $CO_2$ CEMS and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording $CO_2$ emissions. To demonstrate compliance with the $CO_2$ BACT limit using $CO_2$ CEMS, the measured hourly $CO_2$ emissions are divided by the net hourly energy output and averaged daily. For any period of time that the $CO_2$ CEMS is nonfunctional, FGE shall use the methods and procedures outlined in the Missing Data Substitution Procedures as specified in 40 CFR Part 75, Subpart D.

FGE will determine a site-specific Fc factor using the ultimate analysis and GCV in equation F-7b of 40 CFR Part 75, Appendix F. The site-specific Fc factor will be re-determined annually in accordance with 40 CFR Part 75, Appendix F § 3.3.6.

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

- Fuel flow meter shall meet an accuracy of 2.0% and is required to be tested once each calendar quarter pursuant to 40 CFR Part 75, Appendix D § 2.1.5 and 2.1.6(a).
- Gross Calorific Value (GCV) of pipeline natural gas shall be determined at least once per calendar month pursuant to 40 CFR Part 75, Appendix D § 2.3.4.1

This approach is consistent with the $CO_2$ reporting requirements of 40 CFR Part 98, Subpart D (Mandatory GHG Reporting Rule for Electricity Generation). The $CO_2$ monitoring method proposed by FGE is consistent with the recently proposed NSPS, Subpart TTTT (40 CFR 60.5535(c)), which allows for EGUs firing gaseous fuel to determine $CO_2$ mass emissions by monitoring fuel combusted in the affected EGU and using a site specific Fc factor determined in accordance to 40 CFR Part 75, Appendix F.

The emission limits associated with $CH_4$ and $N_2O$ are calculated based on emission factors provided in 40 CFR Part 98, Subpart C, Table C-2, fuel usage, and the actual heat input (HHV). Comparatively, $CO_2$ emissions contribute the most volume (greater than 99%) to the overall emissions from the combined cycle combustion turbines; therefore, 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 shall be required to be kept to demonstrate compliance with the emission limits on a 12-month rolling total.

An initial stack test demonstration will be required for $CO_2$ emissions from GT-1, GT-2, GT-3, and GT-4. FGE proposes to demonstrate compliance with the proposed heat rate with an annual compliance test at 90% load, corrected to ISO conditions. An initial stack test demonstration for $CH_4$ and $N_2O$ emissions is not required because the $CH_4$ and $N_2O$ emissions comprise approximately 0.01% of the total $CO_2e$ emissions from the combustion turbines.

## X. Emergency Engines (EG-1, EG-2, FWP-1, and FWP-2)

The FGETP site will be equipped with two nominally rated 900-hp diesel-fired emergency generators to provide electricity to the facility in the case of power failure and two nominally rated 389-hp diesel-fired pumps to provide water in the event of a fire.

**Step 1 –** Identification of Potential Control Technologies

- *Low Carbon Fuels* – Engine options include engines powered by electricity, natural gas, or liquid fuel, such as gasoline or fuel oil.
- *Good Combustion Practices and Maintenance* – Good combustion practices include appropriate maintenance of equipment, such as periodic readiness testing, and operating within the recommended air to fuel ratio recommended by the manufacturer.
- *Low Annual Capacity Factor* – Limiting the hours of operation reduces the emissions produced. Each emergency engine will be limited to 52 hours of operation per year for purposes of maintenance checks and readiness testing.

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

- *Low Carbon Fuels* – The purpose of the engines is to provide a power source during emergencies, which includes outages of the combustion turbines, natural gas supply outages, and natural disasters. Electricity and natural gas may not be available during an emergency and, therefore, cannot be relied on as an energy source for the emergency engines and are eliminated as technically infeasible for this use at this facility. The engines must be powered by a liquid fuel that can be stored on-site in a tank and supplied to the engines on demand, such as gasoline or diesel. The default $CO_2$ emission factors for gasoline and diesel are very similar, 70.22 kg/MMBtu and 73.96 kg/MMBtu respectively; however, gasoline has a higher volatility than and cannot be stored for as long as diesel fuel. Due to the need to store the emergency equipment fuel on site and the ability to store diesel for longer periods of time than gasoline, it is technically infeasible to utilize gasoline as a lower-carbon fuel for this use at this facility.
- *Good Combustion Practices and Maintenance* – Technically feasible.

- *Low Annual Capacity Factor* – Technically feasible since the engines will only be operated either for readiness testing or for actual emergencies.

**Step 3 –** Ranking of Remaining Technologies Based on Effectiveness

Since the remaining technically feasible processes, practices, and designs in Step 1 are being proposed for the engines, a ranking of the control technologies is not necessary.

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

Since the remaining technically feasible processes, practices, and designs in Step 1 are being proposed for the engines, an evaluation of the most effective controls is not necessary.

**Step 5 –** Selection of BACT

The following specific BACT practices are proposed for the diesel-fired emergency generators:

- *Good Combustion Practices and Maintenance* – Good combustion practices for compression ignition engines include appropriate maintenance of equipment, periodic testing conducted weekly, and operating within the recommended air to fuel ratio, as specified by the manufacturer.
- *Low Annual Capacity Factor* – Each emergency engine will not be operated more than 52 hours per year. Emergency engines will only be operated for maintenance and readiness testing and in actual emergency operation.

Using the BACT practices identified above results in an emission limit of 27 tpy $CO_2e$ for each of the Emergency Generators (EPNs: EG-1 and EG-2) and 12 tpy $CO_2e$ for each of the Fire Water Pumps (EPNs: FWP-1 and FWP-2). FGE will demonstrate compliance with the $CO_2$ emission limit using the default emission factor and default high heating value for diesel fuel from 40 CFR Part 98, Subpart C, Table C-1. The equation for estimating $CO_2$ emissions as specified in 40 CFR § 98.33(a)(3)(iii) is as follows:

$$CO_2 = 1 \times 10^{-3} * Fuel * HHV * EF * 1.102311$$

Where:
$CO_2$ = Annual $CO_2$ mass emissions from combustion of diesel fuel (short tons)
Fuel = Mass or volume of fuel combusted per year, from company records.
HHV = Default high heat value of the fuel, from Table C-1 of 40 CFR Part 98, Subpart C.

EF = Fuel specific default $CO_2$ emission factor, from Table C-1 of 40 CFR Part 98 Subpart C.
$1 \times 10^{-3}$ = Conversion of kg to metric tons.
1.102311 = Conversion of metric tons to short tons.

As BACT for the engines is focused on reductions in GHGs through reductions in fuel usage, the reductions in fuel use conferred by the $CO_2$ emission limits will also lead to a reduction of, and thus act as a surrogate for limitations on, $CH_4$ and $N_2O$.

## XI. Natural Gas Fugitive Emissions (NG-FUG)

The proposed project will include natural gas piping components. These components are potential sources of $CH_4$ emissions due to emissions from rotary shaft seals, connection interfaces, valve stems, and similar points. The additional $CH_4$ emissions from process fugitives have been conservatively estimated to be 418 tpy as $CO_2$e. Fugitive emissions are negligible, and account for less than 0.01% of the project's total $CO_2$e emissions.

**Step 1 –** Identification of Potential Control Technologies for GHGs

- *Implementing a leak detection and repair (LDAR) program using a handheld analyzer;*
- *Implement alternative monitoring using a remote sensing technology such as infrared camera monitoring; and*
- *Implementing an auditory/visual/olfactory (AVO) monitoring program.*

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

LDAR programs are a technically feasible option for controlling process fugitive GHG emissions. Remote sensing is a technically feasible option. Since pipeline natural gas is odorized with a small amount of mercaptan, an AVO detection plan for natural gas piping fugitives is technically feasible.

**Step 3 –** Ranking of Remaining Technologies Based on Effectiveness

Instrument LDAR programs and remote sensing using an infrared camera have been determined by EPA to be equivalent methods of piping fugitive controls.[11] The use of an LDAR program with a portable gas analyzer meeting the requirements of 40 CFR Part 60, Appendix A, Method 21 can be effective for identifying leaking methane. Quarterly instrument monitoring with a leak definition of 10,000 ppmv (TCEQ 28M LDAR Program) is generally assigned a control efficiency of 75% for valves, relief valves,

[11] 73 FR 78199, December 22, 2008.

sampling connections, and compressors, and 30% for flanges. Quarterly instrument monitoring with a leak definition of 500 ppmv (TCEQ 28VHP LDAR Program) is generally assigned a control efficiency of 97% for valves, relief valves, and sampling connections, 85% for compressors, and 30% for flanges. EPA has allowed the use of an optical gas imaging instrument as an alternative work practice for a Method 21 portable analyzer for monitoring equipment for leaks in 40 CFR § 60.18(g). For components containing inorganic or odorous compounds, periodic AVO walk-through inspections provide predicted control efficiencies of 97% control for valves, flanges, relief valves, and sampling connections, and 95% for compressors.[12]

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

Although instrument LDAR and/or remote sensing of piping fugitive emissions in natural gas service may be somewhat more effective than as-observed AVO methods, the incremental GHG emissions controlled by implementation of the TCEQ 28LAER LDAR program or a comparable remote sensing program is less than 0.01% of the total project's proposed $CO_2e$ emissions. Accordingly, given the costs of implementing 28LAER 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. The frequency of inspection and the low odor threshold of mercaptans in natural gas make AVO inspections an effective means of detecting leaking components in natural gas service. As discussed in Step 3, the predicted emission control efficiency is comparable to the LDAR programs using Method 21 portable analyzers.

**Step 5 –** Selection of BACT

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

Based on the economic impracticability of instrument monitoring and remote sensing for natural gas piping components, EPA proposes to incorporate as-observed AVO as BACT

[12] TCEQ – Control Efficiencies for TCEQ Leak Detection and Repair Programs (revised July 2011). Available at: http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/control_eff.pdf. Accessed March 2014.

for the piping components in the new combined cycle power plant in natural gas service. The proposed permit contains a condition to implement AVO inspections on a daily basis.

## XII. $SF_6$ Insulated Electrical Equipment (SF6-FUG)

The generator circuit breakers associated with the proposed units will be insulated with $SF_6$. The capacity of the circuit breakers associated with the proposed plant is currently estimated to be 462 lb of $SF_6$.

**Step 1 –** Identification of Potential Control Technologies for GHGs

In determining whether a technology is available for controlling and reducing $SF_6$ emissions from circuit breakers, permits and permit applications and EPA's RBLC were consulted. In addition, currently available literature was reviewed to identify emission reduction methods.[13,14,15] Based on these resources, the following available control technologies were identified:

- Use of new and state-of-the-art circuit breakers that are gas-tight and require less s$SF_6$.
- Evaluating alternate substances to $SF_6$ (e.g., oil or air blast circuit breakers).
- Implementing an LDAR program to identify and repair leaks and leaking equipment as quickly as possible.
- Systematic operations tracking, including cylinder management and $SF_6$ gas recycling cart use.
- Educating and training employees onabout proper $SF_6$ handling methods and maintenance operations.

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

Of the control technologies identified above, only substitution of $SF_6$ with another non-GHG substance is determined as technically infeasible. Though dielectric oil or compressed air circuit breakers have been used historically, these units require large equipment components to achieve the same insulating capabilities of $SF_6$ circuit breakers. In addition, per an EPA report, "no clear alternative exists for this gas that is used

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[13] Robert Mueller. *10 Steps to Help Reduce SF6 Emissions in T&D.* Airgas Inc. Available at: http://www.airgas.com/documents/pdf/50170-120.pdf.

[14] U.S. EPA. 2008. *SF6 Emission Reduction Partnership for Electric Power Systems 2007 Annual Report.* Available at: http://www.epa.gov/electricpower-sf6/documents/sf6_2007_ann_report.pdf.

[15] J. Blackman (U.S. EPA, Program Manager, $SF_6$ Emission Reduction Partnership for Electric Power Systems), M. Averyt (ICF Consulting), and Z. Taylor (ICF Consulting). 2006. *$SF_6$ Leak Rates from High Voltage Circuit Breakers – U.S. EPA Investigates Greenhouse Gas Emissions Source*. Available at: http://www.epa.gov/electricpower-sf6/documents/leakrates_ circuitbreakers.pdf.

extensively in circuit breakers, gas-insulated substations, and switch gear, due to its inertness and dielectric properties."[16] According to the report NTIS Technical Note 1425, $SF_6$ is a superior dielectric gas for nearly all high voltage applications.[17] It is easy to use, exhibits exceptional insulation and arc-interruption properties, and has proven its performance through 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."

**Step 3 –** Ranking of Remaining Technologies Based on Effectiveness

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 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

Energy, environmental, or economic impacts are not addressed because the use of the highest ranked remaining control technology – state-of-the-art $SF_6$ technology with leak detection – is being proposed to limit fugitive emissions from the circuit breakers.

**Step 5 –** Selection of BACT

EPA concludes that using state-of-the-art enclosed-pressure $SF_6$ circuit breakers with leak detection as 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.[18] 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.

FGETP will monitor emissions annually in accordance with the requirements of the Mandatory Greenhouse Gas Reporting rules for Electrical Transmissions and Distribution

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[16] U.S. Environmental Protection Agency. 2008. *$SF_6$ Emission Reduction Partnership for Electric Power Systems 2007 Annual Report*. Available at: http://www.epa.gov/electricpower-sf6/documents/sf6_2007_ann_report.pdf.

[17] Chrsitophorous, L.G., J.K. Olthoff, and D.S. Green. 1997. *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF6*. NIST Technical Note 1425.

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

Equipment Use.[19] Annual $SF_6$ emissions will be calculated according to the mass balance approach in Equation DD-1 of 40 CFR Part 98, Subpart DD.

FGE will implement the following work practices as $SF_6$ BACT:

- Use of state-of-the-art circuit breakers that are gas-tight and guaranteed to achieve a leak rate of 0.5% by year by weight or less (the current maximum leak rate standard established by the International Electrotechnical Commission);
- An LDAR program to identify and repair leaks and leaking equipment as quickly as possible;
- Systematic operations tracking, including cylinder management and $SF_6$ gas recycling cart use; and
- Educating and training employees with proper SF6 handling methods and maintenance operations

## 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.

To meet the requirements of Section 7, EPA is relying on a Biological Assessment (BA) prepared by the applicant, FGE Power, LLC and its consultant, SWCA Environmental Consultants, and adopted by EPA.

A draft BA has identified six (6) species listed as federally endangered or threatened in Mitchell County, Texas:

| **Federally Listed Species for Mitchell County** by the U.S. Fish and Wildlife Service (USFWS) and the Texas Parks and Wildlife Department (TPWD) | **Scientific Name** |
|---|---|
| **Birds** | |
| Black-capped vireo | *Vireo atricapilla* |
| Interior least tern | *Sterna anillarum alhalossos* |
| Whooping Crane | *Grus americana* |
| **Flowering Plants** | |
| Texas poppy mallow | *Callirhoe scabriuscula* |

[19] See 40 CFR Part 98 Subpart DD.

| **Federally Listed Species for Mitchell County** by the U.S. Fish and Wildlife Service (USFWS) and the Texas Parks and Wildlife Department (TPWD) | **Scientific Name** |
|---|---|
| **Mammals** | |
| Black footed ferret | *Mustela nigripes* |
| Gray wolf | *Rufus lupus* |

EPA has determined that issuance of the proposed permit will have no effect on any of the six (6) 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 for the six species because they are not expected to occur in the geographical, 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.

## XIV. National Historic Preservation Act (NHPA)

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 and pipeline addendum prepared by SWCA Environmental Consultants, Inc, submitted in February 2014.

For purposes of the NHPA review, the Area of Potential Effect (APE) was determined to be location of the proposed natural gas combined cycle combustion turbine electrical generating station. SWCA Environmental Consultants 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, including shovel testing, within the APE, no cultural resources were recorded at the location of the proposed natural gas combined cycle combustion turbine electrical generating station. Based on the desktop review, no cultural resources were identified within 1-mile of the APE. However, two historic markers for the former Conway School 540 meters south of the proposed facility were identified but the school was dismantled in 1947. Secondly, a farmstead was located with 11 structures was located about 0.85 miles northeast of the project area. The farmstead is recommended as not eligible for listing based on the poor condition of the structures.

For purposes of the NHPA review, the Area of Potential Effect (APE) was determined to be approximately 386.5 acres of land that includes 339 acres of the site facility that contains the construction footprint of the project, 46 acres for a 3.8-mile long pipeline corridor with 100 feet right-of-way, and 1.5 acres for 900 feet of a proposed water discharge line associated with this project. Following consultation with the State Historic Preservation Officer (SHPO), SWCA conducted a field survey of the APE and a desktop review on the archaeological background and historical records within a 1.0-mile radius APE which included a review of the Texas Historical Commission's online Texas Archaeological Site Atlas (TASA) and the National Park Service's National Register of Historic Places (NRHP) were done.

Based on the desktop review for the site facility and the linear facilities, Spindletop Oil Field, which is listed in the NHRP and also listed as a National Historic Landmark (NHL), is located 0.92 miles from the project area. Numerous surveys have been performed within the Spindletop property and at least seven cultural surveys were previously conducted within a 1-mile radius of the APE. Ten historic sites associated with Spindletop Oil Field were identified and were located within 1 mile of the APE; two of those sites are within the APE along the proposed 3.8-mile long pipeline corridor. Both of those sites located within the APE did not meet the any criteria for NHRP listing and were therefore were not recommended to be eligible for listing on the National Register. Eleven other historic or archaeological sites were identified from previous reports, all of which are outside of the APE. Based on the results of the field survey, which included 223 shovel tests, of the site facility, water discharge pipeline and pipeline corridor, no intact archaeological resources or historic structures were found.

With regard to the linear facilities, 291 shovel tests along the gas pipeline and a total of five isolated finds were also recorded (four prehistoric and one historic), which investigations determined were not associated with an archaeological site. Due to the potential for deeply buried cultural deposits in the area immediately south of Beals Creek, FGE plans to cross this area using an above ground pipeline for a distance of 300 m, thus avoiding impacts. If future construction occurs immediately south of Beals Creek that differs from the currently proposed project then further investigations are recommended; specifically, deep, mechanical excavation (e.g., backhoe trenching) to determine the presence/absence of deeply buried cultural deposits. With this stipulation, SWCA recommends that a determination of *No Historic Properties Affected* be granted for the project to proceed as planned

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 FGE Power will not affect properties potentially eligible for listing on the National Register.

On February 24, 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.

## XV. 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 GHG. 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.

## XVI. Conclusion and Proposed Action

Based on the information supplied by FGE, our review of the analyses contained 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 FGE 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 A**

Annual Emission Limits

Annual emissions, in tons per year (TPY) on a 12-month rolling total, shall not exceed the following:

**Table 1. Annual Emission Limits[1]**

| FIN | EPN | Description | GHG Mass Basis | | TPY $CO_2e$[3] | BACT Requirements |
|---|---|---|---|---|---|---|
| | | | | TPY[2] | | |
| GT-1 | GT-1 | CT Combined Cycle | $CO_2$ | 1,459,718 | 1,472,228 | 889 lb $CO_2$/MWh (gross) on a 12-month rolling average per turbine. Special Condition III.A.1. and Table 2.<br><br>Startup Emissions – 48 tons $CO_2$/hour per turbine and 1,735 lbs $CH_4$/event per turbine.<br><br>Shutdown Emissions - 192 tons $CO_2$/hour per turbine and 510 lbs $CH_4$/event per turbine.<br><br>MSS Emissions - Special Condition III.A.4. and Table 3. |
| | | | $CH_4$ | 469.44 | | |
| | | | $N_2O$ | 2.6 | | |
| GT-2 | GT-2 | CT Combined Cycle | $CO_2$ | 1,459,718 | 1,472,228 | |
| | | | $CH_4$ | 469.44 | | |
| | | | $N_2O$ | 2.6 | | |
| GT-3 | GT-3 | CT Combined Cycle | $CO_2$ | 1,459,718 | 1,472,228 | |
| | | | $CH_4$ | 469.44 | | |
| | | | $N_2O$ | 2.6 | | |
| GT-4 | GT-4 | CT Combined Cycle | $CO_2$ | 1,459,718 | 1,472,228 | |
| | | | $CH_4$ | 469.44 | | |
| | | | $N_2O$ | 2.6 | | |
| FWP-1 | FWP-1 | Firewater Pump | $CO_2$ | 11.55 | 11.59 | Good Combustion and Operating Practices<br><br>Limit to 52 hr/yr - Special Condition III.B.2. |
| | | | $CH_4$ | No Emission Limit Established[4] | | |
| | | | $N_2O$ | No Emission Limit Established[4] | | |
| FWP-2 | FWP-2 | Firewater Pump | $CO_2$ | 11.55 | 11.59 | Good Combustion and Operating Practices<br><br>Limit to 52 hr/yr - Special Condition III.B.2. |
| | | | $CH_4$ | No Emission Limit Established[4] | | |
| | | | $N_2O$ | No Emission Limit Established[4] | | |
| EG-1 | EG-1 | Emergency Generator | $CO_2$ | 26.71 | 26.82 | Good Combustion and Operating Practices<br><br>Limit to 52 hr/yr - Special Condition III.B.2. |
| | | | $CH_4$ | No Emission Limit Established[4] | | |
| | | | $N_2O$ | No Emission Limit Established[4] | | |

| FIN | EPN | Description | GHG Mass Basis | | TPY $CO_2e$[3] | BACT Requirements |
|---|---|---|---|---|---|---|
| | | | | TPY[2] | | |
| EG-2 | EG-2 | Emergency Generator | $CO_2$ | 26.71 | 26.82 | Good Combustion and Operating Practices<br><br>Limit to 52 hr/yr - Special Condition III.B.2. |
| | | | $CH_4$ | No Emission Limit Established[4] | | |
| | | | $N_2O$ | No Emission Limit Established[4] | | |
| FUG-NGAS | FUG-NGAS | Natural Gas Fugitives | $CO_2$ | No Emission Limit Established[5] | No Emission Limit Established[5] | AVO monitoring - Special Condition III.C.1. |
| | | | $CH_4$ | No Emission Limit Established[5] | | |
| FUG-SF6 | FUG-SF6 | Electric Equipment Fugitives | $SF_6$ | No Emission Limit Established[6] | No Emission Limit Established[6] | Instrument monitoring and alarm system - Special Condition III.C.3. |
| **Totals**[7] | | | **$CO_2$** | 5,838,948 | 5,889,434 | |
| | | | **$CH_4$** | 1,894 | | |
| | | | **$N_2O$** | 10.40 | | |
| | | | **$SF_6$** | 0.0012 | | |

1. Compliance with the annual emission limits (tons per year) is based on a 12-month rolling total, to be updated the last day of the following month.
2. The TPY GHG Mass Basis values are for informational purposes only and do not constitute an emission limit.
3. The TPY emission limits specified in this table shall not to be exceeded for this facility and include emissions from the facility during all operations including MSS activities.
4. Global Warming Potentials (GWP): $CH_4$ = 25, $N_2O$ = 298, $SF_6$ = 22,800
5. These values 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 process emissions from EPN FUG are estimated to be 16.64 TPY of $CH_{4,}$ 0.08 TPY $CO_2$, and 418 TPY $CO_2e$. Fugitive process emission totals are for information only and do not constitute an emission limit. The emission limit will be a design/work practice standard as specified in the permit.
7. $SF_6$ emissions from EPN FUG-SF6 are estimated to be 0.0012 TPY $SF_6$ and 26.4 TPY $CO_2e$. Fugitive process emission totals are for information only and do not constitute an emission limit. The emission limit will be a design/work practice standard as specified in the permit.
8. The total emissions for $CH_4$ and $CO_2e$ include the PTE for process fugitive emissions of $CH_{4.}$ Total emissions are for information only and do not constitute an emission limit.

## Appendix B

**FGE Texas Project**
**GHG BACT Analysis**
**Conceptual Carbon Capture and Sequestration Cost Estimate (Updated: 03/09/14)**

| **Post-Combustion $CO_2$ Capture and Compression Equipment** | | |
|---|---|---|
| Plant Output (kW) [1] = | | 1,621,462 |
| Total Heat Input, HHV (mmBtu/hr) [1] = | | 10,786 |
| $CO_2$ Captured [2] | | 3,919,629 |
| | *Capture and Compression Cost Breakdown* | |
| Capital [3] | \$878.84/kW | \$1,425,005,664 |
| Annual O&M (Fixed) [3] | \$22.61/kW | \$36,661,256 |
| Annual O&M (Variable) [3] | \$0.0014/kWh | \$18,160,374 |
| Total Annual O&M Costs | Fixed + Variable | \$54,821,630 |
| Annual Fuel [4] | 14.7% fuel use at \$2.77/mmBtu | \$38,473,494 |

| **$CO_2$ Transport --- Pipeline Cost Breakdown [5]** | | |
|---|---|---|
| L, Pipeline Length (miles) = | | 100 |
| D, Pipeline Diameter (inches) = | | 10 |
| | *Pipeline Costs* | |
| Materials | \$70,350 + \$2.01 x L x (330.5 x $D^2$ + 686.7 x D + 26,960) | \$13,512,627 |
| Labor | \$371,850 + \$2.01 x L x (343.2 x $D^2$ + 2,074 x D + 170,013) | \$45,611,523 |
| Miscellaneous | \$147,250 + \$1.55 x L x (8,417 x D + 7,234) | \$14,314,870 |
| Right of Way | \$51,200 + \$1.28 x L x (577 x D + 29,788) | \$4,602,624 |
| | *Other Capital* | |
| $CO_2$ Surge Tank | \$1,244,724 | \$1,244,724 |
| Pipeline Control System | \$111,907 | \$111,907 |
| Total Pipeline Capital Cost [6] | | \$82,574,206 |
| | *O&M* | |
| Fixed O&M (\$/year) | \$8454 x L | \$879,216 |

| **$CO_2$ Transport --- Compression Cost Breakdown** | | |
|---|---|---|
| $CO_2$ Transport (\$/year) [7] | \$3.32 x ton $CO_2$ captured/year | \$13,533,694 |

| **EOR Revenue** | | |
|---|---|---|
| EOR Revenue (\$/year) [8] | \$9.09 x ton $CO_2$ captured/year | \$17,814,713 |

| **Non-EOR/Geologic Storage Costs** | | |
|---|---|---|
| $CO_2$ Storage (\$/year) [7] | \$6.06 x ton $CO_2$ captured/year | \$24,703,069 |

| **Capital Recovery Factor** | |
|---|---|
| % of Project Funded by Equity (%) | 49 |
| % of Project Funded by Debt (%) | 51 |
| Cost of Equity (%) | 20 |
| Cost of Debt (%) | 7 |
| Weighted Cost of Capital (%) [9] | 13.37 |
| Equipment Lifetime (years) | 20 |
| Capital Recovery Factor [10] | 0.1455 |

| **Annualized Cost Estimate** | |
|---|---|
| Total Capital Cost (\$) | \$1,507,579,870 |
| Annualized Capital Cost (\$) [11] | \$219,398,315 |
| Total Annualized Cost - non EOR (\$) | \$351,809,418 |
| Total Annualized Cost - EOR (\$) | \$321,643,171 |
| $CO_2$ Cost Effectiveness - non EOR (\$/ton) | 90 |
| $CO_2$ Cost Effectiveness (\$/ton) - EOR (\$/ton) | 82 |

[1] Alstom turbine performance data represents the maximum value from all normal and LLOC operating scenarios.

[2] For the purposes of the conceptual cost estimate, the tons of $CO_2$ captured is based on the average $CO_2$ emission rate represented by the Alstom turbine performance data during base load conditions (100% Load) operating 8,000 hours with an assumed $CO_2$ capture rate of 85%.

[3] Adapted from *Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous and Natural Gas to Electricity*, DOE/2010/1397 (Revision 2, November 2010). The difference in the plant (\$779/kW) and O&M (fixed = \$20.039/kW and variable = \$0.00124/kWh) costs between Case 14 (NGCC w/ CCS) and Case 13 (NGCC w/o CCS) was used to estimate the capital cost of the CCS capture and compression equipment for the FGE Texas Project. Capital costs adjusted using the U.S. BLS CPI Inflation Calculator from 2007 (\$779/kW) to 2014 dollars (\$878.84/kW) (http://www.bls.gov/data/inflation_calculator.htm). O&M costs adjusted using the U.S. BLS CPI Inflation Calculator from 2007 (\$20.039/kW and \$0.00124/kWh) to 2014 dollars (\$22.61/kW and \$0.0014/kWh).

[4] Fuel costs represent the additional fuel necessary to compensate for parasitic load caused by the addition of CCS. Based on review of the plant heat rates used in Case 13 and 14 presented in Cost and Performance Baseline For Fossil Energy Plants, Volume 1: Bituminous and Natural Gas to Electricity, DOE/2010/1397 (Revision 2, November 2010), CCS imposes a 14.7% increase in the plant heat rate. Therefore, 14.7% more fuel would be necessary to meet the plant output.

[5] Pipeline capital cost and O&M costs based on equations from DOE NETL analysis $CO_2$ Transport, Storage & Monitoring Costs Quality Guidelines for Energy Systems Studies, DOE/NETL-2013/1614 (March 2013) utilizing pipeline length and diameter values. Capital and O&M costs multiplied by 1.04 to convert from 2011 to 2014 dollars (http://www.bls.gov/data/inflation_calculator.htm).

[6] Sum of materials, labor, miscellaneous, right of way, $CO_2$ surge tank, and pipeline control system capital costs, multiplied by 1.04 to convert from 2011 to 2014 dollars (http: //www.bls.gov/data/inflation_calculator.htm).

[7] $CO_2$ transport and storage costs from DOE NETL analysis *CO2 Transport, Storage & Monitoring Costs Quality Guidelines for Energy Systems Studies,* DOE/NETL-2013/1614 (March 2013) using the Texas location, East Texas basin as representative of transport and storage costs. Transport cost for East Texas basin were listed as \$3.65/tonne (\$3.32/ton) in 2011 and storage cost for the East Texas basin were listed at \$6.06/tonne (\$5.51/ton) in 2011. Capital costs multiplied by 1.04 to convert from 2011 to 2014 dollars (http: //www.bls.gov/data/inflation_calculator.htm).

[8] US price from sale of $CO_2$ for Enhanced Oil Recovery (EOR) is \$10-40/tonne (\$9.09/ton-\$36.36/ton) obtained from Global CCS Institute's report, The Global Status of CCS, Chapter 9 – *$CO_2$ Enhanced Oil Recovery as CCS*, Section 9.2 – *Potential role of CO2 EOR in CCS*, page 146 (2012). Once the captured $CO_2$ in the pipeline reaches the oil producers in the nearest EOR markets (100 miles to the west); FGE is uncertain of the ability for existing EOR markets and the availability of other existing pipelines to accept the volume of $CO_2$ produced by the FGE project. Therefore, it has been assumed for the purposes of this calculation that FGE would be able to sell 50% of its captured $CO_2$.
http://cdn.globalccsinstitute.com/sites/default/files/publications/47936/global-status-ccs-2012.pdf

[9] Weighted cost of capital calculated by summing the products of the weighted averages of the different financing components with the cost of the particular financing component.

[10] Capital recovery factor calculated via the following equation:

$$CRF= (i\,[(1+i)]^{n})/([(1+i)]^{n}-1)$$

with:
CFR = capital recovery factor
*i* = weighted cost of capital (interest rate)
*n* = number of years over which project is annualized

[11] Annualized capital cost calculated by multiplying the total capital cost by the capital recovery factor.