Statement of Basis

Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit
for the Golden Spread Electric Cooperative, Inc., Antelope Elk Energy Center

Permit Number: PSD-TX-1358-GHG

April 24, 2014

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

I. Executive Summary

On January 29, 2013, Golden Spread Electric Cooperative, Inc. (GSEC), Antelope Elk Energy Center[1] submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions. In connection with the same proposed project, GSEC submitted a PSD permit application for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on April 1, 2013.

GSEC proposes to construct a gas turbine to expand capacity at an existing power plant (Antelope Elk Energy Center) located near Abernathy, Texas in Hale County. GSEC expects the proposed project to provide power generation support to wind energy resources in a primarily peaking and intermediate power generation operation, maintaining grid stability and meeting load when weather conditions are not conducive to wind energy production. With this proposed project, GSEC plans to construct a natural gas-fired simple cycle turbine GE Model 7F 5 Series and associated equipment, a diesel-fired emergency generator, a gas-fired fuel gas heater, and circuit breakers (not to exceed 2,920 lbs SF_6). For the purposes of this proposed permitting action, GHG emissions are permitted from the turbine, its auxiliary fuel gas heater, the diesel emergency generator engine, fugitive emissions from circuit breakers and natural gas piping, and maintenance, startup, and shut down emissions. The remaining equipment in this project is not considered to be potential GHG emission sources. After reviewing the application and supplemental information provided by GSEC, EPA Region 6 has prepared the following Statement of Basis (SOB) and draft air permit to authorize construction of new GHG air emission sources at the Antelope Elk Energy Center.

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

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

[1] GSEC originally named this plant site Antelope Station. In December 2013, GSEC submitted a Core Data Form to TCEQ to change its name to Antelope Elk Energy Center.

EPA's conclusions rely upon information provided in the permit application, supplemental information requested by EPA and provided by GSEC, and EPA's own technical analysis. The Texas Commission on Environmental Quality (TCEQ) also provided assistance by preparing the draft permit documents. EPA is making all this information available as part of the public record.

II. Applicant

Golden Spread Electric Cooperative, Inc.
Antelope Elk Energy Center
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Amarillo, TX 79105-5898

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Contact:
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III. Permitting Authority

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

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

EPA, Region 6
1445 Ross Avenue
Dallas, TX 75202

The EPA, Region 6 Permit Writer is:
Melanie Magee
Air Permitting Section (6PD-R)
1445 Ross Avenue
Dallas, TX 75202
(214) 665-7161

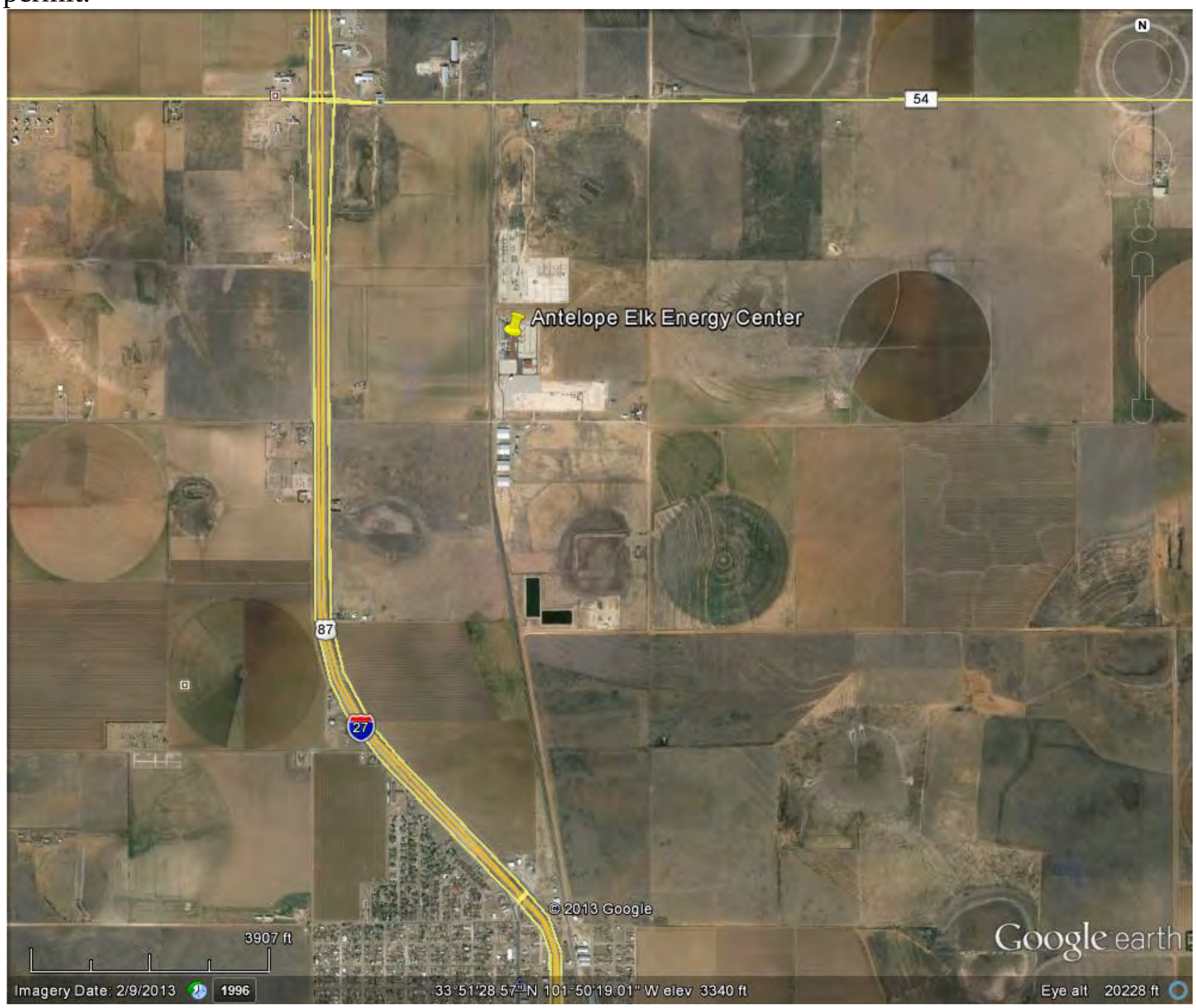
IV. Facility Location

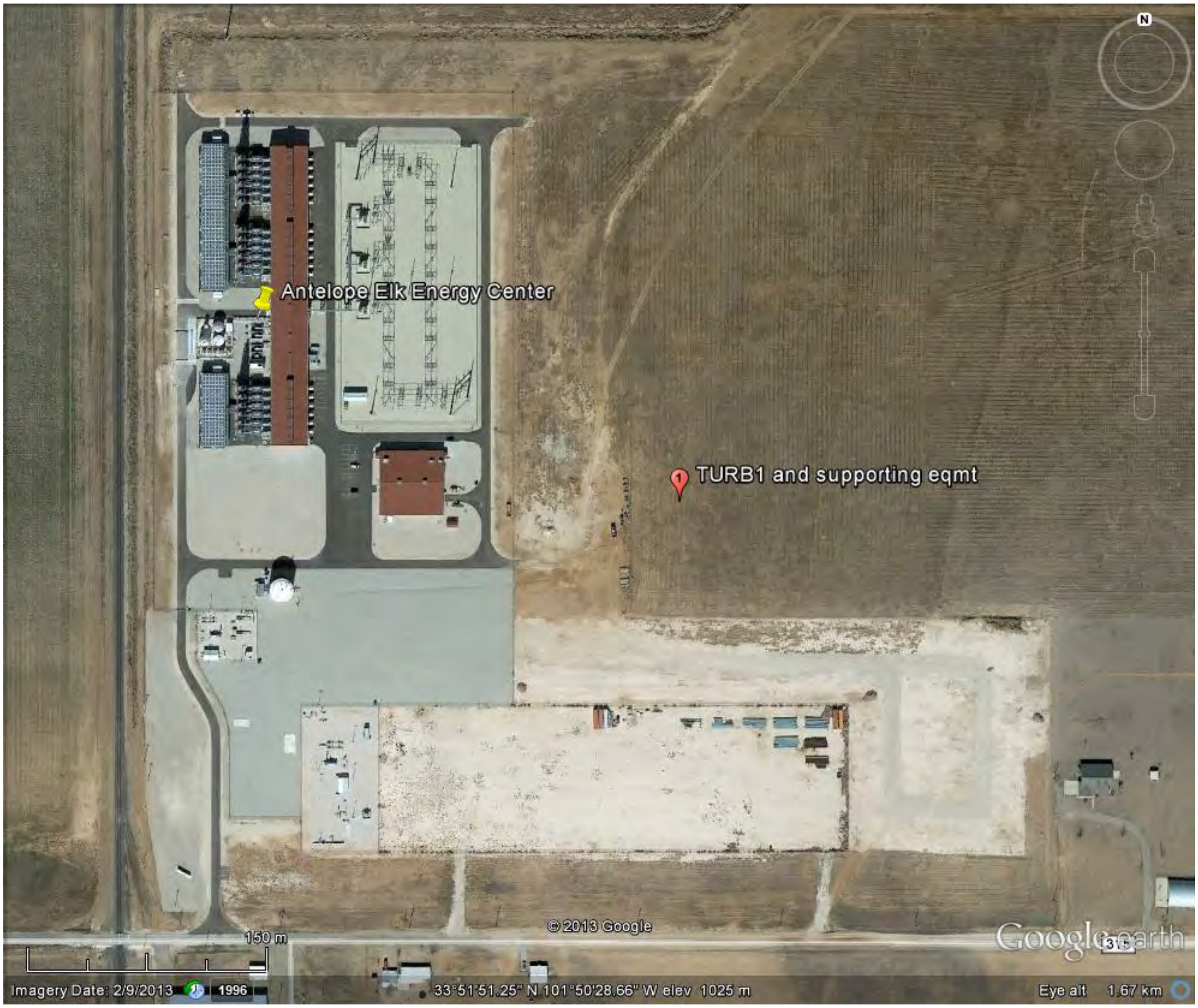
Antelope Elk Energy Center is located in Hale County, Texas. Hale County is currently designated attainment for all criteria pollutants. The Antelope Elk Energy Center expansion is to be located east of existing gas-fired engine generators on an undeveloped tract of land within the property lines of the existing Antelope Elk Energy Center, located east of I-27, north of County Road (CR) 316, and west of CR P approximately 2.3 miles (3.7 km) north of Abernathy, Texas. The nearest Class I area, Salt Creek Wilderness in Chaves County, New Mexico, is located approximately 240 km (150 miles) from the proposed site.

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

Latitude: 33° 51' 56"
Longitude: 101° 50' 37"

The following figures illustrate the Antelope Station facility location and the site layout for this draft permit.




Antelope Elk Energy Center
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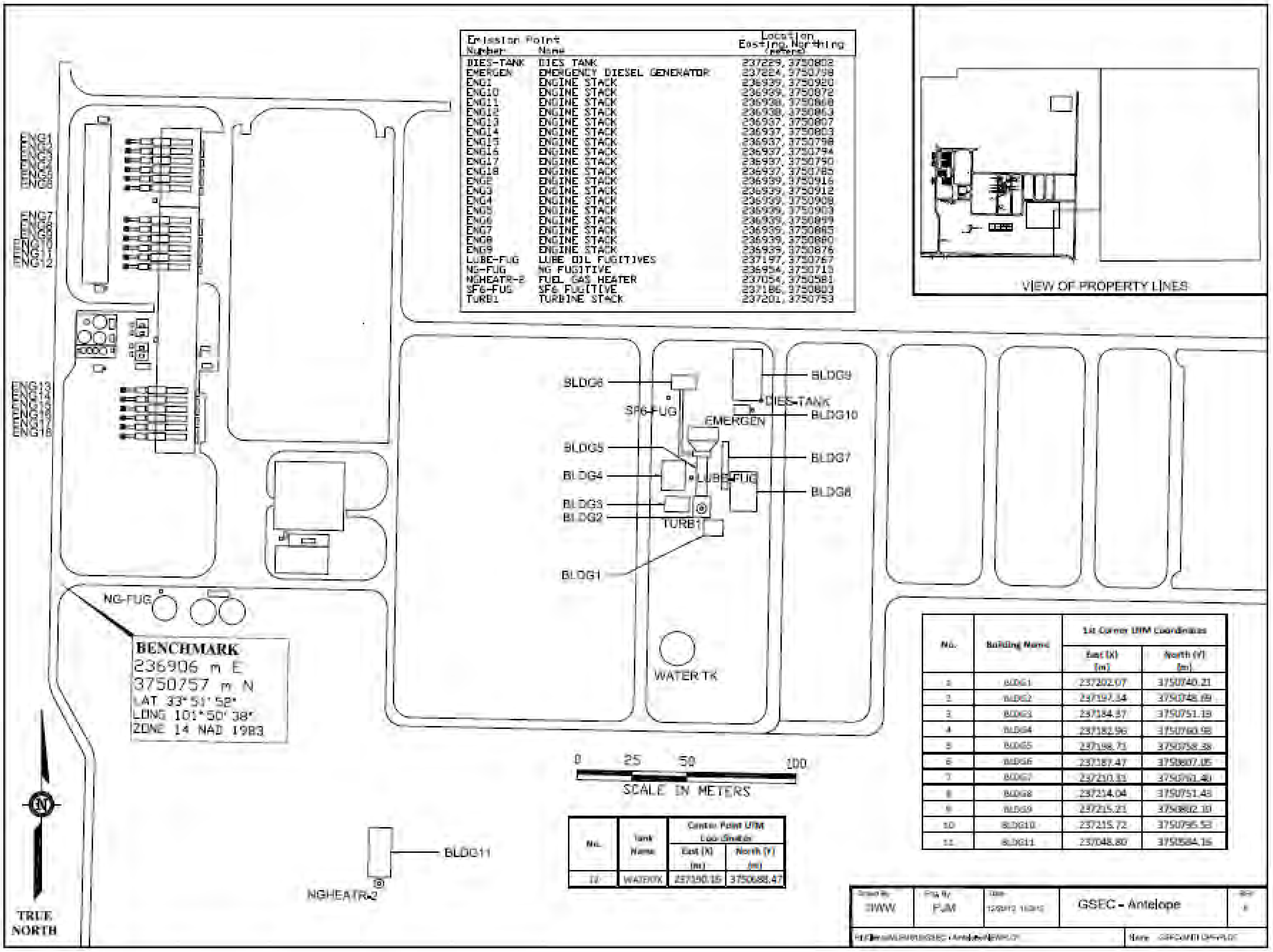


V. Applicability of Prevention of Significant Deterioration (PSD) Regulations

EPA concludes that GSEC's application is subject to PSD review for the pollutant GHGs because the project would lead to an emissions increase of 75,000 tons per year (tpy) carbon dioxide equivalent (CO_2e) as described at 40 CFR § 52.21(b)(49)(iv)(b) and an emissions increase greater than zero tpy on a mass basis as described at 40 CFR § 52.21(b)(23)(ii) (GSEC calculates CO_2e emissions of 540,978 tpy). EPA Region 6 implements a GHG PSD FIP for Texas under the provisions of 40 CFR § 52.21 (except paragraph (a)(1)). See 40 CFR § 52.2305.

As the permitting authority for regulated NSR pollutants that trigger PSD (other than GHGs), TCEQ has determined that the proposed project is subject to PSD review for non-GHG pollutants. TCEQ has determined that the proposed project is subject to PSD review for increases of nitrogen oxides (NO_x), carbon monoxide (CO), particulate matter 10 microns or less (PM_{10}) and particulate matter 2.5 microns or less ($PM_{2.5}$). Accordingly, under the circumstances of this project, the TCEQ will issue the non-GHG portion of the PSD permit and EPA will issue the GHG portion.[2]

[2] *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

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 has determined that compliance with BACT is the best technique that can be employed at present to satisfy additional impacts analysis and Class I area requirements of the rules as they relate to GHGs. We note again, however, that the proposed project will emit regulated NSR pollutants that are non-GHG pollutants, which will be addressed by the PSD permit to be issued by TCEQ.

On January 8, 2014, EPA proposed a revised New Source Performance Standard (NSPS) that could influence the ultimate emission requirements for this source. The definition of BACT in PSD rules at 40 CFR § 52.21(b)(12) states that "in no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60 and 61." Although this facility may be within the source category covered by the proposed NSPS, the proposed NSPS emission limits are not a controlling floor for BACT purposes since the proposed NSPS is not a final action and the proposed standard may change. The NSPS, however, is an independent requirement that will apply to any source subject to the NSPS that commences construction after the date the NSPS is proposed (unless that source is covered by a transitional source exemption adopted in the NSPS). Thus, this facility may ultimately be subject to, and need to comply with, the NSPS after it is finalized, even if the emission limits in the final permit are higher than the NSPS. See EPA,"PSD and Title V Permitting Guidance for Greenhouse Gases" (March 2011) at 25.

VI. Project Description

GSEC is a tax-exempt, consumer-owned public utility organized in 1984 to provide low cost, reliable electric service for its rural distribution cooperative members. Its 16 member systems serve more than 199,000 retail consumers located in the Oklahoma Panhandle and an area covering 24 percent of Texas including the Panhandle, South Plains and Edwards Plateau Regions. Several of Golden Spread's members are located in both the Electric Reliability Council of Texas (ERCOT) and the Southwest Power Pool (SPP).

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

GSEC owns Mustang Station, a 480 MW, gas-fueled, combined cycle generating plant located near

Denver City, Texas, as well as Mustang Station Units 4, 5, and 6, comprised of three 168 MW combustion turbine generators located at the Mustang Station site. GSEC also owns Antelope Elk Energy Center (the site of the current project) which is a 168 MW generating facility comprised of 18 quick start engines[3] located near Abernathy, Texas, and Golden Spread Panhandle Wind Ranch, a 78 MW wind facility made up of 34 wind turbines located near Amarillo, Texas. GSEC also has two 20 year purchased power contracts for over 200 MW of wind in the SPP market. Through its affiliate Fort Concho Gas Storage, Inc., GSEC also owns a gas storage facility near San Angelo, Texas, capable of storing more than two billion cubic feet of natural gas.

Due to concerns about the adequacy of future power reserve margins in West Texas and in other areas in Texas, GSEC is proposing to build a new simple cycle combustion turbine generator. GSEC expects the new facility to provide power generation support to wind energy resources in a primarily peaking and intermediate power generation operation. The proposed simple cycle combustion turbine generator is proposed to operate in a highly cyclical manner and support electricity generation in the SPP and ERCOT regions.[4]

GSEC proposes to construct a new General Electric F class 5 series combustion turbine generator (CTG) with a maximum gross electric power output of approximately 202 MW (nominal). GSEC also proposes to install one diesel-fired emergency generator, one natural gas-fired fuel gas heater, and other auxiliary equipment. GHG emissions will result from the following emission units:

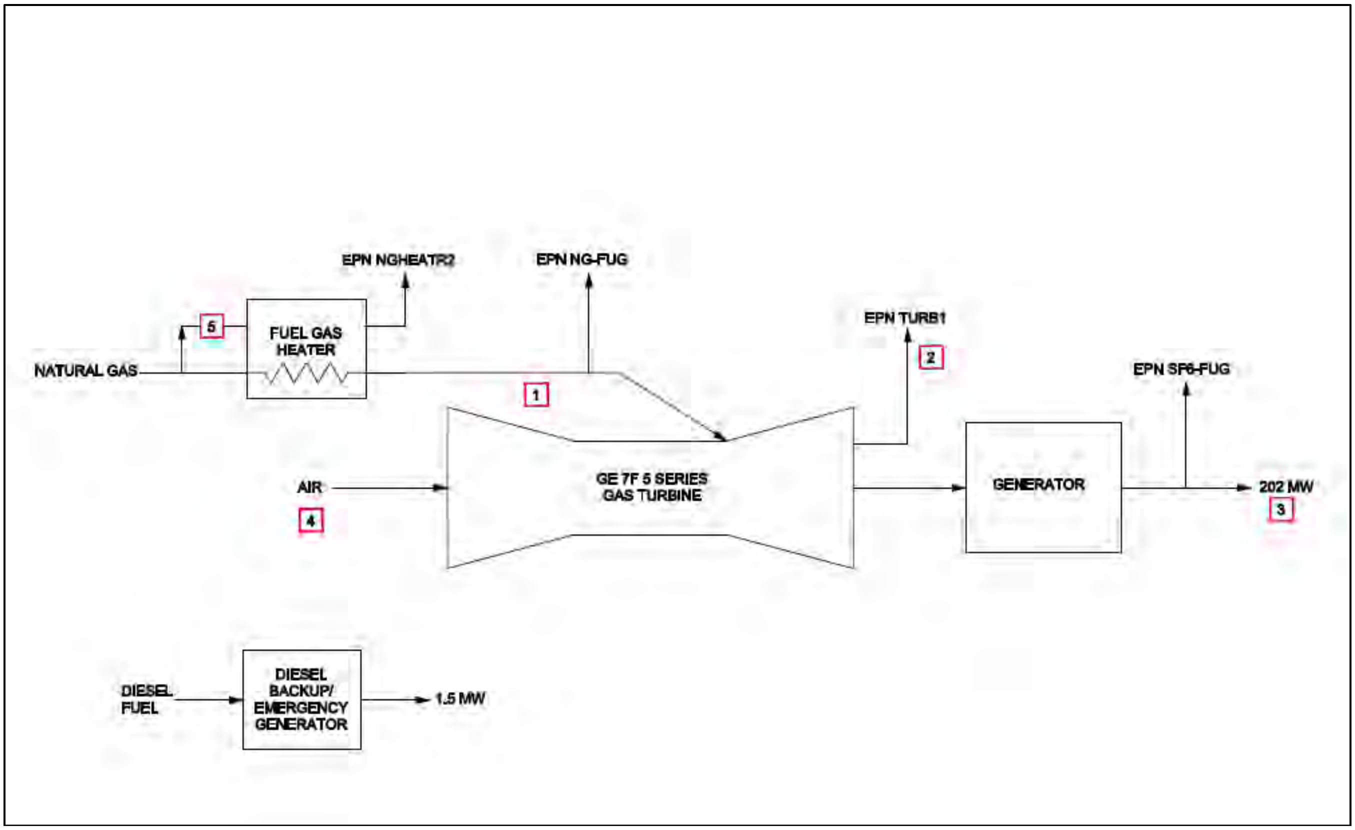
- One Simple Cycle Combustion Turbine (EPN: TURB1);
- One Emergency Generator Engine (EPN: EMERGEN);
- One Fuel Gas Heater (EPN: NGHEATR-2);
- Fugitive Emissions from SF_6 Circuit Breakers (EPN: SF6-FUG); and
- Fugitive Emissions from Piping Components (EPN: NG-FUG).

Process Description and Process Flow Diagram

The following presents a process flow diagram for the simple cycle CTG at Antelope Elk Energy Center. The CTG will burn pipeline natural gas to power an electrical generator to produce electricity. The main components of a CTG consist of a compressor, combustor, turbine, and generator. The compressor pressurizes combustion air to the combustor where the fuel is mixed with the combustion air and burned. Hot exhaust gases then enter the turbine where the gases expand across the turbine blades, driving a shaft to power an electrical generator.

[3] These engines are authorized via 30 Texas Administrative Code, Chapter 116.601-615 through TCEQ Standard Permit 91644.

[4] In 2013, ERCOT and SPP regions experienced peak renewable generation percentages of up to 28% and 23%, respectively. In October 2013, ERCOT released data showing projected installed and planned wind power generation in Texas by the end of 2014 to be 15,290 MW, or 20% of total installed capacity. This growth is not expected to slow down, with installed and planned wind power in Texas predicted to be 16,729 MW by the end of 2016 or 22%. See email from GSEC to EPA, March 26, 2014.



Combustion Turbine Generator – GSEC is proposing to install a new GE 7F 5-Series[5] gas-fired combustion turbine. The turbine will have the potential to generate a nominal 202 MW (maximum in winter conditions) of electricity. Supply air will be compressed by the integral 14-stage compressor. Natural gas fuel will be combusted in GE's Dry Low NO_x (DLN) 2.6+ combustion system and the combustion exhaust gases will power the 3-stage expansion turbine. The turbine is air cooled, and an evaporative air cooler and/or chiller is also used for inlet air cooling during summer peak ambient air temperatures.

The proposed 7F 5-Series turbine is the latest development of GE's F-class turbine technology, which is used in over 1100 gas turbines worldwide. The 7F 5-Series turbine features a 14-stage compressor with super-finish 3-dimensional airfoils for improved efficiency with less long-term degradation. The 3-stage combustion turbine in the 5-Series features a hot gas path with advanced cooling and sealing technologies to improve efficiency and lower lifecycle costs. A new model-based process control system also improves performance efficiency. As a result, the 7F 5-Series turbine can achieve an efficiency above 38.7%[6] in a simple cycle application. The unit can produce up to 202 MW in cold weather conditions, and nominally 190.1 MW in peak summer operation. Compared to other 7F class turbines, the 5-Series turbine also has improvements in start-up and turndown capability, ramp-up rate, and lifecycle costs in peaking, cyclic, and steady-state operation. During normal start-up, the 7F 5-Series turbine will achieve 100% capacity load in 30 minutes, and thereafter operate at design emission limits.

[5] These units were previously designated as 7FA.005 series turbines.
[6] This efficiency is equivalent to a heat rate of 8905 BTU (LHV)/kWh of gross power output, and is guaranteed at 98°F ambient temperatures and 18% relative humidity and other specified operating conditions and parameters.

In 2012, renewable energy resources (other than hydroelectric) accounted for approximately 5 percent of the electricity generated by electric utilities.[7] Due to the current and expected increase in base load wind power generation in both the SPP and ERCOT regions, additional generation resources are required to maintain grid stability and meet load when weather conditions are not conducive to wind energy production. Simple cycle units such as the proposed turbine unit are able to complement and support wind energy production because their fast start capability allows simple cycle turbines to support grid reliability and stability by quickly meeting load demands when wind speeds slow, causing wind generated power to drop off. The turbine is proposed to operate up to 4000 hours per year in normal operation, with another 572 hours in start-up or shut-down mode, including up to 635 turbine start-ups and 635 turbine shut-downs. The number of start-up and shut-down events is largely due to the need to supply both the SPP and the ERCOT power pools.

Diesel-Powered Emergency Generator - The proposed diesel-fired emergency generator (2,205 hp) will produce nominally 1656 kW of back-up power. GSEC proposes to limit the engine to 100 hours per year of non-emergency operation. The engine will meet EPA Tier 2 emission standards.

Natural Gas-Fired Fuel Gas Heater – The proposed natural gas heater is an indirect-fired water bath heater used to heat the natural gas fuel above the dewpoint, which protects the turbine from the condensation from hydrocarbons and moisture. The turbine manufacturer requires that the natural gas fuel have a temperature of at least 50°F above the dewpoints of hydrocarbons and moisture in the inlet gas stream. The proposed heater has a gross firing capacity of 5.5 million BTU (HHV basis) per hour and is proposed to operate up to 4572 hours per year.

Electrical Equipment Insulated with Sulfur Hexafluoride (SF_6) - The circuit breakers associated with the proposed units and associated equipment will be insulated with SF_6. SF_6 is a colorless, odorless, non-flammable, and non-toxic synthetic gas. It is a fluorinated compound that has an extremely stable molecular structure. The unique chemical properties of SF_6 make it an efficient electrical insulator. The gas is used for electrical insulation, arc quenching, and current interruption in high-voltage electrical equipment. SF_6 is only used in sealed and safe systems which under normal circumstances do not leak gas. The total capacity of the circuit breakers associated with the proposed facilities is no more than 2920 lbs SF_6. The proposed circuit breakers will have a low pressure alarm and a low pressure lockout. The alarm will alert personnel of any leakage in the system and the lockout prevents any operation of the breaker due to lack of "quenching and cooling" of SF_6 gas.

Fugitive Emissions from Piping Components - Emissions from piping components (valves and flanges) associated with this project consist of methane (CH_4) and carbon dioxide (CO_2). The CO_2e from fugitive emissions, account for less than 0.016% of the project's total CO_2e emissions.

The gas turbine will exhaust through stack Emission Point Number (EPN) TURB1 and will release both GHG and non-GHG air pollutants. The GHG pollutant sulfur hexafluoride (SF_6) will be released in low-volume leaks from circuit breakers as EPN SF_6-FUG. Leaks from the natural gas supply equipment (EPN NG-FUG) will release mostly GHG emissions but a small amount of non-GHG emissions. The

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

natural gas fired fuel gas heater discharges through EPN NGHEATR-2. An emergency/backup diesel generator discharges through EPN EMERGEN. Non-GHG emissions are not covered in this permit.

VII. General Format of the BACT Analysis

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

(1) Identify all available control options;
(2) Eliminate technically infeasible control options;
(3) Rank remaining control options;
(4) Evaluate the most effective controls (taking into account the energy, environmental, and economic impacts) and document the results; and
(5) Select BACT.

As part of the PSD review, GSEC provided in the GHG permit application a five-step top-down BACT analysis for the emission units covered by the proposed GHG PSD permit. EPA has reviewed GSEC's BACT analysis for the applicable emission units, which has been incorporated into this SOB, and also provides its own analysis in setting forth BACT for this proposed permit, as summarized below.

VIII. Applicable Emission Units and BACT Discussion

The majority of the GHG emissions associated with the project are from the simple cycle combustion turbine. In comparison to the combustion turbine, the emergency generator and natural gas fired fuel gas heater have a small amount of GHG emissions. The project also includes fugitive emissions from piping components and circuit breakers, which contribute an insignificant amount of GHGs. These stationary combustion sources primarily emit carbon dioxide (CO_2) and small amounts of nitrous oxide (N_2O), methane (CH_4) and sulfur hexafluoride (SF_6). The following emission units are subject to this GHG PSD Permit:

- Natural Gas Fired-Simple Cycle Turbine (EPN: TURB1)
- Emergency Diesel Generator (EPN: EMERGEN)
- Natural Gas Fired Fuel Gas Heater (EPN: NGHEATR-2)
- Fugitive SF6 Circuit Breaker Emissions (EPN: SF6-FUG)
- Components Fugitive Leak Emissions (EPN: NG-FUG)

IX. Natural Gas Fired Simple Cycle Combustion Turbine BACT Analysis (EPN: TURB1)

Step 1 – Identify all available control technologies

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

- *Carbon Capture and Storage* (CCS) - CCS is classified as an add-on pollution control technology that 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 an add-on pollution control option for "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)."[8]

  CCS contains three major components: carbon capture, transport and storage. With respect to carbon capture, CCS systems use 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 suitable 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 facilities and 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 control options for this proposed gas turbine facility because these technologies do not appear to have the potential for practical application to this type of facility. The third approach, post-combustion capture, is an available option for 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 on at least part of the exhaust gas stream (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 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 approximately 320 to 350 tons per day of CO_2 from a 13 to 15% slipstream of the exhaust gas from a natural gas combined

[8] 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.

cycle plant previously owned by Florida Power and Light in Bellingham, Massachusetts. The CO_2 capture operation at the plant was maintained in continuous operation from 1991 to 2005 (Reddy, Scherffius, Freguia, & Roberts, 2003). The CO_2 capture operation was discontinued in 2005 due to a change in operations from a baseload unit to a peak load shaving facility, which created technical impediments to continuing to operate the system.

In applications where CO_2 has been captured from the flue gas, the captured CO_2 is typically compressed to 100 atmospheres (atm) or higher for ease of transport (usually by pipeline). The CO_2 may then be transported to an appropriate location for underground injection if a suitable geological storage reservoir, such as a deep saline aquifer or depleted coal seam, is available 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.

Currently, most CO_2 pipelines in the state are concentrated in west Texas. The closest existing CO_2 pipeline—the Anton-Irish Pipeline—is located about 20 miles west of the Antelope Elk Energy Center. The Anton-Irish Pipeline is an 8-inch pipeline that is privately owned by Oxy Permian, and the pipeline's capacity is dedicated to Oxy Permian's operations.[9]

- *Combined cycle CTGs* –As stated in the "PSD and Title V Permitting Guidance for Greenhouse Gases," combined cycle CTGs should be listed as an option for proposed natural gas-fired projects. However, the guidance also recognizes that this option may be evaluated under the redefining-the-source framework and excluded from consideration at Step 1 on a case-by-case basis if it can be shown that application of this control technology would disrupt the applicant's basic or fundamental business purpose for the proposed facility.[10] The applicant's project is conceived as a peaking and intermediate power provider and is designed to provide power quickly when dispatched to respond to varying needs of the electric grid, including support of renewable power generation by maintaining grid stability when wind power generation decreases, and to expeditiously shut down when no longer needed. Simple cycle turbines, such as the CTG selected by the applicant, are well suited for peaking power supply due to their ability to rapidly respond to immediate needs for additional power generation at variable levels and quickly cease operation when those additional power needs are satisfied. Simple cycle turbines are also well suited for this smaller peaking and intermediate facility (200 MW) by providing the flexibility to operate at partial load and respond to dispatch requirements in smaller increments than would be consistent with the operations of a larger integrated combined cycle system.

  Combined cycle units generally have higher efficiencies than simple cycle units; however, while combined cycle units are well suited as baseload power generating units, EPA has not concluded, at this time, that combined cycle units can provide the rapid response and shutdown required of a peaking power source producing power to sell in a deregulated market or responding to fluctuations in renewable power generation. The start-up sequence for a combined cycle plant includes three phases: 1) purging of the heat recovery steam generator (HRSG); 2) gas turbine speed-up, synchronization and loading; and 3) steam turbine speed-up, synchronization and loading. The

[9] A Policy, Legal and Regulatory Evaluation of the Feasibility of a National Pipeline Infrastructure for the Transport and Storage of Carbon Dioxide, page 38 (September 2010).
[10] U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, *PSD and Title V Permitting Guidance for Greenhouse Gases*, at 29-30, March 2011, <http:/www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf.

duration of the third phase of this process is dependent on the amount of time that the plant has been shut down prior to being restarted, because the HRSG and steam turbine contain parts that can be damaged by thermal stress and require time to heat up and prepare for normal operation. For this reason, the complete startup time for a combined cycle plant is typically longer than that of a similarly sized simple cycle plant.[11] It is important to note that when describing the amount of time for "start-up", this amount of time is comprised of the time for the combustion turbine to reach a level of operation of add-on pollution control devices and the expectation to fully meet all air emission limitations. In contrast, EPA understands that ramping times in the generation sector can describe the time that a combustion turbine requires to meet a specific electrical output need – in many situations the point where the turbine generation system reaches full or optimal generating capacity. An additional important factor is the time that a power configuration may require to deliver electricity to the power grid; however, for purposes of this analysis, this comparison will not be included. While a quick ramp rate is an important characteristic for a peaking and intermediate load facility, it is not the sole defining characteristic. In meeting GSEC's fundamental needs, the combustion turbine needs to be able to start up quickly, cycle off when not required, and accommodate the rapidly changing scale and complexity of providing power generation support for renewable energy sources.

Fast-start technology is capable of enabling startup of a combined cycle combustion turbine within 30 minutes; however, the technology requires that the unit be maintained in a state allowing warm or hot startup. To keep the HRSG and the steam turbine seals and auxiliary equipment at a sufficiently high temperature to allow for quick startup of the combustion turbine, the facility would have to continuously operate an auxiliary boiler. These longer startup times are incompatible with the purpose of the proposed project to provide a rapid response to changes in the supply of renewable power and demand for electricity.

An additional concern with the use of a combined-cycle configuration is the thermal mechanical fatigue due to the large numbers of startups and shutdowns. There are many considerations in the successful selection of a combustion turbine design that include correct steam chemistry, establishment of steam seals, vibration, and controls.[12] For fast-start technology, one of the most important factors is the thermal stress management. For a high pressure drum type HRSG, thermal stress management becomes an integral part of the design considerations. For fast-start technology to optimize the startup to minimize the time to dispatch power without a system failure, the gas turbine and steam turbine must be thermally decoupled. The steam turbine metal temperature at the startup initiation is a key controlling factor to establishing startup times. To help alleviate, to a certain degree, the impacts from thermal stress, a stronger alloy steel (resulting is a higher cost) may need to be used in the steam turbine.

Combined cycle units, including units with fast-start technology, produce more electricity than simple cycle CTGs due to the additional generation capacity of the HRSG. Operating turbines outside their design range will compromise GHG efficiency, the control of non-GHG pollutants, and the mechanical integrity of the system. For example, the GE 7FA.05 turbine selected by GSEC is

[11] U.S. Environmental Protect Agency, Region 9. Fact Sheet and Ambient Air Quality Impact Report for the Proposed Prevention of Significant Deterioration Permit, Pio Pico Energy Center.
[12] http://www.power-eng.com/articles/print/volume-117/issue-6/features/gas-turbine-combined-cycle-fast-start-the-physics-behind-the-con.html (last visited April 1, 2014).

expected to reach minimum emission compliant levels at nominally 50% combustion turbine loading. If this turbine was incorporated into a combined cycle unit, the minimum electricity generation output would be substantially higher than the 100 MW minimum output of a simple cycle configuration.

GSEC's business purpose requires the ability to accommodate flexible and on-demand operations in the 100 MW to 202 MW range, including the operational flexibility to start up and shut down to respond immediately to variable electricity grid demand in support of renewable power sources within GSEC's power generation portfolio and as dispatched by ERCOT. Therefore, based on the defined business purpose of the proposed project and for the reasons discussed herein, the use of combined cycle units would result in a redefinition of the source for this specific project and can be excluded from Step 1 of this BACT analysis.[13]

- *Efficient Generating Technology* – A key factor in minimizing GHG emissions is to maximize the efficiency of electricity production. Older, inefficient turbines consume more fuel to generate the same amount of electricity as newer, more efficient turbines. This is due to equipment wear and tear, improved design in newer models and the use of higher quality metallurgy. Use of modern, efficient simple cycle turbine models is an available control option.

  While GSEC initially considered reciprocating engines as an alternate generating technology; GSEC has entered into an Interconnection Agreement with SPP in which GSEC committed to provide one gas combustion turbine 232 MVA generator nominally rated at 196 MW (summer) and 203 MW (winter). Therefore, reciprocating engines no longer meet the purpose of GSECs project, are excluded as not available for this project, and will not be evaluated in the remainder of this BACT analysis.

- *Fuel Selection* – In 2008, approximately 70% of the electricity used in the United States was generated by burning fossil fuels (e.g., coal, natural gas or petroleum liquids). Fuels vary in the amount of carbon per Btu, which in turn affects the quantity of CO_2 emissions generated per unit of heat input. This BACT analysis evaluates the use of coal, distillate oil and natural gas as fuel for the CTG.

- *Good Combustion, Operating, and Maintenance Practices* – Good combustion, operating, and maintenance practices are a potential control option for improving the fuel efficiency of the combustion turbine. Natural gas-fired combustion turbines typically operate in a lean pre-mix mode to ensure effective staging of air/fuel ratios in the turbine, thus maximizing the fuel efficiency and minimizing incomplete combustion. Modern combustion turbines have sophisticated instrumentation and controls to automatically control the operation of the combustion turbine. The control system monitors the operation of the unit and modulates the fuel flow and turbine operation to achieve optimal high-efficiency, low emissions performance.

[13] Even if combined cycle technology were not excluded as a redefinition of the source for this project, the case-by-case analysis of GSEC's peaking and intermediate power generation project also demonstrates that combined cycle technology with fast start technology may be infeasible under the standard BACT analysis. Therefore, while maintaining that combined cycle technology is a redefinition of the source, we have also analyzed whether the technology is feasible for this project under the Step 2 analysis.

Step 2 – Elimination of Technically Infeasible Alternatives

- *Carbon Capture and Storage:* As discussed in the August 2010 Report of the Interagency Task Force on Carbon Capture and Storage (co-chaired by US EPA and US Department of Energy), while amine- or ammonia-based post-combustion CO_2 capture technologies are commercially available, they have not been demonstrated nor utilized commercially for simple cycle electric generating units operating as peaking power providers with multiple starts and stops to respond to electricity demand dispatch requirements. The proposed GSEC project's highly cyclical operation (up to 635 startups and 635 shutdowns per year) is similar to peaking power electric generation units. Peaking units frequently cycle their operation, and it is unclear how part-load operation and frequent startup and shutdown events would impact the efficiency and reliability of a carbon capture system. Further, operation of carbon capture technology in a "start/stop" mode as an add-on control technology does not presently appear to have the potential for practical application to gas-fired CTGs, thus adding carbon capture to a cycling operation may limit operational flexibility. EPA is not aware of any pilot scale carbon capture project that has operated in a cycling mode. GSEC's proposed project is to be operated in a frequent cycling mode, thus carbon capture is not applicable. Further, EPA is not aware of any CCS system that is commercially available at this time for a simple cycle combustion unit that operates in a cycling mode. Therefore, carbon capture is eliminated as not technically feasible at this facility and will not be evaluated in the remainder of this BACT analysis.[14]

- *Combined cycle CTGs* – Although the case-by-case analysis of GSEC's proposed project demonstrates that incorporation of combined cycle technology would result in a redefinition of the source, many of the same considerations also render combined cycle technology technically infeasible. For the reasons stated above, while fast-start technology has increased the flexibility of combined cycle plants, EPA has not concluded, at this time, that combined cycle plants can provide the rapid response and shutdown of GSEC's smaller peaking/intermediate power generation project.

  Use of a combined-cycle turbine with fast start technology has not been demonstrated in practice on a facility of the size of this project. Recently permitted projects equipped with fast start technology[15] are considerably larger in scale (300 MW to 758 MW) than GSEC's 100 to 200 MW project requirements and operate as intermediate/baseload units. To produce 100 MW, these plants would need to operate below minimum emission compliant levels for turbine loading. Additionally, a review of public information on fast-start combined cycle units does not indicate that any commercially available units can meet GSEC's 100 to 200 MW operational requirements.

  For the reasons stated herein, even equipped with the fast-start technology, the use of combined cycle technology for this proposed project is neither available nor applicable to GSEC's proposed project. Therefore, combined cycle technology is technically infeasible.

- *Efficient Generating Technologies* – GSEC documented its considerations in selecting a particular turbine model for this facility, while weighing operational variables such as project size, project

[14] Since CCS is eliminated in Step 2 of the BACT analysis, EPA does not need to include a cost analysis in Step 4 of the BACT analysis. GSEC did, however, submit a cost analysis for CCS as part of the application, and that analysis is included in the administrative record.
[15] Response to Public Comments, El Paso Electric Company Montana Power Station, PSD-TX-1290-GHG, 25.

purpose, fuel use, technical feasibility, and ambient conditions. The turbine model selected by GSEC is considered an efficient, modern simple cycle turbine. Operation of this turbine has been demonstrated in practice at similar facilities, thus this is a technically feasible option.

- The remaining control options identified in Step 1, *Fuel Selection* and *Use of Good Combustion, Operation, and Maintenance Practices* are technically feasible and are being proposed for Step 3 analysis.

Step 3 – Ranking of Controls

- Efficient Generating Technologies
- Fuel Selection
- Good Combustion, Operating, and Maintenance Practices

Selection of highly efficient simple cycle combustion turbines is considered the most effective control technology in this analysis. Fuel selection and good combustion, operation, and maintenance practices are all considered effective and have a range of efficiency improvements which cannot be directly quantified; therefore, ranking is not possible. In assessing CO_2 emissions for potential fuel types, natural gas combustion results in lower GHG emissions (119 lbs CO_2e/mmBtu) than distillate oil (163 lbs CO_2e/mmBtu) or coal (243 lbs CO_2e/mmBtu). [16]

Step 4 – Economic, Energy and Environmental Impacts

- *Efficient Generating Technology* – The applicant assessed reciprocating and frame engine combustion turbines operating in a simple cycle configuration. GSEC has noted that the GE 7F Series 5 turbine also has lower installed and annualized costs than alternate turbine types and offers a high overall efficiency.

- *Low Carbon Fuels* – As discussed in Step 3, natural gas produces the lowest GHG emissions and is the top ranked option. EPA concludes that natural gas is the appropriate fuel for this source and no economic, energy or environmental impacts warrant elimination of this control option.

- *Good Combustion, Operation, and Maintenance Practices* -- EPA concludes that no economic, energy, or environmental impacts warrant elimination of this control option.

[16] No hydrogen-rich fuel gas is available near the Antelope Elk Energy Center, so it is not considered.

Step 5 – Selection of BACT

To date, other similar peaking and intermediate power generating 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
Cheyenne Light, Fuel & Power / Black Hills Power, Inc. Laramie County, WY	Simple cycle combustion turbine	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT limit of 1,600 lbs CO_2e/MWhr (gross) 365-day average, rolling daily	2012	PSD-WY-000001-2011.001
York Plant Holding, LLC Springettsbury Township, PA	Simple cycle combustion turbine	Energy Efficiency/ Good Design & Combustion Practices	Combustion turbine annual net heat rate limited to 11,389 Btu/kWh (HHV) when firing natural gas GHG BACT limit of 1,330 lb CO_2e/MWhr (net) when firing natural gas 30-day rolling average	2012	67-05009C
Pio Pico Energy Center, LLC Otay Mesa, CA	300 MW simple cycle power plant-Peak/Intermediate Power Generation	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT limit of 1,328 lb CO_2e/MWhr (gross) 720 rolling operating-hour average	2012	SD 11-01
El Paso Electric Company, Montana Power Station	400 MW simple cycle power plant-Peak/Intermediate Power Generation	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT limit of 1,100 lb CO2/MWhr (gross) 5,000 rolling operating-hour average	2014	PSD-TX-1290-GHG

From this analysis, EPA has concluded that the GHG BACT for GSEC is the use of a modern natural gas-fired, thermally efficient simple cycle combustion turbine combined with good combustion and maintenance practices to maintain optimum efficiency. The GE FA7.05 is consistent with the BACT requirement and the specific goals of this project. EPA is proposing an emission limit of 1,304 lb CO_2/MWhr gross output on a 4,572 rolling operational hour basis.

The turbine is limited to 4,572 hours of operation per year, including 635 startup and 635 shutdown events, on a 12-month rolling basis. The GHG rolling operational hour average BACT limit for combustion turbine generators is determined by the calculation of the total summed CO_2 mass emission rate of the unit over 4,572 rolling operational hours. The total summed CO_2 mass emission rate is divided by the total summed gross electrical output generated by the unit over the same corresponding operational time period. The resulting quotient of this mathematical operation is compared to the 1,304 lb CO_2/MWhr BACT limit. Until the 4,572 operational hour basis has been established, the company should utilize the performance testing data to establish a plan whereby the company may operate the emission unit in a manner that will not exceed the permitted limits.

The company is responsible for demonstrating compliance with the permitted emission limit and should evaluate its actual emissions and verify actual compliance from recorded operational data. The operating scenario provided by the applicant (4,572 hours at 100% loading per year) was used to calculate the worst-case annual emission rates from the facility; however, the applicant has proposed a BACT emission limit based on a 75% operational load scenario. To account for the additional hours of operation associated with the startup and shutdowns, each turbine is limited by fuel use associated with the 4,572 hours of operation per year. Limiting the fuel use achieves the same objective as limiting the number of hours of operation for the turbine to 4,572 hours. The fuel use limit for the combustion turbine that corresponds to the 4,572 hour of operation per 12-month rolling basis is 8,873,053 MMBtu (HHV).

The proposed BACT limit of 1,304 lb CO_2/MWhr (gross) for the GE 7FA.05 combustion turbine is comparable to or lower than other recently proposed or issued GHG BACT limits for power generation projects characterized as peak and intermediate load. The recently issued GHG PSD permit for El Paso Electric Company contains a GHG BACT limit of 1,100 lb CO_2/MWhr; however, in EPA's analysis the BACT limit was proposed as 1,194 lb CO_2/MWhr, but the company requested that the limit be lowered. Another recently issued permit for peak and intermediate load power generation is the Pio Pico Energy Center. The BACT limit for Pio Pico Energy Center is approximately 2% higher than the proposed BACT limit for GSEC.

As demonstrated above, the BACT limit for GSEC's proposed combustion turbine is comparable to recently permitted BACT limits at similar facilities; however, it is important to note that surface level comparison does not account for factors such as operational hours and load, elevation, and ambient conditions, which directly impact turbine efficiency. While EPA considered these BACT limits from previously permitted actions, EPA also examined the available literature (such as the Gas Turbine World handbook) and confirmed that the CTGs proposed by GSEC are, in general, considered highly efficient, modern CTG models.

Variations in elevation and ambient temperature will affect a combustion turbine's operational performance and is an important consideration in the comparison of various combustion turbines in different locations. In a discussion about CTG efficiency, it is important to note that the calculated gross CTG power and efficiency are as "measured" across the electric generator terminals at ISO (International Organization for Standardization) site conditions without allowances for inlet filter and duct losses, exhaust stack and silencer losses, gearbox efficiency, or any auxiliary mechanical and electrical systems' parasitic power consumption. ISO design ratings are typically set at 59°F and sea level. To assess site-specific CTG performance, correction factors should be applied. Within the Appendix section of this document, Table 2 shows the anticipated combustion turbine performance data across various load percentages and at the various ambient conditions for the GE 7FA.05.

To allow for variations in manufacturing tolerances and test uncertainties, equipment manufacturers frequently rely on design margins to accommodate the small variation in turbine performance. A design margin of 3 percent was included within the calculations for the combustion turbine, which is comparable to other recently permitted projects. The performance margin used in this analysis (3 percent) is also comparable to other recently permitted projects and within the 2 to 6 percent range provided in the Gas Turbine World handbook (2012).

BACT during Startup and Shutdown

BACT applies during all periods of turbine operation, including startup and shutdown. For this project, EPA is proposing a BACT emission limit of 1,304 lb CO_2/MWh gross output on a 4,572 operational rolling hour basis. The number of startups and shutdowns is limited to 635 startups and 635 shutdowns per year on a 12-month rolling basis. All startups are limited to 30 minutes in duration per event, while shutdowns are limited to 24 minutes. A startup of the turbine is defined as the period that begins when fuel flow is initiated in the combustion turbine as indicated by flame detection and ends when the normal low-NOx combustion mode is achieved. A shutdown is defined as the period that begins when the combustion turbine, following an instruction to shut down, drops out of the normal operating low-NOx combustion mode and ends when a flame is no longer detected in the combustion turbine combustor. In addition to the BACT emission limit of 1,304 lb/CO_2/MWh gross output, BACT for startup/shutdown includes the work practice standard to utilize good pollution control practices, safe operating practices and protection of the facility. The startup /shutdown activities shall be minimized by limiting the duration of operation in startup/shutdown mode as follows:

- Startups are limited to no more than 30 minutes per event, and shutdowns are limited to no more than 24 minutes per event.
- No more than 635 startup and 635 shutdown events may occur on a 12-month rolling basis.

BACT Compliance:

Proposed BACT for this project is the use of new natural gas-fired, thermally efficient simple cycle combustion turbines combined with good combustion and maintenance practices to maintain optimum efficiency, and an output based limit of 1,304 lbs CO_2/MWh (gross). Compliance will be based on a 4,572 operational hour rolling basis, calculated daily for the turbine. GSEC will maintain records of tune-ups, O_2 analyzer calibrations, and maintenance for the combustion turbine. For the combustion turbine, the parameters that will be measured are natural-gas flow rate using an operational non-resettable elapsed flow meter, total amount of fuel combusted on an hourly basis, fuel gross calorific value (GCV) on a high heat value (HHV), carbon content, combustion temperature, exhaust temperature, and gross hourly energy output (MWhr).

GSEC will demonstrate compliance with the CO_2 limit by using a non-resettable elapsed time fuel flow meter to monitor the quantity of fuel combusted in the electric generating unit and performing periodic scheduled fuel sampling pursuant to 40 CFR § 75.10(a)(3)(ii) and the procedures listed in 40 CFR Part 75, Appendix G. GSEC may choose to use the results of the fuel sampling to calculate a site-specific Fc factor, and that factor will be used in the equation below to calculate CO_2 mass emissions. The proposed permit also includes an alternative compliance demonstration method in which GSEC may install, calibrate, and operate a CO_2 Continuous Emission Monitoring System (CEMS) and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording CO_2 emissions. The GHG rolling operational hour average BACT limit for the combustion turbine generator is determined by the calculation of the total summed CO_2 mass emission rate of the unit over 4,572 rolling operational hours. The total summed CO_2 mass emission rate is divided by the total summed gross electrical output generated by the unit over the same corresponding operational time period. The resulting quotient of this mathematical operation is compared to the 1,304 lb CO_2/MWhr BACT limit. Until the 4,572 operational hour basis has been established, the company should utilize the performance testing data to establish a plan whereby the company may operate the emission unit in a manner that will not exceed the permitted limits.

If GSEC chooses to determine a site-specific Fc factor, the analysis and GCV in equation F-7b of 40 CFR Part 75, Appendix F shall be used. The site-specific Fc factor will be re-determined annually in accordance with 40 CFR Part 75, Appendix F, § 3.3.6.

The equation for estimating CO_2 emissions as specified in 40 CFR Part 75, Appendix G, Procedure 2.3 is as follows:

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

Where:

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

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

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

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

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

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

- The 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).
- GSEC shall determine the Gross Calorific Value (GCV) of pipeline natural gas at least once per calendar month pursuant to 40 CFR Part 75, Appendix D, § 2.3.4.1

The emission limits associated with CH_4 and N_2O are calculated based on emission factors either represented in the permit application or the default factors provided in 40 CFR Part 98, Subpart C, Table C-2 and the actual heat input (HHV). Comparatively, the emissions from CO_2 contribute the most (greater than 99%) to the overall emissions from the turbines and additional analysis is not required for CH_4 and N_2O. To calculate the CO_2e emissions, the draft permit requires calculation of the emissions based on the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1. Records of the calculations are required to be kept to demonstrate compliance with the emission limits on a 4,572 operational hour average, calculated daily. The demonstration of compliance with the BACT emission limit includes emissions during periods of startup and shutdown. The Permittee shall also demonstrate compliance with the startup and shutdown work practice standard by maintaining a copy of the vendor recommendations and maintaining documentation on-site to show that each startup event does not exceed the 30 minute duration and each shutdown does not exceed the 24 minute duration. In addition, records shall be maintained that demonstrate that the number of startup and shutdown events on a 12-month rolling basis does not exceed 635 startup events and 635 shutdown events.

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

X. Emergency Generator BACT Analysis (EPN: EMERGEN)

The proposed project will use a diesel-fired emergency generator, nominally rated at 2205 hp. The engine will operate a maximum of 100 hours per year in non-emergency operations on a 12-month rolling basis for testing and maintenance.

Step 1 – Identification of Potential Control Technologies

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

Step 2 – Elimination of Technically Infeasible Alternatives

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

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

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

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

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

Efficient Engine Design: GSEC will install a new emergency generator. It is anticipated that this equipment will be designed for optimal combustion efficiency. EPA concludes that no economic, energy, or environmental impacts warrant elimination of this control option.

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

Step 5 – Selection of BACT

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

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

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

XI. Natural Gas-Fired Fuel Gas Heater BACT Analysis (EPN: NGHEATR-2)

The proposed project will be equipped with one new natural gas-fired heater. The heater will have a capacity of 5.5 MMBtu/hr (HHV) and will be operated no more than 4,572 hours per year. This heater will serve to preheat the natural gas feed into the combustion turbines to maximize combustion efficiency. The pipeline heater represents 0.27% of the facility-wide GHG emissions.

Step 1 – Identification of Potential Control Technologies for GHGs

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

Step 2 – Elimination of Technically Infeasible Alternatives

Use of low carbon fuels, heater design, heater air/fuel control, and periodic tune-ups are considered technically feasible. Waste heat recovery is not demonstrated in practice at and is not applicable to intermittently operated combustion units, and is therefore rejected for the heater.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

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

Virtually all GHG emissions from fuel combustion result from the conversion of carbon in the fuel to CO_2. Fuels used in industrial processes and power generation are typically coal, fuel oil, natural gas, and process fuel gas. Of these, natural gas is typically the lowest carbon fuel that can be burned, with a CO_2 emissions factor in lb/MMBtu about 55% of that of subbituminous coal. Process fuel gas is a byproduct of chemical processes that typically contain a higher fraction of longer-chain carbon compounds than natural gas and thus results in more CO_2 emissions. Some processes produce significant quantities of hydrogen, which produces no CO_2 emissions when burned. Thus, use of a completely carbon-free fuel such as 100% hydrogen has the potential of reducing CO_2 emissions by 100%. Hydrogen is not readily available at the GSEC site and, therefore, is not a viable fuel for the proposed heater. Natural gas is the lowest carbon fuel available for use in the proposed heater.

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

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

Use of Low Carbon Fuel: Natural gas is the lowest carbon fuel available for use in the proposed heater. Natural gas is readily available at the GSEC site and is currently considered a very cost effective fuel alternative. Natural gas is also a very clean burning fuel with respect to criteria pollutants and thus has minimal environmental impact compared to other fuels. Natural gas is the fuel choice for most industrial facilities in addition to being the lowest carbon fuel available at this facility.

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

Periodic Heater Tune-ups: Periodic tune-ups of the heater includes:
- Preventative maintenance check of gas flow meters,
- Preventative maintenance check of oxygen control analyzers,
- Cleaning of burner tips on an as-needed basis, and
- Cleaning of convection section tubes on an as-needed basis.

These activities ensure maximum thermal efficiency is maintained; however, it is not possible to quantify an efficiency improvement, although convection cleaning has shown improvements in the 0.5 to 1.5% range. Due to the minimal use of this heater, regularly scheduled tune-ups and inspections are not warranted.

Heater Air/Fuel Controls: Manual controls of the air/fuel ratio enable the heater to operate under optimal conditions ensuring heater efficiency.

Step 5 – Selection of BACT

The following specific BACT practices are proposed for the heaters:

- Use of low carbon fuel (natural gas). Natural gas will be the only fuel fired in the proposed heater. It is the lowest carbon fuel available for use at the facility.
- Good heater design and operation to maximize thermal efficiency and reduce heat loss to the extent practical for heaters of this size in intermittent service.
- Use of manual air/fuel controls to maximize combustion efficiency.
- Clean and inspect heater burner tips and perform tune-ups as needed and per vendor recommendations.
- Limit the operational use of the heaters to no more than 4,572 hours per year per heater on a 12-month rolling basis.

Use of these practices corresponds with an emission limit of 1488 tpy CO_2e for the heater. Compliance with this limit will be determined by calculating the emissions on a monthly basis and keeping a 12-month rolling total of hours of operation, including during startup and shutdown.

XII. Fugitive Emissions from SF_6 Circuit Breakers BACT Analysis (EPN: SF6-FUG)

The circuit breakers associated with the proposed units will be insulated with SF_6. The capacity of the circuit breakers associated with the proposed plant expansion is currently estimated to 2920 lbs SF_6.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Circuit Breaker Design Efficiency* - In comparison to older SF_6 circuit breakers, modern circuit breakers are designed as a totally enclosed-pressure system with far lower potential for SF_6 emissions. In addition, the effectiveness of leak-tight closed systems can be enhanced by equipping them with a density alarm that provides a warning when 10% of the SF_6 (by weight) has escaped. The use of an alarm identifies potential leak problems before the bulk of the SF_6 has escaped, so that it can be addressed proactively in order to prevent further release of the gas.

- *Alternative Dielectric Material* – Because SF_6 has a high GWP, one alternative considered in this analysis is to substitute another non-GHG substance for SF_6 as the dielectric material in the breakers. Potential alternatives to SF_6 were addressed in the National Institute of Standards and Technology (NIST) Technical Note 1425, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF_6*.[17] The alternatives considered include mixtures of SF_6 and nitrogen, gases and mixtures and potential gases for which little experimental data are available.

Step 2 – Elimination of Technically Infeasible Alternatives

[17] Christophorous, L.G., J.K. Olthoff, and D.S. Green, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF_6*. NIST Technical Note 1425, Nov. 1997. Available at http://www.epa.gov/electricpower-sf6/documents/new_report_final.pdf

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

- *Alternative Dielectric Material* - According to the report NIST Technical Note 1425, among the alternatives examined in the report, SF_6 is a superior dielectric gas for nearly all high voltage applications. It is easy to use, exhibits exceptional insulation and arc-interruption properties, and has proven its performance by many years of use and investigation. It is clearly superior in 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." The mixture of SF_6 and nitrogen is noted to need further development and may only be applicable in limited installations. This alternative has not been demonstrated in practice for this project's design installation. The second alternative of various gases and mixtures has not been demonstrated in practice, and needs additional systematic study before this alternative could be considered technically feasible. The third alternative of potential gases has not been demonstrated in practice, and there is little experimental data available. Additional studies are needed before this alternative would be considered feasible. Based on the information contained in this report, "it is clear that a significant amount of research must be performed for any new gas or gas mixture to be used in electrical equipment." Therefore, because the alternative dielectric material options have not been demonstrated in practice for this project's proposed design application and are not be commercially available, this alternative is considered technically infeasible.

Step 3 – Ranking of Remaining Technologies

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

Step 4 –Economic, Energy, and Environmental Impacts

Since the only remaining control option is the circuit breaker design efficiency, and since that option is selected as BACT, a Step 4 evaluation of the most effective controls is not necessary.

Step 5 – Selection of BACT

Circuit breaker design efficiency is selected as BACT. Specifically, state-of-the-art, enclosed-pressure SF_6 circuit breakers with leak detection is the BACT control technology option. The circuit breakers will be designed to meet the latest American National Standards Institute (ANSI) C37.06 and C37.010 standards 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 SF6 emissions problems to light before a substantial portion of the SF_6 escapes. The lockout prevents any operation of the breaker due to the lack of "quenching and cooling" SF_6 gas.

BACT compliance will be demonstrated by GSEC through annual monitoring of emissions in accordance with the requirements of the Mandatory Greenhouse Gas Reporting rules for Electrical

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[18] ANSI Standard C37.06, *Standard for AC High-Voltage Generator Circuit Breakers on a Symmetrical Current Basis* and ANSI Standard C37.010, *Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis*.

Transmissions and Distribution Equipment Use.[19] Annual SF_6 emissions will be calculated according to the mass balance approach in Equation DD-1 of Subpart DD.

XIII. Fugitive Emissions from Piping Components BACT Analysis (EPN: NG-FUG)

Emissions from piping components (valves and flanges) associated with this project consist of methane (CH_4) and carbon dioxide (CO_2). Emissions of CO_2e are estimated to be 101.83 tons/yr.

Step 1 – Identification of Potential Control Technologies

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

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

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

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

Remote sensing using infrared imaging has proven effective in identifying leaks, especially for components in difficult to monitor areas. LDAR programs and remote sensing using an infrared camera have been determined by EPA to be equivalent methods of piping fugitive controls.[20]

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

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

Step 4 –Economic, Energy, and Environmental Impacts

The use of leakless components, instrument LDAR and/or remote sensing of piping fugitive emission in natural gas service may be somewhat more effective than as-observed AVO methods, but the

[19] See 40 CFR Part 98, Subpart DD.
[20] 73 FR 78199-78219, December 22, 2008.

incremental GHG emissions controlled by implementation of the TCEQ 28 LAER LDAR program or a comparable remote sensing program is considered a *de minimis* level in comparison to the total project's proposed CO_2e emissions. Given that GHG fugitives are conservatively estimated to be little more than 4 tons per year CH_4, there is, in any case, a negligible difference in emissions between the considered control alternatives. Accordingly, given the costs of implementing 28 LAER or a comparable remote sensing program when not otherwise required, these methods are not economically practicable for GHG control from components in natural gas service.

Step 5 – Selection of BACT

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

XIV. 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) submitted on January 29, 2014 and supplemental information to the Biological Assessment on April 9, 2014 that was prepared by the applicant, Golden Spread Electrical Cooperative, Inc. ("GSEC"), and its consultant, Horizon Environmental Services, Inc. ("Horizon"), reviewed and adopted by EPA.

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

Federally Listed Species for Swisher and Castro counties by the U.S. Fish and Wildlife Service (USFWS) and the Texas Parks and Wildlife Department (TPWD)	**Scientific Name**
Birds	
Whooping Crane	*Grus americana*
Mammals	
Black-Footed Ferret	*Mustela nigripes*
Grey Wolf	*Canis lupus*
Lesser Prairie Chicken	*Tympanuchus pallidicinctus*

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

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

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

XV. 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 a cultural resource report prepared by Horizon on behalf of GSEC submitted on October 31, 2013.

For purposes of the NHPA review, the Area of Potential Effect (APE) was determined to be location of the proposed construction of a natural gas-fired, single-cycle combustion turbine at an existing power generation facility on a 549-acre property. Horizon conducted a desktop review within a 1-mile radius of the 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, a cultural resources survey, including shovel testing, was previously performed in 1982 that covered the entire APE. No previously recorded archaeological and historical sites were identified within the site facility or within a 1-mile radius of the APE.

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

On October 31, 2013, 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.

XVI. Environmental Justice (EJ)

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

XVII. Conclusion and Proposed Action

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

Appendix

Table 1. Annual Emission Limits

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[1,2]	BACT Requirements
				TPY[1]		
TURB1	TURB1	Natural Gas Fired-Simple Cycle Turbine	CO_2	532,007.00	539,094	- BACT limit of 1,304 lb CO_2/MW-hr (gross) on a 4,572 rolling operational hour average -Not to exceed 4,572 hours of operation (including startups, and shutdowns) on a 12-month rolling basis -See permit condition III.A.2 and 4.
			CH_4	125.00		
			N_2O	13.30		
EMERGEN	EMERGEN	Emergency Diesel Generator	CO_2	128.00	128	- Not to exceed 100 hours of non-emergency operation on a 12-month rolling basis - Use of Good Combustion Practices. See permit condition III.B.
			CH_4	0.01		
			N_2O	No Numerical Limit Established[3]		
NGHEATR-2	NGHEATR-2	Natural Gas Fired Fuel Gas Heater	CO_2	1,479.00	1488	- Not to exceed 4,572 hours of operation on a 12-month rolling basis - Use of Good Combustion Practices. See permit condition III.C.
			CH_4	0.03		
			N_2O	0.03		
SF6-FUG	SF6-FUG	Fugitive SF_6 Circuit Breaker Emissions	SF_6	No Numerical Limit Established[4]	No Numerical Limit Established[4]	Work Practices. See permit condition III.D.
NG-FUG	NG-FUG	Components Fugitive Leak Emissions	CH_4	No Numerical Limit Established[4]	No Numerical Limit Established[4]	Implementation of AVO Program. See permit condition III.E.
Totals[5]			CO_2	533,614.00	**540,978**	
			CH_4	129.10		
			N_2O	13.33		
			SF_6	0.01		

1. The TPY emission limits specified in this table are not to be exceeded for this facility and include emissions from the facility during all operations and include MSS activities.
2. Global Warming Potentials (GWP): CO_2=1, CH_4 = 25, N_2O = 298, SF_6=22,800
3. No numerical limit established because emissions are 0.01 tons/yr or less.
4. Fugitive leak emissions from SF_6-FUG and NG-FUG are estimated to be 0.0073 TPY SF_6 and 166.44 TPY CO_2e from SF_6-FUG, and 0.079 TPY CO_2, 4.07 TPY CH_4, and 101.83 TPY CO_2e from NG-FUG. In lieu of an emission limit, the emissions will be limited by implementing a design/work practice standard as specified in the permit.
5. Total emissions include the PTE for fugitive emissions. Totals are given for informational purposes only and do not constitute emission limits.

Estimated Performance Data (GE)

Load Condition	BASE	BASE	BASE	BASE	BASE	75% LOAD	75% LOAD	75% LOAD	75% LOAD	75% LOAD	50% LOAD	54% LOAD	50% LOAD	50% LOAD	50% LOAD
Ambient Temperature, °F	98	-10	110	50	20	98	-10	110	50	20	98	-10	110	50	20
Turbine Output, MW (gross)	190.117	199.546	185.459	195.287	202.067	142.588	149.66	139.094	146.465	151.551	95.058	99.773	92.729	97.643	101.034
Heat Rate (LHV), BTU/kWh	8905	8828	8950	8783	8732	9420	9587	9506	9291	9281	11024	11473	11159	11029	11118
Exhaust Flow, 1000 lbs/hr	3688	3877	3620	3710	3818	2930	3181	2907	2956	3108	2387	2549	2387	2377	2491
Exhaust MW, lbs/lb-mol	28.28	28.52	28.22	28.49	28.51	28.39	28.52	28.34	28.49	28.52	28.41	28.53	28.36	28.5	28.52
UHC, lbs/hr	15	15	14	15	15	12	12	11	12	12	9	10	9	9	10
CO_2, % vol	3.89	3.89	3.88	3.95	3.95	3.9	3.86	3.87	3.93	3.87	3.74	3.84	3.69	3.87	3.86
% Efficiency, LHV basis	38.33%	38.66%	38.13%	38.86%	39.09%	36.23%	35.60%	35.90%	36.73%	36.77%	30.96%	29.75%	30.59%	30.95%	30.70%

Calculated Performance Parameters

Load Condition	BASE	BASE	BASE	BASE	BASE	75% LOAD	75% LOAD	75% LOAD	75% LOAD	75% LOAD	50% LOAD	54% LOAD	50% LOAD	50% LOAD	50% LOAD
Ambient Temperature, °F	98	-10	110	50	20	98	-10	110	50	20	98	-10	110	50	20
CH_4, lbs/hr	12	12	11.2	12	12	9.6	9.6	8.8	9.6	9.6	7.2	8	7.2	7.2	8
N_2O, lbs/hr	5.59	5.81	5.48	5.66	5.82	4.43	4.73	4.36	4.49	4.64	3.46	3.78	3.41	3.55	3.71
CO_2, lbs/hr	223,210	232,674	218,996	226,324	232,749	177,100	189,432	174,666	179,414	185,565	138,263	150,957	136,655	142,019	148,342
CO_2-e, lbs/hr	225,176	234,705	220,909	228,311	234,783	178,660	191,082	176,185	180,992	187,188	139,474	152,283	137,851	143,257	149,648
CO_2, lbs/MWh	1209	1201	1216	1194	1186	1279	1304	1293	1262	1261	1498	1558	1518	1498	1512
CO_2-e, lbs/MWh	1221	1213	1228	1205	1198	1292	1316	1306	1274	1273	1513	1573	1533	1513	1527

Red values denote maximum values over range of normal operation, except that BACT limits in lbs/MWh are proposed at 75% load as a rolling 365-day average.

Factors Used for Calculations

CH_4/UHC, % as a fraction	0.8	Based on GE data for VOC and total HC emissions.
HHV/LHV	1.1	Typical ratio.
N_2O emission factor, lbs/MM BTU (HHV)	0.003	From EPA's AP-42, Table 3.1-2a
GHG warming equivalency factors, lb CO_2-e/lb:		From GHG Warming Potential Equivalency Factors (40 CFR Part 98 Subpart A, Table A-1)
- CO_2	1	
- CH_4	25	
- N_2O	298	
Heat Rate degradation factor, %	3	Based on degradation in heat rate between major overhauls

Example Calculations (Base Load, 98°F Ambient)

CH4: (15 lbs UHC/hr) X (0.8 lbs CH4/lb UHC) = 12 lbs CH4/hr

N2O: (190117 kW) X (8905 BTU-LHV/kWh) X (MM BTU/1,000,000 BTU) X (1.1 BTU-HHV/BTU-LHV) X (0.003 lbs N2O/MM BTU-HHV) = 5.59 lbs N2O/hr

CO2: (3688000 lbs exhaust/hr) X (lb-mol exhaust/28.28 lbs exhaust) X (3.89 lb-mol CO2/100 lb-mol exhaust) X (44 lbs CO2/lb-mol CO2) = 223210 lbs CO2/hr

CO2-e: (223,210 lb CO2/hr) X (1lb CO2-e/lb CO2) + (12 lbs CH4/hr) X (25 lb CO2-e/lb CH4) + (5.59 lbs N2O/hr) X (298 lb CO2-e/lb N2O) = 225176 lbs CO2-e/hr

CO2-e, lbs/MWh: (225176 lbs CO2-e/hr) / [190.117 MW (gross) X (100% - 3 % HR degradation)/100%] = 1221 lbs CO2-e/MWh

The seal appearing on this document was authorized by Patrick J. Murin, P.E. 67271 on 4/21/2014
P.E. Expiration Date: 12/31/2014

Murin Environmental Inc.
TBPE Registration No. F-7702
Firm Registration Expiration Date: 3/31/2015