Statement of Basis

Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit
for the South Texas Electric Cooperative, Inc. - Red Gate Power Plant

Permit Number: PSD-TX-1322-GHG

September 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 2, 2013, South Texas Electric Cooperative, Inc. (STEC) submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions from its proposed Red Gate Power Plant. STEC submitted additional information to EPA on June 7, 2013, and July 31, 2014. In connection with the same proposed project, STEC submitted a PSD permit application for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on October 16, 2012, which was issued on December 20, 2013.

STEC proposes to construct a new 225 MW (nominal) electric power plant in Edinburg, Hidalgo County, Texas. With this proposed project, STEC plans to construct twelve Wartsila natural gas-fired engines (Model 18V50SG) and associated equipment including a firewater pump engine, circuit breakers and a diesel-fired emergency generator. For the purposes of this proposed permitting action GHG emissions are permitted from the twelve engines, firewater pump engine, circuit breakers, and emergency generator, including periods of maintenance, startup and shut down emissions. The remaining units are not considered to be potential GHG emission sources.

EPA Region 6 has prepared the following Statement of Basis (SOB) and draft air permit to authorize construction of air emission sources at the Red Gate Power Plant. 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 STEC'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 EPA requested and provided by STEC, and EPA's own technical analysis. EPA is making all this information available as part of the public record.

II. Applicant

South Texas Electric Cooperative, Inc.
Red Gate Power Plant
P.O. Box 119
Nursery, TX 77976-0119

Facility Physical Address:
3428 West FM 490
Edinburg, Hidalgo County, TX 78541

Contact:
John Packard
Manager of Generation
P.O. Box 119
Nursery, TX 77976-0119
(361) 485-6320

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 approval of its plan and PSD program for pollutants that were subject to regulation before January 2, 2011, i.e., regulated New Source Review (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:
Kyndall Cox
Air Permitting Section (6PD-R)
1445 Ross Avenue
Dallas, TX 75202
(214) 665-8567

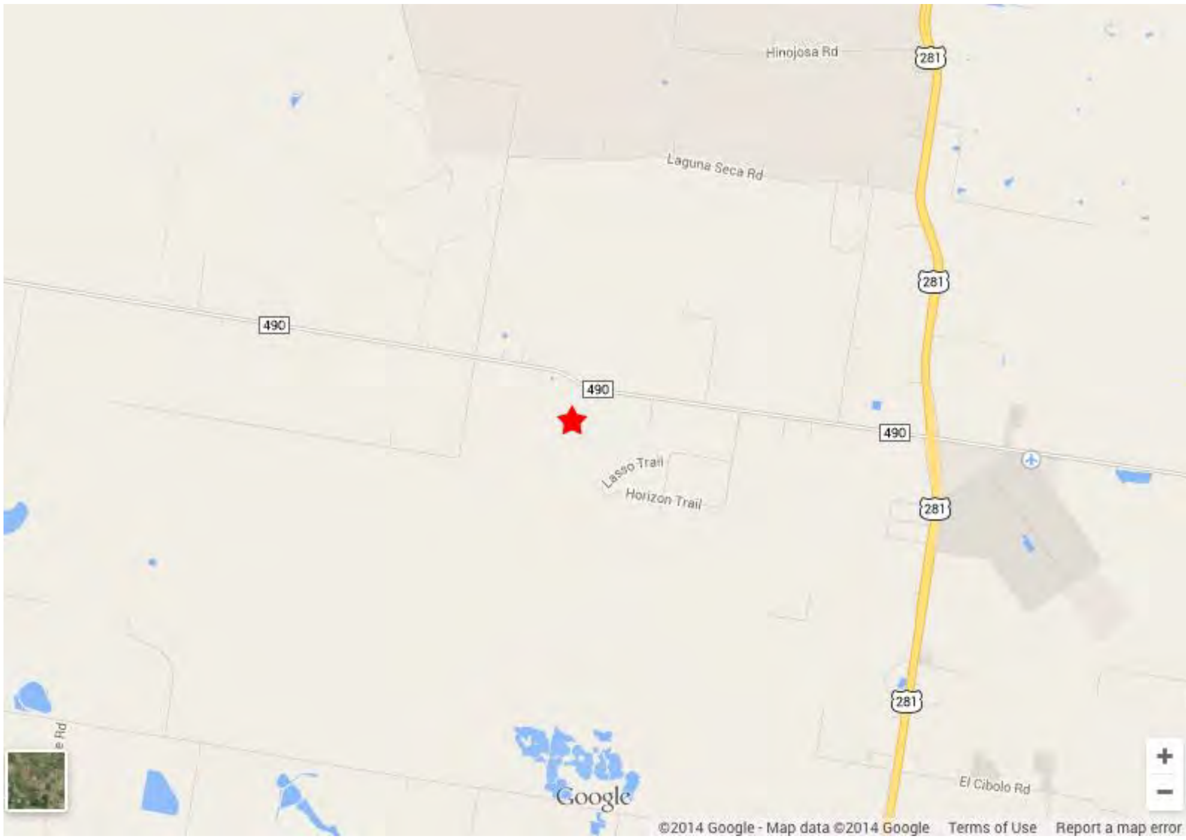
IV. Facility Location

The proposed project is located in Hidalgo County, Texas. Hidalgo County is currently designated attainment/unclassifiable for all criteria pollutants as per 40 CFR Part 81. The proposed plant site is located on undeveloped land in Edinburg, approximately 2.5 miles west of Texas State Highway 281, with Farm-to-Market Road 490 forming the northern border. The nearest Class I area, Big Bend National Park is approximately 600 km (373 miles) from the proposed site.

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

Latitude: 26° 27’ 2.3292”
Longitude: -98° 10’ 35.4462”

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



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

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. On June 23, 2014, the United States Supreme Court issued a decision addressing the application of stationary source permitting requirements to GHGs. *Utility Air Regulatory Group v. Environmental Protection Agency* (No. 12-1146). The Supreme Court said that the EPA may not treat GHGs as an air pollutant for purposes of determining whether a source is a major source required to obtain a PSD or Title V permit. The court also said that EPA could continue to require that PSD permits that are otherwise required based on emissions of conventional pollutants contain limitations on GHG emissions based on the application of Best Available Control Technology (BACT). Pending further EPA engagement in the ongoing judicial process before the United States Court of Appeals for the D.C. Circuit, EPA is proposing to issue this permit consistent with EPA’s understanding of the Supreme Court’s decision.

The source is a major source because the facility has the potential to emit 398 tpy carbon monoxide (CO), 331tpy nitrogen oxides (NOx), 380 tpy volatile organic compounds (VOC), and 182 tpy total particulate matter (PM). In this case, the applicant represents that TCEQ, the permitting authority for regulated NSR pollutants other than GHGs, has determined the project is subject to PSD review for the following conventional regulated NSR pollutants CO, NOx, VOC, PM, PM_{10}, and $PM_{2.5}$.

The applicant also estimates that this same project will result in a GHG emissions increase and a net GHG emissions increase of 1,036,615 tpy CO_2e and 1,035,269 tpy on a mass basis, which well exceeds the GHG threshold in EPA regulations. 40 C.F.R § 52.21 (b)(49)(iv); see also, *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011) at 12-13. Since the Supreme Court recognized EPA's authority to limit application of BACT to sources that emit GHGs in greater than *de minimis* amounts, EPA believes it may apply the 75,000 tons per year CO_2e threshold in existing regulations at this time to determine whether BACT applies to GHGs at this facility.

This project continues to require a PSD permit that includes limitations on GHG emissions based on the application of BACT. The Supreme Court's decision does not materially limit the FIP authority and responsibility of Region 6 with regard to this particular permitting action. Accordingly, under the circumstances of this project, the TCEQ has issued the non-GHG portion of the permit and EPA will issue the GHG portion.

EPA Region 6 proposes to follow the policies and practices reflected in EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011). For the reasons described in 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. Instead, EPA believes 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 (PSDTX1322) issued by TCEQ on December 20, 2013.

VI. Project Description

According to the application, STEC is a wholesale generation and transmission electricity provider serving eight member distribution cooperatives over a 44-county area in South Texas. STEC represents that its member cooperatives represent a combined retail load of over 214,745 wires and 21,062 non-wires customers, and serves its member load with a resource portfolio incorporating lignite, natural gas, diesel, wind, and hydro-electric power from both owned and purchased resources. STEC's application explains that its system experienced strong growth in 2011 as a result of extreme weather conditions in both the summer and winter months, such that sales to member cooperatives increased 11.78% to 5,014,032 megawatt (MW) hours. STEC asserts that system peak load was 1242 MW, up over 10% from the 1127 MW peak load realized in 2010 and that strong system growth is expected to continue with a projected 219 MW capacity additions required to serve the STEC member load by 2017.

To respond to this increasing system growth, STEC has proposed the Red Gate Power Plant consisting of twelve (12) Wartsila 18V50SG reciprocating engines capable of producing a combined 225 MW of power. The Wartsila 18V50SG is a nominal 18.76 MW, four-stroke, spark-ignition, lean burn reciprocating internal combustion engine (SI RICE). The engines will be used to provide renewable support, transmission grid support, energy and ancillary services to meet its eight member distribution cooperatives' energy and capacity needs as well as to support the Energy Reliability Council of Texas (ERCOT) grid.

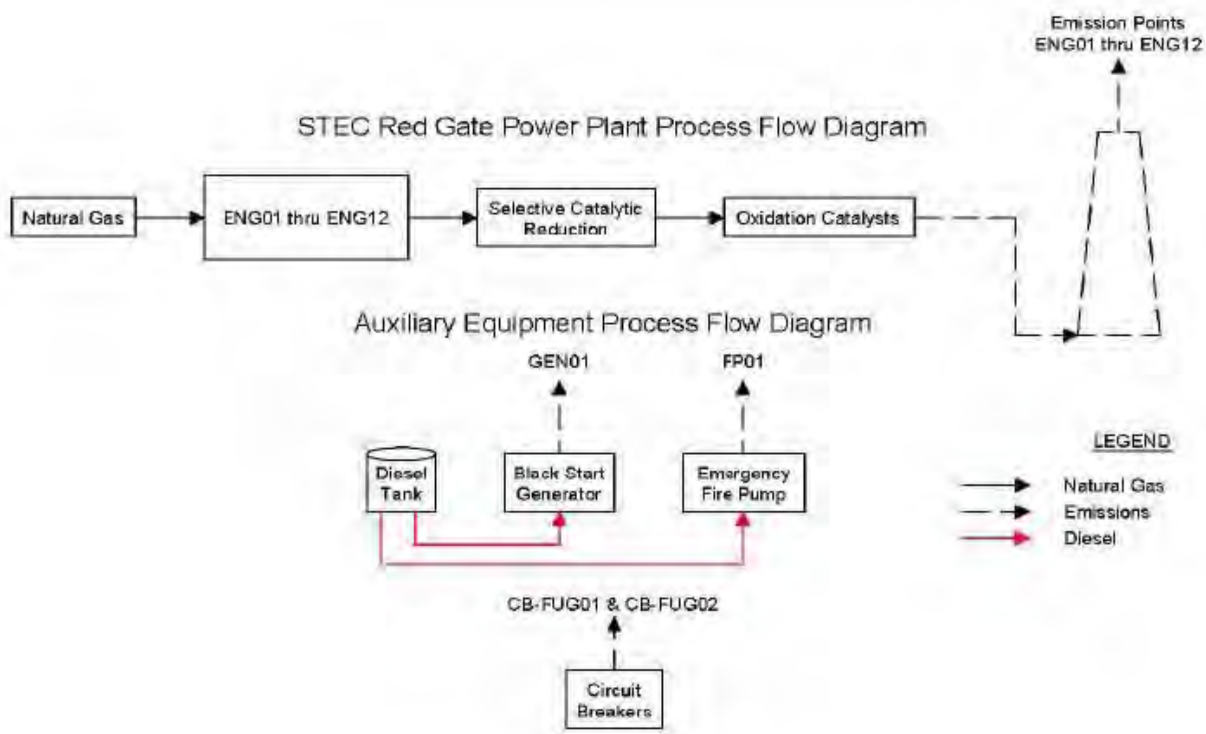
The influx of renewable energy into the ERCOT market and the variability associated with renewable technologies, such as wind and solar, put increased demands on grid stability. STEC has represented that larger baseload units are unable to respond adequately to the large swings in generation caused by connection of large quantities of renewables to the grid. Fast ramping, quick starting, natural gas-fired reciprocating internal combustion engines can help stabilize this volatility and enable the grid to handle the increase renewable profile. ERCOT has recognized this need and increased the amount of responsive reserve and regulation resources that are needed to support grid operations. This project's rapid start capability, combined with the dispatchable unit size, minimizes part load operation and results in greater overall plant efficiency and reduced emissions.

ERCOT load serving entities are required to procure their load ratio share of ancillary services to support reliable grid operation. These ancillary services include responsive reserve, regulation up, regulation down, and non-spinning reserve and may be purchased on the market or self provided. Quick start capability along with fast ramp rates and good part-load efficiency are essential qualities for units providing ancillary services. Since these services are awarded and paid on a capacity basis even if the service is not dispatched in real-time, they may artificially lower the energy cost and increase the dispatch of flexible simple cycle engine units, such as those proposed for Red Gate. STEC is forecasting that the engines' efficiency and flexibility, combined with dispatch from ERCOT for ancillary services and transmission support, will lead to dispatch levels that are considerably higher than comparably sized simple cycle turbine facilities.

Process Description and Process Flow Diagram

The Red Gate Power Plant will be comprised of twelve Wartsila 18V50SG nominal 18.76 MW four-stroke, spark-ignition, lean burn reciprocating internal combustion engines operating in simple cycle configuration (EPNs: ENG01 – ENG12). The engines will be fueled by pipeline quality natural gas and will be connected to air cooled generators to produce electricity. During starts and stops, a small amount of natural gas will be vented to atmosphere during the double block and bleed process that prevents accumulation of natural gas in the engine due to valve leakage when the engine is offline.

Exhaust gases from the combustion of the natural gas in ENG01 through ENG12 will flow through a catalyst module containing both oxidation catalyst and selective catalytic reduction (SCR) catalyst. Aqua ammonia (19%) will be injected upstream of the catalyst module for the SCR. Fugitives from the ammonia injection piping will be emitted at the facility. The ammonia fugitive emissions are collectively referred to in the permit as "NH3FUG." Auxiliary emission units will include a fire pump driven by a diesel-fueled engine (EPN FP01), a diesel fuel black-start generator (EPN GEN01), and electrical equipment insulated with sulfur hexafluoride (EPNs CB-FUG01 and CB-FUG02). Fugitive emissions from piping and equipment will be emitted from the facility (EPN NGFUG).



Reciprocal Combustion Engines

STEC is proposing to construct twelve identical, four-stroke, lean burn natural gas-fired engines to meet demand for peak power. The engines will be the Wartsila 18V50SG, each with a maximum base-load electric power output of approximately 18.76 megawatts (MW, nominal). The engines will fire natural gas and include selective catalytic reduction for control of NOx and an oxidation catalyst for control of CO and VOCs. Lean-burn engines utilize more air than is necessary for complete combustion to increase efficiency and reduce NOx emissions.

Diesel-fired Emergency Black Start Generator

The facility will also include one 500 kilowatt (kW) (670 hp) diesel-fired emergency black start generator. The generator is intended to provide black start capability for the ERCOT market. The function of the generator is to provide the plant with emergency back-up power in case of disconnection with the grid, and non-emergency operation of the generator (for maintenance and testing) no more than 100 hours per year.

Fire Water Pump

The site will be equipped with one nominally rated 150-hp diesel-fired firewater pump engine to provide water in the event of a fire. The firewater pump engine will be limited to 100 hours per year of non-emergency operation for purposes of maintenance checks and readiness testing.

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 capacity of the circuit breakers associated with the proposed plant is currently estimated to be two large circuit breakers with a capacity of 200 pounds of SF_6 each. The proposed circuit breakers will have a low pressure alarm.

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 natural gas pipeline will be routed underground to the plant site. Within the plant site, the natural gas pipeline will be routed mostly underground utilizing welded joints, except within the gas yard and immediately outside the two engine hall buildings, where access to the flange connections are required to allow for maintenance on equipment. The CO_2e from fugitive emissions are estimated to total 270.9 tpy and will account for less than 0.025% of the project's total CO_2e emissions.

VII. General Format of the BACT Analysis

The BACT analyses for this draft permit were conducted in accordance with EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011; hereinafter "*GHG Permitting Guidance"*), 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, STEC provided a 5-step, top-down BACT analysis for the proposed Red Gate project in the GHG permit application. EPA has reviewed STEC's BACT analysis, which has been incorporated into this SOB, and also provides its own analysis in setting forth BACT for this proposed permit. EPA's BACT analysis is provided below.

VIII. Applicable Emission Units and BACT Discussion

Combustion sources (e.g., engines ENG01 – ENG12) represent the majority contribution of GHGs associated with the project. The site has some fugitive emissions from piping components that contribute an insignificant amount of GHGs. This source primarily emits carbon dioxide (CO_2) and small amounts of nitrous oxide (N_2O), methane (CH_4) and sulfur hexafluoride (SF_6). Greenhouse gas emissions will result from the following emission units:

- Twelve Spark-Ignition Reciprocating Internal Combustion Engines (EPNs: ENG01, ENG02, ENG03, ENG04, ENG05, ENG06, ENG07, ENG08, ENG09, ENG10, ENG11, ENG12);
- One Diesel-fired Emergency Black-Start Generator (EPN: GEN01);
- One Fire Water Pump (EPN: FP01);
- Fugitive Emissions from SF_6 Circuit Breakers (EPNs: CB-FUG01 and CB-FUG02); and,
- Fugitive Emissions from Piping Components (EPN: NGFUG).

IX. Natural Gas-Fired SI RICE BACT Analysis (EPNs: ENG01 – ENG12)

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. *GHG Permitting Guidance* at 24.

- *Carbon Capture and Storage (CCS)* – CCS is classified as an add-on pollution control technology, which involves the separation and capture of CO_2 from flue gas, pressurizing of the captured CO_2 into a pipeline for transport, and injection/storage within a geologic formation. CCS is generally applicable 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)."

  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 natural gas fired power plant 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 IC engine facility; the third approach, post-combustion capture, is applicable to natural gas-fired RICE.

  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), which would have similar exhaust streams as RICE. As such, post-combustion capture using MEA is the sole carbon capture technology considered as available in this BACT analysis.

Once CO_2 is captured and compressed from the flue gas, 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.[1] For purposes of this analysis, the closest area for consideration of EOR is the "Candidate EOR reservoir(s)" in Starr County as identified in the NETL atlas IV, ARRA Site Characterization Projects section, p. 109.[2] This site is approximately 40 miles away from the proposed Red Gate Power Plant.

- *Combined-cycle Gas Turbines* – Consideration of the use of a combined cycle combustion turbine.
- *SI RICE Design Efficiency* – Selection of a high efficiency design and emission unit for the natural gas-fired SI RICE.
- *Fuel Selection* – 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.
- *Good Combustion, Operating, and Maintenance Practices* – Good combustion, operating, and maintenance practices are a potential control option for improving the fuel efficiency of the RICE.

Step 2 – Elimination of Technically Infeasible Alternatives

EPA generally considers a technology to be technically feasible if it: (1) has been demonstrated and operated successfully on the same type of source under review, or (2) is available and applicable to the source type under review. *GHG Permitting Guidance* at 33.

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 reciprocal internal combustion engine units operating multiple starts and stops to respond to electricity demand dispatch requirements. The proposed STEC project is a highly cyclical operation with up to 730 startups and 730 shutdowns per year., and it is unclear how 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 SI RICE, 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. Further, EPA

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[1] U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory *Carbon Sequestration Program: Technology Program Plan*, <http://www.netl.doe.gov/technologies/carbon_seq/refshelf/2011_Sequestration_Program_Plan.pdf>, February 2011

[2] <http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlasIV/index.html>

is not aware of any CCS system that is commercially available at this time for RICE engines that operate in a cycling mode. Therefore, we believe carbon capture is not technically feasible for the RICE engines at this facility and may be eliminated from the SI RICE BACT analysis on this basis, but we are providing further economic justification in Step 4 of the BACT analysis for why CCS is not economically feasible for this project.

Combined-cycle Gas Turbines: The *GHG Permitting Guidance* notes that combined cycle combustion turbines, in many applications, may be more efficient than simple-cycle operations. *Id.* at 29. In a typical combined cycle turbine, the use of a heat recovery steam generator (HRSG) allows the production of more electricity without the additional fuel consumption.

In determining the technical feasibility of a control technology, it is appropriate to consider whether the technology may reasonably be deployed on, or is applicable to, the source type under consideration. When selecting a type of generation, it is important to match the generation resource to the load in the most efficient and reliable manner possible. STEC has proposed to utilize the Wartsila 18V50SG because of its power generation capabilities and flexibility. Within two minutes of operation, the 18V50SG can provide up to 10% of its power load to the grid. In seven minutes, total start-up and full load can be accomplished. Shutdown and unloading can occur within one minute. Fuel efficiency remains relatively stable (approximately 45% efficient) from 10MW up to 225MW load.

Combined cycle turbine configurations do not meet the turndown requirements for the plant. An additional concern with the use of a combined-cycle configuration is the thermal mechanical fatigue due to the number of startups and shutdowns. By shutting down when the demand abates, a SI RICE may shut down faster than a combined cycle turbine and therefore, reduce emissions that would otherwise have occurred with the use of a combined cycle turbine with a longer shutdown period. Considering the STEC need for operational flexibility to turndown to at least 10MW as well as to startup and shutdown multiple times daily, the selection of a combined cycle facility is technically infeasible for the purpose of the proposed project.

The remaining control options identified in Step 1 are considered technically feasible and are being proposed for Step 3 analysis.

Step 3 – Ranking of Controls

- *Carbon Capture and Storage,*
- *SI RICE Design Efficiency,*
- *Fuel Selection,*
- *Good Combustion, Operating, and Maintenance Practices,*

STEC considered alternative engines for the proposed project. For this analysis, the efficiencies of the comparable RICE, the Caterpillar G20CM34 and the MAN 20V35/44G, are as follows:

RICE Model	Base Rating (MW)	Number of Engines	Heat Rate (Btu/kWh)	Efficiency (%)
Wartsila 18V50SG	18.76	12	8,302	48.6
Caterpillar G20CM34	10	24	8,512	45.7
MAN 20V35/44F	10.2	24	8,450[3]	47.3

With the differing nominal engine ratings, the number of engines required to meet Red Gate's demand of 220MW to 240MW would vary depending on the manufacturer. The proposed operating load range of Red Gate is stated to be roughly 40% to 100%. The Wartsila engine 18V50SG has the highest efficiency over the proposed operating load range and meets the turn down requirements for the plant.

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 general, natural gas combustion in RICE, such as that selected for this project, results in lower GHG emissions than RICE using diesel for compression ignition.

Step 4 – Economic, Energy and Environmental Impacts

Carbon Capture and Storage: STEC developed a cost analysis for CCS as an add-on control option for the proposed Red Gate project and a detailed analysis is available for review in the appendix to this document. EPA Region 6 reviewed STEC's CCS cost estimate and believes it adequately approximates the cost of a CCS control for this project. The majority of the cost for CCS is attributed to the capture and compression facilities that would be required. STEC estimated the capital cost to add CCS at the Red Gate plant is over $325 million. STEC estimated the total cost of the project with CCS to be $525 million and approximately $200 million without CCS. Based on STEC's assessment, the addition of CCS would increase the total capital project costs by more than 100%. Another tradeoff from the addition of CCS is the necessity for more water and land use. Approximately 44% more water may be needed for cooling applications using a carbon capture process. Thus, even if CCS were technically feasible, it would not be economically feasible for this project.

- *SI RICE Design Efficiency:* STEC elects to use the Wartsila engine 18V50SG, which has the highest efficiency over the proposed operating load range and meets the turn down requirements for the proposed Red Gate plant. There are no economic, energy or environmental impacts that warrant elimination of this control option.

- *Fuel Selection:* As discussed in Step 3, natural gas produces the lowest GHG emissions and is the top ranked option. There are no economic, energy or environmental impacts that warrant elimination of this control option.

- *Good Combustion, Operating, and Maintenance Practices:* Good combustion, operating, and maintenance practices are a control option for improving the fuel efficiency of the engines. The natural gas-fired SI RICE will operate in a lean pre-mix mode to ensure effective staging of air/fuel ratios; thus, maximizing fuel efficiency and minimizing incomplete combustion. The engines' operation is automated to ensure optimal fuel combustion and efficient operation

[3] Conversion from LHV provided by the manufacturer.

leaving virtually no operator ability to further tune these aspects of operation. Good combustion practices also include proper maintenance and tune-up of the SI RICE system per the manufacturer's specifications. There are no economic, energy or environmental impacts that warrant elimination of this control option

Step 5 – Selection of BACT

To date, other similar RICE 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
Port Dolphin Energy LLC Hillsborough, FL	Power Generator Engine (two 11,400 kW dual fuel Wartsila engines and one 5700 kW dual fuel Wartsila engine)	Use of efficient engine design and use of primarily natural gas	181.0 g/KW-H for natural gas (8-hr rolling average) when firing natural gas 253.0 g/KW-H (8-hr rolling average) when firing low sulfur diesel	2011	DPA-EPA-R4001
Mid-Kansas Electric Company, Rubart Station Grant County, KS	Spark ignition 4 stroke lean burn reciprocating internal combustion engine (24 Caterpillar model G20CM34)	Energy Efficiency/ Good Design & Combustion Practices, use of natural gas	GHG BACT limit of 1.25 lb CO_2/kWh at all times except during startup, 12-month rolling average (~1,250 lb CO_2/MWh)	2013	0670173 C-10021
Lacey Randall Generation Facility, LLC Thomas County, KS	Spark ignition 4 stroke lean burn reciprocating internal combustion engine (10 Wartsila 20V34SG)	Good combustion practices, efficient lean-burn engines and use of natural gas	GHG BACT limit of 1.08 lb CO_2/kWh at all times except during startup, 12-month rolling average (~1,080 lb CO_2/MWh)	2014	1930036 C-10593

From this analysis, EPA has concluded that the GHG BACT for Red Gate is the use of new natural gas-fired, thermally efficient SI RICE combined with good combustion and maintenance practices to maintain optimum efficiency. EPA believes that the applicant's proposal to use the Wartsila 18V50SG is consistent as the BACT requirement. The proposed output based emission limit is 1,145 lb CO_2/MWh on a 12-month rolling average, which is consistent with the recent RICE power generation projects permitted as shown above. In order to account for factors such as tolerances in manufacturing and construction of equipment, ambient operating conditions and seasonal variation, as well as losses in efficiency over the life of the equipment a 9% compliance margin has been applied to the proposed emissions limit. The engines shall meet the requirements of 40 CFR Part 60 Subpart JJJJ.

BACT During Startup and Shutdown

The output-based emission limit of 1,145 lb CO_2/MWh on a 12-month rolling average applies during all periods of engine operation, including startup and shutdown. STEC is proposing 730 startups/shutdowns per year per engine. BACT for startup/shutdown is also the work practice standard to utilize good pollution control practices, safe operating practices and protection of the facility and to limit the number of startups per year to 730 startups/shutdowns per engine on a 12-month rolling basis.

BACT Compliance:

BACT for each engine is 1,145 lb CO_2/MWh. Compliance will be demonstrated by determining CO_2 mass emissions using the Tier 1 Calculation Methodology from 40 CFR Part 98 with continuous monitoring of fuel metered to each engine. The gross output (MWh) will be continuously monitored for each engine by a power monitoring unit. The CO_2 mass emission will be divided by the gross output to yield an output-based emission rate per engine for comparison to the emission limit. Record keeping will be accomplished by a data acquisition and handling system with a back-up data historian. STEC will comply with the applicable provisions of 40 CFR Part 98, including reporting.

Compliance will be based on a 12-month rolling average, calculated daily for each engine. STEC will maintain records of tune-ups, startups and shutdowns for each engine. In addition, records of fuel temperature, ambient temperature, and stack exhaust temperature will be maintained for each engine. For each engine, 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, and gross hourly energy output (MWh).

The permittee shall use the metered fuel consumption and emission factors for natural gas from 40 CFR Part 98 Subpart C, Table C-1 and/or fuel composition and mass balance. The equation for estimating CO_2 emissions as specified in 40 CFR § 98.33(a)(1)(i) is as follows:

$$CO_2 = 1x10^{-3} * Fuel * HHV * EF$$

Where:

CO_2 = Annual CO_2 mass emissions for the specific fuel type (metric tons).
Fuel = Mass or volume of fuel combusted per year, from company records as defined in 40 CFR § 98.6 (express volume in gallons)
HHV = Default high heat value of the fuel, from Table C-1 of this subpart (mmBtu per mass or mmBtu per volume as applicable).
EF = Fuel-specific CO_2 emission factor from Wartsila
$1x10^{-3}$ = Conversion factor from kilograms to metric tons

To calculate the CO_2e emissions, the draft permit requires calculation of the emissions based on the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1. Records of the calculations would be required to be kept to demonstrate compliance with the emission limits on a 12-month rolling total, calculated daily. An initial stack test demonstration will be required for CO_2 emissions from each emission unit.

With regard to CH_4 and N_2O emissions from the RICE, we noted that these emission are less than 0.1% of the total CO_2e emissions from the engines. Accordingly, the proposed permit includes CH_4 and N_2O emission limits based on use of emission factors provided in 40 CFR Part 98, Table C-2 and the actual heat input (HHV) from the engine, and does not require additional emissions analyses or initial stack test demonstrations for CH_4 and N_2O emissions.

X. Diesel-fired Emergency Black-Start Generator (EPN: GEN01)

Red Gate will be equipped with one 500-kW diesel-fired emergency black-start generator to provide electricity to the facility in the case of power failure.

Step 1 – Identification of Potential Control Technologies

- *Low Carbon Fuels* – Engine options includes 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. The engine will be limited to a total of 100 hours of non-emergency operation on a 12-month rolling basis for maintenance and testing.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible except low carbon fuels.

Low Carbon Fuels – The purpose of this generator is to provide a power source during emergencies, which includes outages of the RICE, natural gas supply outages, and natural disasters. Electricity and natural gas may not be available during an emergency and therefore cannot be used as an energy source for the emergency generator and are eliminated as technically infeasible for 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. Gasoline fuel has a much higher volatility than diesel, and is thus less safe for use in an emergency situation. It also cannot be stored for long periods of time, which may be necessary for emergency use. Therefore, gasoline is eliminated as infeasible for this emergency engine.

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 generator:

- *Good Combustion Practices and Maintenance* – Good combustion practices for compression ignition engines include appropriate maintenance of equipment, annual tune-ups, and operating within the recommended air to fuel ratio, as specified by its design.
- *Low Annual Capacity Factor* – The emergency engine will not be operated more than 100 hours of non-emergency operation per year. Non-emergency operation will only be for maintenance and testing. Compliance will be based on runtime hour meter readings on a 12-month rolling basis.

The generator shall meet the requirements of 40 CFR Part 60 Subpart IIII.

XI. Fire Water Pump (EPN: FP01)

Red Gate will be equipped with one nominally rated 15-hp diesel-fired pump engine to provide water in the event of a fire.

Step 1 – Identification of Potential Control Technologies

- *Low Carbon Fuels* – Engine options includes 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. The emergency engine will be limited to 100 hours per 12-month rolling average of non-emergency operation for purposes of maintenance checks and readiness testing.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible except low carbon fuels.

Low Carbon Fuels – The purpose of the fire water pump engine is to supply water in the even to a fire at the facility, which may include outages of the RICE, natural gas supply outages, and natural disasters. Electricity and natural gas may not be available during a fire and therefore cannot be used as an energy source for the fire water pump engine and are eliminated as technically infeasible for this facility. The engine must be powered by a liquid fuel that can be stored on-site in a tank and supplied to the engine on demand, such as gasoline or diesel. Gasoline fuel has a much higher volatility than diesel, and is thus less safe for use in an emergency situation. It also cannot be stored for long periods of time, which may be necessary for emergency use. Therefore, gasoline is eliminated as infeasible for the fire water pump engine.

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 fire water pump:

- *Good Combustion Practices and Maintenance* – Good combustion practices for compression ignition engines include appropriate maintenance of equipment, and operating within the recommended air to fuel ratio, as specified by its design.
- *Low Annual Capacity Factor* – The fire water pump will not be operated more than 100 hours of non-emergency operation per year. Non-emergency operation will only be for maintenance and readiness testing. Compliance will be based on runtime hour meter readings on a 12-month rolling basis.

The engine shall meet the requirements of 40 CFR Part 60 Subpart IIII.

XII. Fugitive Emissions from SF_6 Circuit Breakers BACT Analysis (EPNs: CB-FUG01 and CB-FUG02)

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 is currently estimated to be two (2) breakers of 200 lb SF_6 each.

Step 1 – Identification of Potential Control Technologies for GHGs

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

- *Alternative Dielectric Material* – Because SF_6 has a high GWP, one alternative considered in this analysis is to substitute another non-GHG substance for SF_6 as the dielectric material in the breakers. Potential alternatives to SF_6 were addressed in the National Institute of Standards and Technology (NIST) Technical note 1425, *Gases for Electrical Insulation and Arc Interruption: Possible Present* *and Future Alternatives to Pure SF_6*.[4] The alternatives considered include mixtures of SF_6 and nitrogen, gases and potential gases for which little experimental data are available.

Step 2 – Elimination of Technically Infeasible Alternatives

Circuit breaker design efficiency is considered technically feasible and is carried forward for Step 3 analysis.

Alternative Dielectric Material – According to the report NIST Technical Note 1425, SF_6 is a superior dielectric gas among the alternatives examined in the report 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 mixture of SF6 and nitrogen is noted to need further development and may only be applicable in limited installations. The second alternative of various gases and mixtures needs additional systematic study before the alternative could be considered technically feasible. The third alternative of potential gases has not been demonstrated in practice, and there is little experimental data available to examine applicability. Therefore, based on the information contained in this report, "it is clear that a significant amount of research must be performed for any new gas or gas mixture to be used in electrical equipment." Consequently, because the alternative dielectric material options have not been demonstrated in practice for this project's circuit breakers and there is insufficient data to determine whether they are commercially available or applicable to the circuit breakers, this alternative is considered technically infeasible and excluded from the remainder of this BACT analysis.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

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

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

Since the only remaining technically feasible control identified in Step 1 is being proposed for the engines, an evaluation of the most effective controls is not necessary.

Step 5 – Selection of BACT

State-of-the-art, enclosed-pressure SF_6 circuit breakers with leak detection is concluded to be BACT. The circuit breakers will be designed to meet the latest of the American National Standards Institute (ANSI) C37.06 AND C37.010 standards for high voltage circuit breakers.[5] The proposed circuit breaker at the generator output will have a low pressure alarm and a low pressure lockout. This alarm will

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[4] 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

[5] 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*.

function as an early leak detector that will bring potential fugitive SF_6 emissions problems to light before a substantial portion of the SF_6 escapes. The lockout prevents any operation of the breaker due to lack of "quenching and cooling" SF_6 gas.

BACT compliance will be demonstrated by STEC through annual monitoring emissions in accordance with the requirements of the Mandatory Greenhouse Gas Reporting rules for Electrical Transmissions and Distribution Equipment Use.[6] 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: NGFUG)

Emissions from piping components (valves and flanges) associated with this project consist of methane (CH_4) and carbon dioxide (CO_2). Because a majority of the GHG fugitives comes from methane and the GWP is higher for methane, a conservative estimate was done to assume that all piping components are in a rich methane stream. Even with that conservative estimate, fugitive emissions account for less than 0.02% of the project's total CO_2e emissions.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Leakless/Sealless Technology*
- *Instrument Leak Detection and Repair (LDAR) program*
- *Remote sensing technology, such as infrared camera monitoring*
- *Auditory/Visual/Olfactory (AVO) monitoring program*
- *Use of High Quality Components and Materials*

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

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

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

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

[6] See 40 CFR Part 98 Subpart DD.

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 CH4. However, because pipeline natural gas is odorized with very small quantities of mercaptan, AVO observation is a very effective method for identifying and correcting leaks in natural-gas systems. Due to the pressure and other physical properties of plant fuel gas, AVO observations of potential fugitive leaks are likewise moderately effective.

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

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

Although the use of leakless components, 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 as compared to AVO methods is considered very small in comparison to the total project's proposed CO_2e emissions. The Red Gate facility is not subject to any regulations requiring an LDAR program, thus any additional controls and monitoring would be done solely for GHG emissions from natural gas fugitives. Accordingly, given the costs of implementing leakless components (wich are estimated to be 3 to 10 times higher than comparable high quality valves), 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 at this project and are eliminated in this BACT analysis.

Step 5 – Selection of BACT

Based on the economic impracticability of instrument monitoring and remote sensing for fuel gas and natural gas piping components, STEC proposes to incorporate AVO as BACT for the piping components associated with this project in fuel gas and natural gas service. The proposed permit contains a condition to implement an AVO program 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) prepared by Blanton & Associates, Inc. (Blanton) on behalf of the applicant, South Texas Electric Cooperative, Inc. Red Gate Power Plant (Red Gate), and EPA, thoroughly reviewed and adopted by EPA.

The draft BA identifies ten species as federally endangered or threatened in Hidalgo and Starr Counties, Texas:

Federally Listed Species for Hidalgo and Starr Counties by the U.S. Fish and Wildlife Service (USFWS) and the Texas Parks and Wildlife Department (TPWD)	**Scientific Name**
Birds	
Northern Aplomado Falcon	*Falco femoralis septentrionalis*
Interior least tern	*Sterna antillarum athalassos*
Flowering Plants	
Ashy Dogweed	*Thymnophylla tephroleuca*
Johnston's Frankenia	*Frankenia johnstonii*
Star Cactus	*Astrophytum asterias*
Texas Ayenia	*Ayenia limitaris*
Walker's Manioc	*Manihot walkerae*
Zapata Bladderpod	*Lesquerella thamnophila*
Mammals	
Gulf Coast Jaguarundi	*Herpailurus yaguarondi*
Ocelot	*Leopardus pardalis*

EPA has determined that issuance of the proposed permit to Red Gate for twelve natural gas-fired internal combustion engines at a new electric generation facility and associated natural gas pipeline will have no effect on the ten federally-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. EPA hosted a conference call on August 27, 2014, with Blanton and the U.S. Fish and Wildlife Service (USFWS) Corpus Christi Field Office in which USFWS reviewed the draft BA and confirmed the determinations of "no effect" on the federally-listed species.

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 and adopted a cultural resource report prepared by Blanton, a consultant to Red Gate.

For purposes of the NHPA review, the Area of Potential Effect (APE) was determined to be two components: first, the construction footprint of the proposed power plant, approximately 336 acres, located approximately 3.85 miles northwest of Faysville, Texas, and second, a 24.5-mile natural gas pipeline and associated 300-foot right-of-way measuring approximately 891 acres. Blanton performed a field survey of the property and a desktop review on the archeological background and historical records within several miles of the entire 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 results of the field survey, which included shovel testing, no archeological resources or historic structures eligible for listing on the National Register of Historic Places were found within the APE. Based on the desktop review, no cultural resource sites eligible for listing on the National Register of Historic Places were identified within a one-mile radius of the APE.

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

On August 7, 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 submitted a copy of the final draft of the cultural report to the State Historic Preservation Officer (SHPO) for consultation and requested concurrence with its determination on September 5, 2014. 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 [*GHG Permitting Guidance* 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 STEC, our review of the analyses contained in the TCEQ PSD Permit and Permit Application, 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 STEC 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.

Table 1. Annual Emission Limit

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[1,2]	BACT Requirements
				TPY[1]		
ENG01 ENG02 ENG03 ENG04 ENG05 ENG06 ENG07 ENG08 ENG09 ENG10 ENG11 ENG12	ENG01 ENG02 ENG03 ENG04 ENG05 ENG06 ENG07 ENG08 ENG09 ENG10 ENG11 ENG12	4 Stroke Lean Burn SI RICE	CO_2	86,271[3]	86,358.7[3]	- BACT limit of 1,145 lb CO_2/MW-hr (gross) on a 12-month rolling average basis. -See permit conditions III.A.
			CH_4	1.59[3]		
			N_2O	0.161[3]		
GEN01	GEN01	Diesel Black Start Emergency Generator	CO_2	13.94	13.98	- Not to exceed 100 hours of non-emergency operation on a 12-month rolling basis - Use of Good Combustion Practices. See permit conditions III.B.
			CH_4	No Numerical Limit Established[4]		
			N_2O	No Numerical Limit Established[4]		
FP01	FP01	Firewater Pump Engine	CO_2	3.10	3.11	-Not to exceed 100 hours of operation on a 12-month rolling basis - Use of Good Combustion Practices. See permit conditions III.C.
			CH_4	No Numerical Limit Established[4]		
			N_2O	No Numerical Limit Established[4]		
CB-FUG01 CB-FUG02	CB-FUG01 CB-FUG02	Fugitive SF_6 Circuit Breaker Emissions	SF_6	No Numerical Limit Established[5]	No Numerical Limit Established[5]	Work Practices. See permit conditions III.D.
NGFUG	NGFUG	Components Fugitive Leak Emissions	CO_2	No Numerical Limit Established[6]	No Numerical Limit Established[6]	Implementation of AVO LDAR Program. See permit conditions III.E.
			CH_4	No Numerical Limit Established[6]		

Totals[7]	**CO_2**	**1,035,269.36**	**1,036,615**	
	CH_4	**29.9**		
	N_2O	**1.93**		
	SF_6	**0.001**		

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. The GHG Mass Basis TPY limit and the CO2e TPY limit for the twelve (12) natural gas fired SI RICE applies to each engine and is not a combined limit.
4. These values indicated as "No Numerical Limit Established" are less than 0.01 TPY with appropriate rounding. The emission limit will be a design/work practice standard as specified in the permit.
5. SF_6 fugitive emissions from EPNs CB-FUG01 and CB-FUG02 are estimated to be 0.001 TPY of SF_6 and 22.8 TPY CO_2e. In lieu of an emission limit, the emissions will be limited by implementing a design/work practice standard as specified in the permit.
6. Fugitive Leak Emissions from EPN NGFUG are estimated to be 0.319 TPY CO_2, 10.824 TPY CH_4, and 270.9 TPY CO_2e. In lieu of an emission limit, the emissions will be limited by implementing a design/work practice standard as specified in the permit.
7. Total emissions include the PTE for fugitive emissions. Totals are given for informational purposes only and do not constitute emission limits.

Table 2. CCS Cost

Component	Cost
Conversion to CC	$41,870,000[(1)]
Cost of Process Water (annual)	$450,000[(2)]
CO_2 Capture[(3)]	$185,460,000 plus annual O&M costs
CO_2 Transport[(4)]	$46,160,336 plus $338,160 annual O&M costs
CO_2 Storage and Monitoring[(5)]	$51,510,000
TOTAL	$325,450,336

(1) Preliminary estimate provided by Wartsila for 12 engine combined cycle plant.
(2) Based on increased water withdrawal rates in NETL "*Cost and Performance Baseline for Fossil Energy Plants*, Volume 1: Bituminous Coal and Natural Gas to Electricity," Revision 2, November 2010, Exhibit 5-27 for NGCC with and without CCS (4.1 gpm/MW_{net}) and a 30% capacity factor for usage of 142 million gallons per year, and water rates from the City of Edinburg.
(3) Based on difference in $/kW for NGCC with and without CCS ($843/kW, Case 14 – Case 13) in NETL "*Cost and Performance Baseline for Fossil Energy Plants*, Volume 1: Bituminous Coal and Natural Gas to Electricity," Revision 2, November 2010, and 220,000 kW.
(4,5) Based on NETL Quality Guidelines for Energy Systems Studies calculations, see below for details.

Table 3. CCS Pipeline Cost

Pipeline Capital Costs		
Component	**Equation, D = diameter (in), L = length (mi)**	**Cost**
Materials	$70,350 + $2.01 x L x (330.5 x D^2 + 686.7 x D + 26,960)	$4,380,240
Labor	$371,850 + $2.01 x L x (343.2 x D^2 + 2,704 x D + 170,013)	$17,140,862
Miscellaneous	$147,250 + $1.55 x L x (8,417 x D + 7,234)	$21,469,918
Right-of-way	$51,200 + $1.28 x L x (577 x D + 29,788)	$1,812,685
Other Capital Costs		
CO_2 Surge Tank	Units = $	$1,244,724
Pipeline Control System	Units = $	$111,907
Pipeline O&M Costs		
Fixed O&M	$8,454 x mile/year	$338,160/year