Statement of Basis

Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit for Cheniere Corpus Christi Pipeline, L.P. Sinton Compressor Station

Permit Number: PSD-TX-1304-GHG

February 2014

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

I. Executive Summary

On August 31, 2012, Cheniere Corpus Christi Pipeline, L.P. (CCCP), submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for greenhouse gas (GHG) emissions from the proposed Sinton Compressor Station. At EPA's request, CCCP submitted additional information on January 14, 2013. Representatives of CCCP and Region 6 met on February 12, 2013, and additional information was submitted by CCCP on March 22, 2013. In addition to GHGs, the proposed compressor station will require PSD review for NOx, PM, PM_{10}, $PM_{2.5}$, and CO. CCCP submitted a concurrent application to the Texas Commission on Environmental Quality (TCEQ) for PSD review for those pollutants. The proposed compressor station is being constructed to serve CCCP's Corpus Christi pipeline, which will connect five inter- and intrastate pipelines. Natural gas will be piped to the compressor station, where it will be compressed for further transport in the pipeline by two natural gas-fired combustion turbines. In addition to the turbines, there will be an emergency generator onsite.

EPA concludes that CCCP's application is complete and provides the necessary information to demonstrate that the proposed project meets the applicable air permit regulations. EPA's conclusions rely upon information provided in the permit application, supplemental information requested by EPA and provided by CCCP, and EPA's own technical analysis.

II. Applicant

Cheniere Corpus Christi Pipeline, L.P.
700 Milam Street, Suite 800
Houston, TX 77002

Facility Physical Address:
From the city of Sinton, TX, proceed northeast on U.S. Highway 77 and turn left onto Edwards Road in approximately 3.6 miles. Proceed northwest for approximately 1.2 miles. Compressor station site will be on the right.

Contact:
Andrew Chartrand
Director, Environmental and Regulatory Projects
Cheniere Energy, Inc.
(713) 375-5429

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). The State of Texas still retains approval of its plan and PSD program 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:
Aimee Wilson
Air Permitting Section (6PD-R)
(214) 665-7596

IV. Facility Location

The proposed compressor station will be constructed in San Patricio County, Texas, and this area is currently designated "attainment" for all NAAQS. The nearest Class 1 area is the Big Bend National Park, which is located over 100 miles from the site. The geographic coordinates for this facility are as follows:

Latitude: 28° 5' 29.328" North
Longitude: -97° 29' 36.877" West

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

Figure 1: Sinton Compressor Station

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

EPA concludes that CCCP's application is subject to PSD review for the pollutant GHGs, because the project would lead to an emissions increase of GHGs for a facility as described at 40 CFR section 52.21(b)(49)(v). The source is a new major source for PSD and the project exceeds the threshold of 100,000 tpy CO_2e (and equals or exceeds 100/250 TPY CO_2e mass basis). CCCP calculates CO_2e emissions of 175,064 TPY. EPA Region 6 implements a GHG PSD FIP for Texas under the provisions of 40 CFR section 52.21 (except paragraph (a)(1)). *See,* 40 CFR section 52.2305.

The applicant represents that the source emits regulated NSR pollutants other than GHGs below the major source thresholds and that PSD review applies to the construction solely because the source emits GHGs above the thresholds described above. The applicant acknowledges that under 40 CFR 52.21 and EPA guidance, PSD review is additionally required for all accompanying increases of regulated NSR pollutants other than GHGs that are increased or emitted at rates equaling or exceeding applicable significant emission rates. Accordingly, the applicant has applied for a preconstruction authorization from TCEQ and requested that the TCEQ apply applicable non-GHG PSD criteria for review and authorization of the projected significant increases of NOx, CO, PM, PM_{10}, and $PM_{2.5}$.[1] By a letter dated February 13, 2013, TCEQ has explained to EPA Region 6 the basis for TCEQ's view that it has the legal authority to issue permits meeting PSD requirements for regulated NSR pollutants other than GHGs for sources that are major sources based solely on the level of GHG emissions. Based on these representations by TCEQ, EPA has communicated that it has no objection to TCEQ's proposal to address regulated NSR pollutants other than GHGs in PSD permits issued in conformity with state law and TCEQ's EPA approved PSD rules.[2] Under the circumstances of this project, EPA will therefore issue a PSD permit covering GHG emissions, while the state will issue a PSD permit covering emission of all other regulated NSR pollutants increased or emitted in amounts equaling or exceeding the significant emissions rates.

EPA Region 6 applies the policies and practices reflected in the EPA document entitled "PSD and Title V Permitting Guidance for Greenhouse Gases" (March 2011). Consistent with that guidance, we have neither required the applicant to model or conduct ambient monitoring for GHGs, nor have we required any assessment of impacts of GHGs in the context of the additional impacts analysis or Class I area provisions. Instead, EPA has determined that compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs. We note again, however, that the project has triggered review for regulated NSR pollutants that are non-GHG

[1] The applicant has also sought TCEQ issuance of a nonattainment NSR permit for NOx (as an ozone precursor), because the project will constitute a "major source" of a nonattainment pollutant.
[2] Letter from EPA Region 6 Deputy Regional Administrator Samuel Coleman to TCEQ Executive Director Zak Covar (April 4, 2013).

pollutants under the PSD permit sought from TCEQ. Thus, TCEQ's PSD permit that will address regulated NSR pollutants other than GHGs, and should address the additional impacts analysis and Class I area requirements for other pollutants as appropriate.

VI. Project Description

CCCP is proposing to construct the Sinton Compressor Station to serve its Corpus Christi Pipeline which will connect five interstate and intrastate pipelines. The compressor station is designed for an annual average throughput capacity of 2.0 billion cubic feet (ft^3)/day of natural gas. Upon conveyance of natural gas to the compressor station, condensate will be separated and stored in an onsite storage tank for eventual removal/disposal. Two natural gas-fired turbines will compress the gas for onward transport throughout the Corpus Christi Pipeline. The compressed natural gas will pass through two cooling units before discharge into the pipeline. Suction and discharge blowdown stacks, as well as unit blowdown stacks will be constructed for use in the event of process upsets. Additionally, the facility will house an emergency generator. GHG emissions will be primarily generated as a result of combustion in the turbines and the emergency generator.

<u>Combustion Turbines</u>

The proposed project involves the construction of two (2) Solar Turbine 15.5 MW, natural-gas fired turbines (or their equivalent) for compression/transport of natural gas through the pipeline.

<u>Emergency Generator</u>

The proposed facility will also include one (1) 1,328 hp (.99 MW) natural gas-fired emergency generator (Waukesha or equivalent).

<u>Ancillary Equipment</u>

Additional equipment at the facility will include blowdown stacks, gas cooling units, and condensate storage tanks and offloading.

VII. General Format of the BACT Analysis

The BACT analyses were conducted in accordance with the *"Top-Down" Best Available Control Technology Guidance Document* outlined in the 1990 draft U.S. EPA *New Source Review Workshop Manual*, which outlines the steps for conducting a top-down BACT analysis. Those steps are listed below.

(1) Identify all potentially available control options;
(2) Eliminate technically infeasible control options;
(3) Rank remaining control technologies;
(4) Evaluate the most effective controls and document the results; and
(5) Select BACT.

VIII. Applicable Emission Units and BACT Discussion

The majority of the GHG emissions associated with the proposed compressor station will be generated by combustion sources. Stationary combustion sources primarily emit CO_2, but also emit relatively small amounts of N_2O and CH_4. Emissions from the following units or processes are within the scope of the BACT analysis submitted by CCCP in their application:

- Natural Gas-Fired Turbines
- Emergency Generator
- Blowdown Stacks
- Fugitive Emissions

IX. Combustion Turbines (EPNs: EQT006 and EQT007)

The proposed combustion turbines will be simple cycle, natural gas-fired units. They will be used in a compression application. They will be 15.5 MW Solar Titan 134-20502S or equivalent turbines with a minimum thermal efficiency of 36%, at ISO rated conditions. The turbines will be used to compress the natural gas for onward transport through the Corpus Christi Pipeline.

Step 1 – Identification of Potential Control Technologies for GHGs

- Carbon Capture and Storage (CCS)
- Post-combustion catalytic oxidation for CH_4 control
- N_2O catalysts
- Use of low carbon/N_2O emitting fuel
- Energy Efficiency and Good Design and Combustion Practices

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible for this project, except for carbon capture and storage, post-combustion catalytic oxidation, and N_2O catalysts.

Carbon Capture and Storage (CCS)

Carbon capture and storage is a GHG control process that can be used by "facilities emitting CO_2 in large concentrations, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing)."[3] The Sinton Compressor Station will neither emit CO_2 in large concentrations nor have a high-purity CO_2 stream (purity estimated to be in the range of approximately 4 – 5%). CCS has not been demonstrated in practice on low CO_2 concentration emission streams such as this. Although CCS technology is generally available from commercial vendors, we do not have information indicating that this technology can be applied to dilute emissions streams generated from combustion sources.

The three main approaches for CCS are pre-combustion capture, post-combustion capture, and oxyfuel combustion (IPCC, 2005[4]). 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[5]). At this time, oxyfuel combustion has not yet reached a commercial stage of deployment for gas turbine applications and still requires the development of oxy-fuel combustors and other components with higher temperature tolerances (IPCC, 2005). The third approach, post-combustion capture, is applicable to gas turbines.

With respect to post-combustion capture, a number of methods may potentially be used for separating the CO_2 from the exhaust gas stream, including adsorption, physical absorption, chemical absorption, cryogenic separation, and membrane separation (Wang et al., 2011[6]). Many of these methods are either still in development or are not suitable for simple cycle turbines. 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[7]), 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

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

[4]Intergovernmental Panel on Climate Change. (2005). *IPCC Special Report on Carbon Dioxide Capture and Storage*. Prepared by Working Group III of the Intergovernmental Panel on Climate Change [Metz, B., O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA. http://www.ipcc.ch/pdf/special-reports/srccs/srccs_wholereport.pdf

[5] U.S. Department of Energy. (2011). *DOE/NETL Advanced Carbon Dioxide Capture R&DProgram: Technology Update*. Retrieved from DOE website at http://www.netl.doe.gov/technologies/coalpower/ewr/pubs/CO2Handbook/

[6] Wang, M., Lawal, A., Stephenson, P., Sidders, J., & Ramshaw, C. (2011). Post-combustion CO2 capture with chemical absorption: A state-of-the-art review. *Chemical Engineering Research and Design*, 89, 1609-1624.

[7] Kvamsdal, H., Chikukwa, A., Hillestad, M., Zakeri, A., & Einbu, A. (2011). A comparison of different parameter correlation models and the validation of an MEA-based absorber model. *Energy Procedia*, 4, 1526-1533.

previously demonstrated in practice on gas turbines (Reddy, Scherffius, Freguia, & Roberts, 2003[8]). As such, it 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[9]). This process has been used successfully to capture 365 tons per day of CO_2 from the exhaust of a natural gas combined-cycle plant owned by Florida Power and Light in Bellingham, Massachusetts. The CO_2 capture plant was maintained in continuous operation from 1991 to 2005 (Reddy, Scherffius, Freguia, & Roberts, 2003[10]). As this technology is commercially available and has been demonstrated in practice on a combined-cycle plant, EPA generally considers it to be technically feasible for natural gas combined cycle turbines, but not technically feasible for simple cycle turbines.

In 2003, Fluor and BP completed a joint study that examined the prospect of capturing CO_2 from eleven *simple cycle* gas turbines at a BP gas processing plant in Alaska known as the Central Gas Facility (CGF) (Hurst & Walker, 2005[11]; Simmonds et al., 2003[12]). Although this project was not actually implemented, the feasibility study provides valuable information about the design of a capture system for simple-cycle applications, particularly with respect to flue gas cooling and heat recovery. Absorption of CO_2 by MEA is a reversible exothermic reaction. Before entering the absorber, the turbine exhaust gas must be cooled to around 50 ^{o}C to improve absorption and minimize solvent loss due to evaporation (Wang, 2011). In the case of the CGF design study, the flue gas would need to be cooled by feeding it first to a heat recovery steam generator (HRSG) for bulk removal of the heat energy and then to a direct contact cooler (DCC). It should be noted that while Hurst & Walker (2005) found that the HRSG could be omitted from the design for another type of source studied (heaters and boilers at a refinery), the DCC alone would be insufficient for the gas turbines due to the high exhaust gas temperature (480-500 ^{o}C). After the

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[8] Reddy, S., Scherffius, J., Freguia, S., & Roberts, C. (2003, May). *Fluor's Econamine FG PlusSM Technology: An Enhanced Amine-Based CO2 Capture Process*. Paper presented at the Second Annual Conference on Carbon Sequestration, Alexandria, VA.
[9] Fluor Corporation. (2009). Econamine FG Plus Process. Retrieved from http://www.fluor.com/econamine/Pages/efgprocess.aspx
[10] Reddy, S., Scherffius, J., Freguia, S., & Roberts, C. (2003, May). *Fluor's Econamine FG PlusSM Technology: An Enhanced Amine-Based CO2 Capture Process*. Paper presented at the Second Annual Conference on Carbon Sequestration, Alexandria, VA.
[11] Hurst, P., & Walker, G. (2005). Post-combustion Separation and Capture Baseline Studies for the CCP Industrial Scenarios. In Thomas, D.C., & Benson, S.M. (Eds.), *Carbon Dioxide Capture for Storage in Deep Geologic Formations, Volume 1* (pp. 117-131). Oxford: Elsevier Ltd.
[12] Simmonds, M., Hurst, P., Wilkinson, M.B., Reddy, S., & Khambaty, S., (2003, May). *Amine Based CO2 Capture from Gas Turbines*. Paper presented at the Second Annual Conference on Carbon Sequestration, Alexandria, VA.

MEA is loaded with CO_2 in the absorber, it is sent to a stripper where it is heated to reverse the reaction and liberate the CO_2 for compression. The heat for this regeneration stage comes from high- and intermediate-pressure steam generated in the HRSG. Excess steam from the CGF HRSGs would also be used to export electricity to the local grid.

The integral nature of the HRSG to the overall process for the CGF is notable because it would essentially require conversion of the turbines from simple-cycle to combined-cycle operation. Combined cycle turbines are not necessary for the Sinton Compressor Station due to the fact that they will not generate electricity or supply process heat at the facility. The Sinton Compressor Station has no need for the excess heat or power. Therefore, based on this information, we conclude carbon capture with an MEA absorption process is not feasible for the simple-cycle combustion turbines for this project.

<u>Post-Combustion Catalytic Oxidation</u>

The turbine exhaust is expected to contain less than 1 ppmv of CH_4. The exhaust gas CH_4 concentration is about two orders of a degree magnitude below the lower end of VOC concentration in streams which would typically be fitted with catalytic oxidation for control. Addition of post-combustion catalytic oxidation on the turbines for control of CH_4 is technically infeasible and will not be considered further in this analysis.

<u>N_2O Catalysts</u>

N_2O catalysts have been used to reduce N_2O emissions from adipic acid and nitric acid plants. The very low N_2O concentrations (<1ppm) present in the exhaust stream would make installation of N_2O catalysts technically infeasible. In comparison, the application of a catalyst in the nitric industry sector has been effective due to high (1,000 to 2,000 ppm) N_2O concentration in those exhaust streams. N_2O catalysts are eliminated as a technically feasible option for the proposed project.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- Low Carbon Fuel
- Energy Efficiency and Good Design and Combustion Practices

<u>Low Carbon Fuel</u>

Use of a low-carbon intensity (mass of carbon per MMBtu) fuel selection is a control option that can be considered a lower emitting process. The turbines will be fired with pipeline quality natural gas. This is the cleanest and lowest carbon fuel available for combustion in the turbines.

Energy Efficiency and Good Design and Combustion Practices

The turbines selected will have a minimum thermal efficiency of 36%. CCCP will ensure proper operation and maintain good combustion practices following the manufacturer's recommendations.

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

Low-Carbon Fuel

Natural gas will be the only fuel fired in the combustion turbines. Natural gas has the lowest carbon intensity of any available fuel for the combustion turbine. There are no negative economic, energy, or environmental impacts associated with this control technology.

Energy Efficiency and Good Design and Combustion Practices

Energy efficient design and good combustion practices ensure the turbines are operating efficiently, which uses less fuel causing fewer emissions. There are no negative economic, energy, or environmental impacts associated with this control technology.

Step 5 – Selection of BACT

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

Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
Copano Processing, L.P., Houston Central Gas Plant	Compressor Turbine with Waste Heat Recovery	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT is to maintain a minimum thermal efficiency of 40% with WHRU on a 12-month rolling average basis. This equates to 0.84 lb of CO_2e/hp-hr. Excluding WHRU the output based limit is 1.32 lb CO_2e/hp-hr	2013	PSD-TX-104949-GHG

The CCCP turbines have not yet been selected. For BACT purposes CCCP based their analysis on Solar Titan 134-20502S simple cycle turbines. Regardless of the turbine manufacturer and model selected, the turbine will meet the BACT limit established in the proposed permit and will have a minimum thermal efficiency of 36%. The turbines are similar to some of the turbines above, but unlike most of the turbines listed; CCCP will be using the turbines for compression and not for the generation of electricity. The only facility listed above that will utilize turbines for compression purposes is Copano Processing, Houston Central Gas Plant, but the Copano turbines operate as combined cycle units. Copano operates a cryogenic process train at the Houston Central Gas Plant, not a compressor station. Copano will meet a BACT limit of 40% thermal efficiency with Waste Heat Recovery Units (WHRU). The efficiency is equivalent to 0.84 lb CO_2/hp-hr with WHRU. The Copano turbines include waste heat recovery units (WHRU), whereas CCCP turbines do not have WHRU. The WHRUs on the Copano turbines make them more efficient. Copano uses the heat recovered through the WHRU to heat the inlet gas heater, regeneration heater, amine reboiler, and the trim reboiler. CCCP has no need for the excess heat or power generated by WHRUs since they are only operating as a compressor station and do not operate any other processes that require heat. The Copano turbines alone (without WHRU) have a rated efficiency of 34.4% at 100% load and an output based limit of 1.32 lb CO_2e/hp-hr, at 70% load the turbines alone have a 25% thermal efficiency. CCCP has proposed an output based limit of 1.18 lb CO_2/hp-hr (HHV). The output based limit for CCCP in CO_2e/hp-hr would not increase significantly over the CO_2/hp-hr limit since CH_4 and N_2O are minor fractions of the emissions from the turbines. This value is comparable with the limits established in the table above for turbines used for compression.

BACT Limits and Compliance

Total GHG emissions will be limited to 167,372 tons CO_2e/year for both turbines combined, with an additional limit of 1.18 lb CO_2/hp-hr, for each turbine (based on a 12-month rolling average).

Compliance with the limits shall be demonstrated using the following equations:

Compliance with the CO_2 limits for the turbines based on metered fuel consumption and using the average high heat value (HHV) calculated according to the requirements at 40 CFR 98.33(a)(2)(ii), and the default CO_2 emission factor 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)(2)(i) is as follows:

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

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 mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).
HHV = Annual average high heat value of the gaseous fuel (MMBtu/scf). The average HHV shall be calculated according to the requirements at 40 CFR 98.33(a)(2)(ii).
EF = Fuel-specific default CO_2 emission factor, from Table C-1 of this subpart (kg CO_2 /mmBtu).
1×10^{-3} = Conversion factor from kilograms to metric tons.
1.102311 = Conversion of metric tons to short tons.

As an alternative, CCCP 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 emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Table C-2 and the actual heat input. Comparatively, the emissions from CO_2 contribute the most (greater than 99%) to the overall emissions from the heaters and; therefore, additional analysis is not required for CH_4 and N_2O. To calculate the CO_2e emissions, the draft permit requires calculation of the emissions based on the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1. Records of the calculations would be required to be kept to demonstrate compliance with the emission limits on a 12-month rolling basis.

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

X. Blowdown Stacks (EPNs: EQT001, EQT002, EQT003, and EQT004)

The proposed design includes four blowdown stacks: one for each combustion turbine, and one each for station suction and discharge. The stacks will be used in the event of process upsets.

Step 1 – Identification of Potential Control Technologies

- The use of a seal gas booster system
- The use of blowdown gas as fuel in the turbines

The seal gas booster system will provide additional clean, dry gas to the compressor seals, allowing the compressors to stay pressurized for longer periods during shut-down, thus reducing the need to use the blowdown stacks. Using the blowdown gas as fuel in the turbines will reduce the amount of CH_4 released to the atmosphere.

Step 2 – Elimination of Technically Infeasible Alternatives

CCCP determined that both options were feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

CCCP is proposing to implement both control options. Therefore, ranking 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

CCCP is proposing to implement both control options. Therefore, detailed cost analysis is not necessary. No adverse collateral impacts are expected.

Step 5 – Selection of BACT

CCCP is proposing to install a seal gas booster system, and to recover blowdown gas for fuel in the turbines.

<u>BACT Limits and Compliance</u>

Total CO_2e emissions from the four blowdown stacks shall not exceed the following, based on a 12-month rolling average:

1. Unit A Blowdown Stack (EPN: EQT001) – 1,145 tons CO_2e/year
2. Unit B Blowdown Stack (EPN: EQT002) – 1,145 tons CO_2e/year
3. Station Suction Blowdown Stack (EPN: EQT003) – 2,062 tons CO_2e/year
4. Station Discharge Blowdown Stack (EPN: EQT004) – 3,101 tons CO_2e/year

CCCP shall maintain a record of each system upset which results in the blowdown stacks being used, as well as the amount of GHG vented to the atmosphere. CO_2e emissions shall be calculated using the global warming potentials in Table A-1 of 40 CFR Part 98.

XI. Emergency Generator Engine (EPN: EQT005)

The proposed compressor station includes an emergency generator for standby power. GHG emissions from this engine results from combustion and is comprised primarily of CO_2, with CH_4 and N_2O present in smaller quantities.

Step 1 – Identification of Potential Control Technologies

CCCP identified two technologies as being available for the emergency generator: good combustion practices and the use of lower emitting fuel.

Step 2 – Elimination of Technically Infeasible Alternatives

CCCP determined that both of the above technologies are technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

CCCP is proposing to implement both control options. Therefore, ranking 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

CCCP is proposing to implement both control options. Therefore, detailed cost analysis is not necessary. No adverse collateral impacts are expected.

Step 5 – Selection of BACT

CCCP has proposed an efficiently designed generator with good combustion practices and low-carbon fuel (natural gas) as BACT.

<u>BACT Limits and Compliance</u>

Total GHG emissions from the emergency engines shall be limited to 57 tons CO_2e/year for non-emergency operations. The emergency generator shall be fueled solely by pipeline quality natural gas. Additionally, the emergency engine shall be limited to 100 hours/year of non-emergency operation. CCCP shall employ good combustion practices, including annual tune-ups and manufacturer's recommended inspections and maintenance. The engines selected will meet the requirements of 40 CFR Part 60 Subpart JJJJ.

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 as published on November 29, 2013 (78 FR 71904). Records of the calculations would be required to be kept to demonstrate compliance with the emission limits on a 12-month rolling average. Additionally, CCCP shall maintain records of fuel usage, hours of operation, and maintenance/tune-ups performed on the engine.

XII. Process Fugitives (EPN: FUG01)

Hydrocarbon emissions from leaking piping components (process fugitives) associated with the proposed project include methane, a GHG. CCCP calculates that fugitive emissions from the proposed compressor station will be less than 10 tons/year of CH_4.

Step 1 – Identification of Potential Control Technologies for GHGs

- Installing leakless technology components to eliminate fugitive emission sources;
- Implementing various leak detection and repair (LDAR) programs in accordance with applicable state and federal air regulations;
- Implementing an alternative monitoring program using a remote sensing technology such as infrared camera monitoring;
- Implementing an audio/visual/olfactory (AVO) monitoring program for compounds; and
- Designing and constructing facilities with high quality components and materials of construction compatible with the process.

Step 2 – Elimination of Technically Infeasible Alternatives

Leakless/Sealless Technology –Leakless valves and sealless pumps are effective at minimizing or eliminating leaks, but their use may be limited by materials of construction considerations and process operating conditions. Leakless technology valves may be incorporated in situations where highly toxic or otherwise hazardous materials are present. Likewise, some technologies, such as bellows valves, cannot be repaired without a unit shutdown. Installing leakless and sealless equipment components is generally reserved for individual, chronic leaking components and specialized services. Leakless technology components are not considered technically feasible on a facility-wide basis for the Sinton Compressor Station.

Instrument LDAR Programs – LDAR programs have traditionally been developed for control of VOC emissions. Instrumented monitoring is considered technically feasible for components in CH_4 service.

Remote Sensing – Remote sensing technologies have been proven effective in leak detection and repair. The use of sensitive infrared camera technology has become widely accepted as a cost effective means for identifying leaks of hydrocarbon.

AVO Monitoring – Leaking components can be identified through AVO methods. AVO programs are common and in place industry and are considered technically feasible.

High quality components - A key element in control of fugitive emissions is the use of high quality equipment that is designed for the specific service in which it is employed. The olefins unit at Equistar's La Porte plant utilizes such components, and materials of construction, including gasketing that is compatible with the service in which they are employed.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Instrumented monitoring can identify leaking CH_4, making identification of components requiring repair possible. This is the most effective of the controls.

Remote sensing using an infrared imaging has proven effective for identification of leaks. Instrument LDAR programs and the alternative work practice of remote sensing using an infrared camera have been determined by EPA to be equivalent methods of piping fugitive controls.[13]

As-observed AVO methods are generally somewhat less effective than instrument LDAR and remote sensing, since they are not conducted at specific intervals. This method cannot generally identify leaks at as low a leak rate as instrumented reading can identify. This method, due to frequency of observation is effective for identification of larger leaks.

Use of high quality components is effective in preventing emissions of GHGs, relative to use of lower quality components.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

Instrumented monitoring implemented through the 28VHP[14] LDAR program, with control effectiveness of 97%, is considered BACT for CCCP. In addition, CCCP will utilize an AVO program to monitor for leaks in between instrumented checks, and will perform remote sensing on an annual basis.

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[13] 73 FR 78199-78219, December 22, 2008.
[14] The boilerplate special conditions for the TCEQ 28VHP LDAR program can be found at http://www.tceq.state.tx.us/assets/public/permitting/air/Guidance/NewSourceReview/bpc_rev28vhp.pdf

Step 5 – Selection of BACT

CCCP will install valves, seals, and piping, that while not classified as “leakless technology” will be designed to be as fully pressure containing as possible. Examples include: installing valves that are equipped with lubrication/sealant ports around stem packing; ensuring correct flange alignment during construction and use of spiral wound gaskets in flanges; and use of dry gas seals for centrifugal compressors. In addition, the Solar turbines that are proposed for the Sinton Compressor Station use tandem dry gas seals. CCCP will implement with the TCEQ 28VHP LDAR program under the permit issued for non-GHG pollutants issued by TCEQ, and supplement with an as-observed AVO program. Additionally, CCCP will conduct annual infrared screening for fugitive leaks of methane in compliance with 40 CFR Part 98 for stand-alone compression stations.

Because GHG emissions associated with leaks are difficult to quantify, the proposed permit contains no numerical BACT limitation for fugitives from equipment leaks. CCCP will be required to implement an LDAR program that is compliant with TCEQ 28VHP. The leak thresholds, and repair requirements, and record keeping requirements will be consistent with the TCEQ air permit requirements for VOC emissions.

XIII. Compliance with Endangered Species Act (ESA), Magnuson-Stevens Fishery Conservation and Management Act, and National Historic Preservation Act (NHPA)

Before EPA may issue CCCP’s GHG PSD permit, EPA must comply with Section 7(a)(2) of the Endangered Species Act (ESA) (16 U.S.C. 1536) the Magnuson-Stevens Fishery Conservation and Management Act (Magnuson-Stevens Act) and Section 106 of the National Historic Preservation Act (NHPA). Under the Energy Policy Act of 2005, FERC is designated as the lead agency for LNG projects. As such, FERC is responsible for complying with these regulations and in addition the National Environmental Policy Act.

CCCP is currently pursuing approval and authorization from several federal regulatory agencies including the Federal Energy Regulatory Commission (FERC), U.S. Army Corp of Engineers (USACE), and EPA. As such, FERC is responsible for complying with these regulations and in addition the National Environmental Policy Act. EPA intends to rely on the findings, consultations, and concurrences with NOAA’s National Marine Fisheries Office, Protected Resources Division and the US Fish and Wildlife Service for Section 7 of the ESA; NOAA’s National Marine Fisheries, Habitat Conservation Division for Magnuson-Stevens Act; and the Texas State Historic Preservation Officer for NHPA.

EPA may not issue its permits until it receives confirmation from FERC and/or these agencies that consultations under these laws are complete.

XIV. Environmental Justice (EJ)

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

APPENDIX

Annual Facility Emission Limits

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

Table 1. Facility Emission Limits[1]

EPN	FIN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
EQT006	SCPLC1	Gas Compressor Unit A	CO_2	83,644	83,721	1.18 lb CO_2/hp-hr for each turbine on a 12-month rolling average. See permit conditions III.A.2.
			CH_4	1.41		
			N_2O	0.14		
EQT007	SCPLC2	Gas Compressor Unit B	CO_2	83,644	83,721	
			CH_4	1.41		
			N_2O	0.14		
EQT001	SCBDS1	Unit A Blowdown Stack	CO_2	1.26	1,145	Seal gas booster system; use of blowdown gas as fuel in turbines. See permit conditions III.A.3.
			CH_4	45.76		
EQT002	SCBDS2	Unit B Blowdown Stack	CO_2	1.26	1,145	
			CH_4	45.76		
EQT003	SSBDS	Station Suction Blowdown	CO_2	2.26	2,062	
			CH_4	82.4		
EQT004	SDBDS	Station Discharge Blowdown	CO_2	3.4	3,101	
			CH_4	123.91		
EQT005	SCGEN1	Emergency Generator	CO_2	57	57	Good combustion practices, 100 hrs/yr non-emergency use. See permit condition III.A.4.
			CH_4	No Numerical Limit Established[4]		
			N_2O	No Numerical Limit Established[4]		
FUG01	SCFUG01	Fugitive Emissions	CH_4	No Numerical Limit Established[5]	No Numerical Limit Established[5]	Implementation of enhanced LDAR program
Totals[6]			**CO_2**	**167,535**	**CO_2e 175,134**	
			CH_4	**308**		
			N_2O	**0.28**		

1. Compliance with the annual emission limits (tons per year) is based on a 12-month rolling total.
2. 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.
3. Global Warming Potentials (GWP): CH_4 = 25, N_2O = 298
4. The emissions 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. Fugitive process emissions from EPN FUG01 are estimated to be 7.29 TPY of CH_4 and 182 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. The total emissions for CH_4 and CO_2e include the PTE for process fugitive emissions of CH_4. These totals are given for informational purposes only and do not constitute emission limits.