Statement of Basis

Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit for Formosa Plastics Corporation, Texas, Point Comfort, Chemical Complex Expansion: Two New Combined-Cycle Gas-Fired Turbines

Permit Number: PSD-TX-760-GHG

June 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 December 11, 2012, EPA Region 6 received a Prevention of Significant Deterioration (PSD) permit application from Formosa Plastics Corporation, Texas (Formosa) for Greenhouse Gas (GHG) emissions from a proposed construction project to expand Formosa's existing chemical complex in Point Comfort, Calhoun County, Texas. This expansion project consists of two new combined-cycle gas-fired combustion turbines (gas turbines), a new low density polyethylene (LDPE) plant, and an olefins expansion (a new olefins 3 plant and an associated propane dehydrogenation unit). Formosa submitted three separate permit applications for the three different operational area expansions and this permit is only for the GHG emissions for one of those expansions, the addition of two new combined-cycle gas-fired turbines to provide additional power for Formosa's operations. On April 29, 2013 and July 10, 2013, Formosa submitted additional information in response to follow up clarification questions. In connection with the same proposed construction project, Formosa submitted an application for an amendment to its current PSD Permit (PSD-TX-760M9) for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ).

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

II. Applicant

Formosa Plastics Corporation, Texas
201 Formosa Drive
Point Comfort, Texas 77978

Facility Physical Address:
201 Formosa Drive
Point Comfort, Texas 77978

Contact:
Randy Smith
Vice President
Formosa Plastics Corporation, Texas
P.O. Box 700
Point Comfort, Texas 77978
(361) 987-7000

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

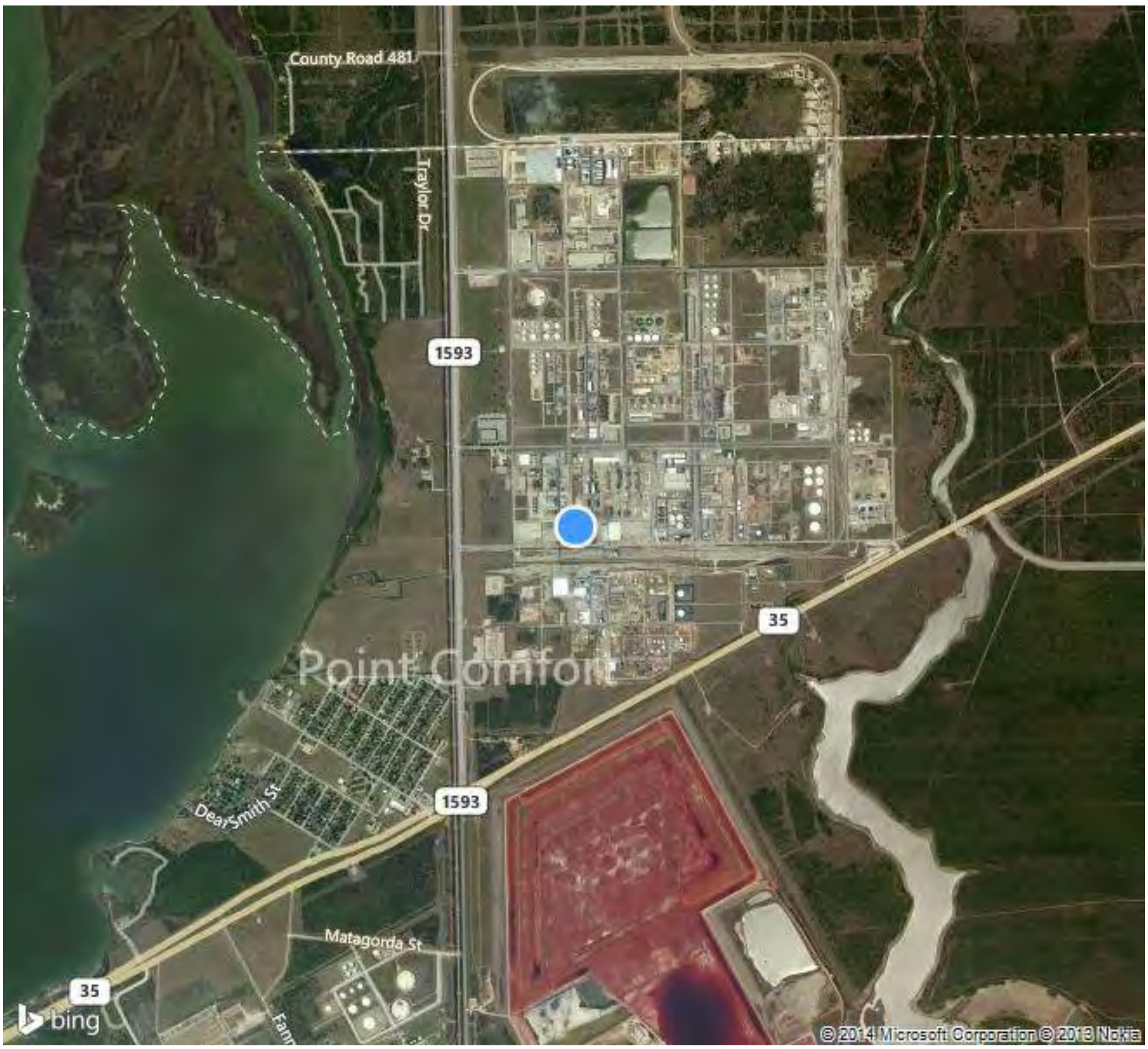
Facility Location

The Formosa chemical complex is located in Point Comfort, Calhoun County, Texas, and this area is currently designated "attainment" for all criteria pollutants. The nearest Class 1 area is the Big Bend National Park, which is located well over 100 miles from the site. The geographic coordinates for this proposed facility site are as follows

Latitude: 28º 41'20" North
Longitude: 96º 32'50" West

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

Figure 1. Formosa chemical complex location



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

EPA concludes that Formosa's application is subject to PSD review for the pollutant GHGs, because the project would lead to an emissions increase of 75,000 TPY CO_2e as described at 40 CFR § 52.21(b)(49)(iv)(*b*) and an emissions increase greater than zero TPY on a mass basis as described at 40 CFR § 52.21(b)(23)(ii) (Formosa calculated a CO_2e emissions increase of 1,145,433 TPY for the proposed project). EPA Region 6 implements a GHG PSD FIP for Texas under the provisions of 40 CFR § 52.21 (except paragraph (a)(1)). See 40 CFR § 52.2305.

While EPA Region 6 is the PSD permitting authority in Texas for GHGs, TCEQ is the PSD permitting authority for regulated NSR pollutants other than GHGs. [1] TCEQ has determined that the proposed project is subject to PSD review for the following non-GHG pollutants: VOC, CO, NO_2, CO, and $PM/PM_{10}/PM_{2.5}$. At this time, TCEQ has not issued a PSD permit for the non-GHG pollutants.

EPA Region 6 applies the policies and practices reflected in EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011). Consistent with that guidance, we have not required the applicant to model or conduct ambient monitoring for GHGs, nor have we required any assessment of impacts of GHGs in the context of the additional impacts analysis or Class I area provisions of 40 CFR §§ 52.21(o) and (p), respectively. Instead, EPA has determined that compliance with BACT is the best technique that can be employed at present to satisfy additional impacts analysis and Class I area requirements of the rules as they relate to GHGs. We note again, however, that the proposed project has regulated NSR pollutants that are non-GHG pollutants, which will be addressed by the PSD permit to be issued by TCEQ.

V. Project Description

The proposed GHG PSD permit, if finalized, will authorize Formosa to modify its existing chemical complex's utility plant to add two GE 7EA combined-cycle gas-fired combustion turbines, each with heat recovery steam generator (HRSG), to the existing six GE 7EA gas-fired combustion turbines. Each of the two proposed GE 7EA natural gas-fired turbine generators will have a gross output of 80 MW and the HRSGs would have a steam output of 360,000 lb/hr with duct firing. Steam from the HRSGs will be routed to the existing utility plant steam header to combine with steam produced by the existing utility plant. Steam is routed from the steam header to the three existing steam turbines for electricity generation or it can be used for thermal energy in other operational chemical production processes on-site. The Formosa utility plant provides the electricity and steam demands of the Formosa chemical complex and does not provide electricity to the grid.

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

The Formosa utility plant expansion will consist of the following sources of GHG emissions:

- Two combined-cycle natural gas-fired combustion turbines equipped with dry low-NOx combustors;
- Two Heat Recovery Steam Generators (HRSG) with duct burners;
- Natural gas and OL tail gas piping and metering fugitives;
- Electrical equipment insulated with sulfur hexafluoride (SF_6); and
- Turbine startup natural gas purges.

Combustion Turbine Generator

The utility plant modification will consist of two identical GE 7EA natural gas-fired combustion turbines. Each combustion turbine will exhaust to a dedicated HRSG supplemented by a duct burner. Each combustion turbine will only burn pipeline natural gas to rotate an electrical generator to generate electricity. The main components of a combustion turbine generator consist of a compressor, combustor, turbine, and generator. The compressor pressurizes combustion air to the combustor where the fuel is mixed with the combustion air and burned. Hot exhaust gases then enter the turbine where the gases expand across the turbine blades, driving a shaft to power an electric generator. The exhaust gas will exit the combustion turbine and be routed to the HRSG for steam production.

Heat Recovery Steam Generators (HRSGs)

Heat recovered in the two pressure reheat HRSGs will be utilized to produce steam. Each HRSG will be equipped with duct burners for supplemental heat input for steam production. The duct burners will have the capability of firing fuel from three different sources: pipeline-quality natural gas, a pure hydrogen stream (from another process unit), and a hydrogen/methane mixture (Olefins unit “OL tail gas”). Each of the HRSG’s duct burners will have a maximum heat input capacity of 120 MMBtu/hr and normal duct burner operation will vary from 0 to 100 percent of the maximum capacity. Steam generated within the HRSGs will be utilized to drive an existing steam turbine and associated electrical generator. The flue gases from the HRSGs will be directed to a Selective Catalytic Reduction (SCR) system. The flue gases from the SCR will be released through the atmosphere through two stacks (EPNs 7K and 7L).

Steam produced by each of the two HRSGs will be routed to the existing utility plant steam header to combine with steam produced by the existing utility plant. Steam is routed from the steam header to the three existing steam turbines for electricity generation. Each GE 7EA combustion turbine has a nominal electric power output of 80 MW and the HRSGs have a nominal steam output of 360,000 lb/hr with duct firing. The steam turbine is a non-combusting unit and is not a source of GHG emissions. The units may operate at reduced load to respond to changes in system power requirements and/or stability.

Natural Gas and OL Tail Gas Piping

Fugitive methane emissions may occur from piping equipment carrying natural gas and OL tail gas at the site. Natural gas will be metered and piped to the gas combustion turbines and HRSGs, and OL tail gas will be piped to the HRSGs. The fugitive emissions may include methane and carbon dioxide. Formosa's application proposes to do weekly AVO (audio/visual/olfactory) monitoring of the natural gas and fuel gas piping to help control the fugitive methane emissions.

Turbine Startup Natural Gas Purges

During the startup of each gas turbine, a portion of the natural gas supply line is purged through a separate purge vent stack. The purge results in GHG emissions of methane and carbon dioxide. Formosa's application proposes that GHG emissions will be minimized by limiting the turbine startup purges to 15 per year per turbine.

Electrical Equipment Insulated with Sulfur Hexafluoride (SF_6)

The two generator circuit breakers associated with the proposed units will be insulated with SF_6. SF_6 is a colorless, odorless, non-flammable, and non-toxic synthetic gas. It is a fluorinated compound that has an extremely stable molecular structure. The unique chemical properties of SF_6 make it an efficient electrical insulator. The gas is used for electrical insulation, arc quenching, and current interruption in high-voltage electrical equipment. SF_6 is only used in sealed and safe systems which under normal circumstances do not leak gas. The capacity of the circuit breakers associated with the proposed plant is currently estimated to be 248 lbs of SF_6 in each circuit breaker (496 lbs total). Formosa's application proposes that the circuit breakers have a low pressure alarm and low pressure lockout, acting as a leak detection system.

VI. General Format of the BACT Analysis

The BACT analyses for this draft permit were conducted by following the "top-down" BACT approach contained in EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011) and earlier EPA guidance. The five steps in the top-down BACT process are listed below.

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

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

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

VII. Applicable Emission Units for BACT Analysis

The majority of the GHGs associated with the project are from emissions from the combustion sources. Stationary combustion sources primarily emit CO_2, and small amounts of N_2O and CH_4. The following equipment is included in this proposed GHG PSD permit:

- Combined-cycle Combustion Turbines (EPNs: 7K, 7L)
- HRSG Duct Burner Fuel Combustion (EPNs: 7K, 7L)
- Natural Gas and OL Tail Gas Fugitives (EPN: NG-FUG)
- SF_6 Insulated Equipment (EPN: SF6-FUG)
- Turbine Startup Natural Gas Purges (EPNs: 7K-NGVENT, 7L-NGVENT)

VIII. Combined-cycle Combustion Turbines with HRSG Duct Burner Fuel Combustion (EPNs: 7K, 7L)

The combustion turbines proposed by Formosa will be installed in a combined heat and power (CHP) configuration. Formosa will utilize high efficiency GE 7EA turbines consisting of two natural gas-fired combustion turbines each exhausting to a heat recovery steam generator (HRSG). The combustion turbines have a nominal output of 80 MW each and the HRSGs have a nominal steam output of 360,000 lb/hr with duct firing. The produced steam will be routed to an existing steam header and from there it may be sent to three existing steam turbines, or the steam may be used for thermal energy in other production processes on-site.

Step 1 – Identify All Available Control Options

Energy Efficiency Processes, Practices, and Design

Combustion Turbine:

- *Combustion Turbine Design* – The most efficient way to generate electricity for base load conditions from a natural gas fuel source is the use of a combined-cycle combustion turbine.
- *Periodic Burner Tuning* – Periodic combustion inspections involving tuning of the combustors to restore highly efficient low-emission operation.
- *Instrumentation and Controls* – The control system is a digital type that is supplied with the combustion turbine. The distributed control system monitors the operation of the unit and modulates the fuel flow and turbine operation to achieve optimal high-efficiency low-emission performance for full load and part-load conditions on a real time basis by ensuring good combustion.

Heat Recovery Steam Generator

- *Heat Exchanger Design Considerations* – The pressure reheat duct-fired HRSG's are designed with multiple pressure levels. Each pressure level incorporates an economizer section, evaporator section, and superheater section. These heat transfer sections are made up of many thin-walled tubes to provide surface area to maximize the transfer of heat to the working fluid.
- *Insulation* – Insulation minimizes heat loss to the surrounding air thereby improving the overall efficiency of the HRSG. Insulation is applied to the HRSG panels that make up the shell of the unit, to the high-temperature steam and water lines, and typically to the bottom portion of the stack.
- *Minimizing Fouling of Heat Exchange Surfaces* – Filtration of the inlet air to the combustion turbine is performed to minimize fouling. Additionally, cleaning of the tubes is performed during periodic outages. By reducing the fouling, the efficiency of the unit is maintained.
- *Minimizing Vented Steam and Repair of Steam Leaks* – Steam is vented from the system from deaerator vents, blowdown tank vents, and vacuum pumps/steam jet air ejectors. These vents are necessary to improve the overall heat transfer within the HRSG and condenser by removing solids and air that potentially blankets the heat transfer surfaces lowering the equipment's performance. Steam leaks are repaired as soon as possible to maintain facility performance.
- *Low Carbon Fuels* – The HRSG duct burners will utilize pipeline quality natural gas, a pure hydrogen stream (from another process unit), and a hydrogen/methane mixture (Olefins unit "OL" tail gas) as fuel.

Auxiliary Energy Efficiency Processes

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

- *Fuel Gas Preheating* – The overall efficiency of the combustion turbine is increased with increased fuel inlet temperatures. Fuel to be introduced in the turbines will be preheated through a shell and tube "performance heater" utilizing heated intermediate pressure (IP) feedwater.
- *Multiple Combustion Turbine/HRSG Trains* – Multiple trains allow the unit to achieve higher overall plant part-load efficiency by shutting down a train operating at less efficient part-load conditions and ramping up the remaining train to high-efficiency full-load operation.

Carbon Capture and Storage

CCS is classified as an add-on pollution control technology, which involves the separation and capture of CO_2 from flue gas, pressurizing of the captured CO_2 into a pipeline for transport, and injection/storage within a geologic formation. CCS is general applied to "facilities emitting CO_2 in large concentrations, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing)."[2]

CCS systems involve the use of adsorption or absorption processes to remove CO_2 from flue gas, with subsequent desorption to produce a concentrated CO_2 stream. The three main capture technologies for CCS are pre-combustion capture, post-combustion capture, and oxyfuel combustion (IPCC, 2005). Of these approaches, pre-combustion capture is applicable to gasification plants, where solid fuel such as coal is converted into gaseous components by applying heat under pressure in the presence of steam and oxygen (U.S. Department of Energy, 2011). At this time, oxyfuel combustion has not yet reached a commercial stage of deployment for gas turbine applications and still requires the development of oxy-fuel combustors and other components with higher temperature tolerances (IPCC, 2005). Accordingly, pre-combustion capture and oxyfuel combustion are not considered available control options for this proposed gas turbine. The third approach, post-combustion capture, is applicable to gas turbines.

With respect to post-combustion capture, a number of methods may potentially be used for separating the CO_2 from the exhaust gas stream, including adsorption, physical absorption, chemical absorption, cryogenic separation, and membrane separation (Wang et al., 2011). Many

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

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

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

Once CO_2 is captured from the flue gas, the captured CO_2 is compressed to 100 atmospheres (atm) or higher for ease of transport (usually by pipeline). The CO_2 would then be transported to an appropriate location for underground injection into a suitable geological storage reservoir, such as a deep saline aquifer or depleted coal seam, or used in crude oil production for enhanced oil recovery (EOR). There is a large body of ongoing research and field studies focused on developing better understanding of the science and technologies for CO_2 storage.[3]

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

Step 2 – Elimination of Technically Infeasible Alternatives

Formosa's application examines the technical feasibility of CCS for this project and the two other projects which comprise the Point Comfort expansion project and concludes that "While amine absorption technology for the capture of CO_2 has been applied to processes in the petroleum refining and natural gas processing industries it has not been applied to process vents at chemical manufacturing plants. Large commercial applications, such as the expansion project sources, present even more difficult application of carbon capture, in part, due to the additional variability in flow volumes as typically experiences in chemical plants." Formosa Application at 6.1.2.

Formosa has estimated that the combustion turbine exhaust stream has a concentration of 3.3% CO_2 by volume. Formosa estimated the annual volume of CO_2 that could be captured from the combustion turbines to be 1,029,375 tons per year.

As noted here in footnote 3, in the proposed rule addressing the NSPS for new EGUs, EPA stated that CCS was not the best system of emission reduction for a nation-wide standard for natural gas-fired combined-cycle (NGCC) turbines based on questions about whether full or partial capture CCS is technical feasible for the NGCC source category. Considering this, EPA is evaluating whether there is sufficient information to conclude that CCS is technically feasible at this specific NGCC source and will consider public comments on this issue. However, because there is a basis to eliminate CCS on other grounds, we have assumed, for purposes of this specific permitting action, that potential technical or logistical barriers do not make CCS technically infeasible for this project and have addressed the economic feasibility issues in Step 4 of the BACT analysis in order to assess whether CCS is BACT for this project.

In addition, all of the other control options identified in Step 1 are considered technically feasible for this project.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The remaining technologically feasible options (which are not mutually exclusive) have been ranked based on their GHG emissions reductions performance levels.

- CCS (up to 90% control),
- Low carbon fuels (4 – 55% control),
- Periodic burner tuning (5 – 25%),
- Fuel gas preheating (1 – 2% control),
- Combustion turbine design,
- Instrumentation and controls,

- Heat exchanger design considerations,
- Insulation,
- Minimizing fouling of heat exchange surfaces,
- Minimizing vented steam and repair of steam leaks,
- Multiple combustion turbine/HRSG trains

CO_2 capture and storage is capable of achieving 90% reduction of produced CO_2 emissions and thus considered to be the most effective control method. Use of low carbon fuel, fuel gas preheating, periodic burner tuning, combustion turbine design, instrumentation and controls, heat exchanger design considerations, insulation, minimizing fouling of heat exchange surfaces, minimizing vented steam and repair of steam leaks, and multiple combustion turbine/HRSG trains are all considered effective, can be used in tandem (and with CCS), and have a range of efficiency improvements which cannot be directly quantified; therefore, the above ranking is approximate only (and is not especially meaningful, given that these technologies are not mutally exclusive).

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

Carbon Capture and Storage

Capital costs associated with CCS fall into two primary areas – CO_2 Capture and Compression Equipment and CO_2 Transport. The capture and compression equipment associated with CCS would have cost impacts based on the installation of the additional process equipment (e.g., amine units, cryogenic units, dehydration units, and compression facilities), while transport costs are associated with construction of a pipeline to transport the captured CO_2.

Formosa conducted an analysis of the capital cost impact of CCS on all three proposed projects that are part of the total Point Comfort expansion project. Formosa's analysis is included in the record for this proposed permit, and it uses project specific data along with the data provided by the *Report of the Interagency Task Force on Carbon Capture and Storage (August 2010)*. Formosa developed a cost analysis for CCS with geologic storage with a 438 mile pipeline. Formosa estimated that the capture and compression direct capital costs to be $905 million. Formosa estimated the capital cost for the pipeline needed for geologic sequestration to be $604 million. Their cost estimate does not include the additional costs for obtaining rights of way for construction of a pipeline. Formosa also estimated the geologic storage costs at $11 million. These cost estimates would make the direct capital cost for CCS with geologic storage approximately $1.52 billion. Formosa also provided a cost analysis for CCS with an enhanced oil recovery (EOR) end user, based on the potential development of a nearby EOR site and the need for an approximately 10 mile long pipeline from the Formosa Point Comfort Plant. Formosa estimated the capital cost for the pipeline to be $20 million. Formosa assumed the cost for capture and compression to remain the same. Formosa estimated the total annualized capital and operating cost of CCS with EOR at $7 billion (including indirect costs) for the life of the plant, which Formosa estimated would more than triple the capital cost of the total Point Comfort expansion project. Looking at only the direct capital costs, CCS with EOR would be approximately $925 million for the entire expansion (all three projects). Based on these costs, Formosa maintains that CCS is not economically feasible for the overall Point Comfort expansion project or for the specific turbine expansion project addressed in this permit.

Formosa has estimated that the gas turbine expansion project would contribute 34% of the CO_2 flow rate to the CCS system. Therefore, it can be assumed that to capture only the CO_2 from the gas turbines expansion project the cost would be 34% of the total CCS costs identified in the paragraph above. This equates to a direct capital cost of $314.5 million for CCS with EOR for the gas turbines expansion project only. Formosa has estimated the capital cost of their CHP project to be approximately $543 million. Therefore, CCS with EOR would increase the direct capital cost of the gas turbine project by more than 55%. Based on these costs, Formosa maintains that CCS is not economically feasible.

In preparing this proposed permit, EPA Region 6 evaluated Formosa's CCS cost estimate and compared it to the cost of CCS for other similar projects that are undergoing permitting. We note that both Air Liquide (Pasadena, TX) and Freeport LNG (Freeport, TX) have each proposed projects for a CHP facility that would be almost identical to that proposed by Formosa and those applications included CCS cost estimates that can be compared with those provided by Formosa. Specifically, Air Liquide's permit authorizes the construction of four combustion turbines and uses existing HRSGs, while Freeport LNG has proposed to construct one combustion turbine with a heat exchanger. In the case of the Air Liquide permit, the applicant estimated that the capital costs for post-combustion capture and compression to be $537 million with a 30-mile pipeline capital cost estimated at $34 million. Air Liquide's CO_2 emissions from each combustion turbine are permitted at 485,112 TPY. For the Freeport LNG proposed permit, the applicant provided a cost analysis for capture and geological sequestration of the CO_2 from the pretreatment facility (combustion turbines and amine units). Their capital cost estimate for geologic storage was $444 million. Freeport LNG also provided a CCS cost estimate for EOR that would require post-processing to meet the CO_2 specifications for EOR use. The estimated capital cost for treatment, compression, and delivery for EOR was $466 million. It was estimated that the CHP portion of the Freeport LNG project had a capital cost of $900 million. Freeport's CO_2 emissions from the combustion turbine were calculated at 561,118 TPY. Based on EPA's evaluation of these other proposed CHP plants, EPA finds that Formosa's estimated CCS capital cost for this gas turbine project are comparable to other similar facilities.

Furthermore, EPA notes that the recovery and purification of CO_2 from the turbines would necessitate significant additional processing and treatment to achieve the necessary CO_2 concentration for effective sequestration, and this additional processing and treatment could have potential energy and environmental impacts. The additional process equipment required to separate, cool, and compress the CO_2, such as amine scrubber vessels, CO_2 strippers, amine transfer pumps, flue gas fans, an amine storage tank, and CO_2 gas compressors, would require a significant additional power expenditure. For example, operation of carbon capture equipment at a typical natural gas-fired combined-cycle plant is estimated to reduce the net energy efficiency of the plant from approximately 50% (based on the fuel higher heating value (HHV)) to approximately 42.7% (based on fuel HHV).[4] Alternatively, to provide the amount of reliable electricity needed to power a CO_2 capture system, Formosa could significantly expand the scope of the utility plant expansion proposed with this project to install one or more additional electric generating units, which would further increase the emissions of criteria air pollutants, as well as GHGs. To put these additional power requirements in perspective, gas-fired electric generating units typically emit more than 100,000 tons CO_2e/yr.

CCS Conclusion

EPA concludes that CCS should be eliminated under Step 4 for this project as economically prohibitive, based on a capital cost increase of at least 55% for CCS control, as well as the potential energy and environmental impacts that could result from decreases in net power output or increases in air pollution emissions due the additional power requirements for CCS equipment.

None of the remaining control options have been eliminated from the BACT review based on adverse economic, environmental, or energy impacts.

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
Air Liquide Large Industries U.S., Bayou Cogeneration Plant Pasadena, TX	GE 7EA Combustion Turbines in a Combined Heat & Power Configuration	Energy Efficiency/ Good Design & Combustion Practices	7,720 $Btu_{(HHV)}/kWh_{gross}$ equivalent based on a 365-day rolling average.	2013	PSD-TX-612-GHG

[4] US Department of Energy, National Energy Technology Laboratory, "Costs and Performance Baseline For Fossil Energy Plants, Volume 1 - Bituminous Coal and Natural Gas to Energy", Revision 2, November 2010

Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
Freeport LNG Freeport, TX	GE 7EA Combustion Turbine in a Combined Heat & Power Configuration	Energy Efficiency/ Good Design & Combustion Practices	738 lb CO_2/Mwh based on gross CT energy output and equivalent energy produced. 5,210 Btu/kWh on a 12-month rolling average basis.	*	PSD-TX-1302-GHG

*Proposed permit – final permit has not been issued.

The Formosa combustion turbines are to be installed in a combined heat and power (CHP) configuration. In comparing similarly situated CHP facilities, EPA Region 6 issued a permit for Air Liquide and proposed issuance of a permit for Freeport LNG. Since combustion turbine exhaust energy is being recovered and utilized for use along with electrical energy from the generator, more of the fuel burned in a CHP application and the subsequent thermal energy generated is recovered as useful energy than in a simple cycle combustion turbine application. In order to have a more direct comparison with the BACT examples above, the useful thermal energy recovered from the combustion turbine exhaust must be added to the combustion turbine net electrical output to determine the total useful energy recovered from burned fuel in order to calculate the lb CO_2/MWh in a meaningful way. This is the same methodology that requires the electrical output of a steam turbine be added to the electrical output of the combustion turbine in order to arrive at the total useful energy recovered in a combined-cycle combustion turbine application. In the case of CHP at Formosa, the useful thermal energy recovered from the combustion turbine exhaust converted to the same unit of measure, kW, as the combustion turbine electrical output is analogous to the steam turbine electrical output. Formosa used a steam turbine generator conversion rate of 14,110 lbs steam per MWh[5], giving an equivalent combined-cycle design heat rate for each unit of 10,330 Btu/kWh (HHV, Gross) with duct firing on a 365-day rolling average basis. Air Liquide used a steam turbine conversion rate of 9.1 lbs steam per kWh (equates to 9,100 lbs steam per MWh) giving an equivalent combined-cycle design heat rate of 7,720 Btu/kWh (HHV, Gross) on a 365-day rolling average basis. The BACT limit proposed by Freeport LNG is significantly lower. However, Freeport's process is significantly different than Air Liquide and Formosa and therefore not a good comparison. Freeport's CHP unit will consist of one combustion turbine which will exhaust to a heat exchanger which is part of a heating medium system and does not produce steam for process heat. Formosa is similar to the Air Liquide facility since Air Liquide is doing a unit replacement at an existing utility plant and utilizing existing HRSGs.

The following specific operating practices are proposed for the turbines:

[5] This steam turbine conversion rate was based on Formosa's historical annual average performance data for the existing steam turbines at the Point Comfort Utility plant. This is not intended to be a permit limit or enforceable representation.

- Combustion Turbine Design
- Periodic burner tuning as part of a regular maintenance program to help ensure a more reliable operation of the unit and maintain optimal efficiency
    - Periodic Turbine Burner Tuning
    - Instrumentation and Model Based Controls
- HRSG Energy Efficiency Processes, Practices, and Design
    - Heat Exchanger Design Considerations
    - Insulation
    - Minimizing Fouling of Heat Exchange Surfaces
    - Minimizing Vented Steam and Repair of Steam Leaks
    - Low Carbon Fuels
- Auxiliary Energy Efficiency Processes, Practices, and Design
    - Fuel Gas Preheating
    - Multiple Combustion Turbine/HRSG Trains

<u>BACT Limits and Compliance</u>:

To determine the proposed output-based BACT limit, and heat input efficiency limit, Formosa started with the turbine's design heat rate for combined-cycle operation with duct firing and calculated a compliance margin based upon degradation factors that may foreseeably reduce efficiency under real-world conditions. The design heat rate for the gas-fired combustion turbines is 12,000 Btu/kWh (HHV, gross basis). Formosa proposed a combined-cycle design heat rate that considers the steam generated in each HRSG in addition to the 80 MW of electricity generated by each turbine since existing steam turbines will be used to convert HRSG steam into electrical energy. Using a steam turbine generator conversion rate of 14,110 lbs steam per MWh, the equivalent combined-cycle design heat rate for each unit is 10,330 Btu/kWhr (HHV, gross basis) with duct firing.

To determine an appropriate heat rate limit for the permit, the following compliance margins are added to the base heat rate limit:

- A 3.3% design margin reflecting the possibility that the constructed facility will not be able to achieve the design heat rate.
- A 6% performance margin reflecting efficiency losses due to equipment degradation prior to maintenance overhauls.
- A 3% degradation margin reflecting the variability in operation of auxiliary plant equipment due to use over time.

Design and construction of a combined-cycle power plant involves many assumptions about anticipated performance of the many elements of the plant, which are often imprecise or not reflective of the conditions once installed at the site. As a consequence, the facility also calculates an “Installed Base Heat Rate” which represents a design margin of 3.3% to address such items as equipment underperformance and short-term degradation.

To establish an enforceable BACT condition that can be achieved over the life of the facility, the permit limit accounts for anticipated degradation of the equipment over time between regular maintenance cycles. The manufacturer’s degradation curves project anticipated degradation rate of 5% within the first 48,000 hours of the gas turbine’s useful life; they do not reflect any potential increase in this rate, which might be expected after the first major overhaul and/or as the equipment approaches the end of its useful life. Further, the projected 5% degradation rate represents the average, and not the maximum or guaranteed, rate of degradation for the gas turbines. Therefore, Formosa proposed that, for purposes of deriving an enforceable BACT limitation on the proposed facility’s heat rate, gas turbine degradation may reasonably be estimated at 6% of the facility’s heat rate.

Finally, in addition to the heat rate degradation from normal wear and tear on the combustion turbines, Formosa is also providing a compliance margin based on potential degradation in other elements of the combined-cycle plant that would cause the overall plant heat rate to rise (i.e., cause efficiency to fall). Degradation in the performance of the heat recovery steam generator, heat transfer, and ancillary equipment such as pumps and motors is also expected to occur over the course of a major maintenance cycle.

The BACT limit proposed for each of the two combustion turbine generators with heat recovery steam generators with duct burners is an output based efficiency limit of 11,650 Btu_{gross}/kWh (HHV basis) on a 365-day rolling average. The GHG BACT limit for the Formosa chemical complex’s utility plant expansion is equivalent to 1,136 lbs CO_2/MWh. Total GHG emissions will be limited to 572,438 tons CO_2e/year per turbine. Air Liquide’s heat rate is 7,720 Btu/kWh, which equates to an output based limit of 1,380 lb CO_2/MWh (gross). Formosa’s output based BACT limit of 11,650 Btu/kWh is higher than Air Liquid’s, however, the lbs CO_2/MWh equivalent for Formosa is nearly 20% lower than Air Liquide’s. Formosa’s heat rate is higher due to the use of older, existing steam turbines that have an approximately 55% lower efficiency in converting steam to electricity. Formosa has to produce 14,110 lbs of steam to produce 1 MW of electricity versus Air Liquide only needing to produce 9,100 lbs of steam per MW. The Freeport LNG proposed BACT limit was considerably lower. However, Freeport’s process is significantly different in that it does not produce steam. Formosa and Air Liquide are both adding combustion turbines to an existing utility plant. Formosa chose the GE 7EA combined-cycle gas turbine because of the following reasons:

- The Formosa utility plant does not provide electricity to the grid and the total electrical generation has to be managed to meet and not exceed the varying demands of the more than one dozen operating plants at the chemical complex. The GE 7EA electrical generation capacity provides the operational flexibility necessary to optimize the number of units operating at higher loads to generate the instantaneous electricity and steam demands of the Formosa chemical complex.

- The six existing turbines at the utility plant are all GE 7EAs. As such, Formosa has twenty years experience operating and maintaining this model turbine and its associated monitoring equipment. Since the same model is proposed for the two new turbines, this operating experience will result in more effective and reliable performance results for the new turbines because of more efficient and effective maintenance since there are:
  - Established consistent maintenance practices for all turbines,
  - The proposed combined-cycle unit HRSG design is unique to Formosa to which Formosa has very specialized design, operation and maintenance experience,
  - Interchangeability of parts for all turbines provides quicker maintenance and higher on-stream time at efficient operation,
  - Existing GE turbine control system ("Mark VIE") is uniform across all Formosa's existing turbines and is compatible with GE 7EA units. Similar sized turbines from other turbine manufacturers would require a separate control system.
- Comparable turbine designs from other manufacturers were not available at the specified 80 MW output (per turbine) for this project.

Thus, EPA agrees with Formosa's basis for computing and is proposing a BACT limit of 11,650 Btu/kWh (HHV, gross basis) for each combined-cycle unit.[6] Formosa shall meet the BACT limit, for the combined-cycle unit, on a 365-day rolling average.

To achieve this BACT limit, the combined-cycle combustion turbine unit have the following additional combustion turbine design features to improve the overall efficiency:

- Periodic burner tuning as part of a regularly scheduled maintenance program to help ensure a more reliable operation of the unit and maintain optimal efficiency;
- A Distributed Control System will control all aspects of the turbine's operation, including fuel feed and burner operations, to achieve optimal high-efficiency low-emission performance for full-load and partial-load conditions;

[6] We note that this limit is higher that the proposed NSPS limit in EPA's recent proposed rule addressing *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units* (see footnote 3, supra). However, the turbines in this project would not be covered by the NSPS requirements because they are producing steam for process use, not for distribution on the electrical grid. In addition, a large amount of the steam may not go to the steam turbines for producing electricity and the steam that does go to the existing steam turbines is converted to electricity at a lower efficiency than in that of a new steam turbine. This means the turbines (operating in a combined-cycle configuration) at this project have a lower MW output than a traditional combined-cycle unit used to produce electricity for distribution on the grid. However, the limit proposed for the Formosa turbines/HRSG is consistent with the limits proposed for other similar turbines used for similar purposes, as explained above.

The Heat Recovery Steam Generator (HRSG) will have energy efficiency processes, practices and designs that include:

- Energy efficient heat exchanger design. In this design, each pressure level incorporates an economizer section(s), an evaporator section(s), and each superheater section has interstage attemperation.
- Addition of insulation to the HRSG panels;
- Filtration of the inlet air to the combustion turbine and periodic cleaning of the tubes is performed to minimize; and
- Minimization of steam vents and repairs of steam leaks.

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

- Fuel gas preheating. Fuel to be introduced in the turbines will be preheated through a shell and tube “performance heater” utilizing heated intermediate pressure (IP) feedwater; and
- Multiple combustion turbine/HRSG trains. Multiple combustion turbine/HRSG trains help with part-load operation. A higher overall plant part-load efficiency is achieved by shutting down trains operating at less efficient part-load conditions and ramping up the remaining train(s) to high-efficiency full-load operation.

The BACT limit for each combustion turbine is 11,650 Btu/kWh (HHV, gross basis) on a 365-day rolling average basis. Combustion turbine fuel efficiency is based in the physics of the compressor and expander design and condition rather than control of the air-fuel ratio in the charge. Fuel input to the combustion turbine is controlled primarily by monitoring and controlling the rotating speed and the combustion temperature and applying that data to a control algorithm inside the unit control system. Parameters that will be measured include fuel flow, combustion temperature, exhaust temperature, and a number of other internal parameters, such as rpm and vibration levels that affect turbine operations and safety, but not emissions. Formosa will calculate the combined-cycle unit thermal efficiency daily using the following equation:

$$Thermal\ Efficiency\ = \left(\frac{HI_{GT} + HI_{HRSG}}{P_{GT} + P_{HRSG}}\right) x\ 1{,}000{,}000$$

Where:

Thermal efficiency = heat rate of combined-cycle unit (Btu/kWh)
HI_{GT} = Heat input of fuel to the gas turbine (MMBtu/day)
HI_{HRSG} = Heat input of fuels to the HRSG (MMBtu/day)
P_{GT} = Gross Electrical Power produced from the gas turbine (kWh/day)

P_{HRSG} = Gross energy (electrical equivalent) produced from the HRSG (kWh/day), calculated using the Equation below.
1,000,000 = Btu/MMBtu conversion

$$P_{HRSG} = \dot{m_{steam}} x\ 14.11$$

Where:

$\dot{m_{steam}}$ = mass flow rate of steam produced from the HRSG (lb/day)
14.11 = steam to electric conversion rate (lb/kWh), based on the existing plant steam turbines

The combustion turbine control system, as well as the plant control system, will monitor and archive periodic data points for operational data gathered from installed instrumentation. Data points collected and archived will include the following:

- CT Fuel input - volumetric measurement of fuel flow converted into mass (lb/hr) and energy flow (MMBtu/hr);
- Gross hourly energy output (Mwh);
- CT plant thermal efficiency, %;
- Gas turbine electrical output, MW; and
- Mass of steam produced.

Formosa will demonstrate compliance with the CO_2 mass emissions limit for the combustion turbines/HRSG based on metered fuel consumption and using the Tier I (natural gas) and Tier III (OL tail gas) methodology and the emission factors for natural gas from 40 CFR Part 98, Subpart C, Table C-2 and/or fuel composition and mass balance.

The Tier I equation for estimating CO_2 emissions from combustion of natural gas in the gas turbines and duct burners as specified in 40 CFR 98.33(a)(1)(i) is as follows:

$$CO_2 = 0.001 * Fuel * HHV * EF * 1.102311$$

Where:
CO_2 = Annual CO_2 mass emissions for the specific fuel type, metric tons/yr
Fuel = Volume of fuel combusted per year, standard cubic feet/yr, based on the maximum rated equipment capacity and maximum hours of operation (8,760 hours/yr)
EF = Emission factor for natural gas from table C-1
HHV = default high heat value of fuel, from table C-1
0.001 = conversion from kg to metric tons
1.102311 = Conversion of metric tons to short tons.

The Tier III equation for estimating CO_2 emissions from combustion of OL tail gas in the duct burners as specified in 40 CFR 98.33(a)(3)(iii) is as follows:

$$CO_2 = \frac{44}{12} * Fuel * CC * \frac{MW}{MVC} * 0.001 * 1.102311$$

Where:
CO_2 = Annual CO_2 mass emissions from combustion of natural gas (short tons)
Fuel = Annual volume of the gaseous fuel combusted (scf). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to §98.3(i).
CC = Annual average carbon content of the gaseous fuel (kg C per kg of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV at §98.33(a)(2)(ii).
MW = Annual average molecular weight of the gaseous fuel (kg/kg-mole). The annual average molecular weight shall be determined using the same procedure as specified for HHV at §98.33(a)(2)(ii).
MVC = Molar volume conversion factor at standard conditions, as defined in §98.6.
44/12 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion of kg to metric tons.
1.102311 = Conversion of metric tons to short tons.

As an alternative, Formosa 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 Equation C-8 and the emission factors provided in 40 CFR Part 98, Table C-2 and the actual heat input (HHV). Comparatively, the emissions from CO_2 contribute the most (greater than 99%) to the overall emissions from the heaters, and since the efficiency controls described above will limit all GHGs, an additional separate analysis is not required for CH_4 and N_2O emissions. 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 revised 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 basis.

An initial stack test demonstration will be required for CO_2 emissions from the combustion turbine exhaust. An initial stack test demonstration for CH_4 and N_2O emissions is 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.

IX. Natural Gas and OL Tail Gas Fugitive Emissions (NG-FUG)

Fugitive methane emissions may occur from piping equipment carrying natural gas and OL tail gas at the site. Natural gas will be metered and piped to the gas combustion turbines and HRSGs, and OL tail gas will be piped to the HRSGs. The fugitive emissions may include methane and carbon dioxide. The additional methane and carbon dioxide emissions from process fugitives have been conservatively estimated to be 425 TPY CO_2e. Fugitive emissions are negligible, and account for less than 0.04% of the project's total CO_2e emissions.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Leakless Technology* – Leakless technology valves may be used in situations where highly toxic or otherwise hazardous materials are present.
- *Instrument LDAR Programs* – LDAR programs have traditionally been developed for control of VOC emissions. Instrumental monitoring may also be technically feasible for components in CH_4 service, including the fuel gas and natural gas piping fugitives.
- *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 hydrocarbons.
- *AVO Monitoring* – AVO monitoring methods are also capable of detecting leaks from piping components as leaks can be detected by sound and sight. AVO programs are commonly used in industry and are considered technically feasible.

Step 2 – Elimination of Technically Infeasible Alternatives

All control technologies identified in Step 1 are technically feasible control options.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

(1) Leakless technology valves may be incorporated in situations where highly toxic or otherwise hazardous materials are present, however leak interfaces remain even with leakless technology components in place. In addition, some sealing mechanisms, such as a bellows, are not repairable online and may leak in event of a failure until the next unit shutdown.

(2) Instrument LDAR programs and remote sensing using an infrared camera have been determined by EPA to be equivalent methods of piping fugitive controls.[7] The most

[7] 73 FR 78199-78219, December 22, 2008.

stringent LDAR program potentially applicable to this facility is TCEQ's 28LAER, which provides for 97% control credit for valves, flanges, and connectors.

(3) AVO methods are generally somewhat less effective than instrument LDAR and remote sensing, since they are not conducted at specific intervals. However, since pipeline natural gas is odorized with very small quantities of mercaptan, as-observed olfactory 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, as-observed audio and visual observations of potential fugitive leaks are likewise moderately effective.

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 leakless components, the TCEQ 28LAER LDAR program or a comparable remote sensing program is less than 0.05% of the total project's proposed CO_2e emissions. Accordingly, given the costs of implementing leakless components (which 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 and are eliminated as BACT for this source.

Step 5 – Selection of BACT

Based on the economic impracticability of leakless components, instrument monitoring, and remote sensing for fuel gas and natural gas piping components, Formosa proposed 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. Formosa is to maintain a written log of daily inspections identifying the operating area inspected, the date inspected, the fuel gas and natural gas equipment inspected (valves, lines, flanges, etc.), whether any leaks were identified by visual, audible or olfactory inspections, and corrective actions/repairs taken. For leaks identified, immediately of detection of the leak, plant personnel shall tag the leaking equipment and commence repair or replacement of the leaking component.

X. SF_6 Insulated Electrical Equipment (SF6-FUG)

The generator circuit breakers will be insulated with sulfur hexafluoride (SF_6) gas. SF_6 is commonly used in circuit breakers associated with electricity generation equipment. The capacity of the circuit breakers associated with the proposed plant is currently estimated to be 248 lb of SF_6 (per circuit breaker).

Step 1 – Identification of Potential Control Technologies for GHGs

- *Use of new and state-of-the-art enclosed-pressure SF_6 circuit breakers.*
- *Use of circuit breakers with leak detection consisting of a low pressure alarm and a low pressure lockout.*
- *Evaluating alternate substances to SF_6 (e.g., oil or air blast circuit breakers).*

Step 2 – Elimination of Technically Infeasible Alternatives

According to the report NIST Technical Note 1425, SF_6 is a superior dielectric gas for nearly all high voltage applications. It is easy to use, exhibits exceptional insulation and arc-interruption properties, and has proven its performance by many years of use and investigation. It is clearly superior in performance to the air and oil insulated equipment used prior to the development of SF_6 insulated equipment. The report concluded that although "…various gas mixtures show considerable promise for use in new equipment, particularly if the equipment is designed specifically for use with a gas mixture…it is clear that a significant amount of research must be performed for any new gas or gas mixture to be used in electrical equipment". Therefore, use of alternative substances to SF_6 is not technically feasible and is eliminated as BACT for this source.

All other control technologies are technically feasible. Formosa proposed to implement these methods to reduce and control SF_6 emissions.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Since Formosa proposed to implement the remaining control option, 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

No adverse economic, energy, or environmental impacts are associated with the remaining control option.

Step 5 – Selection of BACT

The following specific BACT practice is proposed for the SF_6 Insulated Electrical Equipment:

- The use of state-of-the-art enclosed-pressure SF_6 circuit breakers.
- The circuit breakers will have leak detection consisting of a low pressure alarm and a low pressure lockout.

Formosa will monitor emissions annually in accordance with the requirements of the Mandatory Greenhouse Gas Reporting rules for Electrical Transmissions and Distribution Equipment Use. Annual SF_6 emissions will be calculated according to the mass balance approach in 40 CFR Part 98, Subpart DD, equation DD-1.

XI. Turbine Startup Natural Gas Purges (EPN: 7K-NGVENT, 7L-NGVENT)

Step 1 – Identification of Potential Control Technologies for GHGs

- *Minimize startups:* During the startup of each gas turbine, a portion of the natural gas supply line is purged through a separate purge vent stack. The purge results in GHG emissions of methane and carbon dioxide. There are no existing physical GHG control technologies for natural gas venting from maintenance startup and shutdown activities. The primary means of limiting GHG emissions from this activity is minimizing the frequency. Formosa expects to operate the turbines with as much on-stream time as possible thus minimizing the frequency of startups and associated natural gas purges during startup.

Step 2 – Elimination of Technically Infeasible Alternatives

Formosa determined that this option is feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Formosa proposed to minimize the number of turbine startups. 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

Formosa proposed to implement the control option, therefore, detailed cost analysis is not necessary. No adverse collateral impacts are expected.

Step 5 – Selection of BACT

GHG emissions will be minimized by limiting the turbine startup purges to 15 per year per turbine.

XII. Endangered Species Act (ESA)

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) dated February 14, 2014, prepared by the applicant, and reviewed and adopted by EPA. Further, EPA designated Formosa Plastics Corporation ("Formosa") and its consultant, Zephyr Environmental Corporation ("Zephyr"), as non-federal representatives for purposes of preparation of the BA and for conducting informal consultation. Formosa's expansion project is comprised of three separate sub-projects: an olefins expansion project involving the construction of a new olefins cracking unit, identified as Olefins 3 unit, and a propane dehydrogenation unit; a new low density polyethylene plant; and a utilities project involving the construction of two new natural gas-fired combined cycle combustion turbines. Formosa has submitted three (3) GHG (Greenhouse Gas) permit applications for each project; however, for Section 7 ESA purposes, EPA is relying on a Biological Assessment that includes the collective emissions from all three projects and their impacts to endangered species. The biological assessment performed for Formosa projects included in its field survey the physical land area where the new Formosa facilities will be built within Formosa's existing chemical complex.

A draft BA has identified twenty-one (21) species as endangered or threatened in Calhoun and Jackson County, Texas by the U.S. Fish and Wildlife Service (USFWS), National Marine Fisheries Service (NMFS) and the Texas Parks and Wildlife Department (TPWD) and is listed in the table below:

Federally Listed Species for Calhoun and Jackson Counties by the U.S. Fish and Wildlife Service (USFWS), National Marine Fisheries Service (NMFS), and the Texas Parks and Wildlife Department (TPWD)	**Scientific Name**
Birds	
Eskimo curlew	*Numenius borealis*
Interior least tern	*Sterna antillarum alhalassos*
Northern aplomado falcon	*Falco femoralis septentrionalis*
Piping Plover	*Charadrius melodus*
Whooping crane	*Grus americanus*
Mammals	
Jaguarundi	*Herpailurus yagourondi*
Louisiana black bear	*Urus americanus luteolus*
Ocelot	*Leopardus pardalis*
Red wolf	*Canis rufus*
West Indian manatee	*Trichechus manatus*
Reptiles	
Hawksbill Sea Turtle	*Eretmochelys imbricate*
Green Sea Turtle	*Chelonia mydas*
Kemp's Ridley Sea Turtle	*Lepidochelys kempii*
Leatherback Sea Turtle	*Dermochelys coriacea*
Loggerhead Sea Turtle	*Caretta caretta*
Fish	
Smalltooth Sawfish	*Pristis pectinata*
Whales	
Blue whale	*Balaenoptera musculus*
Fin whale	*Balaenoptera physalus*
Humpback whale	*Megaptera novaengliae*
Sei whale	*Balaenoptera borealis*
Sperm whale	*Physeter macrocephalus*

EPA has determined that issuance of the proposed permit to Formosa for the expansion project will have no effect on fifteen (15) of the twenty-one (21) federally-listed species, specifically the Northern aplomado falcon (*Falco femoralis septentrionalis*), red wolf (*Canis rufus*), Louisiana black bear (*Urus americanus luteolus*), jaguarundi (*Herpailurus yagouaroundi cacomitli*), ocelot (*Leopardus pardalis*), eskimo curlew (*Numenius borealis*), West Indian manatee (*Trichechus manatus*), smalltooth sawfish (*Pristis pectinata*), hawksbill sea turtle (*Eretmochelys imbricate*), blue whale (*Balaenoptera musculus*), finback whale (*Balaenoptera physalus*), humpback whale (*Megaptera novaeangliae*), sei whale (*Balaenoptera borealis*), sperm whale (*Physeter *macrocephalus*) and leatherback sea turtle (*Dermochelys coriacea*). These species are either thought to be extirpated from these counties or Texas or not present in the action area.

Three (3) of the twenty-one (21) federally-listed species are species that may be present in the Action Area and are under the jurisdiction of USFWS. As a result of this potential occurrence and based on the information provided in the draft BA, the issuance of the permit may affect, but is not likely to adversely affect the following species:

- Interior least tern (*Sterna antillarum alhalassos*)
- Piping plover (*Charadrius melodus*)
- Whooping crane (*Grus americana*)

On April 16, 2014, EPA submitted the final draft BA to the Southwest Region, Corpus Christi, Texas Ecological Services Field Office of the USFWS for its concurrence that issuance of the permit may affect, but is not likely to adversely affect these six federally-listed species.

Three (3) of the twenty-three federally-listed species identified are marine species that may be present in the Action Area and are under the jurisdiction of NOAA. As a result of this potential occurrence and based on the information provided in the draft BA, the issuance of the permit may affect, but is not likely to adversely affect the following species:

- green sea turtle (*Chelonia mydas*)
- Kemp's ridley sea turtle (*Lepidochelys kempii*)
- loggerhead sea turtle (*Caretta caretta*)

On February 14, 2014, EPA submitted the final draft BA to the NOAA Southeast Regional Office, Protected Resources Division of NMFS for its concurrence that issuance of the permit may affect, but is not likely to adversely affect these three federally-listed species. NOAA provided concurrence and agreed with EPA's determinations on May 23, 2014.

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 BA can be found at EPA's Region 6 Air Permits website at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XIII. Magnuson-Stevens Act (ESA)

The 1996 Essential Fish Habitat (EFH) amendments to the Magnuson-Stevens Fishery Conservation and Management Act (Magnuson-Stevens Act) set forth a mandate for the National Oceanic Atmospheric Administration's National Marine Fisheries Service (NMFS), regional fishery management councils, and other federal agencies to identify and protect important marine and anadromous fish habitat.

To meet the requirements of the Magnuson-Stevens Act, EPA is relying on an EFH assessment prepared by Zephyr on behalf of Formosa and reviewed and adopted by EPA. The EFH assessment looks at the total emissions and impacts from all three projects on marine and fish habitats.

The facility is affects tidally influenced portions of the Lavaca Bay, Keller Bay, and Carancahua Bay that adjoins to the Corpus Christi Bay leading to the Gulf of Mexico. These tidally influenced portions have been identified as potential habitats of postlarval, juvenile, subadult or adult stages of red drum (*Sciaenops ocellatus*), shrimp (4 species), and reef fish (43 species) and the stone crab (*Menippe mercenaria)*. The EFH information was obtained from the NMFS's website (http://www.habitat.noaa.gov/protection/efh/efhmapper/index.html).

Based on the information provided in the EFH Assessment, EPA concludes that the proposed PSD permit allowing Formosa's three expansion projects will have no adverse impacts on listed marine and fish habitats. The assessment's analysis, which is consistent with the analysis used in the BA discussed above, shows the projects' construction and operation will have no adverse effect on EFH.

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 essential fish habitat report can be found at EPA's Region 6 Air Permits website at: http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XIV. National Historic Preservation Act

Section 106 of the NHPA requires EPA to consider the effects of this permit action on properties eligible or potentially eligible for inclusion in the National Register of Historic Places. To make this determination, EPA relied on a cultural resources report dated January 10, 2014 prepared by Horizon Environmental Services, Inc. ("Horizon") on behalf of Formosa's consultant, Zephyr, and reviewed and adopted by the EPA. For purposes of the NHPA review, the Area of Potential Effect (APE) was determined to be approximately 372 acres of land that contains the construction footprint of the three projects. Horizon performed a field survey of the property and a desktop review on the archaeological background and historical records within a 1-mile radius of the APE.

Based on the results of the field survey, including shovel tests, no archaeological resources or historic structures were found within the APE. Based on the desktop review for the site, no cultural resource sites were identified within a 1-mile radius of the APE.

Based upon the information provided in the cultural resources report, EPA Region 6 determines that because no historic properties are located within the APE of the facility site and a potential for the location of archaeological resources is low within the construction footprint itself, issuance of the permit to Formosa will not affect properties on or potentially eligible for listing on the National Register.

On February 24, 2014, EPA sent letters to Indian tribes identified by the Texas Historical Commission as having historical interests in Texas to inquire if any of the tribes have historical interest in the particular location of the project and to inquire whether any of the tribes wished to consult with EPA in the Section 106 process. EPA received no requests from any tribe to consult on this proposed permit.

EPA will provide a copy of the report to the State Historic Preservation Officer for consultation and concurrence with its determination. Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on historic properties. A copy of the report may be found at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XV. Environmental Justice (EJ)

Executive Order (EO) 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive branch policy on environmental justice. Based on this Executive Order, the EPA's Environmental Appeals Board (EAB) has held that environmental justice issues must be considered in connection with the issuance of federal Prevention of Significant Deterioration (PSD) permits issued by EPA Regional Offices [See, e.g., *In re Prairie State Generating Company*, 13 E.A.D. 1, 123 (EAB 2006); *In re Knauf Fiber Glass*, Gmbh, 8 E.A.D. 121, 174-75 (EAB 1999)]. This permitting action, if finalized, authorizes emissions of GHG, controlled by what we have determined is the Best Available Control Technology for those emissions. It does not select environmental controls for any other pollutants. Unlike the criteria pollutants for which EPA has historically issued PSD permits, there is no National Ambient Air Quality Standard (NAAQS) for 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.

XVI. Conclusion and Proposed Action

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

APPENDIX

Annual Facility Emission Limits

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

Table 1. Annual Emission Limits[1] - General Electric 7EA

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY		
7K	7K	Combined-Cycle Combustion Turbine/Heat Recovery Steam Generator with Duct Burner	CO_2	571,875	572,466	11,650 Btu/kWh (gross) on a 365-day rolling average. See permit Special Condition III.B.1 and III.B.2.
			CH_4	10.8		
			N_2O	1.1		
7L	7L	Combined-cycle Combustion Turbine/Heat Recovery Steam Generator with Duct Burner	CO_2	571,875	572,466	11,650 Btu/kWh (gross) on a 365-day rolling average. See permit Special Condition III. B.1 and III.B.2.
			CH_4	10.8		
			N_2O	1.1		
NG-FUG	NG-FUG	Natural Gas and OL Tail Gas Fugitives	CO_2	No Numerical Limit Established[4]	No Numerical Limit Established[4]	Implementation of an AVO program. See permit Special Condition III.C.1. and III.C.4.
			CH_4	No Numerical Limit Established[4]		
SF6-FUG	SF6-FUG	SF_6 Insulated Equipment	SF_6	No Numerical Limit Established[5]	No Numerical Limit Established[5]	Gas-tight circuit breakers with leak detection system. See permit Special Condition III.C.2. through III.C.4.
7K-NGVENT 7L-NGVENT	7K-NGVENT 7L-NGVENT	Turbine Startup Natural Gas Purges	CO_2	0.41	30	Limit turbine to 15 start-ups per year. See Special Condition III.D.
			CH_4	1.20		
Totals[6]			**CO_2**	**1,143,751**	**CO_2e 1,145,489**	
			CH_4	**41.6**		
			N_2O	**2.2**		
			SF_6	**0.0012**		

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, SF_6 = 22,800
4. Fugitive process emissions from EPN NG-FUG are estimated to be 0.69 TPY CO_2, 20 TPY of CH_4 and 500 TPY CO_2e. In lieu of an emission limit, the emissions will be limited by implementing a weekly AVO monitoring program.
5. SF_6 fugitive emissions from EPN SF6-FUG are estimated to be 0.0012 TPY of SF_6 and 27 TPY of CO_2e. In lieu of an emission limit, the emissions will be limited by using state of the art enclosed-pressure SF_6 circuit breakers with leak detection.
6. Total emissions include the PTE for fugitive emissions (including SF_6). Totals are given for informational purposes only and do not constitute emission limits.