Statement of Basis

Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit
For Air Liquide Large Industries U.S., LP

Permit Number: PSD-TX-612-GHG

August 2013

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 September 18, 2012, Air Liquide Large Industries U.S., LP (Air Liquide) submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions for the redevelopment of its cogeneration facility in Pasadena, Texas (Bayou Cogeneration Plant). On November 27, 2012 EPA requested further information from Air Liquide before the application could be deemed complete. Air Liquide responded with additional information on January 21, 2013, April 23, 2013 and May 20, 2013. In connection with the same proposed project, Air Liquide submitted a PSD permit amendment application for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on July 27, 2012. The proposed project will involve the replacement of four (4) gas-fired turbines with similar units, the addition of three (3) new gas-fired steam boilers and the subsequent decommissioning/shut down of three (3) existing gas-fired boilers at the Bayou Cogeneration Plant. The project also includes the installation of Selective -Catalytic reduction (SCR) on the Bayou Cogeneration Plant new steam boilers to reduce NO_x emissions. After reviewing the application, EPA Region 6 has prepared the following Statement of Basis (SOB) in support of the draft air permit to authorize the cogeneration facility redevelopment project at the Air Liquide Large Industries U.S., LP plant.

This SOB documents the information and analysis EPA used to support the decisions EPA made in drafting the air permit. It includes a description of the proposed facility, the applicable air permit requirements, and an analysis demonstrating that the proposed permit conditions meet all applicable legal and regulatory requirements.

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

II. Applicant

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III. Permitting Authority

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

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 Air Liquide Bayou Cogeneration Plant is located in Harris County, Texas. This area is currently designated nonattainment for ozone and attainment/unclassified for all other criteria pollutants. The area surrounding the plant is primarily utilized by major industry with residential areas within 1 mile to the east. The nearest Class I area is Big Bend National Park (TX) at an approximate distance of 500 miles from the site. The geographic coordinates for the Air Liquide facility are as follows:

Latitude: 29°37'21" North;
Longitude: 95°02'45" West

Figure 1: Location of the Air Liquide Large Industries U.S., LP Plant

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

EPA concludes Air Liquide's application is subject to PSD review for the pollutant GHG, because the project would lead to an emissions increase of GHG for a facility in excess of the emission thresholds described at 40 CFR § 52.21 (b)(49)(iv). Under the project, the net GHG emissions are calculated net emissions increase over zero tpy on a mass basis and to exceed the applicability threshold of 75,000 tpy CO_2e (Air Liquide calculates CO_2e emissions of 2,572,215 tpy) for a modification to an existing major facility that requires PSD review for its significant net emissions increases of several criteria pollutants. As noted above in Section III, EPA Region 6 implements a GHG PSD FIP for the Texas under the provisions of 40 CFR 52.21 (except paragraph (a)(1)). *See*, 40 CFR § 52.2305.

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

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 the selected BACT 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 proposed project has regulated NSR pollutants that are non-GHG pollutants, which are addressed by the PSD permit to be issued by TCEQ.

VI. Project and Process Description

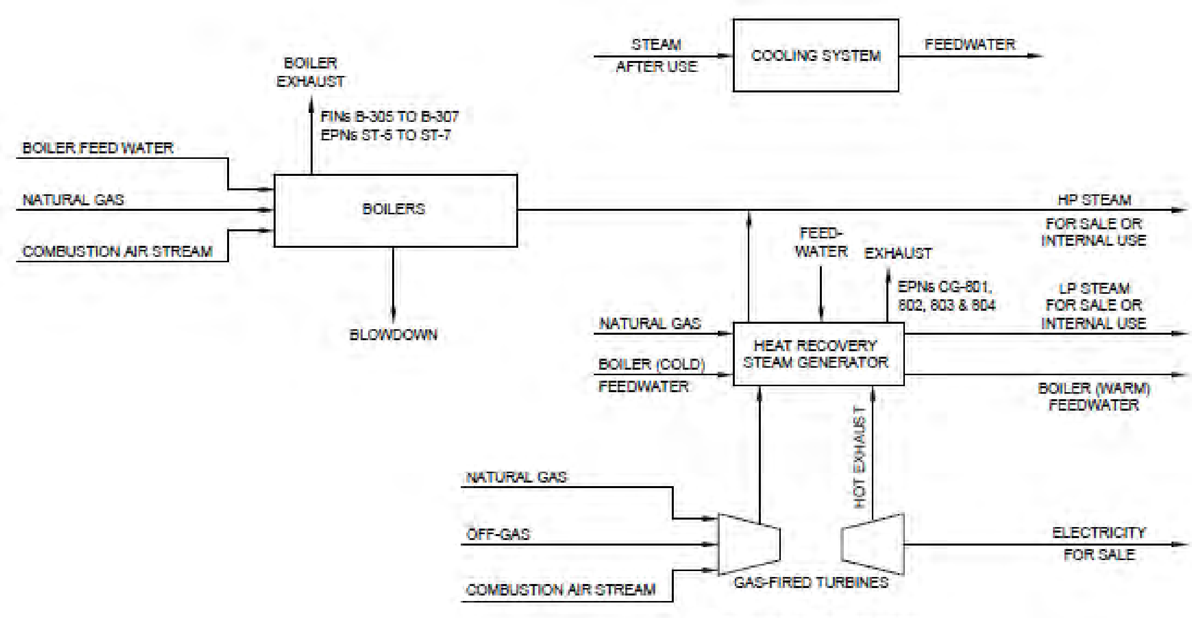
The Bayou Cogeneration Plant consists of four gas turbine power blocks for electricity and steam generation. Each gas turbine power block consists of one natural gas-fired GE Frame 7EA gas turbine and one heat recovery steam generator (HRSG) equipped with natural gas-fired duct burners. The turbine blocks do not have steam turbine generators. The original design of the plant utilized supplemental firing of the HRSG rather than a condensing steam turbine to optimize the thermal performance of the plant. The plant is designed for optimum thermal performance as a CHP facility. The design thermal efficiency of the original plant was 79.5%,

[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

considerably above that of most conventional plants. The proposed project will result in an overall net reduction in NOx emissions by 99 TPY. This reduction is significant considering the facility is located in a severe ozone non-attainment area.

Air Liquide utilizes wet compression on the gas turbine inlets during certain periods of the year to compensate for the seasonal decrease in firing capacity that occurs due to increased temperatures. The addition of wet compression does not increase the maximum capacity of the units. Air Liquide operates the wet compression system for approximately 1,000 hours per year.

In addition, there are three (3) 442.9 MMBtu/hr natural gas-fired boilers at the facility. These boilers produce steam for internal use and to meet the facilities contractual steam obligations. The following is the process flow diagram of the Air Liquide Bayou Cogeneration facility.



COGENERATION PROCESS

Air Liquide is planning to replace the existing combustion turbines at the Bayou Cogeneration Plant with similar GE 7EA units equipped with GE's Closed Loop Emissions Control (CLEC) system. The 7EA is a 60–Hz, heavy duty gas turbine engine that provides approximately 80 MW of output. The primary fuel for the gas turbines at the Bayou Cogeneration Plant is natural gas (~90%), but it also combusts some off gases from the neighboring facility (~10%). The 7EA turbine consists of a 17 stage high-pressure axial compressor, which includes one row of inlet guide vanes, 10 combustion chambers equipped with dry, low-NO_X combustors, and a three-stage pressure turbine. CO_2 emissions will be monitored using continuous emission monitoring systems (CEMS) located after the duct burners. The existing HRSGs and duct burners will not be modified as part of this project.

Additionally, Air Liquide will replace the three existing boilers at the Bayou Cogeneration Plant with three new 550 MMBtu/hr, natural gas-fired boilers equipped with low-NOx burners. CO_2 emissions will be monitored using continuous emission monitoring systems (CEMS).

The redevelopment project at the Bayou Cogeneration Plant will consist of replacing components of the power block and the boilers at the facility. The proposed power block project is to replace the four existing gas turbines at the plant with similar new units. There are no plans to replace the HRSGs or duct burners. The existing turbines are 27 years old and turbines with the exact same specifications are no longer available to Air Liquide. The criteria used to select the turbines for this project included the size of the turbines given the space constraints at the facility, and more importantly the correct output necessary to maximize the CHP benefits of the project. Therefore, Air Liquide will replace the existing turbines with new GE Frame 7EA gas turbines which are closest in specification to the existing turbines and are closer to the maximum design thermal efficiency of the original plant.[2] The redevelopment project will also include the addition of three new 550 MMBtu/hr natural gas-fired boilers to the Bayou Cogeneration plant, and the subsequent shutdown of three existing 442.9 MMBtu/hr boilers at the plant. The new boilers will be controlled using Selective Catalytic Reduction (SCR) units for NO_X emissions.

The proposed project will be executed in three phases[3], no more than 18 months shall pass between the completion of a phase and the beginning of the subsequent phase:

• Phase 1 commences upon start of construction of the three new boilers. Phase 1 only includes the construction of the three new boilers and does not include construction of the four new turbines. Each of the three new boilers will be equipped with selective catalytic reduction (SCR) systems to reduce NO_X emissions. The existing gas turbines and boilers will not be modified during this phase of the project and will continue to operate at currently permitted levels by the TCEQ PSD Permit PSD-TX-612M1; therefore, the only activity during this phase of the project will be the construction of the three new boilers. Phase 1 will be complete when construction on the three new boilers has concluded.

• Phase 2 involves the decommissioning, removal and replacement of each of the four existing turbines. Replacement of the existing turbines is anticipated to occur one turbine at a time, but may involve some concurrent overlapping construction and decommissioning activities involving several turbines. During this phase, the four existing gas turbines will be replaced with

[2] Each new turbine is rated to produce 4 MW of electricity more than the existing turbines at the facility.
[3] Provisions for phased construction apply to the project and can be found at 40 CFR 52.21(j)(4) and (r).

new GE 7EA gas turbine units. In addition to the three existing boilers, the three new boilers will need to be operational and available to fulfill steam/thermal supply contractual obligations during this phase; however, at no point will the four new gas turbines, three new boilers, and three existing boilers operate simultaneously during Phase 2. Once an existing gas turbine has been replaced with a new gas turbine, the new gas turbine will complete initial stack testing in accordance with Special Condition V.A.2. The emissions during this phase will not exceed the potential emissions from the overall project, including the CO_2 emissions. Additionally, Air Liquide will operate the equipment such that all emissions during this phase are less than the respective permit limits.

If any one of the four existing turbines have been shutdown for replacement, then all six boilers (three new and three existing boilers) may be available for operation simultaneously, with a restriction that the three new boilers will operate with a maximum heat input (combined for all three new boilers) not to exceed 990 MMBtu/hour and 8,672,400 MMBtu/year. If two or more of the existing turbines is offline during the interim period, all six boilers (three new and three existing boilers) may operate at full fire in order to meet contractual steam demand. The additional operational limits will exist until the end of Phase 2 when all four existing turbines have been replaced and decommissioned. The four (new or existing) turbines, three new boilers, and the three existing boilers are not allowed to all operate simultaneously at any time during the three construction phases.

As outlined above, the three new boilers constructed in Phase 1 of the project will replace the three existing boilers at the facility in Phase 3; however, the existing boilers will only be decommissioned after the replacement of the gas turbines in Phase 2, so that the new as well as existing boilers are available during Phase 2 to meet the steam/thermal supply contractual obligations. Phase 2 will be complete when all four existing turbines have been replaced and decommissioned and all new gas turbines have completed an initial stack test.

- Phase 3 commences upon completion of Phase 2 and involves the permanent shutdown and decommissioning of the three existing boilers. Phase 3 will be complete when the three existing boilers have been decommissioned.

The proposed GHG PSD permit, if finalized, will allow Air Liquide Bayou Cogeneration Plant to:

1) Install three (3) new 550 MMBtu/hr Rentech gas-fired steam boilers (B-305 through B-307) with Selective Catalytic Reduction (SCR) controls for NOx emissions;

2) Replace four (4) existing GE Frame 7EA combustion turbines (CG801 through CG804) with four (4) new GE Frame 7EA combustion turbines designed with the latest and most efficient combustion technology, one at a time; and

3) Shut down and remove three existing 442.9 MMBtu/hr steam boilers.

The start-up and shutdown emissions have been considered in computing the total GHG emission increases. The permit, upon final issuance, will apply to all operating conditions including normal operations, maintenance, start-up, and shutdown for the Air Liquide Bayou Cogeneration Plant redevelopment project.

VII. GHG Emissions

As described above, this Air Liquide Bayou Cogeneration redevelopment project is a three (3) phase project that, in phase 1 involves the addition of three (3) new gas-fired steam boilers; phase 2 includes the replacement of four (4) gas-fired combustion turbines with four (4) new gas-fired combustion turbines, and phase 3 is the shut down and decomissioning of three (3) existing gas-fired steam boilers. Therefore, the GHG emissions increase is based on these three (3) parts of the project. The applicant represents there will not be any increase in emissions from existing emission sources at the facility as a result of this project.

Combustion Turbines:

The four (4) new GE Frame 7EA combustion turbines are designed to burn either natural gas or a 90/10 blend of natural gas and "off-gas" generated by Air Liquide. GHG emissions are generated from these turbines as a result of combustion and are primarily (99.9%) carbon dioxide (CO_2) with some emissions of methane (CH_4) and nitrous oxide (N_2O).

Air Liquide calculated the GHG maximum potential to emit (PTE) for the 4 new turbines based on using the 90/10 blended fuel at maximum heat input over 8,760 hours per year for each turbine.

In calculating the baseline GHG emission rates for the four existing combustion turbines being replaced, Air Liquide used the actual annual fuel rates during the baseline period of the 24-month period of 2010 through 2011. The baseline actual GHG emission for the 4 existing turbines is 1,279,240 tpy CO_2e.

Steam Boilers:

The three (3) new 550 MMBtu/hr heat input Rentech steam boilers are designed to be natural gas-fired only. GHG emissions are generated from the boiler as a result of combustion and are primarily (99.87%) carbon dioxide (CO_2) with some emissions of methane (CH_4) and nitrous oxide (N_2O).

Air Liquide initially calculated the potential to emit (PTE) for the 3 new boilers based on using natural gas at the full boiler heat input (550 MMBtu/hr for each boiler) operating at 8,760 hours per year. However, Air Liquide has requested an annual limit on the boiler operation of 10,769,647 MMBtu/yr (for all three (3) boilers combined) as a federally enforceable condition to be consistent with the PSD application submitted to TECQ for the criteria pollutants.

VIII. General Format of the BACT Analysis

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

(1) Identify all 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.

IX. Applicable Emission Units

The GHGs associated with the project is from combustion sources (i.e., boilers and combustion turbines). These stationary combustion sources primarily emit carbon dioxide (CO_2), and small amounts of nitrous oxide (N_2O) and methane (CH_4). The following devices are subject to this GHG PSD permit:

- Combustion Turbines (EPNs: CG801, CG802, CG803, and CG804)
- Boilers (EPNs: BO1, BO2, and BO3)

X. <u>Combustion Turbines (EPNs: CG801, CG802, CG803, and CG804) BACT Analysis</u>

Air Liquide is replacing existing GE 7EA gas turbines with similar new GE 7EA units. Air Liquide performed a search of the USEPA RACT/BACT/LAER Clearinghouse (RBLC) for natural-gas fired turbines; however, the database contained no entries for BACT determinations for GHG emissions. Air Liquide did find a recently issued PSD permit for GHG emissions from gas turbines as provided in Appendix C of their September 13, 2012 application. Although the Bayou Cogeneration Plant does not include a steam cycle condensing turbine and is not a combined cycle plant, the facility does include a HRSG and is configured similarly enough to a combined cycle gas turbine to warrant evaluation of any combined cycle facilities with carbon capture.

Step 1 – Identification of Available Control Technologies:

1. Inherently Low Emitting Design.

<u>High Efficiency Turbines</u>

In this project, Air Liquide is replacing the existing GE 7EA with modern and efficient versions of the same power frame. These frames are installed primarily to generate hot exhaust gases for combined heat and power generation. Additional processes, including fuel gas heating and once-through cooling, can improve overall efficiency of the project.

Fuel gas preheating – The overall efficiency of the combustion turbine is increased with increased fuel inlet temperatures. For the E-Class combustion turbine, the fuel gas can be heated with high temperature water from the HRSG. This improves the efficiency of the combustion turbine.

Once-through cooling – There are several sources for providing cooling water to the condenser. The most efficient source is generally through a river, lake, or ocean, typically referred to as once-through cooling. Additionally, a closed-loop design can be used, which includes a cooling tower to cool the water. Closed loop designs are either natural circulation or forced circulation. Both natural circulation and forced circulation designs require higher cooling water pump heads; therefore, increasing the pump's power consumption and reducing overall plant efficiency. Additionally, to provide the forced circulation, fans are used for the forced circulation designs, which consume additional auxiliary power and reduce the plant's efficiency.

2. Good combustion practices, operation and maintenance.

Good combustion, operating and maintenance practices improve fuel efficiency of the combustion turbines by ensuring optimal combustion efficiencies are achieved as intended in the design of the burner. Good operating practices include the use of operating procedures including startup, shutdown and malfunction, the use instrumentation and controls for operational control, and maintaining manufacturer recommended combustion parameters. Maintenance practices include complying with manufacturer recommended preventative maintenance.

3. Fuel selection

The use of fuels with low carbon intensity and high heat intensity is appropriate BACT for GHG.

4. Carbon Capture and Storage

CCS is an available add-on control technology that is applicable for all of the site's affected combustion units.

Step 2 – Elimination of Technically Infeasible Alternatives

Once through cooling

The Air Liquide facility is located in an industrial park without easy access to a fresh water supply which is necessary for a once-through system. Therefore, a once-through cooling water system is considered technically infeasible and will not be further considered.

Carbon Capture and Storage (CCS)[4]

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)."[5] CCS systems involve the use of adsorption or absorption processes to remove CO_2 from flue gas, with subsequent desorption to produce a concentrated CO_2 stream. The three main capture technologies for CCS are pre-combustion capture, post-combustion capture, and oxyfuel combustion (IPCC, 2005). Of these approaches, pre-combustion capture is applicable primarily to gasification plants, where solid fuel such as coal is converted into gaseous components by applying heat under pressure in the presence of steam and oxygen (U.S. Department of Energy, 2011). At this time, oxyfuel combustion has not yet reached a commercial stage of deployment for boiler 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 project; the third approach, post-combustion capture, is available and applicable to the boilers and combustion turbines.

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,

[4] Based on the information provided by Air Liquide and reviewed by EPA for this BACT analysis, while there are some portions of CCS that may be technically infeasible for this project, EPA is assuming that overall Carbon Capture and Storage (CCS) as a technology is technically feasible at this source.

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

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.[6]

Step 3 – Ranking of Remaining Technologies

The remaining technologically feasible options (which are not mutually exclusive) have been ranked based on their GHG emissions reductions performance levels. The table below provides a summary of the remaining technologies.

Emission Reduction Option	Performance Level (% control)	Rank (x)
CCS	Up to 90%	1
Fuel selection	4% - 55%	2
Good combustion, operating and maintenance practices	5 – 25%	3
Fuel Preheater	1 – 2%	4

CCS is capable of achieving up to 90% reduction of generated CO_2 emissions and thus is considered to be the most effective control method. Use of low-carbon fuel, energy efficient design, and good combustion and maintenance practices 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 mutually exclusive).

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

Carbon Capture and Storage

Provided CO_2 capture and compression could be reliably achieved, the high volume stream must be transported by pipeline to long-term storage to a geologic formation capable of long-term storage. The Gulf Coast Carbon Center (GCCC) has identified numerous potential sites along the

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

Texas Gulf Coast that may be suitable for sequestration, the capacity and reliability of these sites remains untested. In particular, a modeling study of the Frio Formation in the Texas Gulf Coast conducted by the GCCC indicated long-term CO2 loss from the geologic formation despite high intrinsic capacity and determined further study is required to determine ascertain the long-term capacity of geologic formations.

Cost Analysis

Air Liquide has estimated the costs for capture, transport, and long term geologic storage of CO_2 from the four combustion turbines alone, since these emission units have the greatest amount of CO_2 emissions. The costs would be even higher when considering recovery of the CO_2 from the boilers as well. These costs are provided in the application. The capital costs for post-combustion capture and compression is estimated to be $537,044,041. The capital cost for pipeline to convey the CO_2 is estimated to be $33,873,469 for a 30 mile long 10 inch diameter pipeline. The annualized cost for CCS and long-term geologic storage is $99,557,484 which is more than four times the estimated annualized capital cost for the proposed project of $22,097,090. Based on the normalized control cost and comparison of total capital cost of control to project cost, Air Liquide maintains that CCS is not economically feasible.

In addition to maintaining that CCS would be economically infeasible for this project, Air Liquide asserts that CCS can also be eliminated as BACT based on the environmental impacts from a collateral increase of National Ambient Air Quality Standards (NAAQS) pollutants. According to the applicant, implementation of CCS would increase emissions of NOx, CO, VOC, PM, and SO_2 by as much as 15% from the additional utilities and energy demands that would be required to operate the CCS system. It is possible that installation of CCS in this situation, assuming it was truly feasible for simple cycle units, would decrease the plant efficiency by as much as 15% or more. To overcome this loss in efficiency and to generate power to support the equipment that would be needed to capture CO_2 and compress the gas into a pipeline for EOR or geologic storage, the plant would attempt to increase its heat input by burning more fuel which would result in a collateral increase in these criteria pollutants.

EPA notes that where GHG control strategies affect emissions of other regulated pollutants, trade-offs in selecting GHG pollution controls can be legitimately taken into account. See PSD Permitting Guidance at pp. 40-42. Here, the plant is located in the Houston, Galveston, and Brazoria (HGB) area of ozone non-attainment and the generation of additional NOx and VOC could exacerbate ozone formation in the area. EPA reviewed Air Liquide's cost analysis and the estimated pollutant increases that would result from the implementation of CCS, and concludes that CCS can be eliminated as BACT for this project due to the cost increase to the project. While not necessary, EPA is also rejecting CCS based on potential negative environmental impact of the projected collateral emission increases of ozone precursors in an ozone non-attainment area.

Low-Carbon Fuel

The use of low-carbon fuel is economically and environmentally practicable for the proposed project. Combustion of gaseous fuel in lieu of higher carbon-based fuels such as diesel or coal reduces emissions not only of GHGs, but of other combustion products such as NO_x, CO, VOC, PM_{10}, and SO_2, providing further environmental benefits.

Energy Efficient Design

The overall efficiency of the combustion turbine is increased with increased fuel inlet temperatures. The use of a fuel preheater will achieve this by heating the fuel gas using high temperature water from the HRSG. By optimizing energy efficiency, the project requires less fuel than comparable less-efficient operations, resulting in cost savings. Further, reduction in fuel consumption corresponding to energy efficient design reduces emissions of both GHGs and other combustion products such as NO_x, CO, VOC, PM_{10}, and SO_2, providing further environmental benefits.

Good Combustion Practices

Good combustion practices effectively support the energy efficient design. Thus, the economic and environmental practicability related to energy efficient design also applies to the use of good combustion practices.

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
Lower Colorado River Authority (LCRA), Thomas C. Ferguson Plant Horseshoe Bay, TX	590 MW combined cycle combustion turbine and heat recovery steam generator	Energy Efficiency/ Good Design & Combustion Practices	Combustion turbine annual net heat rate limited to 7,720 Btu/kWh (HHV) GHG BACT limit of 0.459 tons CO_2/MWh (net) without duct burning. 365-day average, rolling daily for the combustion turbine unit	2011	PSD-TX-1244-GHG

Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
Palmdale Hybrid Power Plant Project Palmdale, CA	570 MW combined cycle combustion turbine and heat recovery steam generator and 50 MW Solar-Thermal Plant	Energy Efficiency/ Good Design & Combustion Practices	Combustion turbine annual net heat rate limited to 7,319 Btu/kWh (HHV) GHG BACT limit of 0.387 tons CO_2/MWh (net)* 365-day average, rolling daily for the combustion turbine unit	2011	SE 09-01
Calpine Russell City Energy Hayward, CA	600 MW combined cycle power plant	Energy Efficiency/ Good Design & Combustion Practices	Combustion Turbine Operational limit of 2,038.6 MMBtu/kWh	2011	15487
PacifiCorp Energy - Lake Side Power Plant Vineyard, UT	629 MW (without duct burning) combined cycle turbine	Energy Efficiency/ Good Design & Combustion Practices	Combustion turbine BACT limit of 950 lb CO_2e/MWh (gross) on a 12-month rolling average basis	2011	DAQE-AN0130310010-11
Kennecott Utah Copper-Repowering South Jordan, UT	275 MW combined combustion	Energy Efficiency/ Good Design & Combustion Practices	Combustion turbine BACT limit of 1,162,552 tpy CO_2e rolling 12-month period	2011	DAQE-IN105720026-11
Pioneer Valley Energy Center Westfield, MA	431 MW combined cycle turbine generator	Energy Efficiency/ Good Design & Combustion Practices	825 lbs CO_2e/MWh_{grid} (initial performance test) 895 lb CO_2e/MWh_{grid} on a 365-day rolling average	2012	052-042-MA15
Calpine Deer Park Energy Center Deer Park, TX	168 MW/180 MW combustion turbine generator with heat recovery steam generator	Energy Efficiency/ Good Design & Combustion Practices	0.460 tons CO_2/MWh on a 30 day rolling average without duct burning.	2012	PSD-TX-979-GHG

Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
Calpine Channel Energy Center Pasadena, TX	168 MW/180 MW combustion turbine generator with heat recovery steam generator	Energy Efficiency/ Good Design & Combustion Practices	0.460 tons CO_2/MWh on a 30 day rolling average without duct burning.	2012	PSD-TX-955-GHG
PL Propylene Houston, TX	Propylene Production	Energy Efficiency/ Good Design & Combustion Practices	Use of good combustion practices.	2013	PSD-TX-18999-GHG
Copano Processing, L.P., Houston Central Gas Plant Sheridan, TX	Natural Gas Processing	Energy Efficiency/ Good Design & Combustion Practices	40% efficiency with WHRU, equates to 0.84 lbs CO_2e/hp-hr.	2013	PSD-TX-104949-GHG

*The Palmdale facility BACT limit is reduced due to the offset of emissions from the use of a 50 MW Solar-Thermal Plant that was part of the permitted project. The incorporation of the solar power generation into the BACT analysis for this facility does not imply that other sources must necessarily consider alternative scenarios involving renewable energy generation in their BACT analyses.[7]

In review of recently issued permits, Air Liquide reviewed the GHG BACT analysis of the Pio Pico Energy Center which includes three 100 MW GE LMS100, aero-derivative, simple cycle turbines. Therein, USEPA Region 6 reviewed the thermal efficiency of several power frames with thermal efficiencies ranging from 9,254 to 9,790 Btu $_{HHV}$/kW-hr gross, and established a thermal efficiency BACT limit of 7,720 Btu $_{HHV}$/kW-hr gross on 365 day rolling average basis as the BACT limit based on number of factors including model and manufacturer specification under site operating conditions. Further, this limit included a 3% margin to account for variations in manufacture, assembly, and site operating conditions. The 3% margin was based on technical data from GE showing that it is expected for a gas turbine to have a non-recoverable performance loss over the lifetime of the plant of 2.5% and a 5% aged performance loss over the lifetime of the plant. Air Liquide also cited The Electric Power Research Institute (EPRI) "Axial Compressor Performance Maintenance Guide Update" from February 2005. The EPRI guidance states that gas turbines experience about a 2-3% loss in capacity in the first year of service,

[7] See page 40 of EPA Region 9's "Response to Public Comments on the Proposed Prevention of Significant Deterioration Permit for the Palmdale Hybrid Power Project". http://www.epa.gov/region09/air/permit/palmdale/palmdale-response-comments-10-2011.pdf

followed by another 3% loss over the next five years of service.[8] Air Liquide reviewed the BACT determination for the LCRA Thomas Ferguson Plant and Calpine Deer Park as well as numerous other simple cycle and combined cycle units with permits under consideration by Region 6. In the permit issued by USEPA Region 6 to the Lower Colorado River Authority (LCRA) for two GE 7FA combined cycle 195 MW turbines, the thermal efficiency limit established as BACT was 7,720 Btu $_{HHV}$/kW-hr gross. It should be noted that at the time of this application, a draft BACT determination for the Calpine Energy Center was issued in November 2012 and was not available when this application was submitted. A review of these BACT determinations is provided in Appendix C of the application. Review of these specific case-by-case BACT determinations, for combined cycle units, found efficiencies to be from 7,720 to 7,730 Btu (HHV)/kWh. There is only one BACT result for simple cycle units and that resulted in a limit of 9,196 Btu (HHV)/kWh for that particular application. Furthermore, not all units have been assigned thermal efficiency limits and have BACT determinations based on mass emission rates of GHG only. Further, BACT is determined on a case-by-case basis, although previous determinations for similar projects should be considered in determining BACT for a new project, other factors including purpose, energy impacts, and environmental impacts must be considered rather than simple reliance on a result of a similar BACT analysis.

The proposed GE 7EA turbines are rated at 80 MW with a manufacturer specified thermal efficiency of 11,988 Btu $_{HHV}$/kW-hr-gross at site operating conditions in simple cycle operation. As shown in the Region 6 analysis, there are other simple cycle power frames capable of achieving greater thermal efficiency; however, these are higher output frames designed primarily for base-load or peak power production. In this project, Air Liquide is replacing the existing GE 7EA with more modern and efficient versions of the same power frame. These power frames are installed primarily to generate hot exhaust gases for combined heat and power generation. Therefore, a direct comparison of thermal efficiency to both simple cycle and combined cycle turbines used solely for electricity generation is not necessarily appropriate.

The Bayou Cogeneration Plant is a combined heat and power (CHP) plant. Electricity generating gas turbines units (EGUs) are designed to optimize the conversion of energy to mechanical work rather than transfer energy to a medium such as generating high temperature exhaust gases for steam production. Further, a combined cycle unit uses two thermodynamic cycles, the Brayton cycle and the Rankine cycle, to convert thermal energy into mechanical work. Electricity is produced by expanding exhaust gases or steam through the gas turbine and then a steam turbine to drive a shaft which converts mechanical work into electricity. Energy is consumed in order to drive the turbine mass resulting in mechanical energy losses and a decrease in thermal efficiency.

[8] See pages 45-47 of The Electric Power Research Institute (EPRI) "Axial Compressor Performance Maintenance Guide Update" from February 2005.

A CHP plant does not generate electricity in a steam turbine and therefore, does not experience the mechanical energy loss resulting from driving the turbine. Instead, the energy in the steam is used through conductive heat transfer in the customers' process. As a result, CHP is an inherently more efficient process than an equivalent combined cycle turbine. For these reasons, comparing thermal efficiency on an energy-to-power basis to either a simple or combined cycle turbine electric generating units (EGUs) to a gas turbine designed for steam production is not appropriate.

Air Liquide conducted an exhaustive search of the USEPA-issued permits and BACT determinations as well as the RACT/BACT/LAER Clearinghouse (RBLC), and could not locate any GHG BACT determinations for a CHP application. In an effort to try to make a comparison between the proposed project and those recently permitted by EPA Region 6, Air Liquide proposes to use a combination of combined cycle power production units with a stand-alone steam generation system for comparison.

For CHP units some of the energy in the fuel is used to generate electricity through the turbine, and some of the energy from the fuel is used to make steam. This use of the residual heat from the turbine is similar to how a combined cycle unit is operated, except the steam generated is left as steam, rather than using it to generate additional electricity in a steam turbine. In CHP processes, because the fuel energy is being used to both generate power and steam, comparing the efficiency of CHP to generate either individually is not an accurate representation of the process efficiency. Instead, we must determine an equivalent measure of useful energy out relative to energy consumed. In a topping unit where the electrical power is generated prior to generation of the steam for heat, the measure of efficiency is Fuel Chargeable to Power (FCP). FCP is defined as the incremental fuel for the generation system relative to the needs of a heat only system divided by the net incremental power produced by the cogeneration system. The FCP is interchangeable to the net heat rate of a plant generating only electrical power; thus FCP is the most appropriate comparison to a combined cycle EGU. FCP is calculated as the difference between total fuel fired and the fuel used to generate steam divided by the net power output as described in Equation 1.

Daily thermal efficiency will be calculated as shown in Equations 1 through 3. FCP is calculated as the difference between total fuel fired and the fuel used to generate steam divided by the net power output as described in Equation 1.

Equation 1 *Calculation of Fuel Chargeable to Power*

$$FCP = \frac{Q_{GT} - FCS}{P_{NET}}$$

Where: FCP = Fuel Chargeable to Power [Btu (HHV)/kWh]

Q_{GT} = Heat input to gas turbine [MMBtu/hr]

FCS = Fuel Chargeable to Steam [MMBtu/hr]

P_{NET} = Net electrical production [kW]

Fuel Chargeable to Steam (FCS) is the net heat used to generate steam divided by the efficiency of an equivalent boiler. Calculation of FCS is described in Equation 2.

Equation 2 *Calculation of Fuel Chargeable to Steam*

$$FCS = \frac{Q_{HP} + Q_{LP} - Q_{FW}}{e\ boiler}$$

Where: FCS = Fuel Chargeable to Steam [MMBtu/hr]

QHP = Heat used to generate high pressure steam [MMBtu/hr]

QLP = Heat used to generate low pressure steam [MMBtu/hr]

QFW = Heat used to heat the feed water [MMBtu/hr]

e boiler = Efficiency of an equivalent boiler [0.84]

The heat required to generate steam of each condition is the product of the change in enthalpy required to convert water to steam of the specified pressure and temperate and the production rate of the steam. The heat used in the feed water is the change in enthalpy to bring the feed water to vaporization temperature and mass flow rate as shown in Equation 3.

Equation 3 *Calculation of Heat Consumption for Steam and Feed water*

$$Q_i = \Delta h_i * m_i$$

Where: Q_i = Heat used for steam or water stream, *i* [MMBtu/hr]

Δh_i = Change in enthalpy, *i* [MMBtu/lb]

m_i = Mass flow of stream *i*

Because the FCP is interchangeable with the net heat rate of an equivalent combined cycle facility, Air Liquide proposes a BACT limit for thermal efficiency of 7,720Btu $_{HHV}$/kWh gross equivalent based on a 365-day rolling average. Air Liquide will comply with the BACT limit for each new combustion turbine or combination of new turbines, following the initial tests. The initial compliance test has been specified, after each turbine is installed, in Section V of the permit. Therefore, Air Liquide is proposing daily record keeping of the following parameters to calculate thermal efficiency:

- Natural gas and off-gas consumed;
- Net electricity produced;
- Mass of high pressure steam produced;
- Mass of low pressure steam produced;
- Mass of feed water used;
- Average daily pressure and temperature of steam produced; and
- Calculated average enthalpy for low and high pressure steam based on average daily steam conditions.

Air Liquide will also maintain monthly records of the fuel heating value provided by the supplier to determine daily heat input. Compliance with the 7,720 Btu (HHV)/kWh limit will be demonstrated by the 365-day rolling total, of the calculated daily thermal efficiency. Until project completion for all four turbine replacements, Air Liquide will comply with the BACT limit for each new turbine / duct burner or combination of new turbine / duct burner, following the initial tests. The initial compliance test has been specified, after each new turbine is installed, in Section V of the permit.
Air Liquide proposes the following design and work practices as BACT for combustion turbines:

- Use of natural gas or fuel gas;
- Good combustion, operation and maintenance practices; and
- Installation of a fuel preheater.

Implementaion of the operational and maintenance practices above results in an annual emission limit of 485,588 tpy of CO_2e for each turbine which includes emissions from maintenance, startup, and shutdown activities. The proposed emission limit is based on a 365-day rolling total basis as monitored by a Continuous Emissions Monitoring System (CEMS) for CO_2. The CO_2 CEMS will be operated as in 40 CFR 60 Appendix B, Specification 3 and meet the quality assurance procedures of 40 CFR 60, Appendix F. The fuel flow into and steam flow rates from each boiler will be continuously monitored. A data acquisition handling system (DAHS) will be used to measure and record the CO_2 to demonstrate compliance with the annual emission limit and the BACT limit.

CO_2 emissions (pounds emitted) shall be calculated monthly in the DAHS based on the CO_2 CEMS and fuel gas flows into the combined turbine / duct burner.

$$BACT\ Limit = \frac{\sum(monthly\ CO_2\ lbs\ from\ each\ new\ GE\ combustion\ \frac{turbine}{existing}\ duct\ burner/stack)}{\sum(monthly\ MM\ Btus\ heat\ input\ to\ each\ new\ GE\ combustion\ \frac{turbine}{existing}\ duct\ burner\ )}$$

XI. Steam Boilers (EPNs: BO1, BO2, and BO3) BACT Analysis

Air Liquide will utilize three boilers at the facility. These boilers will produce steam for internal use and to meet the facilities contractual steam obligations. The proposed boilers will burn pipeline quality natural gas and off gas. CO_2 will be emitted from the boiler since it is a combustion product of any carbon containing fuel. CH_4 will be emitted from the boiler as a result of any incomplete combustion. N_2O will be emitted from the boiler in trace quantities due to partial oxidation of nitrogen in the air which is used as the oxygen source for the combustion process.

Step 1 – Identification of Available Control Technologies:

1. Energy efficient design - Energy efficient design practices include engineered solutions to improve heat transfer between the combustion gases and the working media or increase waste heat recovery.

   These design components can include the following:
   - Replace or upgrade burners
   - Air preheater
   - Economizer
   - Insulation and insulating Jackets
   - Capture energy from boiler blow down
   - Condensate return system

2. Good combustion practices, operation and maintenance - Proper combustion, operation and maintenance ensure the boilers maintain optimal efficiency and perform as designed.

   These operational practices include:
   - Boiler tuning
   - Combustion optimization
   - Operation procedures including startup, shutdown, and malfunction
   - Instrumentation and controls
   - Reduce air leakages
   - Reduce slagging and fouling of heat transfer surfaces
   - Preventive maintenance

3. Alternate fuels - The use of higher energy density fuels or alternative fuels such as biomass may reduce carbon emissions by changing the carbon-to-energy density of the fuel. The use of gaseous fuels (natural gas and fuel gas) results in less carbon emissions as discussed below.

4. Carbon Capture and Sequestration - CCS is an available add-on control technology that is applicable for all of the site's affected combustion units.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible, except for blow down system heat recovery. The only available and applicable CO_2 capture technology, post-combustion capture, is also believed to be technically feasible. [9]

Blow down System Heat Recovery:

Modifications to the blow down system to capture waste heat would require the installation of additional equipment beyond the scope of the project. The site footprint is limited and would not allow for the installation of the necessary piping and heat exchangers necessary for waste heat recovery from the blow down system.

CCS

CCS will not be considered further based on the evaluation in section XI above.

Step 3 – Ranking of Remaining Technologies

The remaining technologically feasible options have been ranked based on their GHG emissions reductions performance levels. The table below provides a summary of the remaining technologies.

Emission Reduction Option	Performance Level (% control)	Rank (x)
Fuel selection	4% - 55%	1
Good combustion, operating and maintenance practices	5 – 25%	2

[9] Based on the information provided by Air Liquide and reviewed by EPA for this BACT analysis, while there are some portions of CCS that may be technically infeasible for this project, EPA has determined that overall Carbon Capture and Storage (CCS) technology is technically feasible at this source.

Emission Reduction Option	Performance Level (% control)	Rank (x)
Condensate return system	1 – 5%	3
Fuel Preheater	1 – 2%	4

Use of low-carbon fuel, energy efficient design, and good combustion and maintenance practices are all considered effective, can be used in tandem, 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 mutually exclusive).

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

The use of low-carbon fuel is economically and environmentally practicable for the proposed project. Combustion of gaseous fuel in lieu of higher carbon-based fuels such as diesel or coal reduces emissions not only of GHGs, but of other combustion products such as NO_x, CO, VOC, PM_{10}, and SO_2, providing further environmental benefits.

Energy Efficient Design

The boilers will incorporate the following technologies; economizer, steam generation from process waste heat, and feed preheat. By optimizing energy efficiency, the project requires less fuel than comparable less-efficient operations, resulting in cost savings. Further, reduction in fuel consumption corresponding to energy efficient design reduces emissions of both GHGs and other combustion products such as NO_x, CO, VOC, PM_{10}, and SO_2, providing further environmental benefits.

Good Combustion Practices

Good combustion practices effectively support the energy efficient design. Thus, the economic and environmental practicability related to energy efficient design also applies to the use of good combustion practices.

Step 5 – Selection of BACT for Steam Boilers

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

Company / Location	Process Description	BACT Control(s)	BACT Emission Limit / Requirements	Year Issued	Reference
BASF FINA Petrochemicals LP, NAFTA Region Olefins Complex Port Arthur, TX	Ethylene Production	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT for steam package boilers - monitor and maintain a thermal efficiency of 77% 12-month rolling average basis	2012	PSD-TX-903-GHG
Chevron Phillips Chemical Company, Cedar Bayou Plant Baytown, TX	Ethylene Production	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT for the VHP boiler - monitor and maintain a thermal efficiency of 77% 12-month rolling average basis	2012	PSD-TX-748-GHG
INVISTA S.à.r.l., Victoria Site, West Powerhouse Victoria, TX	Nylon Intermediate Compounds	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT for the boilers – 235 lbs CO_2/1,000 lbs of steam produced.	2013	PSD-TX-812-GHG
PL Propylene Houston, TX	Propylene Production	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT for the boilers – 117 lb CO_2/MMBtu heat input.	2013	PSD-TX-18999-GHG
ExxonMobil, Mont Blevieu Plastics Plant Baytown, TX	Polyethylene Production	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT for the boilers - monitor and maintain a thermal efficiency of 77% 12-month rolling average basis	2013*	PSD-TX-103048-GHG

*Permit not yet issued.

Air Liquide proposes the following design and work practices as BACT for the boilers:

- Use of natural gas;
- Good combustion, operation and maintenance practices; and
- Installation of a air preheater;
- Installation of condensate return system

A BACT limit of 117 pounds of CO_2 per MMBtu (12-month rolling average) has been proposed for each boiler including emissions from maintenance, startup, and shutdown activities. This BACT limit is identical to the BACT limit established for the PL Propylene boiler. CO_2

emissions (pounds emitted) shall be determined continuously from the each steam boiler by a CO_2 CEMS.

$$BACT\ Limit = \frac{\sum(monthly\ CO_2\ lbs\ from\ each\ new\ Rentech\ boiler\ duct/stack)}{\sum(monthly\ MM\ Btus\ heat\ input\ to\ each\ new\ Rentech\ steam\ boiler)}$$

Until project completion for all three boilers, Air Liquide will comply with the BACT limit for each new boiler or combination of new boilers, following the initial tests. The initial compliance test has been specified, after each boiler is installed, in Section V of the permit.

Additionally, Air Liquide has requested a 10,769,647 MMBtu heat input per 12-month total combined for the three new boilers. The proposed operational and maintenance practices above result in an annual emission limit of 209,957 tpy CO_2e per boiler. The proposed emission limit is based on a 365-day rolling total basis as monitored by a Continuous Emissions Monitoring System (CEMS) for CO_2. The CO_2 CEMS will be operated as in 40 CFR 60 Appendix B, Specification 3 and meet the quality assurance procedures of 40 CFR 60, Appendix F. The fuel flow into and steam flow rates from each boiler will be continuously monitored. A data acquisition handling system (DAHS) will be used to measure and record the CO_2 to demonstrate compliance with the annual emission limit and the BACT limit.

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, site specific analysis of process fuel gas, and the actual heat input (HHV). 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 (74 FR 56374 October 30, 2009). Records of the calculations would be required to be kept to demonstrate compliance with the emission limits on a 12-month average, rolling monthly.

An initial stack test demonstration will be required for CO_2 emissions from the 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 boilers and are considered a *de minimis* level in comparison to the CO_2 emissions.

XII. Endangered Species Act

Pursuant to Section 7(a)(2) of the Endangered Species Act (ESA) (16 U.S.C. 1536) and its implementing regulations at 50 CFR Part 402, EPA is required to insure that any action authorized, funded, or carried out by EPA is not likely to jeopardize the continued existence of any federally-listed endangered or threatened species or result in the destruction or adverse modification of such species' designated critical habitat.

To meet the requirements of Section 7, EPA is relying on a Biological Assessment (BA) prepared by the applicant, Air Liquide Large Industries U.S., L.P. ("Air Liquide"), and its consultant, Environmental Resources Management, Inc., ("ERM"), and adopted by EPA.

A draft BA has identified twelve (12) species listed as federally endangered or threatened in Harris County, Texas:

Federally Listed Species for Harris County by the U.S. Fish and Wildlife Service (USFWS), National Marine Fisheries Service (NMFS), and the Texas Parks and Wildlife Department (TPWD)	**Scientific Name**
Plant	
Texas Prairie Dawn Flower	*Hymenoxys texana*
Birds	
Red-cockaded Woodpecker	*Picoides borealis*
Whooping Crane	*Grus americana*
Fish	
Smalltooth Sawfish	*Pristis pectinata*
Mammals	
Louisiana Black Bear	*Ursus americanus luteolus*
Red Wolf	*Canis rufus*
Amphibians	
Houston Toad	*Bufo houstonensis*
Reptiles	
Green Sea Turtle	*Chelonia mydas*
Kemp's Ridley Sea Turtle	*Lepidochelys kempii*
Leatherback Sea Turtle	*Dermochelys coriacea*
Loggerhead Sea Turtle	*Caretta caretta*
Hawksbill Sea Turtle	*Eretmochelys imbricate*

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

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

Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on listed species. The final draft biological assessment

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

XIII. National Historic Preservation Act (NHPA)

Section 106 of the NHPA requires EPA to consider the effects of this permit action on properties eligible for inclusion in the National Register of Historic Places. To make this determination, EPA relied on and adopted a cultural resource report prepared by ERM on behalf of Air Liquide submitted on June 17, 2013.

For purposes of the NHPA review, the Area of Potential Effect (APE) was determined to be approximately 57 acres of land within and adjacent to the construction footprint of the existing facility. ERM conducted a field survey of the property and desktop review within a 1.0-kilometer radius area of potential effect (APE). The desktop review included an archaeological background and historical records review using the Texas Historical Commission's online Texas Archaeological Site Atlas (TASA) and the National Park Service's National Register of Historic Places (NRHP). Based on the results of the field survey, no archaeological resources or historic structures were found within the APE. Based on the desktop review, no archaeological resources or historic structures were found.

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

On June 18, 2013, EPA sent letters to Indian tribes identified by the Texas Historical Commission as having historical interests in Texas to inquire if any of the tribes have historical interest in the particular location of the project and to inquire whether any of the tribes wished to consult with EPA in the Section 106 process. EPA received no requests from any tribe to consult on this proposed permit. EPA will provide a copy of the report to the State Historic Preservation Officer for consultation and concurrence with its determination. Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on historic properties. A copy of the report may be found at
http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

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 GHG. The global climate-change inducing effects of GHG emissions, according to the "Endangerment and Cause or Contribute Finding", are far-reaching and multi-dimensional (75 FR 66497). Climate change modeling and evaluations of risks and impacts are typically conducted for changes in emissions that are orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible [PSD and Title V Permitting Guidance for GHGS at 48]. Thus, we conclude it would not be meaningful to evaluate impacts of GHG emissions on a local community in the context of a single permit. Accordingly, we have determined an environmental justice analysis is not necessary for the permitting record.

XV. Conclusion and Proposed Action

Based on the information supplied by Air Liquide Bayou Cogeneration Plant, our review of the analyses in the GHG PSD Permit Application, and our independent evaluation of the information contained in our Administrative Record, it is our determination that the proposed project would employ BACT for GHG under the terms contained in the draft permit. Therefore, EPA is proposing to issue Air Liquide a PSD permit for GHG for the Bayou Cogeneration Plant redevelopment project, 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 emissions, in tons per year (TPY) on a 12-month total, rolling monthly, shall not exceed the following:

Table 1: Annual Emission Limits

EPN	FIN	Description	GHG Mass Basis		CO_2e TPY[1, 2]	BACT Requirements
				TPY[1]		
CG801	GT1	Combustion Turbine	CO_2	485,112	485,588	7,720 $Btu_{(HHV)}/kWh_{gross}$ equivalent based on a 365-day rolling average. See Permit Conditions at III.B.1.
			CH_4	9.15		
			N_2O	0.91		
CG802	GT2	Combustion Turbine	CO_2	485,112	485,588	7,720 $Btu_{(HHV)}/kWh_{gross}$ equivalent based on a 365-day rolling average. See Permit Conditions at III.B.1.
			CH_4	9.15		
			N_2O	0.91		
CG803	GT3	Combustion Turbine	CO_2	485,112	485,588	7,720 $Btu_{(HHV)}/kWh_{gross}$ equivalent based on a 365-day rolling average. See Permit Conditions at III.B.1.
			CH_4	9.15		
			N_2O	0.91		
CG804	GT4	Combustion Turbine	CO_2	485,112	485,588	7,720 $Btu_{(HHV)}/kWh_{gross}$ equivalent based on a 365-day rolling average. See Permit Conditions at III.B.1.
			CH_4	9.15		
			N_2O	0.91		
BO1	B-305	Boiler 1	CO_2	209,750	209,957	117 lb CO_2 per MMBtu heat input. Good combustion, operating and maintenance practices. See Permit Conditions at III.D.
			CH_4	3.96		
			N_2O	0.40		
BO2	B-306	Boiler 2	CO_2	209,750	209,957	117 lb CO_2 per MMBtu heat input. Good combustion, operating and maintenance practices. See Permit Conditions at III.D.
			CH_4	3.96		
			N_2O	0.40		
BO3	B-307	Boiler 3	CO_2	209,750	209,957	117 lb CO_2 per MMBtu heat input. Good combustion, operating and maintenance practices. See Permit Conditions at III.D.
			CH_4	3.96		
			N_2O	0.40		
Totals[3]			**CO_2**	**2,569,698**	**CO2e 2,572,215**	
			CH_4	**48.5**		
			N_2O	**4.8**		

1. The TPY emission limits specified in this table are not to be exceeded for this facility and include emissions from the facility during all operations and include MSS activities.
2. Global Warming Potentials (GWP): CH_4 = 21, N_2O = 310
3. Totals are given for informational purposes only and do not constitute emission limits.