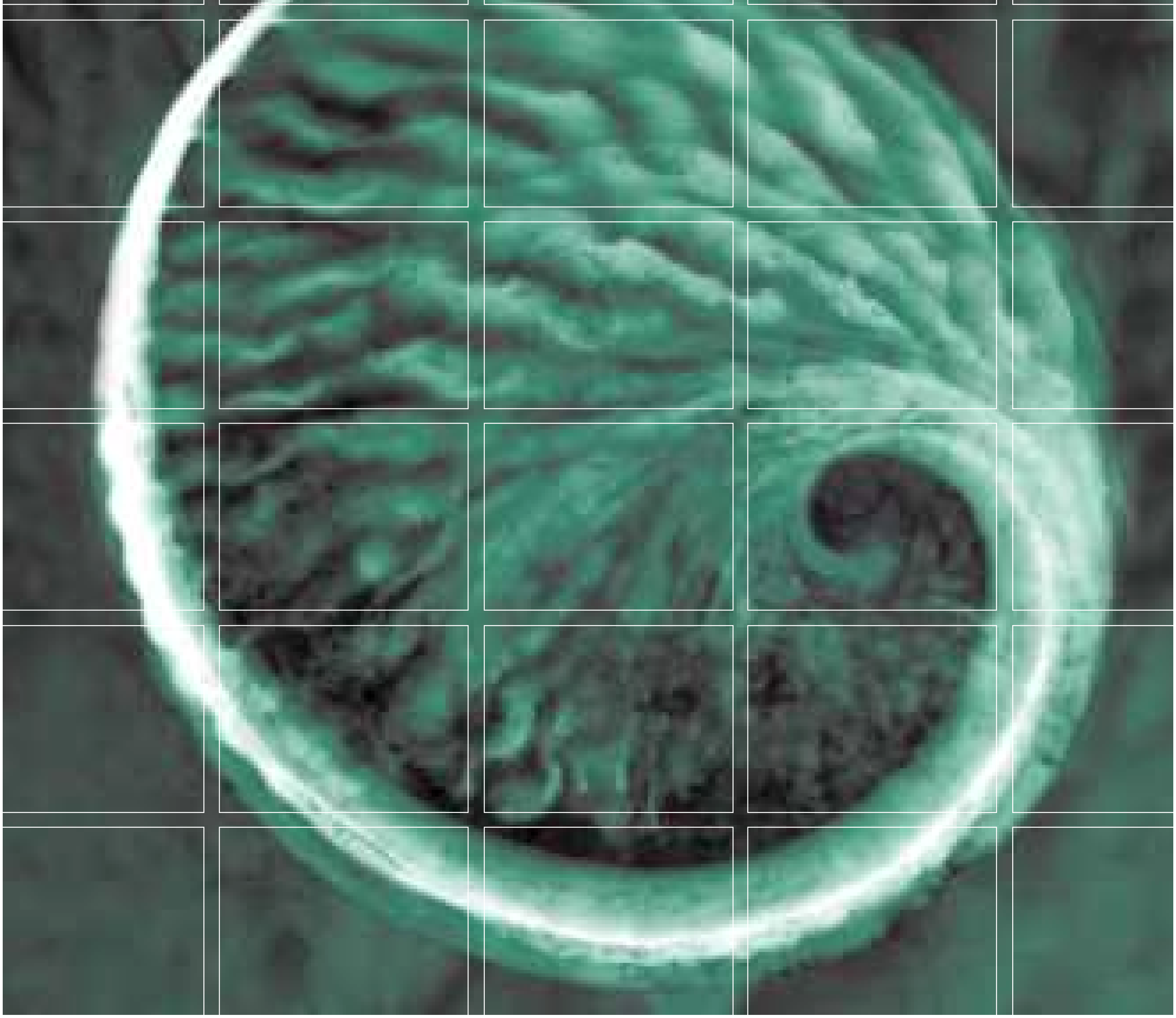

Prevention of Significant Deterioration Greenhouse Gas Permit Application for the Bayou Cogeneration Plant

Prepared for
Air Liquide Large Industries U.S., LP
Houston, Texas

September 13, 2012

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Air Liquide Large Industries U.S., L.P.

Prevention of Significant Deterioration

Greenhouse Gas Permit Application at the Bayou Cogeneration Plant

September 13, 2012

Project No. 0151579
Bayou Cogeneration Plant

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1.0 INTRODUCTION

Air Liquide Large Industries U.S., L.P. (Air Liquide) is submitting this permit application to authorize the redevelopment of its cogeneration facility in Pasadena, Texas (Bayou Cogeneration Plant). The proposed project will involve the replacement of four (4) gas-fired gas turbines (CG-801 through CG-804) with similar units, the addition of three (3) new gas-fired boilers and the subsequent removal of three (3) existing gas-fired boilers (ST-5 through ST-7) at the Bayou Cogeneration Plant. After 27 years of operation, the existing gas turbines and boilers at the facility are nearing the end of their service life. The purpose of this project is to replace the gas turbines and boilers to ensure future reliable operation, construct the project given the current layout and space constraints of the facility, and ensure that the maximum design thermal efficiency of the original plant is maintained.

The Bayou Cogeneration Plant currently consists of four power blocks for power and steam generation, with each block consisting of a gas-fired GE Frame 7EA gas turbine, and a heat recovery steam generator (HRSG). The HRSG includes duct burners for supplemental firing. The power blocks do not include steam turbines. The HRSGs produce steam for sale. Although the gas turbines include HRSGs, the units are not combined cycle combustion turbines because they do not include the steam cycle for power generation. These types of units are referred to as cogeneration or combined heat and power units (CHP).

On August 30, 2012, President Obama issued an executive order to accelerate and expand investments to reduce energy use through more efficient manufacturing processes and facilities and the expanded use of combined heat and power (CHP). Exec. Order Accelerating Investment in Industrial Energy Efficiency (August 30, 2012). President Obama ordered the EPA strongly encourage efforts to achieve a national goal of deploying 40 gigawatts of new, cost effective industrial CHP in the United States by the end of 2020 and provide incentives for the deployment of CHP. As noted in the press release for the executive order, CHP costs as much as 50% less than traditional forms of delivered new baseload power. This planned project at Bayou Cogeneration Plant is the exact type of project the Executive Order encourages and recognizes to be a part of the President's policy to encourage investment in industrial efficiency in order to reduce costs for industrial users, improve U.S. competitiveness, create jobs, and reduce harmful air pollution.

The Bayou Cogeneration Plant also includes three natural gas-fired boilers which produce steam for sale. The existing sources at the Bayou Cogeneration Plant are currently permitted to operate under New Source Review (NSR) air permits, Prevention of Significant Deterioration (PSD) permits, one federal Title V operating permit, as well as various Texas Permits-by-Rule (PBRs).

Per the Greenhouse Gas (GHG) tailoring rule published in the Federal Register on June 3, 2010, modifications to existing major sources increasing GHG emissions by 75,000 tons per year (tpy) of carbon dioxide equivalents (CO_2e) are subject to Prevention of Significant Deterioration (PSD) review under 40 CFR

52.21. Further, facilities emitting at least 100,000 tpy CO_2e are subject to permitting requirements under Title V of the Clean Air Act. Although the state of Texas is the delegated authority for New Source Review (NSR) and PSD under its State Implementation Plan (SIP), it has yet to submit its revision to its SIP to implement the GHG Tailoring Rule. On December 23, 2010, USEPA signed the Federal Implementation Plan (FIP) authorizing the USEPA Region 6 to issue permits in Texas until approval of a SIP.

The emissions increase from the Bayou Cogeneration Plant modification exceeds 75,000 tpy CO_2e. Therefore, the project is subject to PSD review for GHG emissions, and Air Liquide submits this application for a GHG PSD permit. This application includes a description of project scope, calculation of GHG emissions, a netting analysis to account for creditable emissions created by the equipment replacement, and review of Best Available Control Technology (BACT). Further, the project triggered PSD for criteria air pollutants. As such, Air Liquide submitted an application for an air quality permit for construction to the Texas Commission on Environmental Quality (TCEQ) and copy of this application is submitted to the United States Environmental Protection Agency (USEPA) Region 6 herein.

1.1 PROJECT DESCRIPTION

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.[1]

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.

[1] Each new turbine is rated to produce 4 MW of electricity more than the existing turbines at the facility.

The proposed project will be executed in three phases, spanning 24 to 30 months:

- Phase 1 (Anticipated June 2013 – December 2013) – During this phase, three new boilers will be constructed at the facility. These new boilers will eventually replace the three existing boilers during Phase 3 of the project. Each of the three new boilers will be equipped with selective catalytic reduction (SCR) systems to reduce NO_X emissions to the atmosphere. The existing gas turbines and boilers will not be modified during this phase of the project and will continue to operate at current levels; therefore, the only activity during this phase of the project will be the construction of the three new boilers.
- Phase 2 (Anticipated December 2013 – December 2015) - During this phase, the four existing gas turbines will be replaced with new GE 7EA units designed with the latest and most efficient combustion technology offered for this gas turbine. During Phase 2, the new boilers will need to be operational and available to fulfill steam/thermal supply contractual obligations, in addition to the three existing boilers. Each of the four gas turbines will be decommissioned, removed, and subsequently replaced one at a time. As soon as the replacement of a given gas turbine is complete during Phase 2, it will be started and commissioned. Phase 2 will end when the fourth gas turbine is commissioned. The existing boilers will continue to be available for operation during this phase to assist in fulfilling the steam/thermal supply contractual obligations, however, at no point will the four new gas turbines, three new boilers, and three existing boilers operate simultaneously during Phase 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.
- Phase 3 (Anticipated December 2015) – During this phase, the three existing boilers will be retired and permanently shut down and disabled. This marks the completion of the project.

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.

Based on emissions calculations presented in Appendix B of this application, the proposed project will trigger PSD permitting for carbon monoxide (CO), particulates (PM, PM_{10}, and $PM_{2.5}$), and greenhouse gas (GHG) emissions. This application addresses the GHG emissions only. The criteria pollutant PSD permit application filed with TCEQ in a separate submittal is included with this application.

Table 3-1 provides a summary of the Federal PSD applicability analysis for the overall project. A summary of emission calculation methodologies is presented in Section 5 of this application. Criteria air pollutants will be permitted under TCEQ PSD or minor New Source Review (minor NSR) requirements.

1.2 *APPLICATION ORGANIZATION*

This Technical Support Document and the enclosed application forms in Appendix A constitute the application for a permit to construct under 40 CFR 52.21 for the proposed redevelopment project at the Bayou Cogeneration Plant. Please note that confidential information (including proposed plot plan) is being submitted to the USEPA Region 6 under a separate cover.

The remainder of the application is organized as follows:

Section 2.0 – Site Location, Process Description, and Area Map

Section 3.0 – Federal Applicability to the Proposed Project

Section 4.0 – BACT and Lowest Achievable Emission Rate (LAER) Analyses

Section 5.0 – Emission Rate Calculations

Appendix A – TCEQ Permit Application Forms

Appendix B – Emission Rate Calculations and Gas Turbine Data

2.0 SITE LOCATION AND PROCESS DESCRIPTION

2.1 SITE LOCATION

The location of the proposed project is shown on the area and USGS maps provided as Figures 2-1 and 2-2, respectively.

2.2 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 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 turbine (steam turbine) to optimize the thermal performance of the plant[2]. The plant is designed for optimum thermal performance as a CHP facility. The design thermal efficiency of the original plant was 79.5%, considerably above most conventional plants.

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 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.

Air Liquide is planning to replace the existing combustion turbines at the Bayou Cogeneration Plant with similar GE 7EA units. 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. Emissions of GHG will be parametrically monitored by measurement of fuel flow and heating value.

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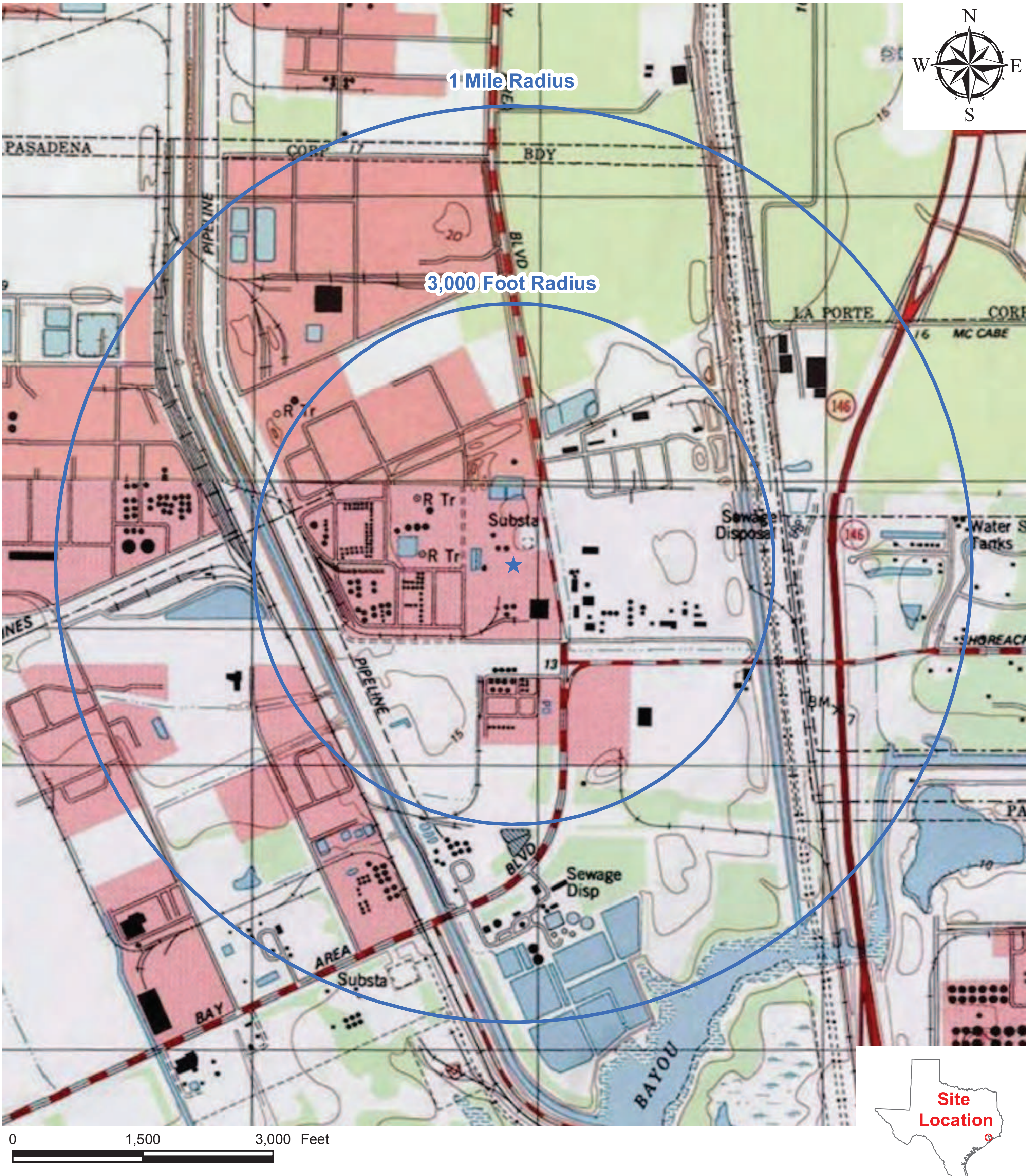
[2] Bray, M.E., Mellor, R., Bollinger, J.M., Bayou Cogeneration Plant - A Case Study, Proceedings from the Seventh National Industrial Energy Technology Conference, Houston, TX, May 12-15, 1985



SOURCE: U.S.G.S. 7.5' QUADRANGLE, LEAGUE CITY, TX (o29095E1).

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FIGURE 2-1
3000 FOOT AND 1 MILE RADII MAP
Air Liquide Bayou Cogeneration Plant
Air Liquide Large Industries U.S., L.P.
11400 Bay Area Boulevard
Pasadena, Texas

ERM

SOURCE: U.S.G.S. 7.5' QUADRANGLE, LEAGUE CITY, TX (o29095E1).

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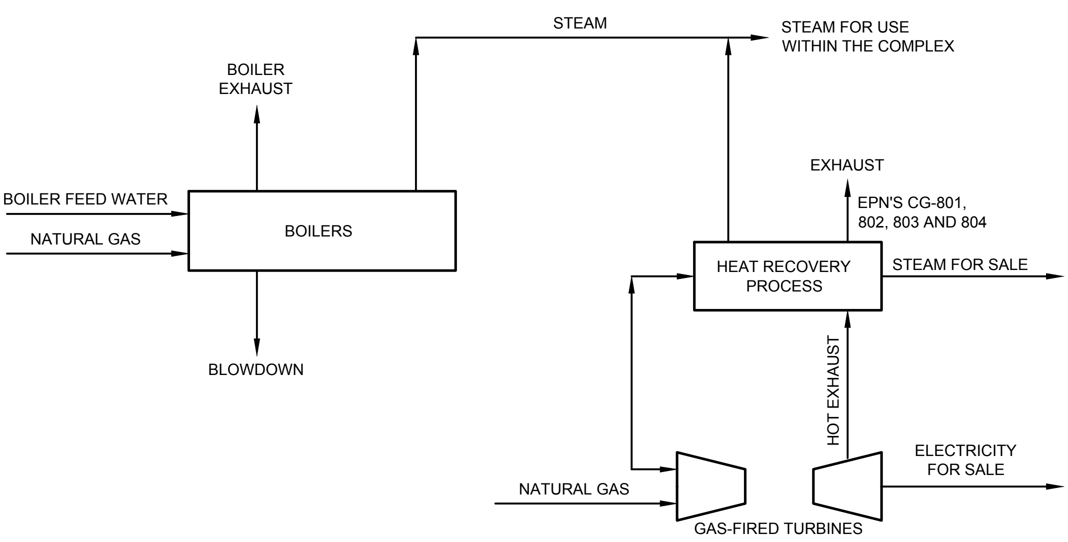
Environmental Resources Management

FIGURE 2-2
3000 FOOT AND 1 MILE RADII MAP
Air Liquide Bayou Cogeneration Plant
Air Liquide Large Industries U.S., L.P.
11400 Bay Area Boulevard
Pasadena, Texas

ERM

FACILITY PROCESS FLOW



COGENERATION PROCESS

COGENERATION UNITS PROCESS FLOW

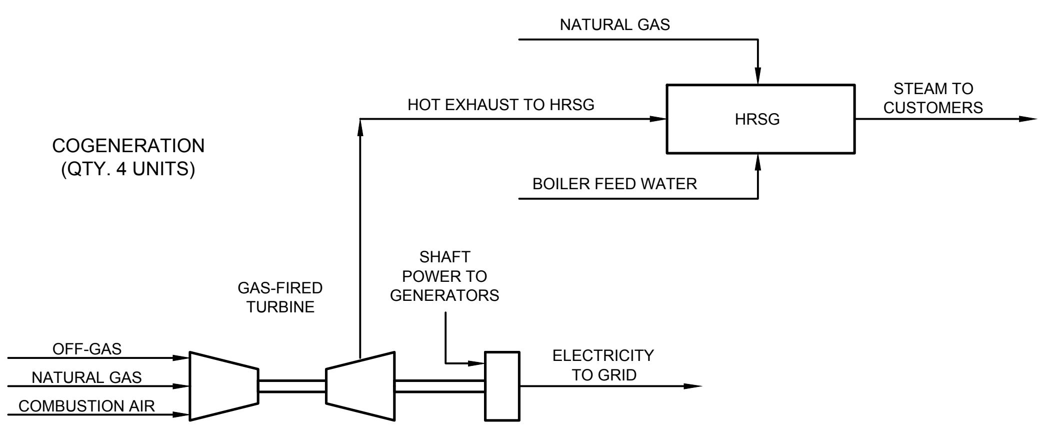


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FIGURE 2-3
PROCESS FLOW DIAGRAM
Air Liquide Bayou Cogeneration Plant
Air Liquide Large Industries U.S., L.P.
11400 Bay Area Boulevard
Pasadena, Texas

ERM

3.0 REGULATORY REVIEW

The proposed project will be subject to federal and state regulatory requirements as outlined in the following sections. Only those regulations that are potentially applicable to the proposed project were reviewed in this application. The USEPA promulgated a Federal Implementation Plan (FIP) for Texas assuming of PSD permitting authority for large GHG-emitting sources in Texas in accordance with the thresholds established under the Tailoring Rule published on June 3, 2010. All other pollutants are regulated by the TCEQ under the SIP and are beyond the scope of this application.

3.1 FEDERAL REGULATIONS

3.1.1 Federal Major New Source Review

3.1.1.1 *Prevention of Significant Deterioration; 40 CFR 52 and GHG Tailoring Rule*

The GHG PSD Tailoring rule defines a major new source of GHG emissions as emitting 100,000 short tons of CO_2 equivalent (CO_2e) and 100 tpy/250 tpy (depending on the source category) on a mass basis. A major modification under the rule is defined as an emission increase and net emissions increase of 75,000 tons or more of GHGs on a CO_2e basis and greater than zero tpy of GHGs on a mass basis. For the second phase of the Tailoring Rule, which began on July 1, 2011, PSD requirements for GHGs are triggered for existing sources only if the existing source's GHG emissions are equal to or greater than 100,000 tpy on a CO_2e basis and equal to or greater than 100 tpy/250 tpy on a mass basis, and the emission increase and net emission increase of GHGs from the modification would be equal to or greater than 75,000 tpy on a CO_2 basis and greater than zero tpy on a mass basis.

Table 3-1 shows the estimated project-related emissions increase as well as the creditable contemporaneous emissions increase and decrease for each PSD GHG. The net emissions rate increase of each pollutant was compared to its PSD significance threshold to evaluate the applicability of PSD for each pollutant. The project is an existing major source with a net emissions increase greater than 75,000 CO_2e and zero tpy on a mass basis.

3.1.2 Compliance Assurance Monitoring (CAM) 40 CFR 64

The provisions of 40 CFR Part 64 (Compliance Assurance Monitoring [CAM]) apply to each Pollutant-Specific Emissions Unit (PSEU) when it is located at a facility that is required to obtain Title V, Part 70 or 71 permit, and the PSEU meets all of the following criteria:

1. The unit is subject to an emission limitation or standard;
2. The unit uses an active control device to achieve compliance with an emission limitation or standard; and

3. The unit has potential pre-control device emissions in the amount of tons per year required to classify that unit as a major source under Part 70.

The proposed replacement turbines and new boilers do not use active control devices to control GHG emissions. Therefore, CAM requirements will not apply to these pollutant emissions. NO_X and CO emissions from the gas turbines are reduced by using low-NO_X burners with GE's CLEC (Closed Loop Emissions Control) system, which is not a post-combustion active control device, but rather an optimization of the dry, low-NO_X system using a closed-loop emissions control. Therefore, CAM requirements also do not apply to NO_X and CO emissions from the gas turbines.

3.1.3 Mandatory Reporting Rule

Under the Mandatory Reporting Rule (40 CFR Part 98), beginning in 2010 facilities with fuel burning equipment with actual CO_2e emissions greater than or equal to 25,000 metric tons per year must submit an annual GHG report must cover all source categories and GHGs for which calculation methodologies are provided in subparts C of the rule. The Bayou Cogeneration Plant has reported and will continue to report GHG emissions under 40 CFR Part 98.

TABLE 3-1: PSD APPLICABILITY SUMMARY TABLE

Pollutant	Project Emissions Increases (tpy)	Creditable Emissions Increases/ Decreases (tpy)	Net Emissions Increase (tpy)	PSD Significance Threshold (tpy)	PSD Triggered? (Yes/No)
GHG (CO_2e)	1,292,978	-102,816	1,190,162	75,000	Yes
CO_2	1,291,888	-102,708	1,189,180	0	Yes
CH_4	20.97	-3.45	17.52	0	Yes
N_2O	2.10	-0.34	1.75	0	Yes

4.0 *BEST AVAILABLE CONTROL TECHNOLOGY (BACT) ANALYSIS*

Under 40 CFR 52.21, BACT shall be applied to reduce or eliminate air emissions from a new or modified facility. PSD BACT is applicable to all pollutants that are subject to PSD review as summarized in Table 3-1. BACT is defined in 40 CFR §52.21(b)(12) as:

> *"An emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results."*

State BACT is defined in 30 TAC §116.10(1) as:

> *"An air pollution control method for a new or modified facility that through experience and research, has proven to be operational, obtainable, and capable of reducing or eliminating emissions from the facility, and is considered technically practical and economically reasonable for the facility. The emissions reduction can be achieved through technology such as use of add-on control equipment or by enforceable changes in production processes, systems, methods or work practice."*

The USEPA guidance document, *PSD and Title V Permitting Guidance for Greenhouse Gases (EPA 457/B-11-001)*, USEPA recommends the use of the five-step "top down" BACT process established in the 1990 draft guidance *New Source Review Workshop* Manual to evaluate and select BACT for GHG. This process requires identification and consideration of all available control technologies. The applicant must then demonstrate control technologies that are infeasible due to engineering constraints. All remaining technologies are ranked in order of descending order of control effectiveness. The top-ranked control option must be selected unless the applicant can demonstrate that it is not viable due to adverse economic or environmental impacts. If the most effective technology is not selected, then the next most effective alternative should be evaluated until an option is selected as BACT. The BACT process is summarized as follows:

- Step 1 – Identify all available control technologies;
- Step 2 – Eliminate technically infeasible options;
- Step 3 – Rank remaining control technologies;
- Step 4 – Evaluate and document remaining control technologies; and
- Step 5 – Select BACT

Each of the steps listed above have been evaluated in detail for each project-related emissions source combination in the following sections.

4.1 SUMMARY OF PROPOSED BACT

A summary of BACT limits and technologies proposed in this permit application are summarized in Tables 4-1 and 4-2.

TABLE 4-1: Summary of Proposed BACT for Combustion Turbines

Pollutant	Limit	Control Technology/Standard	Averaging Time / Compliance Method
CO_2e	8,334 Btu (HHV)/kW-hr equivalent (gross)	Good combustion practices, operation and maintenance Fuel selection	365 day rolling average/ CEMS
CO_2	485,112 tpy CO_2 per turbine		

TABLE 4-2: Summary of Proposed BACT for Boilers

Pollutant	Limit	Control Technology/Standard	Averaging Time / Compliance Method
CO_2	117 lb/MMBtu (HHV)	Good combustion practices, operation and maintenance	12 month rolling average / fuel monitoring

4.2 BACT FOR COMBUSTION TURBINES

4.2.1 *Step 1: Identify All Available Control Technologies*

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. 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.

4.2.1.1 *Inherently Low Emitting Design*

High Efficiency Turbines

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 9 reviewed the thermal efficiency of several power frames with thermal efficiencies ranging from 9,254 to 9,790 $Btu_{HHV}/kW\text{-}hr_{gross}$, and established a thermal efficiency BACT limit of 9,196 $Btu_{HHV}/kW\text{-}hr_{gross}$ 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. Additionally, Air Liquide reviewed 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 in this permit was 7,720 $Btu_{HHV}/kW\text{-}hr_{gross}$.

The proposed GE 7EA turbines are rated at 80 MW with a manufacturer specified thermal efficiency of 11,988 $Btu_{HHV}/kW\text{-}hr_{gross}$ at site operating conditions in simple cycle operation. As shown in the Region 9 analysis, there are other simple cycle power frames capable of achieving greater thermal efficiency; however, these are higher output frames designed primarily for baseload 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 frames are installed primarily to generate hot exhaust gases for combined heat and power generation. Therefore, a direct comparison of thermal efficiency to a both simple cycle and combined cycle turbines used solely for electricity generation is not necessarily appropriate. Assuming 9.1 pounds of high pressure steam generates 1 kilowatt of power through a steam turbine generator, the CHP application of the GE 7EA turbine would be functionally equivalent to a combined cycle unit at 8,334 $Btu_{HHV}/kW\text{-}hr_{gross}$.

Installing an alternate hybrid, aero-derivative turbine such as an LMS100 would require a redesign of the HRSG and ancillary equipment. Further, these frames would require modification to the existing infrastructure. A project of this scope would fundamentally change the business purpose of the project as it was intended to replace the existing frame in kind. Pursuant to USEPA guidance, *PSD and Title V Permitting Guidance for Greenhouse Gases (EPA 457/B-11-001)*, inherently lower polluting processes that fundamentally redefine the nature of the proposed source are not required to be considered in Step 1. As such, alternative or aero-derivative turbines are eliminated from consideration herein.

Plant Wide Energy Efficiency Processes
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.

4.2.1.2 Good Combustion, Operating and Maintenance Practices

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.

4.2.1.3 Fuel Selection

The use of fuels with low carbon intensity and high heat intensity is appropriate BACT for GHG. The use of natural gas fuels meets these criteria as demonstrated in Table 4-3 summarizing emission factors for various solid and gaseous fuels.

TABLE 4-3: Emissions of CO_2 from Solid and Gaseous Fuels Available For Use in Combustion Turbines[3]

Fuel Option	Emission Factor (kg CO_2/MMBtu)	Carbon Intensity (relative to natural gas)
Natural Gas/Fuel Gas Blend	53.02 – 59.00	--
Propane Gas	61.46	1.04 – 1.16
Distillate No. 2	73.96	1.25 – 1.39
Biomass Liquids	68.44 – 81.55	1.16 – 1.54
Biomass Solids	93.80 – 118.17	1.59 – 2.23

4.2.1.4 Carbon Capture and Sequestration

In addition to reduction of GHG emissions by reducing fuel consumption through efficient design and optimal operation, post-combustion control technologies to capture and sequester GHG emissions must be considered. Carbon Capture and Sequestration (CCS) has three main approaches including oxy-fuel combustion, pre-combustion capture, and post-combustion capture.

Oxy-fired technology involves the replacement of combustion air with pure oxygen to create a more concentration CO_2 flow in the combustion exhaust. This technology is in the early stages of review and has not reached a commercial stage of deployment for gas turbine applications. As such, it will not be further considered the Bayou Cogeneration Plant. Pre-combustion capture is primarily applicable to gasification plants and is, therefore, not applicable to the Air Liquide facility.

Of these approaches, post-combustion capture is applicable to gas turbines. Post-combustion capture involves separating CO_2 from the exhaust gas stream. Methods of post-combustion capture include adsorption, absorption, and physical separation. If carbon capture can be reliably achieved, transportation and reliable long-term storage are still required. This requires proximate access to a transport pipeline capable of delivering the enriched flue gases to a geologic formation suitable for long-term sequestration of CO_2.

[3] 40 CFR §98, Table C-1

4.2.2 *Step 2: Eliminate Technically Infeasible Options*

4.2.2.1 *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.

4.2.2.2 *Carbon Capture and Sequestration*

Carbon Capture
As presented in Section 4.2.1.4, carbon capture processes include adsorption, physical absorption, chemical absorption, cryogenic separation, and membrane separation. These technologies are in various stages of development from bench-scale to pilot-scale demonstrations.

Absorption
Chemical absorption is characterized by the occurrence of a chemical reaction between the pollutant in gas phase and a chemical in liquid phase to form a compound. The most prevalent chemical for CO_2 removal from flue gas are amine solutions. Gas scrubbing systems employing amine are used for a wide variety of gas or liquid hydrocarbon treatment applications. Close contact between the gas and liquid amine solution is required to promote the mass transfer between the two phases. CO_2 has a high solubility in the amine scrubbing solution. Several amine solvents are commercially used include monoethanolamine (MEA), diethanolamine (DEA), triethanolamine (TEA), diisopropanolamine (DIPA), diglycolamine (DGA), methyldiethanolamine (MDEA), n-methylethanolamine (NMEA), alkanolamine, and various propriety mixtures of these amines. Other chemical absorbents including ammonia, potassium carbonate, and lime are also in experimental phases.

MEA has been tested in gas turbine applications and offers high capture efficiency, high selectivity, and lowest energy use compared to the other existing processes. However, despite these benefits, MEA requires additional heat recovery which is unobtainable with the current HRSG configuration or installation of supplemental firing which is beyond the scope of this project. Northeast Energy Associates conducted CO_2 capture to produce 320 to 350 tons per day CO_2 using a Fluor Econamine scrubber on 15 percent of the flue gas from its 320 MW natural gas combined cycle facility in Bellingham, Massachusetts, from 1991 to 2005. The CO_2 was not sequestered, but was produced for the commercial (food-grade) CO_2 market and ultimately made its way into the atmosphere. The process was curtailed in 2005 because the CO_2 market no longer made the operation profitable. A cost estimate for an MEA capture system is presented at the end of this absorption section

Physical sorbents include propylene carbonate, Selexol™, Rectisol™, and Morphysorb™. Close contact between the scrubbing solvent and gas forces the CO_2 into solution. The process has been commercially used to remove CO_2 from natural gas production. Although the energy required to regenerate the physical sorbents is much less than that required for chemical sorbents, they are less effective in dilute gas streams such as combustion turbine exhaust. As such, this technology is considered technically infeasible.

Adsorption

Laboratory evaluations of natural zeolite, manufactured zeolite sieves, and activated carbon have all shown that these materials preferentially adsorb CO_2 over nitrogen, oxygen, and water vapor at elevated pressures. Although these materials show promise for CO_2 capture from high pressure gas streams, they are unsuited for low pressure combustion exhaust streams. Therefore, adsorption is considered technically infeasible.

Separation

Polymer-based membrane separation of CO_2 is currently under investigation. Membrane separation is potentially less energy intensive than other methods because there is no chemical reaction or phase change. Currently, potential membrane materials are prone to chemical and thermal degradation. This technology is still experimental and not commercially available. Membrane technology is considered technically infeasible for this project.

In cryogenic separation of CO_2, the gas is cooled and compressed to condense CO_2. This process is only effective on dry gas streams with high CO_2 concentrations and is not feasible for the dilute gas streams from combustion exhaust.

Transportation and Sequestration

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 U.S. Department of Energy National Energy Technology Laboratory (DOE-NETL) states:

"The majority of geologic formations considered for CO2 storage, deep saline or depleted oil and gas reservoirs, are layers of porous rock underground that are "capped" by a layer or multiple layers of non-porous rock above them. Under high pressure, CO2 turns to liquid and can move through a formation as a fluid. Once injected, the liquid CO2 tends to be buoyant and will flow upward until it encounters a barrier of non-porous rock, which can trap the CO_2 and prevent further upward migration. Coal seams are another formation considered a viable option for geologic storage, and their storage process is slightly different. When CO2 is injected into the formation, it is adsorbed onto the coal surfaces, and methane gas is released and produced in adjacent wells.

There are other mechanisms for CO2 trapping as well: CO2 molecules can dissolve in brine: react with minerals to form solid carbonates; or adsorb in the pores of the porous rock. The degree to which a specific underground formation is amenable to CO2 storage can be difficult to discern."[4]

[4] DOE-NETL. *Carbon Sequestration: Storage.* http:///www.netl.doe.gov/technologies/carbon_seq/core_rd/storage.html

The Gulf Coast Carbon Center (GCCC) has identified numerous potential sites along the Texas Gulf Coast that may be suitable for sequestration, the capacity and reliability of these sites remains untested.[5] In particular, a modeling study of the Frio Formation in the Texas Gulf Coast conducted by the GCCC indicated long-term CO_2 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.[6]

Finally, carbon sequestration has potential environmental impacts that must be investigated and considered before declaring sequestration viable as BACT including:

- Impacts from brine displacement into fresh water aquifers or surface water;
- CO_2 leakage into underground or surface drinking water supplies; and
- Subsequent impacts to local flora and fauna

Although numerous research pilot-scale projects for high-volume carbon sequestration are underway, these technologies have not been proven to be reliable nor are they ready for commercial deployment. As such, Air Liquide considers sequestration to be technically infeasible for this project, and it is removed from consideration as BACT.

Cost Analysis

In addition to evaluating the technical feasibility of CCS, Air Liquide evaluated the cost of carbon capture using MEA based on published methodologies. This analysis is shown in Table 4-4. The cost of capture using MEA is approximately \$66/ton of CO_2 removed. For comparison purposes, one could calculate the threshold value of cost effectiveness for CO_2e based on the relative cost effectiveness of control of a criteria pollutant at some threshold value per ton of pollutant removed and the major source threshold of 100 tpy. This approach is supported by USEPA's own rulemaking under the "Tailoring Rule." Through rulemaking the USEPA has "tailored" greenhouse gasses such that 100,000 tons of CO_2e is equal to 100 tons of a criteria pollutant for the purpose of PSD applicability. So, by USEPA's own rulemaking construct, if a criteria pollutant has a cost effectiveness threshold in the range of \$8,000 per ton, then the CO_2e equivalent cost effectiveness should be 0.001 times as much, or \$8/ton controlled. Based on this criterion, the CCS demonstration system for the Bayou Cogeneration Plant is also found to be infeasible based on cost.

[5] Susan Hovorka, et. al. University of Texas, Bureau of Economic Geology – Gulf Coast Carbon Center. *New Developments: Solved and Unsolved Questions Regarding Geologic Sequestration of CO_2 as a Greenhouse Gas Reduction Method.* GCCC Digital Publication #08-13. April 2008.
[6] Christine Doughty, et. al. University of Texas, Bureau of Economic Geology – Gulf Coast Carbon Center. *Capacity Investigation of Brine-bearing Sands of the Frio Formation for Geologic Sequestration of CO_2.* GCCC Digital Publication #01-03. 2001.

TABLE 4-4: MEA Capture Cost Estimate

Item	Value
Basis	
Total Hours per year	8,760
Economic Life, years	15
Interest Rate (%) [1,2]	15
Source(s) Controlled	Four Gas Turbines
Generating Capacity (MW-gross)	320
Gross Generation (kWh/yr)	2,803,200,000
Cost Factors (2012 dollars)	
Capital Cost ($/kW) [1]	595
coe: Capital (mill/kWh, year 2012 dollars) [1]	21
Retrofit Factor (assumed and applied to capital only)	1.5
coe: Total Capital Cost (mill/kWh, year 2012 adjusted for retrofit)	31.5
coe: Fuel (mill/kWh, 2012 dollars) [1,3]	3.4
coe: O&M (mill/kWh, 2000 dollars) [1]	2
coe: O&M (mill/kWh, 2012 dollars) [1, 4]	2.7
Composite Cost Factor (mill/kWh, 2012 dollars)	37.7
Control	
Before Capture Annual Emissions (ton/yr)	1,940,448
Capture Efficiency	90%
Cost of Capture ($/ton CO_2 Captured)	60
Transportation and Storage	
Levelized Transportation Cost (average $/ton CO2, 2012 dollars) [2]	4.6
Levelized Storage Cost ($/ton CO_2, 2012 dollars) [2]	0.5
Total CCS Cost ($/ton CO_2, 2012 dollars)	66
[1] Herzog, H.,J., *The Economics of Carbon Separation and Capture*, MIT Energy Laboratory (2000). Capital cost of installing carbon capture based on the difference between the study plant and baseline plant. Capital cost adjusted from year 2000 to 2012 with ENR Construction Cost Index values 6221 for 2000 and 9351 for 2012.	
[2] McCollum, D. L., Ogden, J. M., *Techno-Economic Models for Carbon Dioxide Compression, Transport, and Storage & Correlations for Estimating Carbon Dioxide Density and Viscosity*, Institute of Transportation Studies – University of California, Davis (2006). Based on 100 km (62 miles) from capture site to storage site. Capital cost adjusted from year 2000 to 2012 with ENR Construction Cost Index values 7446 for 2006 and 9351 for 2012.	
[3] Adjusted based on cost of natural gas of $4.45/Mscf in 2000 and $5.11/Mscf in 2012. http://www.eia.gov/dnav/ng/hist/n3035us3a.htm	
[4] Adjusted based on Consumer Price Index of 172.2 in 2000 to 229.1 in 2012. ftp://ftp.bls.gov/pub/special.requests/cpi/cpiai.txt	

4.2.3 Step 3: Rank Remaining Control Technologies

The remaining technologically and economically feasible options have been ranked based on their control of GHG from combustion turbines. Table 4-5 provides a summary of the remaining technologies.

TABLE 4-5: Ranking of Technically Feasible Emissions Reduction Options of Greenhouse Gases from Combustion Turbines

Emission Reduction Option	Performance Level (% control)	Rank (x)
Fuel selection	4% - 55%	1
Good combustion, operating and maintenance practices	5-25%	2
Fuel preheater	1-2%	3
Uncontrolled	--	--

4.2.4 *Step 4: Evaluate and Document Remaining Control Technologies*

After identifying and ranking available and technically feasible control technologies, the economic, environmental, and energy impacts are evaluated to select the best control option. Air Liquide has determined that the remaining control technologies have no adverse impacts that require additional consideration or evaluation.

4.2.5 *Step 5: Select BACT*

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;

Air Liquide proposes an annual emission limit of 485,112 tpy of CO_2 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. Additionally, Air Liquide proposes a short-term thermal efficiency limit of 8,334 Btu_{HHV}/kWh_{gross} equivalent based on a 365-day rolling average and assuming 9.1 pounds of steam per kW equivalent. Compliance will be demonstrated by monitoring fuel gas flow, fuel higher heating value, and gross power production.

4.3 *NATURAL GAS-FIRED BOILER*

4.3.1 *Step 1: Identify All Available Control Technologies*

Air Liquide performed a search of the USEPA RBLC for natural-gas fired boilers; however, the database contained no entries for BACT determinations for GHG emissions. Air Liquide did find two recently issued PSD permits for GHG from gas-fired boilers provided in Appendix C. In addition, Air Liquide reviewed the

GHG BACT identified in USEPA guidance for industrial boilers[7]. Based on this information, Air Liquide has identified the following control options for natural-gas fired boilers:

- Energy Efficient Design
- Good Combustion Practices, Operation and Maintenance
- Alternative Fuels
- Carbon Capture and Sequestration

4.3.1.1 *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 blowdown
- Condensate return system

The Air Liquide project includes the installation of three 550 MMBtu/hr package boilers equipped new highly efficient burners with an economizer. The boiler is refractory lined to provide maximum insulation preventing reduction in efficiency through radiant heat loss.

4.3.1.2 *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
- Preventative maintenance

[7] USEPA, Office of Air and Radiation. *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions From Industrial, Commercial, and Institutional Boilers*. October 2010.

4.3.1.3 *Alternative 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 in Section 4.2.1.3. Alternative (biomass) fuels are removed from consideration.

4.3.1.4 *Carbon Capture and Sequestration*

CCS of exhaust gases from natural-gas fired boilers will be equivalent to CCS of combustion turbine exhaust. Please refer to Section 4.2.1.4 for a discussion of CCS.

4.3.2 *Step 2: Eliminate Technically Infeasible Options*

4.3.2.1 *Blowdown System Heat Recovery*

Modifications to the blowdown 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 blowdown system which is beyond the scope of the turbine replacement.

4.3.2.3 *Carbon Capture and Sequestration*

CCS of exhaust gases from natural-gas fired boilers will be equivalent to CCS of combustion turbine exhaust. Please refer to Section 4.2.2.2 for a discussion of the technical and economic feasibility of CCS.

4.3.3 *Step 3: Rank Remaining Control Technologies*

The remaining technologically feasible options have been ranked based on their GHG emissions reductions performance levels. Table 4-6 provides a summary of the remaining technologies.

TABLE 4-6: Ranking of Technically Feasible Emissions Reduction Options of Greenhouse Gases from Industrial Boilers

Emission Reduction Option	Performance Level (% control)	Rank (x)
Fuel selection	4% - 55%	1
Good combustion, operating and maintenance practices	5-25%	2
Condensate return system	1-5%	3
Fuel preheater	1-2%	4

4.3.4 Step 4: Evaluate and Document Remaining Control Technologies

After identifying and ranking available and technically feasible control technologies, the economic, environmental, and energy impacts are evaluated to select the best control option. Air Liquide has determined that the remaining control technologies have no adverse impacts that require additional consideration or evaluation.

4.3.5 Step 5: Select BACT

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 and air preheater;
- Installation of condensate return system

Air Liquide proposes a short-term emission limit of 117 pounds of CO_2 per MMBtu (365-day rolling average) for each boiler including emissions from maintenance, startup, and shutdown activities. Compliance with be demonstrated by monitoring fuel gas flow, fuel higher heating value, and gross power production.

It should be noted that this selection of BACT is based on the purpose of the project, which is to replace existing turbines and boilers that have reached the end of their useful life. This is a fit for purpose project as there are no other combustion turbines in the market that meet the exact specifications, dimensions and size as the GE Frame 7EA for the purpose of generating CHP. The combustion turbines are part of an overall system which includes heat recovery in the existing HRSG. As a result, the project will benefit in further GHG reductions due to the nature and efficiency of a cogeneration system that are not calculated here since it is not being modified. For this application, BACT has been determined for only the boilers and combustion turbines.

5.0 EMISSION RATE CALCULATIONS

This section summarizes the methodologies and emission factors used to calculate emissions for each emission source type affected by this project. As previously mentioned, this project involves the replacement of existing turbines, the addition of new boilers, and the removal of existing boilers at the facility. Detailed NSR emissions calculations for the overall project, as well as for Phase 2 of project are presented in Appendix B.

5.1 POTENTIAL EMISSIONS CALCULATIONS

5.1.1 Combustion Turbines Emissions

Potential emissions for the combustion turbines were calculated based on 8,760 hours of operation. The emissions factors used for calculating potential emissions from the turbines are summarized in Table 5-1 below.

TABLE 5-1: Turbine Emission Factors

Pollutant	Emission Factor	Basis
CO_2	53.02 (kg/MMBtu)	EPA's Mandatory Reporting Rule, Table C-1
CH_4	0.001 (kg/MMBtu)	EPA's Mandatory Reporting Rule, Table C-1
N_2O	0.0001 (kg/MMBtu)	EPA's Mandatory Reporting Rule, Table C-1
CO_2e	-	-

To convert the CO_2e, the following global warming potentials were used: 1 for CO_2, 21 for CH_4, and 310 for N_2O.

5.1.2 Boiler Emissions

The emissions factors used for calculating potential emissions from the boilers are summarized in Table 5-2 below. The new boilers will each be available to operate at the maximum rated capacity of 550 MMBtu/hr (short term basis), and for 8,760 hours per year each, however, Air Liquide is proposing to establish an enforceable limitation of 10,769,647 MMBtu per year on the combined annual fuel heat input for the three new boilers.

TABLE 5-2: Boiler Emission Factors

Pollutant	Emission Factor	Basis
CO_2	53.02 (kg/MMBtu)	EPA's Mandatory Reporting Rule, Table C-1
CH_4	0.001 (kg/MMBtu)	EPA's Mandatory Reporting Rule, Table C-1
N_2O	0.0001 (kg/MMBtu)	EPA's Mandatory Reporting Rule, Table C-1
CO_2e	-	-

To convert the CO_2e, the following global warming potentials were used: 1 for CO_2, 21 for CH_4, and 310 for N_2O.

5.2 BASELINE EMISSIONS CALCULATIONS

Per 40 CFR §52.21(b)(48)(ii):

…for an existing emissions unit (other than an electric utility steam generating unit), baseline actual emissions means the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 10-year period immediately preceding either the date the owner or operator begins actual construction of the project, or the date a complete permit application is received by the Administrator for a permit required under this section or by the reviewing authority for a permit required by a plan, whichever is earlier, except that the 10-year period shall not include any period earlier than November 15, 1990.

The turbines at the Bayou Cogeneration Plant do not meet the definition of an "electric utility steam generating unit" since they do not produce steam for the purpose of generating electricity; the steam produced by them is supplied to customers or used by the facility. Therefore, Air Liquide has utilized a 10-year look-back period for this analysis. An electric utility steam generating unit is defined in 40 CFR §52.21 as follows:

… any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the affected facility.

Air Liquide intends to perform an in-kind replacement of the four existing turbines; however, since the existing turbines are 27 years old, turbines with the exact same specifications are no longer available to Air Liquide. Therefore, Air Liquide will replace the existing turbines (old GE Frame 7EA) with new GE Frame 7EA gas turbines, which are closest in specification to the existing turbines.[8] This is a fit for purpose project as there are no other combustion turbines in the market that meet the exact specifications, dimensions and size as the GE Frame 7EA otherwise the intent and purpose of the project would change. The new turbine units meet the definition of "replacement facility" per 30 TAC §116.12 as follows:

1. The new turbines are replacing the existing turbines; the two cannot and will not operate simultaneously.
2. The new turbines are functionally equivalent to the existing turbines, and serve the same purpose as the existing turbines;
3. The replacement does not alter the basic design parameters of the process unit; the new turbines have energy efficiency upgrades, however, the underlying basic design parameters of the new and existing turbines are the same.

[8] Each new turbine is rated to produce 4 MW of electricity more than the existing turbines at the facility.

The baseline actual emissions for the four existing turbines were calculated as the annual average emissions over two consecutive calendar years (24-month period) in the last ten years preceding the project.

The emissions numbers reported as part of the facility's Greenhouse Gas Annual Emissions Inventories (GHG AEI), under the Mandatory Greenhouse Gas Rule 40 CFR 98, were used as the source for this emissions data. However, the emissions reported could not be used directly since that lists emissions at the CT/HRSG stack, which includes combined emissions from the combustion turbine and duct burners. Therefore, for the case of combustion turbine baseline emissions, the contribution of the duct burners was calculated using actual natural gas usage data for 2010 through 2011 and the actual emissions factors used to calculate emissions for AEI reporting, and the calculated emissions were subtracted from the reported emissions numbers.

For GHG (CO_2e), the years 2010-2011 were used as the baseline period for the purposes of this application.

5.3 CONTEMPORANEOUS PROJECTS

The only creditable emissions increase or decrease in the project's contemporaneous five year period is the reduction from the shutdown of the existing boilers. There are no other contemporaneous emissions increases or decreases for this project. The emissions numbers reported as part of the facility's GHG AEI for the years 2010 through 2011 were used as the source for the creditable emissions reductions data.

6.0 *ADDITIONAL REQUIREMENTS UNDER PSD*

An analysis of ambient air quality impacts is not provided with this application as there are no National Ambient Air Quality Standards (NAAQS) or PSD increments established for GHG (per EPA's PSD and Title V Permitting Guidance for Greenhouse Gases).

Since there are no NAAQS or PSD increments for GHGs, the requirements in sections 52.21(k) and 51.166(k) of EPA's regulations to demonstrate that a source does not cause contribute to a violation of the NAAQS are not applicable to GHGs. Therefore, there is no requirement to conduct dispersion modeling or ambient monitoring for CO_2 *or GHGs.*

Additionally, an analysis of Air Quality Related Values (AQRV) is not provided because GHG does not contribute to regional haze or terrestrial/aquatic acid deposition.

A pre-construction monitoring analysis for GHG is not being provided with this application in accordance with EPA's recommendations (per EPA's PSD and Title V Permitting Guidance for Greenhouse Gases):

EPA does not consider it necessary for applicants to gather monitoring data to assess ambient air quality for GHGs under section 52.21(m)(1)(ii), section 51.166(m)(1)(ii), or similar provisions that may be contained in state rules based on EPA's rules. GHGs do not affect "ambient air quality" in the sense that EPA intended when these parts of EPA's rules were initially drafted. Considering the nature of GHG emissions and their global impacts, EPA does not believe it is practical or appropriate to expect permitting authorities to collect monitoring data for purpose of assessing ambient air impacts of GHGs

6.1 *IMPACT EVALUATION PURSUANT TO FEDERAL ACTION*

6.1.1 *Federal Endangered Species Act*

Section 7 of the Federal Endangered Species Act (ESA) requires that any activity funded, authorized, or implemented by a federal agency does not jeopardize the continued existence of a listed species or result in the destruction or adverse modification of designated critical habitat (16 U.S.C. §1536). Under 40 CFR §402, federal agencies are required to prepare a biological assessment to determine the impact of the proposed action on endangered species. Air Liquide conducted this biological assessment and determined that the project will not adverse impact any federal or state-listed threatened and endangered species or critical habitat for these species. A copy of the biological assessment will be provided to USEPA Region 6 under separate cover.

6.1.2 *National Historic Preservation Act*

Section 106 of the National Historic Preservation Act (NHPA) requires federal agencies to address the effects of their actions on historic properties and afford the Advisory Council for Historic Preservation (ACHP) the opportunity to comment on the impact to historic properties and preservation as result of federal action. Air Liquide conducted site survey in accordance with the survey methods defined in the Department of Interior Standard and Guidelines and the guidelines of the Council of Texas Archaeologists. Based on this survey, no sites of historical or cultural significance were identified that would be affected by this project. A copy of the historical and cultural resource assessment will be provided to USEPA Region 6 under separate cover.

TCEQ Permit Application Forms

Appendix A

September 13, 2012
Project No. 0151579

Environmental Resources Management
15810 Park Ten Place, Suite 300
Houston, Texas 77084-5140
(281) 600-1000

Texas Commission on Environmental Quality
Form PI-1 General Application for Air Preconstruction Permit and Amendment

TCEQ

Important Note: The agency **requires** that a Core Data Form be submitted on all incoming applications unless a Regulated Entity and Customer Reference Number have been issued *and* no core data information has changed. For more information regarding the Core Data Form, call (512) 239-5175 or go to www.tceq.texas.gov/permitting/central_registry/guidance.html.

I. Applicant Information		
A. Company or Other Legal Name: Air Liquide Large Industries U.S., L.P.		
Texas Secretary of State Charter/Registration Number (*if applicable*):		
B. Company Official Contact Name: Jason Miller		
Title: Plant Manager, Bayport Complex		
Mailing Address: 11777 Bay Area Blvd		
City: Pasadena	State: TX	ZIP Code: 77507
Telephone No.: 281-474-8313	Fax No.: 281-474-8226	E-mail Address: Jason.Miller@Airliquide.com
C. Technical Contact Name: Aswath Kalappa		
Title: Sr. Environmental Specialist		
Company Name: Air Liquide		
Mailing Address: 2700 Post Oak Blvd., Suite 1800		
City: Houston	State: Texas	ZIP Code: 77056
Telephone No.: 713-402-2396	Fax No.:	E-mail Address: Aswath.Kalappa@Airliquide.com
D. Site Name: Bayou Cogeneration Plant		
E. Area Name/Type of Facility: Cogeneration Facility		☒ Permanent ☐ Portable
F. Principal Company Product or Business: Cogeneration Facility (Electricity and Steam)		
Principal Standard Industrial Classification Code (SIC): 4931		
Principal North American Industry Classification System (NAICS): 221112		
G. Projected Start of Construction Date: June 1, 2013		
Projected Start of Operation Date: June 1, 2014		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: 11400 Bay Area Blvd, Pasadena, TX – 77507. On I-610 E, take exit 30B for TX-225 E/La Porte toward Pasadena. Merge onto TX-225 E. Keep right at fork, follow signs for TX-146 S/La Porte and merge onto TX-146 S. Turn right onto Choate Rd. Turn right onto Bay Area Blvd; destination on the left.		
City/Town: Pasadena	County: Harris	ZIP Code: 77507
Latitude (nearest second): 29° 37' 21" N	Longitude (nearest second): 95° 02' 45" W	

Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment

TCEQ

I. Applicant Information (continued)	
I. Account Identification Number (leave blank if new site or facility): HG-0071-Q	
J. Core Data Form.	
Is the Core Data Form (Form 10400) attached? If *No*, provide customer reference number and regulated entity number (complete K and L).	☐ YES ☒ NO
K. Customer Reference Number (CN): CN600300693	
L. Regulated Entity Number (RN): RN100233998	
II. General Information	
A. Is confidential information submitted with this application? If *Yes*, mark each **confidential** page **confidential** in large red letters at the bottom of each page.	☒ YES ☐ NO
B. Is this application in response to an investigation or enforcement action? If *Yes*, attach a copy of any correspondence from the agency.	☐ YES ☒ NO
C. Number of New Jobs: 0	
D. Provide the name of the State Senator and State Representative and district numbers for this facility site:	
Senator: Mike Jackson	District No.: 11
Representative: John E. Davis and Ken Legler	District No.: 129, 144
III. Type of Permit Action Requested	
A. Mark the appropriate box indicating what type of action is requested. * Initial ☐ Amendment ☒ Revision (30 TAC 116.116(e)) ☐ Change of Location ☐ Relocation ☐	
B. Permit Number (if existing): NSR 9346 (Turbines), 56212 (Existing Boilers)	
C. Permit Type: Mark the appropriate box indicating what type of permit is requested. *(check all that apply, skip for change of location)* Construction ☒ Flexible ☐ Multiple Plant ☐ Nonattainment ☐ Prevention of Significant Deterioration ☒ Hazardous Air Pollutant Major Source ☐ Plant-Wide Applicability Limit ☐ Other:________	
D. Is a permit renewal application being submitted in conjunction with this amendment in accordance with 30 TAC 116.315(c).	☐ YES ☒ NO

* The turbines being replaced have an existing PSD permit (NSR 9346). The new boilers do not have any existing PSD permits.

TCEQ

III. Type of Permit Action Requested (continued)	
E. Is this application for a change of location of previously permitted facilities? If Yes, complete III.E.1 - III.E.4.	☐ YES ☒ NO
1. Current Location of Facility (If no street address, provide clear driving directions to the site in writing.):	
Street Address:	
City: County: ZIP Code:	
2. Proposed Location of Facility (If no street address, provide clear driving directions to the site in writing.):	
Street Address:	
City: County: ZIP Code:	
3. Will the proposed facility, site, and plot plan meet all current technical requirements of the permit special conditions? If *No*, attach detailed information.	☐ YES ☐ NO
4. Is the site where the facility is moving considered a major source of criteria pollutants or HAPs?	☐ YES ☐ NO
F. Consolidation into this Permit: List any standard permits, exemptions or permits by rule to be consolidated into this permit including those for planned maintenance, startup, and shutdown.	
List: PBR Registration Number 99546 for wet compression per 30 TAC 106.261 and 106.262.	
G. Are you permitting planned maintenance, startup, and shutdown emissions? If *Yes*, attach information on any changes to emissions under this application as specified in VII and VIII.	☒ YES ☐ NO
H. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability)	
Is this facility located at a site required to obtain a federal operating permit? If *Yes*, list all associated permit number(s), attach pages as needed).	☒ YES ☐ NO ☐ To be determined
Associated Permit No (s.): O1735	
1. Identify the requirements of 30 TAC Chapter 122 that will be triggered if this application is approved.	
FOP Significant Revision ☒ FOP Minor ☐ Application for an FOP Revision ☐ To Be Determined ☐	
Operational Flexibility/Off-Permit Notification ☐ Streamlined Revision for GOP ☐ None ☐	

Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment

III. Type of Permit Action Requested (continued)	
H. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) *(continued)*	
2. Identify the type(s) of FOP(s) issued and/or FOP application(s) submitted/pending for the site. (check all that apply)	
GOP Issued ☐ GOP application/revision application submitted or under APD review ☐	
SOP Issued ☒ SOP application/revision application submitted or under APD review ☐	
IV. Public Notice Applicability	
A. Is this a new permit application or a change of location application?	☐ YES ☒ NO
B. Is this application for a concrete batch plant? If Yes, complete V.C.1 – V.C.2.	☐ YES ☒ NO
C. Is this an application for a major modification of a PSD, nonattainment, FCAA 112(g) permit, or exceedance of a PAL permit?	☒ YES ☐ NO
D. Is this application for a PSD or major modification of a PSD located within 100 kilometers or less of an affected state or Class I Area?	☐ YES ☒ NO
If *Yes*, list the affected state(s) and/or Class I Area(s).	
E. Is this a state permit amendment application? If Yes, complete IV.E.1. – IV.E.3. --- NO	
1. Is there any change in character of emissions in this application?	☐ YES ☐ NO
2. Is there a new air contaminant in this application?	☐ YES ☐ NO
3. Do the facilities handle, load, unload, dry, manufacture, or process grain, seed, legumes, or vegetables fibers (agricultural facilities)?	☐ YES ☐ NO
F. List the total annual emission increases associated with the application (*list* **all** *that apply and attach additional sheets as needed*):	
CO_2: 1,102,055 tpy	
CH_4: 18.88 tpy	
N_2O: 1.89 tpy	
GHG (CO_2e): 1,182,560 tpy	
Other speciated air contaminants **not** listed above:	

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V. Public Notice Information (complete if applicable)			
A. Public Notice Contact Name: Aswath Kalappa			
Title: Sr. Environmental Scientist			
Mailing Address: 2700 Post Oak Blvd., Suite 1800			
City: Houston	State: Texas	ZIP Code: 77056	
Telephone No.: 713-402-2396			
B. Name of the Public Place: Harris County Public Library, La Porte Branch			
Physical Address (No P.O. Boxes): 600 S. Broadway Street			
City: La Porte	County: Harris	ZIP Code: 77571	
The public place has granted authorization to place the application for public viewing and copying.			☒ YES ☐ NO
The public place has internet access available for the public.			☒ YES ☐ NO
C. Concrete Batch Plants, PSD, and Nonattainment Permits			
1. County Judge Information (For Concrete Batch Plants and PSD and/or Nonattainment Permits) for this facility site.			
Mailing Address:			
City:	State:	ZIP Code:	
2. Is the facility located in a municipality or an extraterritorial jurisdiction of a municipality? *(For Concrete Batch Plants)*			☐ YES ☐ NO
Presiding Officers Name(s):			
Title:			
Mailing Address:			
City:	State:	ZIP Code:	
3. Provide the name, mailing address of the chief executive of the city for the location where the facility is or will be located.			
Chief Executive: Mayor Johnny Isbell			
Mailing Address: 1211 Southmore			
City: Pasadena	State: Texas	ZIP Code: 77502	

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V.	**Public Notice Information (complete if applicable) (continued)**		
3.	Provide the name, mailing address of the Indian Governing Body for the location where the facility is or will be located. *(continued)*		
Name of the Indian Governing Body: N/A			
Title:			
Mailing Address:			
City:	State:	ZIP Code:	
D.	Bilingual Notice		
Is a bilingual program **required** by the Texas Education Code in the School District?			☒ YES ☐ NO
Are the children who attend either the elementary school or the middle school closest to your facility eligible to be enrolled in a bilingual program provided by the district?			☒ YES ☐ NO
If *Yes*, list which languages are required by the bilingual program? Spanish			
VI.	**Small Business Classification (Required)**		
A.	Does this company (including parent companies and subsidiary companies) have fewer than 100 employees or less than $6 million in annual gross receipts?		☐ YES ☒ NO
B.	Is the site a major stationary source for federal air quality permitting?		☒ YES NO
C.	Are the site emissions of any regulated air pollutant greater than or equal to 50 tpy?		☒ YES ☐ NO
D.	Are the site emissions of all regulated air pollutants combined less than 75 tpy?		☐ YES ☒ NO
VII.	**Technical Information**		
A.	The following information must be submitted with your Form PI-1 (this is just a checklist to make sure you have included everything)		
1.	Current Area Map ☒		
2.	Plot Plan ☒		
3.	Existing Authorizations ☒		
4.	Process Flow Diagram ☒		
5.	Process Description ☒		
6.	Maximum Emissions Data and Calculations ☒		
7.	Air Permit Application Tables ☒		
a.	Table 1(a) (Form 10153) entitled, Emission Point Summary ☒		
b.	Table 2 (Form 10155) entitled, Material Balance ☒		
c.	Other equipment, process or control device tables ☒		

Texas Commission on Environmental Quality
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VII. Technical Information			
B. Are any schools located within 3,000 feet of this facility?			☐ YES ☒ NO
C. Maximum Operating Schedule:			
Hours: 8760	Day(s): 365	Week(s): 52	Year(s): 8760 hrs/yr
Seasonal Operation? If Yes, please describe in the space provide below.			☐ YES ☒ NO
D. Have the planned MSS emissions been previously submitted as part of an emissions inventory?			☐ YES ☒ NO
Provide a list of each planned MSS facility or related activity and indicate which years the MSS activities have been included in the emissions inventories. Attach pages as needed.			
E. Does this application involve any air contaminants for which a *disaster review* is required?			☐ YES ☒ NO
F. Does this application include a pollutant of concern on the *Air Pollutant Watch List (APWL)*?			☐ YES ☒ NO

VIII. State Regulatory Requirements **Applicants must demonstrate compliance with all applicable state regulations to obtain a permit or amendment**. *The application must contain detailed attachments addressing applicability or non applicability; identify state regulations; show how requirements are met; and include compliance demonstrations.*	
A. Will the emissions from the proposed facility protect public health and welfare, and comply with all rules and regulations of the TCEQ?	☒ YES ☐ NO
B. Will emissions of significant air contaminants from the facility be measured?	☒ YES ☐ NO
C. Is the Best Available Control Technology (BACT) demonstration attached?	☒ YES ☐ NO
D. Will the proposed facilities achieve the performance represented in the permit application as demonstrated through recordkeeping, monitoring, stack testing, or other applicable methods?	☒ YES ☐ NO

IX. Federal Regulatory Requirements **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment** *The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.*	
A. Does Title 40 Code of Federal Regulations Part 60, (40 CFR Part 60) New Source Performance Standard (NSPS) apply to a facility in this application?	☒ YES ☐ NO
B. Does 40 CFR Part 61, National Emissions Standard for Hazardous Air Pollutants (NESHAP) apply to a facility in this application?	☐ YES ☒ NO
C. Does 40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard apply to a facility in this application?	☐ YES ☒ NO

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IX.	**Federal Regulatory Requirements** **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment** ***The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.***	
D.	Do nonattainment permitting requirements apply to this application?	☐ YES ☒ NO
E.	Do prevention of significant deterioration permitting requirements apply to this application?	☒ YES ☐ NO
F.	Do Hazardous Air Pollutant Major Source [FCAA 112(g)] requirements apply to this application?	☐ YES ☒ NO
G.	Is a Plant-wide Applicability Limit permit being requested?	☐ YES ☒ NO

X. Professional Engineer (P.E.) Seal	
Is the estimated capital cost of the project greater than $2 million dollars?	☒ YES ☐ NO
If *Yes*, submit the application under the seal of a Texas licensed P.E.	

XI. Permit Fee Information	
Check, Money Order, Transaction Number ,ePay Voucher Number: 1223534	Fee Amount: $ 75,000
Company name on check: Air Liquide USA LLC	Paid online?: ☐ YES ☒ NO
Is a copy of the check or money order attached to the original submittal of this application?	☒ YES ☐ NO ☐ N/A
Is a Table 30 (Form 10196) entitled, Estimated Capital Cost and Fee Verification, attached?	☒ YES ☐ NO ☐ N/A

XII. Delinquent Fees and Penalties
This form **will not be processed** until all delinquent fees and/or penalties owed to the TCEQ or the Office of the Attorney General on behalf of the TCEQ is paid in accordance with the Delinquent Fee and Penalty Protocol. For more information regarding Delinquent Fees and Penalties, go to the TCEQ Web site at: www.tceq.texas.gov/agency/delin/index.html.
XIII. Signature
The signature below confirms that I have knowledge of the facts included in this application and that these facts are true and correct to the best of my knowledge and belief. I further state that to the best of my knowledge and belief, the project for which application is made will not in any way violate any provision of the Texas Water Code (TWC), Chapter 7, Texas Clean Air Act (TCAA), as amended, or any of the air quality rules and regulations of the Texas Commission on Environmental Quality or any local governmental ordinance or resolution enacted pursuant to the TCAA I further state that I understand my signature indicates that this application meets all applicable nonattainment, prevention of significant deterioration, or major source of hazardous air pollutant permitting requirements. The signature further signifies awareness that intentionally or knowingly making or causing to be made false material statements or representations in the application is a criminal offense subject to criminal penalties.
Name: Jason Miller, Plant Manager, Bayport Complex
Signature: Jason Miller *Original Signature Required*
Date: September 14, 2012

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	**6/29/2012**	Permit No.:	**NSR 9346 (Turbines), 56212 (Boilers), Title V O1735**
Regulated Entity No.:	**RN100233998**		
Area Name:	**Air Liquide Bayou Cogeneration Plant**	Customer No.:	**CN600300693**

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

AIR CONTAMINANT DATA						EMISSION POINT DISCHARGE PARAMETERS										
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate [1]		4. UTM Coordinates of Emission Point			Source							
									5. Building Height (Ft.)	Height Above Ground (Ft.)	7. Stack Exit Data			8. Fugitives		
EPN (A)	FIN (B)	NAME (C)		Pound per Hour (A)	TPY (B)	Zone	East (Meters)	North (Meters)			Diameter (Ft.) (A)	Velocity (FPS) (B)	Temperature (°F) (C)	Length (Ft.) (A)	Width (Ft.) (B)	Axis Degrees (C)
CG801 (see footnote [1] below on emissions)	GT1	Replaced Gas Turbine	NO_X	17.46	76.48	15	301786.55	3279044.79	--	105.02	14.0	75.8	286			
			CO	31.89	139.67											
			VOC	1.83	8.00											
			SO_2	0.66	2.91											
			PM	4.50	19.71											
			PM_{10}	4.50	19.71											
			$PM_{2.5}$	4.50	19.71											
			H_2SO_4	0.07	0.29											
			CO_2e	110,864.82	485,587.90											
			HAPs	0.60	2.64											
CG802 (see footnote [1] below on emissions)	GT2	Replaced Gas Turbine	NO_X	17.46	76.48	15	301813.47	3279044.64	--	105.02	14.0	75.8	286			
			CO	31.89	139.67											
			VOC	1.83	8.00											
			SO_2	0.66	2.91											
			PM	4.50	19.71											
			PM_{10}	4.50	19.71											
			$PM_{2.5}$	4.50	19.71											
			H_2SO_4	0.07	0.29											
			CO_2e	110,864.82	485,587.90											
			HAPs	0.60	2.64											
CG803 (see footnote [1] below on emissions)	GT3	Replaced Gas Turbine	NO_X	17.46	76.48	15	301866.55	3279044.15	--	105.02	14.0	75.8	286			
			CO	31.89	139.67											
			VOC	1.83	8.00											
			SO_2	0.66	2.91											
			PM	4.50	19.71											
			PM_{10}	4.50	19.71											
			$PM_{2.5}$	4.50	19.71											
			H_2SO_4	0.07	0.29											
			CO_2e	110,864.82	485,587.90											
			HAPs	0.60	2.64											
CG804 (see footnote [1] below on emissions)	GT4	Replaced Gas Turbine	NO_X	17.46	76.48	15	301,893	3,279,044	--	105.02	14.0	75.8	286			
			CO	31.89	139.67											
			VOC	1.83	8.00											
			SO_2	0.66	2.91											
			PM	4.50	19.71											
			PM_{10}	4.50	19.71											
			$PM_{2.5}$	4.50	19.71											
			H_2SO_4	0.07	0.29											
			CO_2e	110,864.82	485,587.90											
			HAPs	0.60	2.64											
N/A (new boiler)	BO1	New Boiler 1	NO_X	5.50	17.95	15	301946.63	3278712.78	--	150.033	7.5	56.7	325			
			CO	20.35	66.41											
			VOC	2.20	7.18											
			SO_2	0.39	1.26											
			PM	4.40	14.36											
			PM_{10}	2.75	8.97											
			$PM_{2.5}$	1.65	5.38											
			H_2SO_4	0.04	0.13											
			CO_2e	64,333.88	209,955.50											
			NH_3	2.47	8.07											
			HAPs	1.02E+00	3.32											
N/A (new boiler)	BO2	New Boiler 2	NO_X	5.50	17.95	15	301999.95	3278714.83	--	150.033	7.5	56.7	325			
			CO	20.35	66.41											
			VOC	2.20	7.18											
			SO_2	0.39	1.26											
			PM	4.40	14.36											
			PM_{10}	2.75	8.97											
			$PM_{2.5}$	1.65	5.38											
			H_2SO_4	0.04	0.13											
			CO_2e	64,333.88	209,955.50											
			NH_3	2.47	8.07											
			HAPs	1.02E+00	3.32											
N/A (new boiler)	BO3	New Boiler 3	NO_X	5.50	17.95	15	302019.31	3278714.27	--	150.033	7.5	56.7	325			
			CO	20.35	66.41											
			VOC	2.20	7.18											
			SO_2	0.39	1.26											
			PM	4.40	14.36											
			PM_{10}	2.75	8.97											
			$PM_{2.5}$	1.65	5.38											
			H_2SO_4	0.04	0.13											
			CO_2e	64,333.88	209,955.50											
			NH_3	2.47	8.07											
			HAPs	1.02E+00	3.32											

[1] The emissions numbers presented for the Gas Turbines (GT1 through 4) represent Potential Emissions for the Gas Turbines alone, and do not include potential emissions from the duct burners (since the HRSG/duct burners) are not being modified as part of this project.

EPN = Emission Point Number
FIN = Facility Identification Number
TCEQ-10153 (Revised 04/08) Table 1(a)
This form is for use by sources subject to air quality permit requirements and may be revised periodically. (APDG5178 v5)

TABLE 2

MATERIAL BALANCE

This material balance table is used to quantify possible emissions of air contaminants and special emphasis should be placed on potential air contaminants, for example: If feed contains sulfur, show distribution to all products. Please relate each material (or group of materials) listed to its respective location in the process flow diagram by assigning point numbers (taken from the flow diagram) to each materials.

LIST EVERY MATERIAL INVOLVED IN EACH OF THE FOLLOWING GROUPS	Point No. from Flow Diagram	Process Rate (lbs/hr or SCFM) standard conditions: 70°F 14.7 PSIA. Check appropriate column at right for each process.	Measurement	Estimation	Calculation
1. Raw Materials - Input N/A					
2. Fuels – Input Boilers - Natural Gas – Boilers Turbines – Low sulfur, low ash fuel gas (~ 90% nat. gas)		Boiler = 550 MMBtu/hr Turbine = 947.8 MMBtu/hr (rated)		X	
3. Products & By-Products - Output Electricity and Steam		Electricity = 80 MW per turbine Steam = 400 kpph per boiler. Additional steam from turbine.			
4. Solid Wastes - Output N/A					
5. Liquid Wastes - Output N/A					
6. Airborne Waste (Solid) – Output N/A					X
7. Airborne Wastes (Gaseous) - Output Three New Boilers: CO_2 CH_4 N_2O GHG (CO_2e) Four Turbines: CO_2 CH_4 N_2O GHG (CO_2e)SO_2		Project Increases 629,249 tpy combined (64,271 lb/hr each) 11.9 tpy combined (1.21 lb/hr each) 1.2 tpy combined (0.12 lb/hr each) 629,867 combined (64,334 lb/hr each) 1,940,448 combined (110,756 lb/hr each) 36.6 tpy combined (2.09 lb/hr each) 3.66 tpy combined (0.21 lb/hr each) 1,942,352 tpy combined (110,865 lb/hr each)			X

FORM PI-2(74-7)

TABLE 6

BOILERS AND HEATERS

Type of Device: Three New Boilers (BO1, BO2, BO3)	Manufacturer: Cleaver Brooks
Number from flow diagram:	Model Number: D-Type Elevated Drum

CHARACTERISTICS OF INPUT

Type Fuel	Chemical Composition (% by Weight)	Inlet Air Temp °F (after preheat)	Fuel Flow Rate (scfm* or lb/hr)	
			Average[1]	Design Maximum
		Ambient	19,227 lb/hr	19,227 lb/hr
		Gross Heating Value of Fuel	Total Air Supplied and Excess Air	
		(specify units)	Average[1]	Design Maximum
Natural Gas	Methane – 90.00 Ethane – 5.00 Nitrogen – 5.00	21,815 Btu/lb	352,538 lb/hr 15 % excess (vol)	352,538 lb/hr 15 % excess (vol)

HEAT TRANSFER MEDIUM

Type Transfer Medium	Temperature °F		Pressure (psia)		Flow Rate (specify units)	
(Water, oil, etc.)	Input	Output	Input	Output	Average[1]	Design Maximum
Water – input Steam - output	228	750	814.7	814.7	400,000 lb/hr	400,000 lb/hr

OPERATING CHARACTERISTICS

Ave. Fire Box Temp. At max. firing rate	Fire Box Volume (ft.^{3}), (from drawing)	Gas Velocity in Fire Box (ft/sec) at max firing rate	Residence Time In Fire Box At max firing rate (sec)
2,100 °F	6,400	< 80	0.5

STACK PARAMETERS

Stack Diameters	Stack Height	Stack Gas Velocity (ft/sec)		Stack Gas	Exhaust
		(@Ave.Fuel Flow Rate)[1]	(@Max.Fuel Flow Rate)	Temp °F	scfm
7.5 ft	150 ft	56.7	56.7	325	138,551

CHARACTERISTICS OF OUTPUT

Material	Chemical Composition of Exit Gas Released (% by Weight)
Products of Combustion	CO_2 – 8.3 H_2O – 18.1 , N_2 – 71.2, O_2 – 2.5

Attach an explanation on how temperature, air flow rate, excess air or other operating variables are controlled.

Also supply an assembly drawing, dimensioned and to scale, in plan, elevation, and as many sections as are needed to show clearly the operation of the combustion unit. Show interior dimensions and features of the equipment necessary to calculate in performance.

*Standard Conditions: 70°F, 14.7 psia

Notes:

[1]Max values were conservatively used for average values where appropriate.

TABLE 31
COMBUSTION TURBINES

TURBINE DATA

Emission Point Number From Table 1(a) : CG801, CG802, CG803, CG804

APPLICATION	CYCLE
____X_____ Electric Generation ___ Base Load ___ Peaking __________ Gas Compression __________ Other (Specify)______________	_____ Simple Cycle _____ Regenerative Cycles __X__ Cogeneration _____ Combined Cycle
Manufacturer __GE___________ Model No. ___7EA___________ Serial No. ___TBD____________	Model represented is based on: __X__ Preliminary Design _____ Contract Award _____ Other (specify) ______________ See TNRCC Reg. VI, 116.116(a)

Manufacturer's Rated Output at Baseload, ISO __80 MW each__ (MW)(hp)

Proposed Site Operating Range _Operate around 80 MW each, generally always at high loads (MW)(hp)

Manufacturer's Rated Heat Rate at Basesload, ISO ___11,850______________(Btu/k W-hr)

FUEL DATA

Primary Fuels:*

_X__ Natural Gas	________X_______ Process Offgas	_______________ Landfill/Digester Gas
_____ Fuel Oil	_______________ Refinery Gas	_______________ Other

Backup Fuels

__X___ Not Provided	_______________ Process Offgas	_______________ Ethane
_____ Fuel Oil	_______________ Refinery Gas	_____ Other (specify) ______________

* The turbines will burn a fuel mixture which is primarily natural gas (~90% natural gas)
Attach fuel analyses, including maximum sulfur content, heating value (specify LHV or HHV) and mole percent of gaseous constituents.

EMISSIONS DATA

Attach manufacturer's information showing emissions of NO_x, CO, VOC and PM for each proposed fuel at turbine loads and site ambient temperatures representative of the range of proposed operation. The information must be sufficient to determine maximum hourly and annual emission rates. Annual emissions may be based on a conservatively low approximation of site annual average temperature. Provide emissions in pounds per hour and except for PM, parts per million by volume at actual conditions and corrected to dry, 15% oxygen conditions.

Method of Emission Control:

__X___ Lean Premix Combustors	_____ Oxidation Catalyst	_____ Water Injection	____ Other(specify)
_____ Other Low-NO_x Combustion	_____ SCR Catalyst	_____ Steam Injection	

Low NOx Burners with Closed-loop Emissions Control (CLEC) for NO_x and CO.
See report text for details on emissions data.

ADDITIONAL INFORMATION

On separate sheets attach the following:

A. Details regarding principle of operation of emission controls. If add-on equipment is used, provide make and model and manufacturer's information. Example details include: controller input variables and operational algorithms for water or ammonia injection systems, combustion mode versus turbine load for variable mode combustors, etc.
B. Exhaust parameter information on Table 1(a).
C. If fired duct burners are used, information required on Table 6.[1]

[1] Duct burners are present, but existing duct burners are not being modified as part of this project.

Emission Rate Calculations

Appendix B

September 13, 2012
Project No. 0151579

Environmental Resources Management
15810 Park Ten Place, Suite 300
Houston, Texas 77084-5140
(281) 600-1000

Air Liquide Large Industries U.S., L.P.
Bayou Cogeneration Plant
Pasadena, Texas
Overall Project New Source Review (NSR) Netting Emissions Summary

This project involves the near in-kind replacement of 4 gas-fired turbines, the addition of 3 new gas-fired boilers, and the removal of three existing gas fired boilers at the Bayou Cogeneration Plant. The existing turbines and boilers at the facility are nearing end of life. The removal of the existing boilers will result in contemporaneous reduction in emissions from the facility. There have been no other projects at this facility in the contemporaneous five-year period. There is expected to be no associated increase in emissions from any existing emissions source at the facility as a result of the proposed project.

Net Emissions Increase - Summary

Pollutant	Project Emissions Increases (tpy)	Contemporaneous Emissions Increases/ Decreases (tpy)	Net Emissions Increase (tpy)	PSD Major Modification Trigger (tpy)	NNSR Major Modification Trigger (tpy)	PSD Triggered? (Yes/No) [1]	NNSR Triggered? (Yes/No) [1]
NO_X	-6.49	-75.19	-81.68	---	25	---	No
CO	581.57	-47.09	534.48	100	---	Yes	---
VOC	28.86	-5.48	23.38	---	25	---	No
SO_2	12.93	-0.70	12.23	40	---	No	---
PM	75.36	-5.59	69.77	25	---	Yes	---
PM_{10}	63.38	-5.59	57.79	15	---	Yes	---
$PM_{2.5}$	55.23	-5.59	49.64	10	---	Yes	---
H_2SO_4	1.54	0	1.54	7	---	No	---
CO_2	1,291,888	-102,708	1,189,180.15			Yes	---
CH_4	20.97	-3.45	17.52			Yes	---
N_2O	2.10	-0.34	1.75			Yes	---
GHG (CO_2e)	1,292,978	-102,816	1,190,162	75,000	---	Yes	---
NH_3	24.20	--	24.20	--	--	--	--
Total HAPs	20.54	--	20.54	--	--	--	--

[1] Non Attainment New Source Review (NNSR) applicability analysis applies only to NO_x and VOC (precursors of ozone). Prevention of Significant Deterioration (PSD) applicability analysis applies to all other NSR regulated pollutants. PSD and NNSR permitting do not apply to NH_3 and Hazardous Air Pollutants (HAPs).

Air Liquide Large Industries U.S., L.P.
Bayou Cogeneration Plant
Pasadena, Texas
Overall Project Emissions Increase

The emissions increases from this project consist of two components -
1) Increase in emissions from the power blocks as a result of replacement of the 4 turbines (Increase = Potential emissions - Baseline actuals)
2) Increase in emissions due to the addition of the new boilers (Increase = Potential emissions of new boilers).
The contemporaneous decrease in emissions due to removal of existing boilers in claimed in Step 2 - Creditable Emissions Increases/Decreases

Project Emissions Increase - Summary

Pollutant	Baseline Emissions (tpy) [1]	Potential Emissions (tpy)	Project Emissions Increase (tpy)
NO_X	366.24	359.75	-6.49
CO	176.36	757.93	581.57
VOC	24.67	53.53	28.86
SO_2	2.47	15.40	12.93
PM	46.56	121.92	75.36
PM_{10}	42.39	105.76	63.38
$PM_{2.5}$	39.77	94.99	55.23
H_2SO_4	0.00	1.54	1.54
CO_2	1,277,809.83	2,569,697.86	1,291,888.03
CH_4	27.50	48.47	20.97
N_2O	2.75	4.85	2.10
GHG (CO_2e)	1,279,240	2,572,218	1,292,978
NH_3	N/A	24.20	24.20
Total HAPs	N/A	20.54	20.54

[1] Baseline emissions are zero for new boilers. Baseline emissions for the turbines are based on actual emissions from 24-month consecutive period in the last ten years.

Air Liquide Large Industries U.S., L.P.
Bayou Cogeneration Plant
Pasadena, Texas
Overall Project Emissions Increase

Potential Emissions - Three New Boilers

Boiler Heat Input Rating =	550	MMBtu/hr per boiler
	3,589,882	MMBtu/yr per boiler
Number of Boilers =	3	
Boiler Operating Time =	8760	hours per year

Pollutant	Emissions Factor		Emissions per boiler (lb/hr)	Emissions per boiler (tpy)	Emissions 3 boilers (tpy)	Reference Footnote
NO_X	0.01	lb/MMBtu	5.50	17.95	53.85	[1]
CO	0.037	lb/MMBtu	20.35	66.41	199.24	[2], [3]
VOC	0.004	lb/MMBtu	2.20	7.18	21.54	[2], [3]
SO_2	0.0007	lb/MMBtu	0.39	1.26	3.77	[3], [4]
PM	0.008	lb/MMBtu	4.40	14.36	43.08	[2]
PM_{10}	0.005	lb/MMBtu	2.75	8.97	26.92	[2]
$PM_{2.5}$	0.003	lb/MMBtu	1.65	5.38	16.15	[2]
H_2SO_4	0.00007	lb/MMBtu	0.04	0.13	0.38	[6]
CO_2	53.02	kg/MMBtu	64,271	209,750	629,249	[5]
CH_4	0.001	kg/MMBtu	1.21	3.96	11.9	[5]
N_2O	0.0001	kg/MMBtu	0.12	0.40	1.2	[5]
CO_2e			64,334	209,955.50	629,867	[5]
NH_3	0.0045	lb/MMBtu	2.47	8.07	24.20	[7]

[1] Tier I BACT based on TCEQ guidance documents.
[2] Based on typical emissions factor values provided by Cleaver Brooks.
[3] No published TCEQ Tier 1 BACT for these pollutants. Therefore, these limits have been proposed as BACT.
[4] SO_2 emissions are based on the maximum proposed sulfur content of the fuel (0.25 grains/100scf) to be combusted in the boilers.
[5] Based on USEPA's Mandatory Reporting Rule, Table C-1. To convert to CO_2e, the following global warming potentials were used - CH_4 = 21, N_2O =
[6] Sulfuric acid mist emissions for natural gas combustion are based on worst case 10% conversion of SO_2 to SO_3.
[7] Emissions factor for NH_3 based on TCEQ Tier I BACT limit of 10 ppmvd @ 3% O2. The NH_3 emissions may result from ammonia slip from the SCR.

Air Liquide Large Industries U.S., L.P.
Bayou Cogeneration Plant
Pasadena, Texas
Overall Project Emissions Increase

Potential Emissions - Four Turbines

Turbine Heat Input Rating =	948	MMBtu/hr per turbine
	8,302,728	MMBtu/yr per turbine
Number of Turbines =	4	
Turbine Operating Time =	8760	hours per year

Pollutant	Emissions Factor	Emissions per turbine (lb/hr)	Emissions per turbine (tpy)	Emissions 4 turbines (tpy)	Reference Footnote
NO_X	0.018 lb/MMBtu	17.46	76.48	305.90	[1][7]
CO	0.034 lb/MMBtu	31.89	139.67	558.69	[1][7]
VOC	0.002 lb/MMBtu	1.83	8.00	31.99	[2][7]
SO_2	0.0007 lb/MMBtu	0.66	2.91	11.63	[3][4]
PM	0.0047 lb/MMBtu	4.50	19.71	78.84	[3]
PM_{10}	0.0047 lb/MMBtu	4.50	19.71	78.84	[3]
$PM_{2.5}$	0.0047 lb/MMBtu	4.50	19.71	78.84	[3]
H_2SO_4	0.00007 lb/MMBtu	0.07	0.29	1.16	[6]
CO_2	53.02 kg/MMBtu	110,756	485,112.12	1,940,448	[5]
CH_4	0.001 kg/MMBtu	2.09	9.15	36.60	[5]
N_2O	0.0001 kg/MMBtu	0.21	0.91	3.66	[5]
CO_2e		110,865	485,588	1,942,352	[5]

[1] Proposed as Tier III BACT.
[2] Proposed as Tier I BACT - more stringent than the published TCEQ Tier I BACT.
[3] No published TCEQ Tier 1 BACT for these pollutants. Therefore, these limits have been proposed as BACT.
[4] SO_2 emissions are based on the maximum proposed sulfur content of the fuel (0.25 grains/100scf) to be combusted in the turbines.
[5] Based on USEPA's Mandatory Reporting Rule, Table C-1. To convert to CO_2e, the following global warming potentials were used - CH_4 = 21, N_2O =
[6] Sulfuric acid mist emissions for natural gas combustion are based on worst case 10% conversion of SO_2 to SO_3.
[7] Based on GE vendor guarantees/ estimates for model 7EA with DLN-1+CLEC. Emissions factors in ppmv were converted to lb/MMBtu factors using the F Factor method and U.S. EPA's Method 19 F factors as shown below. Fd value from EPA Method 19, Table 19-2, F Factors for Various Fuels. VOC emissions calculated using molecular weight of methane.

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Air Liquide Large Industries U.S., L.P.
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Pasadena, Texas
Overall Project Emissions Increase

Pollutant	$Cppm_d$ (ppmvd)	C_d (lb/scf)	F_d [2] (scf/10^6 Btu)	$\%O2_d$ (%)	E (lb/10^6 Btu)
NO_X	5	5.97E-07	8,710	15	0.018
CO	15	1.09E-06	8,710	15	0.034
VOC	1.5	6.24E-08	8,710	15	0.002

As seen in EPA Method 19, Equation 19-1:

$$E = C_d * F_d * \left(\frac{20.9}{20.9 - \%O_{2d}} \right)$$

Variable	Units
Pollutant emission rate (E)	lb/10^6 Btu
Pollutant concentrations, dry basis (C_d)	lb/scf
F factor, dry basis (F_d)	scf/10^6 Btu
Oxygen, dry basis ($\%O_{2d}$)	%

Air Liquide Large Industries U.S., L.P.
Bayou Cogeneration Plant
Pasadena, Texas
Overall Project Emissions Increase

Baseline Actual Emissions - Four Turbines [1]

Pollutant	Baseline Years Used	Turbine Baseline Actuals (tpy)
NO_X	2004-05	366.24
CO	2009-10	176.36
VOC	2005-06	24.67
SO_2	2004-05	2.47
PM	2010-11	46.56
PM_{10}	2010-11	42.39
$PM_{2.5}$	2010-11	39.77
H_2SO_4	N/A	0.00
GHG (CO_2e)	2010-11	1,279,239.73

[1] Please refer to the tables on baseline breakdown to see details on baseline actual emissions calculations. Baseline for H_2SO_4 emissions assumed to be zero due to lack of available data. Baseline for particulate emissions based on 2012 stack test conducted on existing turbine. All other baseline emissions based on emissions reported under the annual emissions inventory.

Air Liquide Large Industries U.S., L.P.
Bayou Cogeneration Plant
Pasadena, Texas
Overall Project Emissions Increase

Summary of Potential HAP Emissions

Pollutant	Potential Emissions (tpy)
Toluene	2.18
Naphthalene	0.02
Hexane	9.50
Formaldehyde	5.85
Dichlorobenzene	0.006
Benzene	0.21
Acetaldehyde	0.66
Ethylbenzene	0.53
Propylene Oxide	0.48
Xylenes	1.06
Arsenic	0.001
Cadmium	0.006
Chromium	0.007
Manganese	0.002
Mercury	0.001
Nickel	0.01
Total HAPS	**20.536**

Air Liquide Large Industries U.S., L.P.
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Pasadena, Texas
Overall Project Emissions Increase

<u>Potential HAP Emissions - Three New Boilers</u>

Boiler Heat Input Rating =	550	MMBtu/hr per boiler
	3,589,882	MMBtu/yr per boiler
Number of Boilers =	3	
Boiler Operating Time =	8760	hours per year

Pollutant	Emissions Factor		Emissions per boiler (lb/hr)	Emissions per boiler (tpy)	Emissions 3 boilers (tpy)	Reference Footnote
Toluene	3.40E-03	lb/MMscf	1.83E-03	0.006	0.018	[1]
Naphthalene	6.10E-04	lb/MMscf	3.29E-04	0.001	0.003	[1]
Hexane	1.80E+00	lb/MMscf	9.71E-01	3.168	9.50	[1]
Formaldehyde	7.50E-02	lb/MMscf	4.04E-02	0.132	0.396	[1]
Dichlorobenzene	1.20E-03	lb/MMscf	6.47E-04	0.002	0.006	[1]
Benzene	2.10E-03	lb/MMscf	1.13E-03	0.004	0.011	[1]
Arsenic	2.00E-04	lb/MMscf	1.08E-04	0.0004	0.001	[2]
Cadmium	1.10E-03	lb/MMscf	5.93E-04	0.002	0.006	[2]
Chromium	1.40E-03	lb/MMscf	7.55E-04	0.002	0.007	[2]
Manganese	3.80E-04	lb/MMscf	2.05E-04	0.001	0.002	[2]
Mercury	2.60E-04	lb/MMscf	1.40E-04	0.000	0.001	[2]
Nickel	2.10E-03	lb/MMscf	1.13E-03	0.004	0.011	[2]

[1] Based on AP-42, Table 1.4-3, Emissions factors for speciated organic compounds from natural gas combustion.
[2] Based on AP-42, Table 1.4-4, Emissions factors for metals from natural gas combustion.

Air Liquide Large Industries U.S., L.P.
Bayou Cogeneration Plant
Pasadena, Texas
Overall Project Emissions Increase

Potential HAP Emissions - Four Turbines

Turbine Heat Input Rating =	948	MMBtu/hr per turbine
	8,302,728	MMBtu/yr per turbine
Number of Turbines =	4	
Turbine Operating Time =	8760	hours per year

Pollutant	Emissions Factor		Emissions per Turbine (lb/hr)	Emissions per Turbine (tpy)	Emissions 4 Turbines (tpy)	Reference Footnote
Toluene	1.30E-04	lb/MMBtu	1.23E-01	0.540	2.159	[1]
Naphthalene	1.30E-06	lb/MMBtu	1.23E-03	0.005	0.022	[1]
Formaldehyde	3.28E-04	lb/MMBtu	3.11E-01	1.363	5.451	[1]
Benzene	1.20E-05	lb/MMBtu	1.14E-02	0.050	0.199	[1]
Acetaldehyde	4.00E-05	lb/MMBtu	3.79E-02	0.166	0.664	[1]
Ethylbenzene	3.20E-05	lb/MMBtu	3.03E-02	0.133	0.531	[1]
Propylene Oxide	2.90E-05	lb/MMBtu	2.75E-02	0.120	0.482	[1]
Xylenes	6.40E-05	lb/MMBtu	6.07E-02	0.266	1.063	[1]

[1] Based on AP-42, Table 3.1-3, Emissions factors for HAP from gas-fired stationary gas turbines.
[2] Formaldehyde emissions are based on a factor of 91 ppbvd @ 15% O2 with an added 50% factor of safety.

Air Liquide Large Industries U.S., L.P.
Bayou Cogeneration Plant
Pasadena, Texas
Overall Project Turbine Baseline Emissions - Detailed Calculation

The baseline actual emissions for four existing turbines are based on actual emissions over a consecutive 24 month period in the last ten years prior to the project. The actual emissions reported from the power blocks as part of the annual emissions inventory include emissions from the gas turbine as well as from the duct burners. The duct burners will not be modified as part of this project, therefore, to calculate baseline emissions from only the gas turbines, the contribution of the duct burners to actual emissions have been calculated based on actual gas usage from the duct burners, and backed out from total actual emissions reported for the CT/HRSG stack.

Pollutant	Baseline Years Used	Turbine Baseline Actuals (tpy)
NO_X	2004-05	366.24
CO	2009-10	176.36
VOC	2005-06	24.67
SO_2	2004-05	2.47
PM	2010-11	46.56
PM_{10}	2010-11	42.39
$PM_{2.5}$	2010-11	39.77
GHG (CO_2e)	2010-11	1,279,240

	2004	2005	2006	2007	2008	2009	2010	2011	Baseline Avg (tpy)
CARBON MONOXIDE	89.88	263.93	115.71	72.51	507.10	**189.24**	**163.47**		**176.36**
BCP-1	59.3216	63.77	29.08	18.74	92.78	28.29	51.69		
BCP-2	10.4917	83.16	71.23	13.9	258.14	69.34	45.51		
BCP-3	28.3357	42.76	26.29	14.63	47.59	16.73	38.05		
BCP-4	30.1686	48.03	22.82	45.89	132.68	109.84	37.63		
Backing out Duct Burner Emissions	39.43	33.79	24.66	20.85	22.08	-34.96	-9.41		

	2004	2005	2006	2007	2008	2009	2010	2011	Baseline Avg
NITROGEN OXIDES	**382.32**	**350.16**	367.91	353.46	360.44	334.33	305.31		**366.24**
BCP-1	100.98	97.69	98.02	85.44	93.78	78.14	80.91		
BCP-2	106.75	89.78	85.86	95.89	90.2	92.18	90.83		
BCP-3	98.22	98.19	97.3	93.8	100.04	75.81	91.22		
BCP-4	84.9	71.81	92.06	82.84	81.2	93.04	67.06		
Backing out Duct Burner Emissions	-8.53	-7.31	-5.33	-4.61	-4.76	-4.82	-4.71		

	2004	2005	2006	2007	2008	2009	2010	2011	Baseline Avg
PARTICULATE - TOTAL	17.83	16.55	18.27	15.76	16.90	16.10	**45.51**	**47.62**	**46.56**
BCP-1	4.63	4.72	4.87	3.98	4.58	4.19	10.09	12.63	
BCP-2	5.1812	4.56	4.79	4.12	4.17	4.46	12.52	11.70	
BCP-3	4.9436	4.87	4.92	4.39	4.7	3.54	12.28	11.35	
BCP-4	4.8769	3.95	4.82	4.24	4.46	4.93	10.62	11.94	

	2004	2005	2006	2007	2008	2009	2010	2011	Baseline Avg
PM10 PARTICULATE	17.83	16.55	18.27	15.76	16.90	16.10	**41.43**	**43.35**	**42.39**
BCP-1	4.63	4.72	4.87	3.98	4.58	4.19	9.19	11.50	
BCP-2	5.1812	4.56	4.79	4.12	4.17	4.46	11.40	10.65	
BCP-3	4.9436	4.87	4.92	4.39	4.7	3.54	11.18	10.33	
BCP-4	4.8769	3.95	4.82	4.24	4.46	4.93	9.67	10.87	

Air Liquide Large Industries U.S., L.P.
Bayou Cogeneration Plant
Pasadena, Texas
Overall Project Turbine Baseline Emissions - Detailed Calculation

	2004	2005	2006	2007	2008	2009	2010	2011	Baseline Avg
PM2.5 PARTICULATE	17.63	16.55	18.27	15.76	16.90	16.10	**38.86**	**40.67**	**39.77**
BCP-1	4.63	4.72	4.87	3.96	4.56	4.19	8.62	10.79	
BCP-2	5.1812	4.58	4.79	4.12	4.17	4.46	10.69	9.99	
BCP-3	4.9496	4.87	4.92	4.39	4.7	2.54	10.48	9.69	
BCP-4	4.8759	3.95	4.82	4.24	4.46	4.93	9.07	10.20	

	2004	2005	2006	2007	2008	2009	2010	2011	Baseline Avg
SULFUR DIOXIDE	**2.59**	**2.35**	2.59	2.22	2.40	2.28	2.59		**2.47**
BCP-1	0.6701	0.67	0.69	0.56	0.65	0.5941	0.5713		
BCP-2	0.7499	0.65	0.68	0.58	0.59	0.6181	0.7252		
BCP-3	0.7155	0.69	0.7	0.62	0.67	0.592	0.7284		
BCP-4	0.7057	0.56	0.66	0.6	0.63	0.639	0.6078		
Backing out Duct Burner Emissions	-0.256	-0.219	-0.160	-0.135	-0.143	-0.143	-0.141		

	2004	2005	2006	2007	2008	2009	2010	2011	Baseline Avg
VOC	6.75	**23.44**	**25.90**	22.32		22.80	24.95		**24.67**
BCP-1	6.43	6.70	6.91	5.62	108.25	5.94	5.71		
BCP-2	6.48	6.43	6.76	5.80	69.65	6.30	7.31		
BCP-3	9.46	6.90	6.99	6.23	144.39	5.02	7.26		
BCP-4	9.45	5.60	6.85	6.02	25.39	6.99	6.07		
Backing out Duct Burner Emissions	-2.55766	-2.19	-1.60	-1.35	-1.43	-1.45	-1.41		

GHG Emissions	**2010 (metric tonnes**			**2011 (metric tonnes)**			**Baseline Avg CO_2e**	**Baseline Avg CO_2e**	**Baseline Avg**
Unit	CO2	CH4	N2O	CO2	CH4	N2O	**(metric tonnes)**	**(tons)**	**1,279,240**
GT1	255,463	5.19	0.52	341,273	6.82	0.68	298,680	329,235	
GT2	332,651	6.76	0.68	327,335	6.53	0.65	330,339	364,132	
GT3	328,975	6.69	0.67	302,018	6.03	0.60	315,827	348,136	
GT4	275,423	5.60	0.56	313,383	6.27	0.63	294,712	324,861	
Backing out Duct Burner Emissions	-78,556	--	--	-79,523	--	--	-79,039	-87,125	
Combined Total	1,192,512	24.24	2.42	1,284,010	26	2.56	1,160,519	1,279,240	

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Air Liquide Large Industries U.S., L.P.
Bayou Cogeneration Plant
Pasadena, Texas
Overall Project Turbine Baseline Emissions - Detailed Calculation

Calculating Duct Burner Actual Emissions - For backing out from baseline emissions [1]

	2004	2005	2006	2007	2008	2009	2010	2011
Total Actual Duct Burner Gas Usage for 4 duct burners (MMBtu/yr)	2,435,864	2,087,652	1,523,169	1,288,158	1,360,832	1,377,606	1,344,486	1,361,046
NOx Emissions Factor (lb/MMBtu) [2]	0.007	0.007	0.007	0.007	0.007	0.007	0.007	
Actual NOx Emissions (tpy) to be backed out	8.53	7.31	5.33	4.51	4.76	4.82	4.71	
CO Emissions Factor (lb/MMBtu) [2]	0.032	0.032	0.032	0.032	0.032	0.051	0.014	
Actual CO Emissions (tpy) to be backed out	39.43	33.79	24.66	20.85	22.03	34.96	9.41	
SO_2 Emissions Factor (lb/MMBtu) [2]	0.00021	0.00021	0.00021	0.00021	0.00021	0.00021	0.00021	
Actual SO_2 Emissions (tpy) to be backed out	0.25577	0.21920	0.15993	0.13526	0.14289	0.14465	0.14117	
VOC Emissions Factor (lb/MMBtu) [2]	0.0021	0.0021	0.0021	0.0021	0.0021	0.0021	0.0021	
Actual VOC Emissions (tpy) to be backed out	2.55766	2.19204	1.59933	1.35257	1.42887	1.44649	1.41171	
CO2 Emissions Factor (Kg/MMBtu) [2]	53.02	53.02	53.02	53.02	53.02	53.02	53.02	53.02
Actual CO2 Emissions (tpy) to be backed out	142,323	121,977	88,996	75,265	79,511	80,491	78,556	79,523

[1] The actual emissions reported from the power blocks as part of the annual emissions inventory include emissions from the gas turbine as well as from the duct burners. The duct burners will not be modified as part of this project, therefore, to calculate baseline emissions from only the gas turbines, the contribution of the duct burners to actual emissions have been calculated based on actual gas usage from the duct burners, and backed out from total actual emissions reported for the CT/HRSG stack.

[2] The emissions factors used to calculate emissions for purposes of the annual emissions inventory have been used here for all pollutants (except NOx) to back out duct burner emissions. For NOx, the contribution of duct burners based on CEMS data was estimated to be 2 ppmvd or 0.007 lb/MMBtu. This factor was used to back out duct burner emissions.

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Overall Project Creditable Emissions Increases/Decreases

The removal of the three existing boilers will result in contemporaneous reduction in emissions from the facility. There have been no other projects at this facility in the contemporaneous five-year period.

Pollutant	Baseline Years Used [3]	Baseline Actuals (tpy) [3]	Potential Emissions (tpy)	Creditable Emissions Increase/Decrease (tpy)
NO_X	2004-05	75.19	0.00	-75.19
CO	2009-10	47.09	0.00	-47.09
VOC	2005-06	5.48	0.00	-5.48
SO_2	2004-05	0.70	0.00	-0.70
PM	2010-11	5.59	0.00	-5.59
PM_{10}	2010-11	5.59	0.00	-5.59
$PM_{2.5}$	2010-11	5.59	0.00	-5.59
GHG (CO_2e)	2010-11	102,816	0.00	-102,816

	2004	2005	2006	2007	2008	2009	2010	2011	Baseline Avg (tpy)
CARBON MONOXIDE	15.68	24.70	1.32	1.93	25.64	**40.98**	**53.20**		**47.09**
B-305	0.6431	0.94	0.51	0.53	0.43	26.27	32.24		
B-306	0.6315	1.09	0.27	0.56	0.45	10.42	13.67		
B-307	14.4061	22.67	0.54	0.84	24.76	4.29	7.29		

	2004	2005	2006	2007	2008	2009	2010	2011	Baseline Avg
NITROGEN OXIDES	**63.90**	**86.48**	41.46	58.03	74.64	60.06	50.17		**75.19**
B-305	21.88	27.48	19.07	18.99	16.05	20.82	16.39		
B-306	23.08	34.7	10.3	21.33	28.55	24.98	15.47		
B-307	18.94	24.3	12.09	17.71	30.04	14.26	18.31		

	2004	2005	2006	2007	2008	2009	2010	2011	Baseline Avg
PARTICULATE - TOTAL	6.91	10.94	4.22	6.09	6.38	8.76	**5.83**	**5.34**	**5.59**
B-305	2.384	3.48	1.89	1.96	1.64	2.76	2.02	1.36	
B-306	2.3412	4.03	0.99	2.06	3.32	3.24	1.79	2.62	
B-307	2.1799	3.43	1.34	2.07	3.42	2.76	2.02	1.36	

	2004	2005	2006	2007	2008	2009	2010	2011	Baseline Avg
PM10 PARTICULATE	6.91	10.94	4.22	6.09	6.36	8.76	**5.83**	**5.34**	**5.59**
B-305	2.384	3.48	1.89	1.96	1.62	2.76	2.02	1.36	
B-306	2.3412	4.03	0.99	2.06	3.32	3.24	1.79	2.62	
B-307	2.1799	3.43	1.34	2.07	3.42	2.76	2.02	1.36	

	2004	2005	2006	2007	2008	2009	2010	2011	Baseline Avg
PM2.5 PARTICULATE	6.91	10.94	4.22	6.09	6.36	8.76	**5.83**	**5.34**	**5.59**
B-305	2.384	3.48	1.89	1.96	1.62	2.76	2.02	1.36	
B-306	2.3412	4.03	0.99	2.06	3.32	3.24	1.79	2.62	
B-307	2.1799	3.43	1.34	2.07	3.42	2.76	2.02	1.36	

Air Liquide Large Industries U.S., L.P.
Bayou Cogeneration Plant
Pasadena, Texas
Overall Project Creditable Emissions Increases/Decreases

	2004	2005	2006	2007	2008	2009	2010	2011	Baseline Avg
SULFUR DIOXIDE	**0.55**	**0.86**	0.34	0.47	0.66	0.70	0.46		**0.70**
B-305	0.1882	0.27	0.15	0.15	0.13	0.22	0.16		
B-306	0.1848	0.32	0.08	0.16	0.26	0.26	0.14		
B-307	0.1721	0.27	0.11	0.16	0.27	0.22	0.16		

	2004	2005	2006	2007	2008	2009	2010	2011	Baseline Avg
VOC	5.00	**7.92**	**3.04**	4.41		6.34	4.21		**5.48**
B-305	1.7253	2.52	1.36	1.42	3.32	2	1.46		
B-306	1.6943	2.92	0.71	1.49	0.45	2.34	1.29		
B-307	1.5776	2.48	0.97	1.5	3.32	2	1.46		

GHG Emissions	**2010 (metric tonnes**			**2011 (metric tonnes)**			**Baseline Avg CO_2e**	**Baseline Avg CO_2e**	**Baseline Avg**
Unit	CO2	CH4	N2O	CO2	CH4	N2O	**(metric tonnes)**	**(tons)**	**102,816**
B5	37,602	0.76	0.08	27,186	0.55	0.06	32,428	35,746	
B6	25,284	0.51	0.05	39,357	0.80	0.08	32,355	35,665	
B7	31,136	0.63	0.06	25,787	0.52	0.05	28,491	31,406	
Combined Total	94,021	1.91	0.19	92,331	2	0.19	93,274	102,816	

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Air Liquide Large Industries U.S., L.P.
Bayou Cogeneration Plant
Pasadena, Texas
Phase 2 Only - New Source Review (NSR) Netting Emissions Summary

During Phase 2, the new boilers as well as the old boilers will be operational and available to fulfill steam supply contractual obligations while the four turbines are being replaced one at a time. As soon as the replacement of a given turbine is complete during Phase 2, it will become operational. Phase 2 will end as soon as the fourth turbine is up and running. At no point will four new turbines, three new boilers, and three old boilers all operate simultaneously during Phase 2.

Net Emissions Increase - Summary

Pollutant	Project Emissions Increases (tpy)	Contemporaneous Emissions Increases/ Decreases (tpy)	Net Emissions Increase (tpy)	PSD Major Modification Trigger (tpy)	NNSR Major Modification Trigger (tpy)	PSD Triggered? (Yes/No) [1]	NNSR Triggered? (Yes/No) [1]
NO_X	-82.97	0.00	-82.97	---	25	---	No
CO	441.90	0.00	441.90	100	---	Yes	---
VOC	19.26	0.00	19.26	---	25	---	No
SO_2	10.02	0.00	10.02	40	---	No	---
PM	55.65	0.00	55.65	25	---	Yes	---
PM_{10}	43.67	0.00	43.67	15	---	Yes	---
$PM_{2.5}$	35.52	0.00	35.52	10	---	Yes	---
H_2SO_4	1.25	0.00	1.25	7	---	No	---
GHG (CO_2e)	807,390	0.00	807,390	75,000	---	Yes	---
NH_3	24.20	--	24.20	--	--	--	--
Total HAPs	17.89	--	17.89	--	--	--	--

[1] Non Attainment New Source Review (NNSR) applicability analysis applies only to NO_x and VOC (precursors of ozone). Prevention of Significant Deterioration (PSD) applicability analysis applies to all other NSR regulated pollutants. PSD and NNSR permitting do not apply to NH_3 and Hazardous Air Pollutants (HAPs).

Air Liquide Large Industries U.S., L.P.
Bayou Cogeneration Plant
Pasadena, Texas
Phase 2 Only - Project Emissions Increase

During Phase 2, the new boilers will be operational to fulfill steam supply contractual obligations while the four turbines are being replaced one at a time. As soon as the replacement of a turbine is complete during Phase 2, it will become operational. Phase 2 will end as soon as the fourth turbine is up and running. At no point will four new turbines and three new boilers operate simultaneously during Phase 2. That scenario will only occur during Phase 3 (after existing boiler shutdowns).

The emissions increases from this project upon commencement of Phase 2 will consist of two components -
1) At worst case, increase in emissions as a result of replacement of the 3 turbines (Increase = Potential emissions - Baseline actuals). In reality, the turbines will be replaced in stages, therefore, the worst case of three modified turbines operating will only occur towards the end of Phase 2 (when turbine 4 is being replaced).
2) Increase in emissions due to the addition of the new boilers (Increase = Potential emissions of new boilers).
There will be no creditable decrease in emissions due to removal of existing boilers for Phase 2, since that reduction in emissions will only occur in Phase 3.

Project Emissions Increase - Summary

Pollutant	Baseline Emissions (tpy) [1]	Potential Emissions (tpy)	Project Emissions Increase (tpy)
NO_X	366.24	283.28	-82.97
CO	176.36	618.25	441.90
VOC	24.67	43.93	19.26
SO_2	2.47	12.49	10.02
PM	46.56	102.21	55.65
PM_{10}	42.39	86.05	43.67
$PM_{2.5}$	39.77	75.28	35.52
H_2SO_4	0.00	1.25	1.25
GHG (CO_2e)	1,279,240	2,086,630	807,390
NH_3	N/A	24.20	24.20
Total HAPs	N/A	17.89	17.89

[1] Baseline emissions are zero for new boilers. Baseline emissions for the turbines are based on actual emissions from 24-month consecutive period in the last ten years.

Air Liquide Large Industries U.S., L.P.
Bayou Cogeneration Plant
Pasadena, Texas
Phase 2 Only - Project Emissions Increase

Potential Emissions - Three New Boilers

Boiler Heat Input Rating =	550	MMBtu/hr per boiler
	3,589,882	MMBtu/yr per boiler
Number of Boilers =	3	
Boiler Operating Time =	8760	hours per year

Pollutant	Emissions Factor	Emissions per boiler (lb/hr)	Emissions per boiler (tpy)	Emissions 3 boilers (tpy)	Reference Footnote
NO_X	0.01 lb/MMBtu	5.50	17.95	53.85	[1]
CO	0.037 lb/MMBtu	20.35	66.41	199.24	[2], [3]
VOC	0.004 lb/MMBtu	2.20	7.18	21.54	[2], [3]
SO_2	0.0007 lb/MMBtu	0.39	1.26	3.77	[3], [4]
PM	0.008 lb/MMBtu	4.40	14.36	43.08	[2]
PM_{10}	0.005 lb/MMBtu	2.75	8.97	26.92	[2]
$PM_{2.5}$	0.003 lb/MMBtu	1.65	5.38	16.15	[2]
H_2SO_4	0.00007 lb/MMBtu	0.04	0.13	0.38	[6]
CO_2	53.02 kg/MMBtu	64,271	209,750	629,249	[5]
CH_4	0.001 kg/MMBtu	1.21	3.96	11.9	[5]
N_2O	0.0001 kg/MMBtu	0.12	0.40	1.2	[5]
CO_2e		64,334	209,955.50	629,867	[5]
NH_3	0.0045 lb/MMBtu	2.47	8.07	24.20	[7]

[1] Tier I BACT based on TCEQ guidance documents.
[2] Based on typical emissions factor values provided by Cleaver Brooks.
[3] No published TCEQ Tier 1 BACT for these pollutants. Therefore, these limits have been proposed as BACT.
[4] SO_2 emissions are based on the maximum proposed sulfur content of the fuel (0.25 grains/100scf) to be combusted in the boilers.
[5] Based on USEPA's Mandatory Reporting Rule, Table C-1. To convert to CO_2e, the following global warming potentials were used - CH_4 = 21, N_2O = 310.
[6] Sulfuric acid mist emissions for natural gas combustion are based on worst case 10% conversion of SO_2 to SO_3.
[7] Emissions factor for NH_3 based on TCEQ Tier I BACT limit of 10 ppmvd @ 3% O2. The NH_3 emissions may result from ammonia slip from the SCR.

Air Liquide Large Industries U.S., L.P.
Bayou Cogeneration Plant
Pasadena, Texas
Phase 2 Only - Project Emissions Increase

Potential Emissions - Four Turbines *

Turbine Heat Input Rating =	948	MMBtu/hr per turbine
	8,302,728	MMBtu/yr per turbine
Number of Turbines =	3	
Turbine Operating Time =	8760	hours per year

* Potential emissions from the fourth turbine will be zero for Phase 2 since the end of construction and operation commencement of turbine 4 will also mark the end of Phase 2.

Pollutant	Emissions Factor	Emissions per turbine (lb/hr)	Emissions per turbine (tpy)	Emissions 3 turbines (tpy)	Reference Footnote
NO_X	0.018 lb/MMBtu	17.46	76.48	229.43	[1][7]
CO	0.034 lb/MMBtu	31.89	139.67	419.02	[1][7]
VOC	0.002 lb/MMBtu	1.70	7.47	22.40	[2][7]
SO_2	0.0007 lb/MMBtu	0.66	2.91	8.72	[3][4]
PM	0.0047 lb/MMBtu	4.50	19.71	59.13	[3]
PM_{10}	0.0047 lb/MMBtu	4.50	19.71	59.13	[3]
$PM_{2.5}$	0.0047 lb/MMBtu	4.50	19.71	59.13	[3]
H_2SO_4	0.00007 lb/MMBtu	0.07	0.29	0.87	[6]
CO_2	53.02 kg/MMBtu	110,756	485,112.12	1,455,336	[5]
CH_4	0.001 kg/MMBtu	2.09	9.15	27.45	[5]
N_2O	0.0001 kg/MMBtu	0.21	0.91	2.74	[5]
CO_2e		110,865	485,588	1,456,764	[5]

[1] Proposed as Tier III BACT.
[2] Proposed as Tier I BACT - more stringent than the published TCEQ Tier I BACT.
[3] No published TCEQ Tier 1 BACT for these pollutants. Therefore, these limits have been proposed as BACT.
[4] SO_2 emissions are based on the maximum proposed sulfur content of the fuel (0.25 grains/100scf) to be combusted in the turbines.
[5] Based on USEPA's Mandatory Reporting Rule, Table C-1. To convert to CO_2e, the following global warming potentials were used - CH_4 = 21, N_2O = 310.
[6] Sulfuric acid mist emissions for natural gas combustion are based on worst case 10% conversion of SO_2 to SO_3.
[7] Based on GE vendor guarantees/ estimates for model 7EA with DLN-1+CLEC. Emissions factors in ppmv were converted to lb/MMBtu factors using the F Factor method and U.S. EPA's Method 19 F factors as shown below. Fd value from EPA Method 19, Table 19-2, F Factors for Various Fuels. VOC emissions calculated using molecular weight of methane.

Air Liquide Large Industries U.S., L.P.
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Phase 2 Only - Project Emissions Increase

Pollutant	$Cppm_d$ (ppmvd)	C_d (lb/scf)	F_d [2] (scf/10^6 Btu)	$\%O2_d$ (%)	E (lb/10^6 Btu)
NO_X	5	5.97E-07	8,710	15	0.018
CO	15	1.09E-06	8,710	15	0.034
VOC	1.4	5.83E-08	8,710	15	0.002

As seen in EPA Method 19, Equation 19-1:

$$E = C_D * F_D * \left(\frac{20.9}{20.9 - \%O_{2D}} \right)$$

Variable	Units
Pollutant emission rate (E)	lb/10^6 Btu
Pollutant concentrations, dry basis (C_d)	lb/scf
F factor, dry basis (F_d)	scf/10^6 Btu
Oxygen, dry basis ($\%O_{2d}$)	%

Air Liquide Large Industries U.S., L.P.
Bayou Cogeneration Plant
Pasadena, Texas
Phase 2 Only - Project Emissions Increase

Baseline Actual Emissions - Turbines [1]

Pollutant	Baseline Years Used	Turbine Baseline Actuals (tpy)
NO_X	2004-05	366.24
CO	2009-10	176.36
VOC	2005-06	24.67
SO_2	2004-05	2.47
PM	2010-11	46.56
PM_{10}	2010-11	42.39
$PM_{2.5}$	2010-11	39.77
H_2SO_4	N/A	0.00
GHG (CO_2e)	2010-11	1,279,239.73

[1] Please refer to the tables on baseline breakdown to see details on baseline actual emissions calculations. Baseline for H_2SO_4 emissions assumed to be zero due to lack of available data.

Air Liquide Large Industries U.S., L.P.
Bayou Cogeneration Plant
Pasadena, Texas
Phase 2 Only - Project Emissions Increase

Summary of Potential HAP Emissions

Pollutant	Potential Emissions (tpy)
Toluene	1.64
Naphthalene	0.02
Hexane	9.50
Formaldehyde	4.48
Dichlorobenzene	0.006
Benzene	0.16
Acetaldehyde	0.50
Ethylbenzene	0.40
Propylene Oxide	0.36
Xylenes	0.80
Arsenic	0.001
Cadmium	0.006
Chromium	0.007
Manganese	0.002
Mercury	0.001
Nickel	0.01
Total HAPS	**17.894**

Air Liquide Large Industries U.S., L.P.
Bayou Cogeneration Plant
Pasadena, Texas
Phase 2 Only - Project Emissions Increase

Potential HAP Emissions - Three New Boilers

Boiler Heat Input Rating =	550	MMBtu/hr per boiler
	3,589,882	MMBtu/yr per boiler
Number of Boilers =	3	
Boiler Operating Time =	8760	hours per year

Pollutant	Emissions Factor		Emissions per boiler (lb/hr)	Emissions per boiler (tpy)	Emissions 3 boilers (tpy)	Reference Footnote
Toluene	3.40E-03	lb/MMscf	1.83E-03	0.006	0.018	[1]
Naphthalene	6.10E-04	lb/MMscf	3.29E-04	0.001	0.003	[1]
Hexane	1.80E+00	lb/MMscf	9.71E-01	3.168	9.50	[1]
Formaldehyde	7.50E-02	lb/MMscf	4.04E-02	0.132	0.396	[1]
Dichlorobenzene	1.20E-03	lb/MMscf	6.47E-04	0.002	0.006	[1]
Benzene	2.10E-03	lb/MMscf	1.13E-03	0.004	0.011	[1]
Arsenic	2.00E-04	lb/MMscf	1.08E-04	0.0004	0.001	[2]
Cadmium	1.10E-03	lb/MMscf	5.93E-04	0.002	0.006	[2]
Chromium	1.40E-03	lb/MMscf	7.55E-04	0.002	0.007	[2]
Manganese	3.80E-04	lb/MMscf	2.05E-04	0.001	0.002	[2]
Mercury	2.60E-04	lb/MMscf	1.40E-04	0.000	0.001	[2]
Nickel	2.10E-03	lb/MMscf	1.13E-03	0.004	0.011	[2]

[1] Based on AP-42, Table 1.4-3, Emissions factors for speciated organic compounds from natural gas combustion.
[2] Based on AP-42, Table 1.4-4, Emissions factors for metals from natural gas combustion.

Potential HAP Emissions - Three Turbines

Turbine Heat Input Rating =	948	MMBtu/hr per turbine
	8,302,728	MMBtu/yr per turbine
Number of Turbines =	3	
Turbine Operating Time =	8760	hours per year

Pollutant	Emissions Factor		Emissions per Turbine (lb/hr)	Emissions per Turbine (tpy)	Emissions 4 Turbines (tpy)	Reference Footnote
Toluene	1.30E-04	lb/MMBtu	1.23E-01	0.540	1.619	[1]
Naphthalene	1.30E-06	lb/MMBtu	1.23E-03	0.005	0.016	[1]
Formaldehyde	3.28E-04	lb/MMBtu	3.11E-01	1.363	4.088	[1]
Benzene	1.20E-05	lb/MMBtu	1.14E-02	0.050	0.149	[1]
Acetaldehyde	4.00E-05	lb/MMBtu	3.79E-02	0.166	0.498	[1]
Ethylbenzene	3.20E-05	lb/MMBtu	3.03E-02	0.133	0.399	[1]
Propylene Oxide	2.90E-05	lb/MMBtu	2.75E-02	0.120	0.361	[1]
Xylenes	6.40E-05	lb/MMBtu	6.07E-02	0.266	0.797	[1]

[1] Based on AP-42, Table 3.1-3, Emissions factors for HAP from gas-fired stationary gas turbines.
[2] Formaldehyde emissions are based on a factor of 91 ppbvd @ 15% O2 with an added 50% factor of safety.

Air Liquide Large Industries U.S., L.P.
Bayou Cogeneration Plant
Pasadena, Texas
Phase 2 only - Turbine Baseline Emissions - Detailed Calculation

The baseline actual emissions for four existing turbines are based on actual emissions over a consecutive 24 month period in the last ten years prior to the project. The actual emissions reported from the power blocks as part of the annual emissions inventory include emissions from the gas turbine as well as from the duct burners. The duct burners will not be modified as part of this project, therefore, to calculate baseline emissions from only the gas turbines, the contribution of the duct burners to actual emissions have been calculated based on actual gas usage from the duct burners, and backed out from total actual emissions reported for the CT/HRSG stack.

Pollutant	Baseline Years Used	Turbine Baseline Actuals (tpy)
NO_X	2004-05	366.24
CO	2009-10	176.36
VOC	2005-06	24.67
SO_2	2004-05	2.47
PM	2010-11	46.56
PM_{10}	2010-11	42.39
$PM_{2.5}$	2010-11	39.77
GHG (CO_2e)	2010-11	1,279,240

	2004	2005	2006	2007	2008	2009	2010	2011	Baseline Avg (tpy)
CARBON MONOXIDE	89.88	263.93	115.71	72.51	397.10	**189.24**	**163.47**		**176.36**
BCP-1	59.3216	63.77	29.03	18.74	92.73	28.29	51.69		
BCP-2	10.4817	83.16	71.23	13.9	256.14	69.34	45.51		
BCP-3	23.3357	42.76	23.29	14.83	47.53	16.73	38.05		
BCP-4	36.1686	48.03	22.82	45.80	132.63	109.84	37.63		
Backing out Duct Burner Emissions	39.43	33.79	24.66	20.85	22.03	-34.96	-9.41		

	2004	2005	2006	2007	2008	2009	2010	2011	Baseline Avg
NITROGEN OXIDES	**382.32**	**350.16**	367.91	353.46	360.44	334.33	306.31		**366.24**
BCP-1	100.98	97.69	98.02	85.44	93.78	76.14	60.91		
BCP-2	106.75	89.78	85.56	95.80	90.2	92.16	90.63		
BCP-3	98.22	98.19	97.3	93.8	100.04	75.81	91.22		
BCP-4	84.9	71.81	92.06	82.84	81.2	93.04	67.26		
Backing out Duct Burner Emissions	-8.53	-7.31	-5.33	-4.51	-4.78	-4.82	-4.71		

	2004	2005	2006	2007	2008	2009	2010	2011	Baseline Avg
PARTICULATE - TOTAL	17.83	16.55	18.27	15.76	16.90	16.10	**45.51**	**47.62**	**46.56**
BCP-1	4.63	4.72	4.87	3.86	4.58	4.19	10.09	12.63	
BCP-2	5.1812	4.56	4.79	4.12	4.17	4.46	12.52	11.70	
BCP-3	4.9436	4.27	4.92	4.39	4.7	3.54	12.28	11.35	
BCP-4	4.8769	3.95	4.82	4.24	4.46	4.93	10.62	11.94	

	2004	2005	2006	2007	2008	2009	2010	2011	Baseline Avg
PM10 PARTICULATE	17.83	16.55	18.27	15.76	16.90	16.10	**41.43**	**43.35**	**42.39**
BCP-1	4.63	4.72	4.87	3.86	4.58	4.19	9.19	11.50	
BCP-2	5.1812	4.56	4.79	4.12	4.17	4.46	11.40	10.65	
BCP-3	4.9436	4.27	4.92	4.39	4.7	3.54	11.18	10.33	
BCP-4	4.8769	3.95	4.82	4.24	4.46	4.93	9.67	10.87	

Air Liquide Large Industries U.S., L.P.
Bayou Cogeneration Plant
Pasadena, Texas
Phase 2 only - Turbine Baseline Emissions - Detailed Calculation

	2004	2005	2006	2007	2008	2009	2010	2011	Baseline Avg
PM2.5 PARTICULATE	17.83	16.55	18.27	15.76	16.90	16.10	**38.86**	**40.67**	**39.77**
BCP-1	4.63	4.72	4.87	3.96	4.58	4.19	8.62	10.79	
BCP-2	5.1812	4.58	4.79	4.12	4.17	4.48	10.69	9.99	
BCP-3	4.9496	4.67	4.92	4.39	4.7	3.54	10.48	9.69	
BCP-4	4.8769	3.96	4.82	4.24	4.46	4.93	9.07	10.20	

	2004	2005	2006	2007	2008	2009	2010	2011	Baseline Avg
SULFUR DIOXIDE	**2.59**	**2.35**	2.59	2.22	2.40	2.28	2.60		**2.47**
BCP-1	0.6701	0.67	0.69	0.58	0.65	0.5941	0.5713		
BCP-2	0.7499	0.65	0.68	0.58	0.59	0.6231	0.7352		
BCP-3	0.7155	0.69	0.7	0.62	0.67	0.602	0.7264		
BCP-4	0.7057	0.56	0.66	0.6	0.63	0.699	0.6078		
Backing out Duct Burner Emissions	-0.256	-0.219	-0.160	-0.135	-0.143	-0.145	-0.141		

	2004	2005	2006	2007	2008	2009	2010	2011	Baseline Avg
VOC	0.75	**23.44**	**25.90**	22.32		22.80	24.95		**24.67**
BCP-1	0.43	6.70	6.91	5.62	100.25	5.94	5.71		
BCP-2	0.48	6.43	6.76	5.80	69.85	6.36	7.31		
BCP-3	0.46	6.90	6.99	6.23	144.39	5.02	7.26		
BCP-4	0.45	5.60	6.85	5.53	25.39	6.99	6.07		
Backing out Duct Burner Emissions	-2.55786	-2.19	-1.60	-1.35	-1.43	-1.45	-1.41		

GHG Emissions	**2010 (metric tonnes**			**2011 (metric tonnes)**			**Baseline Avg CO_2e**	**Baseline Avg CO_2e**	**Baseline Avg**
Unit	CO2	CH4	N2O	CO2	CH4	N2O	**(metric tonnes)**	**(tons)**	**1,279,240**
GT1	255,463	5.19	0.52	341,273	6.82	0.68	298,680	329,235	
GT2	332,651	6.76	0.68	327,335	6.53	0.65	330,339	364,132	
GT3	328,975	6.69	0.67	302,018	6.03	0.60	315,827	348,136	
GT4	275,423	5.60	0.56	313,383	6.27	0.63	294,712	324,861	
Backing out Duct Burner Emissions	-78,556	--	--	-79,523	--	--	-79,039	-87,125	
Combined Total	1,192,512	24.24	2.42	1,284,010	26	2.56	1,160,519	1,279,240	

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Air Liquide Large Industries U.S., L.P.
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Pasadena, Texas
Phase 2 only - Turbine Baseline Emissions - Detailed Calculation

Calculating Duct Burner Actual Emissions - For backing out from baseline emissions [1]

	2004	2005	2006	2007	2008	2009	2010	2011
Total Actual Duct Burner Gas Usage for 4 duct burners (MMBtu/yr)	2,435,864	2,087,652	1,523,169	1,288,158	1,360,832	1,377,606	1,344,486	1,361,046
NOx Emissions Factor (lb/MMBtu) [2]	0.007	0.007	0.007	0.007	0.007	0.007	0.007	
Actual NOx Emissions (tpy) to be backed out	8.53	7.31	5.33	4.51	4.76	4.82	4.71	
CO Emissions Factor (lb/MMBtu) [2]	0.032	0.032	0.032	0.032	0.032	0.051	0.014	
Actual CO Emissions (tpy) to be backed out	39.43	33.79	24.66	20.85	22.03	34.96	9.41	
SO_2 Emissions Factor (lb/MMBtu) [2]	0.00021	0.00021	0.00021	0.00021	0.00021	0.00021	0.00021	
Actual SO_2 Emissions (tpy) to be backed out	0.25577	0.21920	0.15993	0.13526	0.14289	0.14465	0.14117	
VOC Emissions Factor (lb/MMBtu) [2]	0.0021	0.0021	0.0021	0.0021	0.0021	0.0021	0.0021	
Actual VOC Emissions (tpy) to be backed out	2.55766	2.19204	1.59933	1.35257	1.42887	1.44649	1.41171	
CO2 Emissions Factor (Kg/MMBtu) [2]	53.02	53.02	53.02	53.02	53.02	53.02	53.02	53.02
Actual CO2 Emissions (tpy) to be backed out	142,323	121,977	88,996	75,265	79,511	80,491	78,556	79,523

[1] The actual emissions reported from the power blocks as part of the annual emissions inventory include emissions from the gas turbine as well as from the duct burners. The duct burners will not be modified as part of this project, therefore, to calculate baseline emissions from only the gas turbines, the contribution of the duct burners to actual emissions have been calculated based on actual gas usage from the duct burners, and backed out from total actual emissions reported for the CT/HRSG stack.

[2] The emissions factors used to calculate emissions for purposes of the annual emissions inventory have been used here for all pollutants (except NOx) to back out duct burner emissions. For NOx, the contribution of duct burners based on CEMS data was estimated to be 2 ppmvd or 0.007 lb/MMBtu. This factor was used to back out duct burner emissions.

Recently Issued Permits and Pending Applications

Appendix C

September 13, 2012
Project No. 0151579

Environmental Resources Management
15810 Park Ten Place, Suite 300
Houston, Texas 77084-5140
(281) 600-1000

Recently Issued Permits and Applications Under Review for Greenhouse Gases from Combustion Turbines

No.	Permit Authority	Permit Number	Company Name Facility Name Location	#	Unit Description Model	Capacity		Control Technology	Thermal Efficiency BTU (HHV) per kW-hr (gross)	PTE tpy CO_2e	Proposed BACT Limits Parameter	 Units	Monitoring
1	USEPA R6	PSD-TX-1244-GHG	Lower Colorado River Authority Thomas C. Ferguson Power Plant Horseshoe Bay, TX	2	GE 7FA	195	MW	Combined cycle operation Efficient design	N/A	909,833	908,958 16.80 1.70 0.46 7,720 [365 day rolling average]	tpy CO2 tpy CH4 tpy N2O ton CO2/MWh (net) Btu/kWh (HHV)	Fuel monitoring or CEMS
2	USEPA R9	PSD-SD-11 (draft)	Pio Pico Energy Center, LLC Pio Pico Energy Center Otay Mesa, CA	3	GE LMS100	100 930	MW MMBtu/hr	Simple cycle operation Efficient design	N/A	N/A	1,181 9,196	lb CO2/MWh (net) Btu/kwH (HHV - gross)	Fuel monitoring CEMS, CMS
Applications Pending													
3	USEPA R6	N/A	Calhoun Port Authority ES Joslin Power Station Point Comfort, TX	3	GE 7FA	208	MW	Combined cycle operation Efficient design Evaporative cooling Steam turbine bypass	N/A	N/A	7,730	Btu/kWh (HHV)	N/A
4	USEPA R6	N/A	Calpine Corporation Deer Park Energy Center Dallas, TX	1	Siemens 501F	180 725	MW MMBtu/hr	Combined cycle operation Efficient design Process monitoring	N/A	N/A	7,730	Btu/kWh (HHV)	N/A
5	USEPA R6	N/A	Copano Processing, LP Houston Central Gas Plant Sheridan, TX	2	Solar Mars 100	15,000	hp	Efficient design Waste heat recovery Process monitoring	N/A	58,672	1.16	ton CO2e/MMscf compressed	monitoring AFR monitoring Quarterly source test
6	USEPA R6	N/A	DCP Midstream, LP Hardin County NGL Fractionation Plant Hardin County, TX	2	Solar Saturn T-4700	43	MMBtu/hr	Efficient design Waste heat recovery Process monitoring	N/A	24,610	24,610	tpy CO2e	None proposed
7	USEPA R6	N/A	DCP Midstream, LP Jefferson County NGL Fractionation Plant Jefferson County, TX	2	Solar Saturn T-4700	43	MMBtu/hr	Efficient design Waste heat recovery Process monitoring	N/A	24,610	24,610	tpy CO2e	None proposed
8	USEPA R6	N/A	El Paso Electric Company Montana Power Station El Paso, TX	4	GE LMS100	100	MW	Efficient design Evaporative cooling Good operating practices Fuel selection	9,074	227,840	227,840	tpy CO2e	Fuel quality monitoring
9	USEPA R6	N/A	Freeport LNG Development Liquiefaction Plant Freeport, TX	1	GE Frame 7EA	87	MW	Efficient design Waste heat recovery Evaporative cooling	N/A	562,693	562,141 0.03 1.06	tpy CO2 tpy CH4 tpy N2O	Fuel monitoring or CEMS
10	USEPA R6	N/A	La Paloma Energy Center Harlingen, TX	2	GE F7FA	183	MW	Engergy Efficiency, Practices and Designs	7,528	1,300,674	1,299,423 24.10 2.40	tpy CO2 tpy CH4 tpy N2O	Fuel monitoring or CEMS
					Siemens SGT6-5000F(4)	265	MW		7,649	1,451,772	1,450,376 26.80 2.70	tpy CO2 tpy CH4 tpy N2O	
					Siemens SGT6-5000F(5)	271	MW		7,720	1,642,317	1,640,737 30.40 3.00	tpy CO2 tpy CH4 tpy N2O	

Recently Issued Permits and Applications Under Review for Greenhouse Gases from Industrial Boilers

No.	Permit Authority	Permit Number	Company Name / Facility Name / Location	Unit Description #	Unit Description Model	Capacity		Control Technology	PTE tpy CO_2e	Proposed BACT Limits Parameter	Proposed BACT Limits Units	Monitoring
1	LA -DEQ	PSD-LA-752	Entergy Louisiana, LLC Ninemile Point Electric Gen. Plant Jefferson County, LA	1	Boiler	338	MMBtu/hr	N/A	N/A	117 0.0022 0.0002	lb/MMBtu CO2 lb/MMBtu methane lb/MMBtu N2O	N/A
2	USEPA R4	DPA-EPA-R4001	Port Dolphin Energy LNG Terminal Port Manatee, FL	4	Boilers	278	MMBtu/hr each	Tuning, optimitzation, instrumentation and controls, insulation, turbulent flow design	2,507,440	117	lb/MMBtu CO2e	Fuel monitoring
Applications Pending												
3	USEPA R6	N/A	Chevron Phillips Chemical Company LP Cedar Bayou Plant Harris County, TX	1	B-83010	500	MMBtu/hr	Proper combustion O&M Carbon Capture & Sequestration (CCS) Low Carbon Fuels Energy Efficiency	127,000	127,000 0.60 0.10	tpy CO2 tpy CH4 tpy N2O	Fuel monitoring
4	USEPA R6	N/A	Exxon Belvieu Plastics Plant Mont Belvieu, TX	2	RUPK 31 RUPK 32	60	MMBtu/hr	Proper combustion O&M Carbon Capture & Sequestration (CCS) Low Carbon Fuels Energy Efficiency	33,614	33,614 1.00 1.00	tpy CO2 tpy CH4 tpy N2O	Fuel monitoring
5	USEPA R6	N/A	Invistas Victoria Plant Victoria, TX	4	15STK-005 15STK-006	300,000 400,000	Lbs/hr	Design Energy Efficiency Operation Energy Efficiency Carbon Capture & Sequestration (CCS)	1,371,684	1,270,730 11.00 325	tpy CO2 tpy CH4 tpy N2O	Fuel monitoring
6	USEPA R6	N/A	LaPaloma Energy Center Harlingen, TX	2	AUXBLR	150	MMBtu/hr	Design Energy Efficiency Low Carbon Fuels Good O&M Practices Low Annual Capacity	7,687	7,679 0.14 0.01	tpy CO2 tpy CH4 tpy N2O	Fuel monitoring

Confidential Information

(Submitted under a separate cover)