PREVENTION OF SIGNIFICANT DETERIORATION PERMIT FOR GREENHOUSE GAS EMISSIONS ISSUED PURSUANT TO THE REQUIREMENTS AT 40 CFR § 52.21

U.S. ENVIRONMENTAL PROTECTION AGENCY, REGION 6

PSD PERMIT NUMBER: PSD-TX-612-GHG

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

FACILITY NAME: Air Liquide Large Industries U.S., L.P.
Bayou Cogeneration Plant

FACILITY LOCATION: 11777 Bay Area Blvd.
Pasadena, Texas 77507

Pursuant to the provisions of the Clean Air Act (CAA), Subchapter I, Part C (42 U.S.C. Section 7470, *et. Seq.*), and the Code of Federal Regulations (CFR) Title 40, Section 52.21, and the Federal Implementation Plan at 40 CFR § 52.2305 (effective May 1, 2011 and published at 76 FR 25178), the U.S. Environmental Protection Agency, Region 6 is issuing a *Prevention of Significant Deterioration* (PSD) permit to Air Liquide Large Industries U.S., L.P. (Air Liquide) for Greenhouse Gas (GHG) emissions. The Permit applies to the redevelopment of its cogeneration facility at their Bayou Cogeneration Plant located in Pasadena, Texas.

Air Liquide is authorized to replace four (4) gas-fired gas turbines with similar units, add three (3) new gas-fired boilers and subsequently remove three (3) existing boilers as described herein, in accordance with the permit application (and plans submitted with the permit application), the federal PSD regulations at 40 CFR § 52.21, and other terms and conditions set forth in this PSD permit in conjunction with the corresponding Texas Commission on Environmental Quality (TCEQ) PSD permit No. PSD-TX-612M2. Failure to comply with any condition or term set forth in this PSD Permit may result in enforcement action pursuant to Section 113 of the Clean Air Act (CAA). This PSD Permit does not relieve Air Liquide of the responsibility to comply with any other applicable provisions of the CAA (including applicable implementing regulations in 40 CFR Parts 51, 52, 60, 61, 72 through 75, and 98) or other federal and state requirements (including the state PSD program that remains under approval at 40 CFR § 52.2303).

In accordance with 40 CFR §124.15(b)(3), this PSD Permit becomes effective immediately upon issuance of this final decision.

Thomas H. Diggs for — 11/21/13

Wren Stenger, Director
Multimedia Planning and Permitting Division

Date

Air Liquide Large Industries U.S., L.P. (PSD-TX-612-GHG)
Prevention of Significant Deterioration Permit
For Greenhouse Gas Emissions
Final Permit Conditions

PROJECT DESCRIPTION

The redevelopment project at the Bayou Cogeneration Plant will replace components of the power block and the boilers at the existing facility. The power block project will replace the four existing gas turbines at the plant 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).

The project does not include replacement of the Heat Recovery Steam Generators (HRSGs) or duct burners. The redevelopment project will also add 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 nitrogen oxides (NO_X) emissions.

The proposed project will be executed in three phases: no more than 18 months shall pass between the completion of a phase and the beginning of the subsequent phase: construction of the phases shall be continuous and completed in a reasonable timeframe:

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

• Phase 2 involves the decommissioning, removal and replacement of each of the four existing turbines. Replacement of the existing turbines is anticipated to occur one turbine at a time, but may involve some concurrent overlapping construction and decommissioning activities involving several turbines. During this phase, the four existing gas turbines will be replaced with new GE 7EA gas turbine units. In addition to the three existing boilers, the three new boilers will need to be operational and available to fulfill steam/thermal supply contractual obligations during this phase; however, at no point will the four new gas turbines, three new boilers, and three existing boilers operate simultaneously during Phase 2. Once an existing gas turbine has been replaced with a new gas turbine, the new gas turbine will complete initial stack testing in accordance with Special Condition V.A.2. The emissions during this phase will not exceed the potential emissions from the overall project, including the CO_2 emissions. Additionally, Air Liquide will operate the equipment such that all emissions during this phase are less than the respective permit limits. Phase 2 is complete when all four existing turbines have been replaced and decommissioned and all new gas turbines have completed an initial stack test.

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

• Phase 3 commences upon completion of Phase 2 and involves the permanent shutdown and decommissioning of the three existing boilers. Phase 3 is complete when the three existing boilers have been decommissioned and mothballed. Theses boilers will not be removed.

EQUIPMENT LIST

The following devices are subject to this GHG PSD permit

FIN	EPN	Source Name
B-305 B-306 B-307	BO1 BO2 BO3	3 Boilers (Combustion Units) 550 MMBtu/hr (each) rated maximum heat input boilers with Selective Catalytic Reduction (SCR) controls
GT1 GT2 GT3 GT4	CG-801 CG-802 CG-803 CG-804	4 GE 7EA Turbines (Combustion Units) 948MMBtu/hr (each) rated heat input CHP turbines

I. GENERAL PERMIT CONDITIONS

A. PERMIT EXPIRATION

As provided in 40 CFR §52.21(r), this PSD Permit shall become invalid if construction:

1. is not commenced (as defined in 40 CFR §52.21(b)(9)) within 18 months after the approval takes effect; or
2. is not completed within a reasonable time.

This permit applies to a phased construction project. Each phase must commence construction within 18 months of the approved construction phase. Pursuant to 40 CFR § 52.21(r), EPA may extend the 18-month period upon a written satisfactory showing that an extension is justified.

B. PERMIT NOTIFICATION REQUIREMENTS

Permittee shall notify EPA Region 6 in writing or by electronic mail of the:

1. Date construction is commenced, postmarked within 30 days of such date;
2. Actual date of initial startup of each emission unit, as defined in 40 CFR § 60.2, postmarked within 15 days of such date;
3. Date upon which initial performance tests will commence, in accordance with the provisions of Section V, postmarked not less than 30 days prior to such date. Notification may be provided with the submittal of the performance test protocol required pursuant to Condition V.B;
4. Date upon which certification tests of the CO_2 , O_2 continuous emission monitoring system (CEMS) will commence in accordance with 40 CFR § 75.61(a)(1)(i) and 40 CFR Part 60, Appendix B, Performance Specification 3. Additionally, the initial certification or recertification application shall be submitted for the CO_2 CEMS as required by 40 CFR 75.63; and,
5. Date the existing gas-fired boilers; ST-5, ST-6 and ST-7, are shutdown, decommissioned and permanently shut down at facility within 15 days of such date.

C. FACILITY OPERATION

At all times, including periods of startup, shutdown, and malfunction, Permittee shall, to the extent practicable, maintain and operate the facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the EPA, which may include, but is not limited to monitoring results, review of operating maintenance procedures and inspection of the facility.

D. MALFUNCTION REPORTING

1. Permittee shall notify EPA by mail, or other means identified by EPA, within 48 hours following the discovery of any failure of air pollution control equipment, process equipment, or of a process to operate in a normal manner, which may result in an increase in GHG emissions above the allowable emission limits stated in Section II and III of this permit.
2. Within 10 days of the discovery of any GHG emissions above the allowable emission limits resulting from malfunctions as described in I.D.1., Permittee shall provide a written supplement to the initial notification that includes a description of the malfunctioning equipment or abnormal operation, the date of the initial malfunction, the period of time over which emissions were increased due to the failure, the cause of the failure, the estimated resultant emissions in excess of those allowed in Sections II and Section III, and the methods utilized to mitigate emissions and restore normal operations.
3. Compliance with this malfunction notification provision shall not excuse or otherwise constitute a defense to any violation of this permit or any law or regulation such malfunction may cause.

E. RIGHT OF ENTRY

EPA authorized representatives, upon the presentation of credentials, shall be permitted:

1. To enter the premises where the facility is located or where any records are required to be kept under the terms and conditions of this PSD Permit;
2. During normal business hours, to have access to and to copy any records required to be kept under the terms and conditions of this PSD Permit;
3. To inspect any equipment, operation, or method subject to requirements in this PSD Permit; and,
4. To sample materials and emissions from the source(s).

F. TRANSFER OF OWNERSHIP

In the event of any changes in control or ownership of the facilities to be constructed, this PSD Permit shall be binding on all subsequent owners and operators. Permittee shall notify the succeeding owner and operator of the existence of the PSD Permit and its conditions by letter; a copy of the letter shall be forwarded to EPA Region 6 within thirty days of the letter signature.

G. SEVERABILITY

The provisions of this PSD Permit are severable, and, if any provision of the PSD Permit is held invalid, the remainder of this PSD Permit shall not be affected.

H. ADHERENCE TO APPLICATION AND COMPLIANCE WITH OTHER ENVIRONMENTAL LAWS

Permittee shall construct this project in compliance with this PSD Permit, the application on which this permit is based, the TCEQ PSD Permit No. PSD-TX-612M2, and all other applicable federal, state, and local air quality regulations. This PSD permit does not release the Permittee from any liability for compliance with other applicable federal, state and local environmental laws and regulations, including the Clean Air Act.

I. ACRONYMS AND ABBREVIATIONS

BACT	Best Available Control Technology
$Btu_{(HHV)}$	British Thermal Unit
CAA	Clean Air Act
CC	Carbon Content
CCS	Carbon Capture and Sequestration
CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
CH_4	Methane
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
dscf	Dry Standard Cubic Foot
EF	Emission Factor
EPN	Emission Point Number
FR	Federal Register
GCV	Gross Calorific Value
GHG	Greenhouse Gas
gr	Grains
GWP	Global Warming Potential
HHV	High Heating Value
hr	Hour
kW	Kilowatt
$kWh_{(gross)}$	Gross Kilowatt-Hour
lb	Pound
LDAR	Leak Detection and Repair
MACT	Maximum Achievable Control Technology
MMBtu	Million British Thermal Units
MSS	Maintenance, Start-up and Shutdown
N_2O	Nitrous Oxides
ppmv	parts per million by volume
PSD	Prevention of Significant Deterioration
QA/QC	Quality Assurance and/or Quality Control
RATA	Relative Accuracy Test Audit
RCRA	Resource Conservation and Recovery Act
SCFH	Standard Cubic Feet per Hour
SCR	Selective Catalytic Reduction
TAC	Texas Administrative Code
TCEQ	Texas Commission on Environmental Quality
TPY	Tons per Year
USC	United States Code
VOC	Volatile Organic Compound

II. Emission Limits and Standards.

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

Table 1: Annual Emission Limits

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

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

III. Special Permit Conditions

A. Combustion Turbines (EPNs: CG801, CG802, CG803, and CG804) Work Practice Standards, Operational Requirements, and Monitoring:

1. Permittee shall limit fuel for turbines (CG801, CG802, CG803, and CG804) to pipeline quality natural gas or a maximum of 90/10 ratio of pipeline quality natural gas blended with off-gas based on an annual average.
2. Natural gas quality fuels with the carbon content will be obtained by semiannual testing per 40 CFR§98.34(b)(3)(A). Upon request, Permittee shall provide a sample and/or analysis of the fuel that is fired in turbine/duct burner (CG801, CG802, CG803, and CG804) at the time of the request, or shall allow a sample to be taken by EPA for analysis.
3. Permittee shall monitor fuel gas flow continuously; determine fuel higher heating value whenever there is a fuel change or monthly, whichever is less; and calculate the total daily heat input per turbine/duct burner combination.
4. Natural gas/off-gas flow meter shall be calibrated in accordance with 40 CFR§98.34(b)(1).
5. Flow meters shall meet the specification in 40 CFR 60 Appendix B Spec. 6.
6. All continuous emission monitors and flow meters shall meet the Quality Assurance Specifications in 40 CFR Appendix F.
7. Permittee shall not begin commercial operation of the fourth combustion turbine until the final steam boiler (EPNs: ST-5, ST-6, and ST-7) is decommissioned from service.
8. Each startup of each combustion turbine is defined as the period when the data acquisition and handling system (DAHS) measures fuel flow to the combustion turbine and ends when the combustion turbine generator (CTG) load reaches 60%. Each startup is limited to 240 minutes per event.
9. Each shutdown for each combustion turbine is defined as the period that begins when the CTG output drops below 60% load and ends when there is no longer measureable fuel flow to the combustion turbine. Each shutdown is limited to 60 minutes per event.
10. Permittee shall install, operate and maintain according to good engineering practices, a fuel preheater for each of the turbines (CG801, CG802, CG803, and CG804).
11. The emission limits established in Table 1 include emissions associated with MSS activities.
12. Permittee shall monitor and record the following parameters daily:
    a. Natural gas consumed;
    b. Net electricity produced;
    c. Mass of high pressure steam produced;
    d. Mass of low pressure steam produced;
    e. Mass of feed water used;

f. Average pressure and temperature of steam produced; and
g. Calculated average enthalpy for low and high pressure steam based on average steam conditions.

13. The combustion turbines shall be equipped with a CO_2 CEMS.
14. Permittee shall calculate the CH_4 and N_2O emissions on a 12-month rolling basis to be updated by the last day of the following month. Permittee shall determine compliance with the CH_4 and N_2O emissions limits contained in this section using the default CH_4 and N_2O emission factors contained in Table C-2 and equation C-9a of 40 CFR Part 98 and the HHV (for natural gas and/or off-gas), converted to short tons.
15. Permittee shall calculate the CO_2e emissions on a 12-month rolling basis, based on the procedures and Global Warming Potentials (GWP) contained in Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1, as published on October 30, 2009 (74 FR 56395). The record shall be updated by the last day of the following month.

B. Combustion Turbines (EPNs: CG801, CG802, CG803, and CG804) BACT Limit:

1. Permittee shall maintain a turbine thermal efficiency as measured by calculating the fuel chargeable to power of 7,720 $Btu_{(HHV)}/kWh_{(gross)}$ on a 365-day rolling average of the calculated daily thermal efficiency for each of the turbines: CG801, CG802, CG803, and CG804.
2. Compliance will be demonstrated by monitoring fuel gas flow, fuel higher heating value, and gross power production and calculating the thermal efficiency using these parameters on a daily basis
3. Permittee shall calculate turbine thermal efficiency daily for turbines (CG801, CG802, CG803, and CG804) as follows:

Equation 1 *Calculation of Fuel Chargeable to Power*

$$FCP = \frac{QGT - FCS}{P_{NET}}$$

Where: FCP = Fuel Chargeable to Power [Btu (HHV)/kWh]
QGT = Heat input to gas turbine [MMBtu/hr]
FCS = Fuel Chargeable to Steam [MMBtu/hr]
P_{NET} = Net electrical production [kW]

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

Equation 2 *Calculation of Fuel Chargeable to Steam*

$$FCS = \frac{QHP + QLP - QFW}{e_{boiler}}$$

Where: FCS = Fuel Chargeable to Steam [MMBtu/hr]
QHP = Heat used to generate high pressure steam [MMBtu/hr]
QLP = Heat used to generate low pressure steam [MMBtu/hr]
QFW = Heat used to heat the feed water [MMBtu/hr]
eboiler = Efficiency of an equivalent boiler [0.84]

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

$$Qi = \Delta hi * mi$$

Where: Qi = Heat used for steam or water stream, *i* [MMBtu/hr]
Δhi = Change in enthalpy, *i* [MMBtu/lb]
mi = Mass flow of stream *i*

C. Steam Boilers (EPNs: BO1, BO2, and BO3) Work Practice Standards, Operational Requirements, and Monitoring:

1. Fuel Specifications: Permittee shall limit fuel for boilers to pipeline quality natural gas or a maximum of 90/10 ratio of pipeline natural gas blended with fuel gas based on an annual average.
2. Each boiler is limited to a maximum heat input of 550 MMBtu/hr based on the higher heating value of the natural gas.
3. Permittee shall limit the total fuel heat input for the combined three (3) boilers to 10,769,647 MMBtu in any 12-month period.
4. Except during Phase 1 and Phase 2 of construction, when all four turbines are operational, the maximum combined hourly heat input to all three new boilers shall not exceed 825 MMBtu/hr.
5. When three turbines are operational (any single turbine is not operating) the maximum combined hourly heat input to all three new boilers shall not exceed 1,650 MMBtu/hr.

6. Except during Phase 1 and Phase 2 of construction, the combined annual heat input to all three new boilers and all four new turbines (excludes heat input to duct burners) shall not exceed 40,437,912 MMBtu/year.
7. Permittee shall install, operate, and maintain according to good engineering practices, an air preheater, and a condensate return system for each of boilers (BO1, BO2, and BO3).
8. Each startup for each boiler is defined as the period that begins when the data acquisition and handling system (DAHS) measures fuel flow to the boiler and ends when the boiler reaches hot standby mode or the fuel flow at which the boiler will operate. Each startup is limited to 240 minutes per event.
9. Each shutdown for each boiler is defined as the period that begins when the boiler drops below the hot standby fuel flow level and ends when no fuel flow is detected. Each shutdown is limited to 60 minutes per event.
10. Permittee shall monitor fuel gas flow continuously; determine fuel higher heating value whenever there is a fuel change or monthly, whichever is less; and calculate the total daily heat input per boiler.
11. Natural gas/fuel gas flow meter shall be calibrated in accordance with 40 CFR §98.34(b)(1).
12. Flow meters shall meet the specification in 40 CFR 60 Appendix B Spec 6.
13. All continuous emission monitors and flow meters shall meet the Quality Assurance Specifications in 40 CFR 60 Appendix F.
14. A data acquisition and handling system (DAHS) shall be used to measure and record the CO_2 emissions and demonstrate compliance with the annual emission rates and BACT limits.
15. Permittee shall maintain the following boiler work practice standards:
    a. Maintain the Oxygen analyzers and calibration to ensure boiler efficiencies per the manufacturers recommendations. Oxygen analyzers shall be maintained and calibrated using 40 CFR 60 Appendix A-2, Method 3A.
    b. Perform regular scheduled maintenance on the air preheater to maintain optimum heat transfer per the manufacturer's recommendations.
16. Perform scheduled maintenance and tune-ups of the boiler burners and equipment to include burner tips and heat convection sections to reduce fouling of the heat transfer surfaces and to maximize boiler efficiency.
17. Compliance with the Annual Emission Limit in Table 1 shall be demonstrated on a 12-month total, rolling monthly, calculated in accordance with equation C-5 found in 40 CFR §98.33(a)(3)(iii).
18. The emission limits established in Table 1 for the boilers includes emissions from MSS activities.

D. Steam Boilers (EPNs: BO1, BO2, and BO3) BACT Limit:

Permittee shall meet a BACT limit of 117 lb CO_2/MMBtu heat input when burning natural gas and/or fuel gas based on a 12-month rolling average for each boiler, including emissions from maintenance, startup and shutdown activities and shall be obtained by using daily CO_2 value from the continuous CO_2 stack gas analyzer, daily fuel flow and current fuel use higher heating value. The equation for calculating the BACT limit is as follows:

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

E. Requirements for Steam Boilers to be Decommissioned (EPNs: ST-5, ST-6, and ST-7):

Permittee shall disable and retire existing steam boilers ST-5, ST-6 and ST-7 concurrent with the startup of the fourth combustion turbine.

F. Requirements for Combustion Turbines to be Decommissioned:

Permittee shall decommission, remove, and replace each of the four existing combustion turbines.

G. Continuous Emissions Monitoring Systems (CEMS)

1. The Permittee shall ensure that all required CO_2 monitoring system/equipment are installed and all certification tests are completed on or before the earlier of 90 unit operating days or 180 calendar days after the date the unit commences operation.
2. Permittee shall ensure compliance with the specifications and test procedures for CO_2 emission monitoring system at stationary sources, 40 CFR Part 75, or 40 CFR Part 60, Appendix B, Performance Specification numbers 1 through 9, as applicable.
3. The Permittee shall meet the appropriate quality assurance requirements specified in 40 CFR Part 60, Appendix F for the CO_2 emission monitoring system.

IV. Excess Emission Reporting and Records:

1. Excess emissions are defined as any period in which the facility emissions exceed a maximum emission limit set forth in this permit. Excess emissions indicated by GHG emission source certification testing or compliance monitoring shall be considered violations of the applicable emission limit for the purpose of this permit.

2. Maintain records and submit a written report of all excess emissions to EPA semi-annually, except when more frequent reporting is specifically required by an applicable subpart; or the Administrator or authorized representative, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. The report is due on the 30th day following the end of each semi-annual period and shall include the following:

   a) Time intervals, data and magnitude of the excess emissions, the nature and cause (if known), corrective actions taken and preventive measures adopted;
   b) Applicable time and date of each period during which the monitoring equipment was inoperative (monitoring down-time);
   c) A statement in the report of a negative declaration; that is a statement when no excess emissions occurred or when the monitoring equipment has not been inoperative, repaired or adjusted; and
   d) Any failure to conduct any required source testing, monitoring, or other compliance activities.
   e) Any violation of limitations on operation, including but not limited to restrictions on hours of operation.

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V. Performance Testing Requirements:

A. The Permittee shall perform stack sampling and other testing to establish the actual pattern and quantities of air contaminants being emitted into the atmosphere from the stacks of the Boilers (BO1, BO2, and BO3), and Combustion Turbines (CG801, CG802, CG803, and CG804), and to determine the initial compliance with the CO_2 emission limits established in this permit. Sampling shall be conducted in accordance with 40 CFR § 60.8 and EPA Method 3a or 3b (40 CFR App. A-2) for the concentration of CO_2.

1. For the Boilers (BO1, BO2, and BO3) calculate the CO_2 hourly average emission rate determined under maximum operating test conditions, convert to lbs of CO_2/MMBtu. Use the following equation to calculate the annual emissions for each boiler.

$$CO_2\,TPY = 410\frac{MMBtu}{hr} * 8{,}760\frac{hr}{year} * lb\frac{CO_2}{MMBtu}$$

Where:

410 MMBtu/hr = is the design annual average furnace firing rate upon which the emissions in Table 1 were based on.

lb CO_2/MMBtu = calculated from V.A.1.

2. For the Combustion Turbines (CG801, CG802, CG803, and CG804) multiply the CO_2 hourly averge emission rate determined under maximum operating conditions by 8,760 hours.
3. If the above calculated CO_2 emission total exceeds the tons per year (TPY) specified in Table 1, the facility shall;
    a. Document the exceedance in the test report; and
    b. Explain within the report how the facility will assure compliance with the CO_2 emission limit listed in Table 1.

B. The Permittee shall conduct an evaluation of the thermal efficiency of the Combustion Turbines (CG801, CG802, CG803, and CG804) to verify compliance with the BACT Limit specified in Condition III.D.1. when performing testing as stated in V.A.2. above. The results of the thermal efficiency shall be submitted to the EPA within 30 days of testing.
C. Within 60 days after achieving the maximum production rate at which each boiler will operate, but not later than 180 days after initial startup of the individual boiler, performance tests must be conducted and a written report of the performance testing results furnished to the EPA. Additional sampling may be required by EPA.
D. Permittee shall submit a performance test protocol to EPA no later than 30 days prior to the test to allow review of the test plan and to arrange for an observer to be present at the test. The performance test shall be conducted in accordance with the submitted protocol, and any changes required by EPA.
E. Performance tests must be conducted under such conditions to ensure representative performance of the affected facility. The owner or operator must make available to the EPA such records as may be necessary to determine the conditions of the performance tests.
F. The owner or operator must provide the EPA at least 30 days prior notice of any performance test, except as specified under other subparts, to afford the EPA the opportunity to have an observer present and/or to attend a pre-test meeting. If there is a delay in the original test date, the facility must provide at least 7 days prior notice of the rescheduled date of the performance test unless EPA approves an earlier rescheduled date.
G. The owner or operator shall provide, or cause to be provided, performance testing facilities as follows:
    1. Sampling ports adequate for test methods applicable to this facility,
    2. Safe sampling platform(s),
    3. Safe access to sampling platform(s), and
    4. Utilities for sampling and testing equipment.
H. Unless otherwise specified, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For purposes of determining compliance with an applicable standard, the arithmetic mean of the results of the three runs shall apply.

I. The Permittee shall conduct its initial CO_2 CEMS relative accuracy test audit (RATA), in accordance with 40 CFR Part 60, Appendix F, Procedure 1, to evaluate compliance of each turbine with the emission standards on a continuous basis, within thirty (30) days of installation and startup of each turbine.

J. Emissions testing, as outlined above, shall be performed every five years, plus or minus 6 months, of when the previous performance test was performed, or within 180 days after the issuance of a permit renewal, whichever comes later to verify continued performance at permitted emission limits.

VI. Recordkeeping and Reporting

1. In order to demonstrate compliance with the GHG emission limits in Sections II and III, the Permittee shall monitor the following parameters and summarize the data on a calendar month basis.
    a. Operating hours for the each steam boiler (BO1, BO2, and BO3) and each combustion turbine (CG801, CG802, CG803, and CG804).
    b. The daily fuel usage for each steam boiler (BO1, BO2, and BO3) and each combustion turbine (CG801, CG802, CG803, and CG804) using continuous fuel flow monitors of natural gas and/or off-gas.
    c. Monthly fuel sampling for natural gas and when switch is made to a natural gas/off-gas combination.
    d. The daily steam production rate steam boiler (BO1, BO2, and BO3) and daily high pressure and low pressure steam produced by each combustion turbine (CG801, CG802, CG803, and CG804).
    e. Average daily steam pressure and steam temperature produced by each combustion turbine, (CG801, CG802, CG803, and CG804).
    f. Average daily enthalpy for the low and high pressure steam based on average conditions for each combustion turbine, (CG801, CG802, CG803, and CG804).
    g. The daily heat input rate for each boiler (BO1, BO2, and BO3) and each turbine/duct burner combination (CG801, CG802, CG803, and CG804).
    h. Daily CO_2e/MMBtu heat input for each boiler (BO1, BO2, and BO3) and daily CO_2e/MMBtu heat input for each combustion turbine/duct burner combination (CG801, CG802, CG803, and CG804).
    i. Inspection of the air preheater performance for the boilers and turbines and fuel preheater performance for the turbines.
2. Maintain a file of all records, data, measurements, reports, and documents related to the operation of the facilities authorized by this permit, including, but not limited to, the following: all records or reports pertaining to the maintenance performed on any system or device that is a part of a facility authorized by this permit; all records relating to performance

tests and monitoring of combustion equipment; and all other information required by this permit recorded in a permanent form suitable for inspection.

3. Maintain records of startup, shutdown, or malfunction, initial startup period for the emission units, performance testing, calibrations, checks, duration of any periods during which a monitoring device is inoperative, and corresponding emission measurement
4. Maintain records of all GHG emission units and CO_2 and O_2 emission certification tests, monitoring and compliance information required by this permit.
5. All records required by this PSD Permit shall be retained for not less than 5 years following the date of such measurements, maintenance, and reporting.

VII. Agency Notifications

Permittee shall submit GHG permit applications, permit amendments, and other applicable permit information to:

Multimedia Planning and Permitting Division
EPA Region 6
1445 Ross Avenue (6 PD-R)
Dallas, TX 75202
Email: Group R6AirPermits@EPA.gov

Permittee shall submit a copy of all performance tests, analyzers quality assurance tests, compliance and enforcement correspondence as required by this Approval to Construct to:

Compliance Assurance and Enforcement Division
EPA Region 6
1445 Ross Avenue (6EN)
Dallas, TX 75202