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-18999-GHG
PERMITTEE:	PL Propylene LLC 9822 La Porte Freeway Houston, TX 77017
FACILITY NAME:	PL Propylene LLC
FACILITY LOCATION:	9822 La Porte Freeway Houston, TX 77017

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 PL Propylene LLC for Greenhouse Gas (GHG) emissions. The Permit applies to the addition of new combustion turbines (combustion units), multiple heaters, a waste heat boiler, and a flare at their existing facility located in Houston, Texas.

PL Propylene (PLP) is authorized to construct six new combustion turbines (combustion units), a charge gas heater, a regeneration air heater, a waste heat boiler, and a flare 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) permit No. 18999. 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 PL Propylene 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.

Wren Stenger

Wren Stenger, Director
Multimedia Planning and Permitting Division

6/10/13

Date

PL Propylene LLC (PSD-TX-18999-GHG)
Prevention of Significant Deterioration Permit
For Greenhouse Gas Emissions
Draft Permit Conditions

PROJECT DESCRIPTION

The PLP plant catalyst regeneration system currently consists of five combustion turbines (combustion units) and three electric blowers whose exhaust gases are manifolded together before passing through a direct-fired air heater to get the gas to sufficient temperature to regenerate the dehydration catalyst. The hot exhaust gases from the regeneration step then pass through a waste heat boiler (WHB2) which has supplemental fuel firing to generate steam before being vented to the atmosphere. The proposed modification will add six new combustion turbines (combustion units), a new charge gas heater, a regeneration air heater, a waste heat boiler, and a flare to the existing facility in Houston, Texas. This modification will increase the production capacity of the plant by approximately 1.6 billion pounds per year of propylene (polymer grade and chemical grade). The facility also produces commercial quantities of hydrogen as well as a C_4 mix hydrocarbon stream and a C_5+ mix hydrocarbon stream.

EQUIPMENT LIST

The following devices are subject to this GHG PSD permit.

FIN	Description
GT6 GT7 GT8 GT9 GT10 GT11	Six Combustion Turbines (Combustion Units). Each gas generator has a maximum design heat input rate of 200 MMbtu/hr,
RCH2	Charge Gas Heater (Combustion Unit). The charge gas heater has a maximum design heat input rate of 373 MMbtu/hr,
RAH2	Regeneration Air Heater (Combustion Unit). The regeneration air heater has a maximum design heat input rate of 200 MMbtu/hr.
WHB2	Waste Heat Boiler (WHB) (Combustion Unit). The WHB has a maximum design heat input rate of 383 MMbtu/hr and is equipped with Selective Catalytic Reduction (SCR) controls.
FLARE2	Flare (Combustion Unit)
PLANT2	Fugitive Process Emissions
SF6FUG	SF6 Circuit Breakers

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 discontinued for a period of 18 months or more; or

3. is not completed within a reasonable time.

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, as defined in 40 CFR §60.2, postmarked within 15 days of such date; and

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.

C. FACILITY OPERATION

At all times, including periods of startup, shutdown, and maintenance, 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 results 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 Section II and 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 NSR Permit No. 18999 (when issued) 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

AVO	Auditory, Visual, and Olfactory
BACT	Best Available Control Technology
C_3+	Hydrocarbon with Three or More Carbon Atoms
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
FIN	Facility Identification Number
FR	Federal Register
GCV	Gross Calorific Value
GHG	Greenhouse Gas
gr	Grains
GWP	Global Warming Potential
HHV	High Heating Value
hr	Hour
HRSG	Heat Recovery Steam Generating
LAER	Lowest Achievable Emission Rate
lb	Pound
LDAR	Leak Detection and Repair
MMBtu	Million British Thermal Units
MSS	Maintenance, Start-up and Shutdown
N_2O	Nitrous Oxides
NSPS	New Source Performance Standards
PSD	Prevention of Significant Deterioration
QA/QC	Quality Assurance and/or Quality Control
SCFH	Standard Cubic Feet per Hour
SCR	Selective Catalytic Reduction
TAC	Texas Administrative Code
TCEQ	Texas Commission on Environmental Quality
TOC	Total Organic Carbon
TPY	Tons per Year
USC	United States Code
VDU	Vapor Destruction Unit
VHP	Very High Pressure
VOC	Volatile Organic Compound
WHB	Waste Heat Boiler

II. Annual Emission Limits

Annual emissions, in tons per year (TPY) on a 365-day rolling average basis, shall not exceed the following:

Table 1. Annual Emission Limit

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[1,2]	BACT Requirements
				TPY[1]		
GT6 GT7 GT8 GT9 GT10 GT11	WHB2	Combustion Turbines	CO_2	101,553[3]	908,729[4]	Use of Good Combustion Practices. See permit conditions III.A.1. c. through h.
			CH_4	2[3]		
			N_2O	0.2[3]		
RAH2	WHB2	Regeneration Air Heater	CO_2	102,395		Maintain firebox temperature ≥ 1,000 °F. See permit condition III.A.3.b.
			CH_4	2		
			N_2O	0.2		
WHB2	WHB2	Waste Heat Boiler/Duct Burners	CO_2	196,086		BACT limit of 117 lb CO_2/MMBtu heat input. See permit condition III.A.4.f.
			CH_4	3.7		
			N_2O	0.4		
GT6 GT7 GT8 GT9 GT10 GT11	GT6MSS GT7MSS GT8MSS GT9MSS GT10MSS GT11MSS	Combustion Turbines MSS	CO_2	842[3]	5,054[5]	BACT limit of 117 lb CO_2/MMBtu heat input. See permit condition III.A.2.d.
			CH_4	No Numerical Limit Established[6]		
			N_2O	No Numerical Limit Established[6]		
RCH2	RCH2	Charge Gas Heater	CO_2	190,966	191,166	BACT limit of 117 lb CO_2/MMBtu heat input. See permit condition III.A.5.f.
			CH_4	3.6		
			N_2O	0.4		
FLARE2	FLARE2	Flare	CO_2	31	33	Use of Low Carbon Fuel and Good Combustion Practices. See permit condition III.A.6.
			CH_4	0.1		
			N_2O	No Numerical Limit Established[6]		
PLANT2	PLANT2	Fugitive Process Emissions	CH_4	No Numerical Limit Established[7]	No Numerical Limit Established[7]	Implementation of Remote Sensing/AVO program. See permit condition III.A.7.

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[1,2]	BACT Requirements
				TPY[1]		
SF6FUG	SF6FUG	SF_6 Fugitive Emissions	SF_6	No Numerical Limit Established[8]	No Numerical Limit Established[8]	Installation of low pressure alarm and low pressure lockout. See permit condition III.A.8.
Totals[9]			CO_2	**1,103,848**	**CO_2e 1,105,893**	
			CH_4	**63**		
			N_2O	**2**		

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. These values are for each individual gas generator combustion unit.
4. This value is for the total emissions from the WHB2 including the six combustion turbines (GT6, GT7, GT8, GT9, GT10, and GT11) and the regeneration air heater (RAH2).
5. This value is the combined allowable MSS emissions from all six combustion turbines (GT6, GT7, GT8, GT9, GT10, and GT11) combined.
6. All values indicated as "No Numerical Limit Established" are less than 0.01 TPY with appropriate rounding. The emission limit will be a design/work practice standard as specified in the permit.
7. Fugitive process emissions from EPN Plant2 are estimated to be 42 TPY of CH_4, and 885 TPY CO_2e. The emission limit will be a design/work practice standard as specified in the permit.
8. SF_6 fugitive emissions from EPN SF6FUG are estimated to be 0.00108 TPY of SF_6 and 26 TPY of CO_2e. The emission limit will be a design/work practice standard as specified in the permit.
9. Total emissions include the PTE for fugitive emissions. Totals are given for informational purposes only and do not constitute emission limits.

III. SPECIAL PERMIT CONDITIONS

A. Emission Unit Work Practice Standards, Operational Requirements, and Monitoring

1. Combustion Turbines (FINs: GT6, GT7, GT8, GT9, GT10, and GT11; EPN: WHB2)

a. The combustion turbines shall combust pipeline quality natural gas with a fuel sulfur content of up to 5 grains of sulfur per 100 dry standard cubic feet (gr S/100 dscf). The fuel gross calorific value (GCV) [high heat value (HHV)] of the fuel shall be determined, at a minimum, semiannually for pipeline quality natural gas by the procedures contained in 40 CFR Part 98.34(a)(6) and records shall be maintained of the semiannual fuel GCV for a period of five years. Upon request, Permittee shall provide a sample and/or analysis of the fuel that is fired in the heaters or shall allow a sample to be taken by EPA for analysis.
b. During normal operations, the combustion turbines shall vent to the regeneration air heater (RAH2 which in turn vents to the waste heat boiler WHB2).
c. All fuel combustion units identified in this permit shall have fuel metering for each fuel, and Permittee shall:

    i. Measure and record the fuel flow rate using an operational non-resettable elapsed flow meter. A computer that collects, sums, and stores electronic data from continuous fuel flow meters is an acceptable totalizer.
    ii. Record the total fuel combusted for each fuel monthly.
    iii. The fuel gross calorific value (GCV) [high heat value (HHV)], carbon content and, if applicable, molecular weight, shall be determined, at a minimum, monthly by the procedures contained in 40 CFR Part 98.34(b)(3). Records of the fuel GCV shall be maintained for a minimum period of five years. Upon request, Permittee shall provide a sample and/or analysis of the fuel that is fired in any unit covered by this permit at the time of the request, or shall allow a sample to be taken by EPA for analysis.

d. Permittee shall calibrate and perform preventative maintenance check of the fuel gas flow meters and document annually.
e. The combustion turbines shall be equipped with temperature monitors for the burners. When the differential temperature across the burners exceeds 158°F, an alarm shall be triggered requiring investigation and resolution by operating personnel.
f. The combustion turbines shall not exceed the one-hour heat input of 200 MMBtu per hour per furnace. The heat input shall be determined using the appropriate procedure as found in 40 CFR Part 75 Appendix F Section 5.

g. The one-hour maximum firing rates shall be determined monthly to demonstrate compliance with the firing rate conditions in III.A.1.f.
h. The combustion turbines shall have a detailed visual inspection performed every 4,000 and 21,000 operating hours (base load).

2. **Combustion Turbines MSS (FINs: GT6, GT7, GT8, GT9, GT10, and GT11; EPNs: GT6MSS, GT7MSS, GT8MSS, GT9MSS, GT10MSS, and GT11MSS)**

a. The combustion turbines shall only vent to the atmosphere during maintenance, startup, and shutdown (MSS).
b. The combustion turbines shall combust pipeline quality natural gas with a fuel sulfur content of up to 5 grains of sulfur per 100 dry standard cubic feet (gr S/100 dscf). The fuel gross calorific value (GCV) [high heat value (HHV)] of the fuel shall be determined, at a minimum, semiannually for pipeline quality natural gas by the procedures contained in 40 CFR Part 98.34(a)(6) and records shall be maintained of the semiannual fuel GCV for a period of five years. Upon request, Permittee shall provide a sample and/or analysis of the fuel that is fired in the heaters or shall allow a sample to be taken by EPA for analysis.
c. All fuel combustion units identified in this permit shall have fuel metering for each fuel, and Permittee shall:

    iv. Measure and record the fuel flow rate using an operational non-resettable elapsed flow meter. A computer that collects, sums, and stores electronic data from continuous fuel flow meters is an acceptable totalizer.
    v. Record the total fuel combusted for each fuel monthly.
    vi. The fuel gross calorific value (GCV) [high heat value (HHV)], carbon content and, if applicable, molecular weight, shall be determined, at a minimum, monthly by the procedures contained in 40 CFR Part 98.34(b)(3). Records of the fuel GCV shall be maintained for a minimum period of five years. Upon request, Permittee shall provide a sample and/or analysis of the fuel that is fired in any unit covered by this permit at the time of the request, or shall allow a sample to be taken by EPA for analysis.

d. The combustion turbines shall each meet a BACT limit of 117 lb CO_2/MMBtu heat input when burning natural gas during MSS. Compliance will be based on a 365-day rolling average.
e. Compliance with the MSS BACT Limit shall be demonstrated for each unit on a 365-day rolling average, calculated in accordance with 40 CFR Part 98 Subpart C §98.33(a)(2)(i). CO_2 emissions shall be calculated using the metered fuel usage and default emission factor for natural gas from 40 CFR Part 98 Subpart C, Table C-1

and/or fuel composition and mass balance, and using equation C-2a of 40 CFR Part 98 Subpart C, converted to short tons.

f. Permittee shall calculate the CH_4 and N_2O emissions on a 365-day rolling average 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-8 of 40 CFR Part 98 Subpart C, and the measured HHV, converted to short tons.

g. Permittee shall calculate the CO_2e emissions on a 365-day rolling average 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.

3. Regeneration Air Heater/Duct Burner (FIN: RAH2; EPN: WHB2)

a. During operation the regeneration air heater (RAH2) vents to the waste heat boiler (WHB2) for control.

b. Permittee shall continuously monitor and record the firebox temperature hourly and maintain the temperature to greater than or equal to 1,000 °F on a 12-month rolling average basis.

c. Fuel for the heater shall be limited to pipeline quality natural gas with a fuel sulfur content of up to 5 grains of sulfur per 100 dry standard cubic feet (gr S/100 dscf) and/or recovered process fuel gas. The fuel gross calorific value (GCV) [high heat value (HHV)] of the fuel shall be determined, at a minimum, semiannually for pipeline quality natural gas and quarterly for recovered process fuel gas by the procedures contained in 40 CFR Part 98.34(a)(6) and records shall be maintained of the semiannual fuel GCV for a period of five years. Upon request, Permittee shall provide a sample and/or analysis of the fuel that is fired in the heaters or shall allow a sample to be taken by EPA for analysis.

d. Permittee shall install and maintain an operational non-resettable flow meter for the heater. The flow meter must be calibrated on an annual basis.

e. The flow rate of the fuel combusted in natural gas-fired combustion emission units identified in this section shall be measured and recorded using an operational totalizing fuel flow meter at each inlet.

f. Permittee shall perform a visual inspection of the burners annually. The Permittee shall conduct a physical inspection and cleaning of the burner tips, approximately every three years during a unit turnaround.

g. The Permittee shall perform annual physical inspections of the burner and firebox either with a bore-scope or visually through inspection ports to see if there is any burner damage or unusual flame patters that would indicate poor combustion.

Records of these inspections must be maintained and corrective actions, if necessary completed and documented.

4. **Waste Heat Boiler/Duct Burner (FIN/EPN: WHB2)**

   a. Permittee shall install and operate an O_2 CEMS, CO_2 CEMS and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording CO_2 emissions discharged to the atmosphere, and use these values to show compliance with the annual emission limit in Table 1 for the waste heat boiler/duct burner (WHB2).
   b. 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 or after CO_2 CEMS are installed.
   c. 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.
   d. Permittee shall calculate the CH_4 and N_2O emissions on a 12-month rolling basis. 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 measured actual heat input (HHV), converted to short tons.
   e. 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).
   f. The waste heat boiler (WHB2) shall meet a BACT limit of 117 lb CO_2/MMBtu heat input when burning natural gas and/or recovered process fuel gas. Compliance will be based on a 365-day rolling average.
   g. Fuel for the waste heat boiler/duct burners shall be limited to pipeline quality natural gas with a fuel sulfur content of up to 5 grains of sulfur per 100 dry standard cubic feet (gr S/100 dscf) and/or recovered process fuel gas. The fuel gross calorific value (GCV) [high heat value (HHV)] of the fuel shall be determined, at a minimum, semiannually for pipeline quality natural gas and quarterly for recovered process fuel gas by the procedures contained in 40 CFR Part 98.34(a)(6) and records shall be maintained of the semiannual fuel GCV for a period of five years. Upon request, Permittee shall provide a sample and/or analysis of the fuel that is fired in the heaters or shall allow a sample to be taken by EPA for analysis.
   h. Permittee shall install and maintain an operational non-resettable flow meter for the waste heat boiler. The flow meters must be calibrated on an annual basis.

i. The flow rate of the fuel combusted in the waste heat boiler (WHB2) shall be measured and recorded using an operational totalizing fuel flow meter at each inlet.
j. Permittee shall perform a visual inspection of the burners annually. The Permittee shall conduct a physical inspection and cleaning of the burner tips, approximately every three years during a unit turnaround.

5. Charge Gas Heater (FIN/EPN: RCH2)

a. Permittee shall install and operate a CO_2 CEMS and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording CO_2 emissions discharged to the atmosphere, and use these values to show compliance with the annual emission limit in Table 1 for the charge gas heater (RCH2).
b. 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 or after CO_2 CEMS are installed.
c. 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.
d. Permittee shall calculate the CH_4 and N_2O emissions on a 12-month rolling basis. 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 measured actual heat input (HHV), converted to short tons.
e. 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).
f. The charge gas heater (RCH2) shall meet a BACT limit of 117 lb CO_2/MMBtu heat input when burning natural gas and/or recovered process fuel gas. Compliance will be based on a 365-day rolling average.
g. Fuel for the charge gas heater (RCH2) shall be limited to pipeline quality natural gas with a fuel sulfur content of up to 5 grains of sulfur per 100 dry standard cubic feet (gr S/100 dscf) and/or recovered process fuel gas. The fuel gross calorific value (GCV) [high heat value (HHV)] of the fuel shall be determined, at a minimum, semiannually for pipeline quality natural gas and quarterly for recovered process fuel gas by the procedures contained in 40 CFR Part 98.34(a)(6) and records shall be maintained of the semiannual fuel GCV for a period of five years. Upon request, Permittee shall provide a sample and/or analysis of the fuel that is fired in the heaters or shall allow a sample to be taken by EPA for analysis.

h. Permittee shall install and maintain an operational non-resettable flow meter for the charge gas heater (RCH2). The flow meters must be calibrated on an annual basis.
i. The flow rate of the fuel combusted in the charge gas heater (RCH2) shall be measured and recorded using an operational totalizing fuel flow meter at each inlet.
j. Permittee shall perform a visual inspection of the burners annually. The Permittee shall conduct a physical inspection and cleaning of the burner tips, approximately every three years during a unit turnaround.
k. Permittee shall install, operate, and maintain an O_2 analyzer on the charge gas heater (RCH2).
l. Oxygen analyzers shall continuously monitor and record oxygen concentration in the charge gas heater (RCH2). It shall reduce the oxygen readings to an averaging period of 15 minutes or less and record it at that frequency.
m. The oxygen analyzers shall be quality-assured at least quarterly using cylinder gas audits (CGAs) in accordance with 40 CFR Part 60, Appendix F, Procedure 1, § 5.1.2, with the following exception: a relative accuracy test audit is not required once every four quarters (i.e., two successive semiannual CGAs may be conducted).

6. Flare (FIN/EPN: FLARE2)

a. The flare shall have a minimum destruction and removal efficiency (DRE) of 98% for methane based on flowrate and gas composition measurements as specified in 40 CFR Part 98 Subpart W § 98.233(n).
b. The flare shall only combust pipeline natural gas in the pilots during normal operations.
c. CO_2 emissions are calculated using equation Y-1 found in 40 CFR Part 98 Subpart Y, §98.253(b)(1)(ii)(A). CH_4 and N_2O emissions are calculated using equations Y-4 and Y-5 as found in 40 CFR Part 98 Subpart Y.
d. The flare shall be designed and operated in accordance with 40 CFR 60.18 including specifications of minimum heating value of the waste gas, maximum tip velocity, and pilot flame monitoring or an approved alternate. An infrared monitor is considered equivalent to a thermocouple for flame monitoring purposes.
e. The on-line gas chromatograph (GC) analyzer shall have an on-stream time of 95% on a semi-annual basis.

7. Fugitive Process Emissions (FIN/EPN: PLANT2)

a. The Permittee shall conduct remote sensing on an annual basis to detect methane leaking from the piping components in natural gas service.
b. The Permittee shall implement an auditory/visual/olfactory (AVO) monitoring program for detecting leaking in recovered process fuel gas and natural gas piping components, including valves and flanges.

c. AVO monitoring shall be performed daily.
d. Any component found to be leaking during remote sensing or AVO monitoring shall be repaired within 15 days.
e. Records of fugitive monitoring by remote sensing and documenting daily AVO monitoring must be maintained on site.

8. SF_6 Fugitives (FIN/EPN: SF6-FUG)

a. For emission unit SF6-FUG, SF_6 emissions shall be calculated annually (calendar year) in accordance with the mass balance approach provided in equation DD-1 of the Mandatory Greenhouse Gas Reporting rules for Electrical Transmission and Distribution Equipment Use, 40 CFR Part 98, Subpart DD. Permittee shall not exceed one new 72 lb enclosed-pressure SF_6 circuit breakers with leak detection.
b. Permittee shall maintain a file of all records, data measurements, reports and documents related to the fugitive emission sources including, but not limited to, the following: all records or reports pertaining to maintenance performed, all records relating to compliance with the Monitoring and Quality Assurance and Quality Control (QA/QC) procedures outlined in 40 CFR 98.304.
c. The circuit breaker shall be equipped with a low pressure alarm and a low pressure lockout.

IV. Recordkeeping and Reporting

A. Records

1. In order to demonstrate compliance with the GHG emission limits in Table 1, the Permittee will monitor the following parameters and summarize the data on a calendar month basis.

   a. Operating hours for all air emission sources;
   b. Records of the fuel consumed by each source
   c. The fuel usage for all combustion sources, using continuous fuel flow monitors (a group of equipment can utilize a common fuel flow meter, as long as actual fuel usage is allocated to the individual equipment based upon actual operating hours and maximum firing rate) A computer that collects, sums, and stores electronic data from continuous fuel flow meters is an acceptable totalizer; and
   d. Semi-annual fuel sampling for natural gas, quarterly fuel sampling of recovered process fuel gas, or other frequencies as allowed by 40 CFR Part 98 Subpart C §98.34(b)(3).

2. Permittee shall maintain records of the following for GHG emissions from the Equipment List (excluding fugitives): all records or reports pertaining to significant maintenance performed; duration of startup, shutdown; the initial startup period for the emission units; malfunctions; all records relating to performance tests, calibrations, checks, and monitoring of combustion equipment; duration of an inoperative monitoring device and emission units with the required corresponding emission data; and all other information required by this permit recorded in a permanent form suitable for inspection. These records may be maintained in electronic databases. The records must be retained for not less than five years following the date of such measurements, maintenance, reports, and/or records.
3. Permittee shall maintain records of all GHG emission units and CO_2 emission certification tests and monitoring and compliance information required by this permit.
4. Permittee shall 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 30^{th} 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;
    d. Any failure to conduct any required source testing, monitoring, or other compliance activities; and
    e. Any violation of limitations on operation, including but not limited to restrictions on hours of operation of the emergency generator or fire pump.

5. Excess emissions shall be defined as any period in which the facility emissions exceed a maximum emission limit set forth in this permit, a malfunction occurs of an emission unit listed in the Equipment List that results in excess GHG emissions, or any other unauthorized GHG emissions occur.
6. 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.
7. Instruments and monitoring systems required by this PSD permit shall have a 95% on-stream time on an annual basis.

8. 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.

V. Initial 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 Charge Gas Heater (RCH2) and Waste Heat Boiler (WHB2) 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 for the concentration of CO_2.

1. Multiply the CO_2 hourly average emission rate determined under maximum operating test conditions by 8,760 hours.
2. If the above calculated CO_2 emission total does not exceed the tons per year (TPY) specified on Table 1, no compliance strategy needs to be developed.
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. Within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility, performance tests(s) must be conducted and a written report of the performance testing results furnished to the EPA. Additional sampling may be required by TCEQ or EPA.

C. 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.

D. The Combustion Turbines (GT6, GT7, GT8, GT9, GT10, and GT11), Regeneration Air Heater (RAH2), and Waste Heat Boiler (WHB2) shall operate at representative production rates during stack emission testing for the Waste Heat Boiler (WHB2).

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 due to unforeseen events, such as delays that are caused by weather.

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. Emissions testing for the emergency engines, as outlined above, shall be performed every 8760 hours or three years whichever comes first to verify continued performance at permitted emission limits.

VI. Agency Notifications

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

Multi Media 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 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