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-1342-GHG
PERMITTEE:	C3 Petrochemicals LLC
FACILITY NAME:	PDH Chocolate Bayou Plant
MAILING ADDRESS:	600 Travis, Suite 300 Houston, TX 77001-2931
FACILITY LOCATION:	8 miles south of the intersection of Texas Hwy. 35 & FM 2917 near Alvin, TX

Pursuant to the provisions of the Clean Air Act (CAA), Subchapter I, Part C (42 U.S.C. § 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 C3 Petrochemicals (C3P) for Greenhouse Gas (GHG) emissions. The Permit applies to the construction of a new propane dehydrogenation (PDH) plant at the existing Chocolate Bayou facility.

C3P is authorized to construct a new PDH plant 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-1342. 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 C3P 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

6/12/14
Date

PROJECT DESCRIPTION

Pursuant to the provisions of this permit, C3 Petrochemicals (C3P) will construct a new propane dehydrogenation (PDH) manufacturing plant near the city of Alvin, Brazoria County, Texas. The C3P PDH plant will use propane as its raw material. Propane will be dehydrogenated to produce polymer grade and chemical grade propylene. The annual design capacity of the new PDH plant is 1,173 kMT of propylene. Other saleable byproducts are ethane, butanes and pipeline quality hydrogen gas.

Propane feedstock will come from outside the battery limits of the Chocolate Bayou site and will be stored in bullets. The dehydrogenation reaction of propane to propylene will occur after pretreatment of the propane feed in two parallel reaction trains. Each reaction train consists of four reactors, each having its own heater. After reaction, the products are then compressed, and separated into the various compounds in a cryogenic separation system. A hydrogen Pressure Swing Absorption Unit is utilized to produce saleable hydrogen product. The catalyst in the reaction train will be continuously regenerated by decoking and processed in the regeneration towers.

Most of the GHG emissions are from the combustion units of the plant that consist of two boilers, two charge heaters, six interheaters, two catalyst regenerator systems, and an 11 stage ground flare. In addition, other ancillary equipment (including the cooling water tower and fugitive emission components) may have GHG emissions. The permit for C3P will consist of the following sources of GHG emissions:

- Eight Process Heaters;
- Two Boilers;
- Two Continuous Catalyst Regeneration Vents;
- Ground Flare;
- Process Fugitives;
- MSS Emissions; and
- Cooling Tower

EQUIPMENT LIST

The following devices are subject to this GHG PSD permit:

FIN	EPN	Description
PDH-H101 PDH-H201	PDH-H101 PDH-H201	PDH Charge Heaters, H101 and H201. Each heater has a maximum design heat input rate of 126 MMBtu/hr, and will be equipped with a Selective Catalytic Reduction (SCR) system and low NOx burners.
PDH-H102 PDH-H202	PDH-H102 PDH-H202	PDH Inter-Heaters 1, H102 and H202. Each heater has a maximum design heat input rate of 135 MMBtu/hr, and will be equipped with a Selective Catalytic Reduction (SCR) system and low NOx burners.
PDH-H103 PDH-H203	PDH-H103 PDH-H203	PDH Inter-Heaters 2, H103 and H203. Each heater has a maximum design heat input rate of 96 MMBtu/hr, and will be equipped with a Selective Catalytic Reduction (SCR) system and ultra-low NOx burners.
PDH-H104 PDH-H204	PDH-H104 PDH-H204	PDH Inter-Heaters 3, H104 and H204. Each heater has a maximum design heat input rate of 78 MMBtu/hr, and will be equipped with a Selective Catalytic Reduction (SCR) system and ultra-low NOx burners.
PDH BOILER 1 PDH BOILER 2	PDH-BOILERS	Two boilers vented to a common stack, PDH Boiler 1 and PDH Boiler 2. Each boiler has a maximum design heat input rate of 615MMBtu/hr, and will be equipped with a Selective Catalytic Reduction (SCR) system and ultra-low NOx burners.
CCR-1	CCR-1	Continuous Catalyst Regeneration Vent, Reactor Train 1
CCR-2	CCR-2	Continuous Catalyst Regeneration Vent, Reactor Train 2
PDH-FUG	PDH-FUG	Process Fugitives
PDH-FLARE	PDH-FLARE	PDH Flare (Combustion Unit), Routine Emissions
PDH-MSS	PDH-MSS	MSS Emissions
PDH-CT	PDH-CT	Cooling Tower

An existing unit for barge loading control may see a small increase in GHG emissions but is not subject to permit requirements since this unit will not be PSD modified but only accommodate an increase in butane product loading.

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 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 Sections II and III of this permit.

2. Within 10 days of the restoration of normal operations after any failure 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 PSD Permit PSD-TX-1342 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
C3	Hydrocarbon with Three Carbon Atoms
CAA	Clean Air Act
CC	Carbon Content
CCR	Continuous Catalyst Regeneration
CCS	Carbon Capture and Sequestration
CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
CGA	Cylinder Gas Audit
CH_4	Methane
CHB	Chocolate Bayou
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
CT	Combustion Turbine
DRE	Destruction and Removal Efficiency
EF	Emission Factor
EPN	Emission Point Number
FIN	Facility Identification Number
FR	Federal Register
GCV	Gross Calorific Value
GHG	Greenhouse Gas
GWP	Global Warming Potential
HHV	High Heating Value
HRVOC	Highly Reactive Volatile Organic Compounds
kMT	Thousand Metric Tons
lb	Pound
LDAR	Leak Detection and Repair
LEL	Lower Explosive Limit
MMBtu	Million British Thermal Units
MSS	Maintenance, Start-up and Shutdown
N_2O	Nitrous Oxides
NO_x	Nitrogen Oxides
NSPS	New Source Performance Standards
O_2	Oxygen

OSBL	Outside the Battery Limits
PDH	Propane Dehydrogenation
PSA	Pressure Swing Adsorption
PSD	Prevention of Significant Deterioration
PSV	Pressure Safety Valve
QA/QC	Quality Assurance and/or Quality Control
RATA	Relative Accuracy Test Audit
SCFH	Standard Cubic Feet per Hour
SCR	Selective Catalytic Reduction
SHP	Selective Hydrogenation Process
TAC	Texas Administrative Code
TCEQ	Texas Commission on Environmental Quality
TOC	Total Organic Carbon
TPY	Tons per Year
USC	United States Code
VOC	Volatile Organic Compound

II. Annual Emission Limits

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

Table 1 Annual Emission Limits[1]

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY		
PDH-H101 PDH-H102 PDH-H103 PDH-H104	PDH-H101 PDH-H102 PDH-H103 PDH-H104	Process Heaters, Reactor Train 1	CO_2	230,078	230,308	Excess oxygen from heaters is limited to 3% or less. 87% thermal efficiency in Reactor Train 1. See Special Condition III.A.2.
			CH_4	4.2		
			N_2O	0.42		
PDH-H201 PDH-H202 PDH-H203 PDH-H204	PDH-H201 PDH-H202 PDH-H203 PDH-H204	Process Heaters, Reactor Train 2	CO_2	230,078	230,308	Excess oxygen from heaters is limited to 3% or less. 87% thermal efficiency in Reactor Train 2. See Special Condition III.A.2.
			CH_4	4.2		
			N_2O	0.42		
PDH BOILER 1 PDH BOILER 2	PDH-BOILERS	Boilers	CO_2	329,748	330,055	Thermal efficiency of 82%. See Special Condition III.A.3.
			CH_4	5.6		
			N_2O	0.56		
CCR-1	CCR-1	Train 1 CCR Vent	CO_2	2,318	2,318	Process design of the plant. Catalyst regeneration will use Nitrogen as purge gas.

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY		
						See Special Condition III.A.4.
CCR-2	CCR-2	Train 2 CCR Vent	CO_2	2,318	2,318	Process design of the plant. Catalyst regeneration will use Nitrogen as purge gas. See Special Condition III.A.4.
PDH-FUG	PDH-FUG	Process Fugitives	CH_4	No Numerical Limit Established[4]	No Numerical Limit Established[4]	Implementation of LDAR 28VHP Program. See Special Condition III.A.5.
PDH-FLARE	PDH-FLARE	Ground Flare	CO_2	165	178	Flare will meet the requirements of 40 CFR 60.18 with an efficiency > 98%. See Special Condition III.A.6.
			CH_4	0.5		
			N_2O	<0.01[5]		
PDH-MSS	PDH-MSS	Ground Flare MSS	CO_2	412	443	Good Operational Practices. See Special Condition III.A.7.
			CH_4	1.2		
			N_2O	<0.01[5]		
PDH-CT	PDH-CT	Cooling Tower	CH_4	0.4	11	Continuous monitoring of cooling water for HRVOCs/ See Special Condition III.A.8.
Totals[6]			**CO_2**	**795,115**	**CO_2e 795,940**	
			CH_4	**16.3**		
			N_2O	**1.4**		

1. Compliance with the annual emission limits (tons per year) is based on a 12-month rolling total.
2. The TPY emission limits specified in this table are not to be exceeded for this facility and include emissions from the facility during all operations and include MSS activities. This total is rounded off for estimation purposes to two significant figures.
3. Global Warming Potentials (GWP): CO_2 =1, CH_4 = 25, N_2O = 298
4. Fugitive process emissions from EPN PDH-FUG are estimated to be <0.001 TPY CO_2, 0.1 TPY of CH_4 and 4 TPY CO_2e.
5. These values are less than 0.01 TPY with appropriate rounding.
6. 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. Fuel Gas for Process Heaters, Boilers and Flares

a. Fuel to all combustion units identified in the permit shall use only pipeline natural gas and/or plant produced process gas.
b. A gas composition monitor/chromatograph shall be installed after the point where the process gas mixes with the natural gas or on the process gas line to determine the composition and carbon content of the gas.
c. The fuel gas monitor shall meet the requirements per 40 CFR §98.34(b)(3)(ii)(E) and/or 40 CFR 98.244(b)(4), for the gas chromatograph.
d. If the fuel gas monitor/chromatograph is installed prior to mixing with natural gas, the natural gas quality and carbon content will be obtained by semiannual testing, 40 CFR §98.34(b)(3)(ii)(A).
e. The fuel analysis shall at a minimum allow for the determination of the fuels volumetric heat content, carbon content, and molecular composition.
f. The heat input as HHV (MMBtu/hr, upper heating value basis) shall be calculated with results from the gas chromatograph and the results recorded.
g. The annual value for determining CO_2 emissions from the total fuel used will be recorded using equation 40 CFR 98.33(a)(1)(iii), Equation C-2b daily. Upon request, Permittee shall provide a sample and/or analysis of the fuel that is fired in the units covered by this permit at the time of the request, or shall allow a sample to be taken by EPA for analysis.
h. The fuel flow rate to the combustion units will be monitored using an operational non-resettable elapsed flow meter, or by recording the flow rate data in an electronic format with individual flow measurements being taken no less frequently than once every 15 minutes. A computer that collects, sums and stores electronic data from continuous fuel flow meters is an acceptable totalizer. Electronic data may be reduced to hourly averages for recordkeeping.
i. The fuel meter measurement will meet the requirements of 40 CFR 98.3(i) and quality assurance requirements of 40 CFR 98.3(i)(2) & (3).
j. Permittee shall calibrate and perform preventative maintenance checks of the fuel gas flow meters and document at the minimum frequency established per the manufacturer's recommendation, or at the interval specified per 40 CFR §98.34(b)(1)(ii).

2. Process Heaters (PDH-H101, H102, H103, H104, H201, H202, H203, H204)

a. The sum of the four heaters in each reactor train shall not exceed the one-hour maximum firing rate of 435 MMBtu/hr per reactor train. A daily rolling 12-month annual average shall be updated daily to demonstrate compliance with the firing rate of the combined heaters of 435 MMBtu/hr per train.
b. Permittee shall install, operate, and maintain an oxygen (O_2) analyzer on the heater flue gas at a location downstream of the radiant sections of the heaters.
c. The oxygen analyzer shall continuously monitor and record the excess oxygen concentration in the combustion gases. The monitoring data shall be reduced to daily average concentrations at least once every day using a minimum of four equally spaced data points over each one-hour period.
d. Permittee shall perform preventative maintenance check of the oxygen analyzer and document quarterly.

e. A relative accuracy test audit (RATA) is required once every four quarters in accordance with 40 CFR Part 60, Appendix F, Procedure 1, § 5.1.1.
f. 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.
g. The Permittee will validate the oxygen analyzer with zero and span gas at least weekly to maintain 1% accuracy based on full scale.
h. Excess oxygen shall be controlled to less than 3% to ensure efficiency on a 12-month rolling average basis.
i. All analyzers identified in this section III.A.1. shall achieve 95% on-stream time or greater when the heaters are operational.
j. Permittee shall utilize insulation materials to minimize heat loss and maintain energy efficiency of the heaters as indicated in the permit application.
k. The heaters will be continuously monitored for exhaust temperature and stack oxygen. The thermal efficiency of the heaters will be calculated monthly by totalizing the fuel to the four heaters in each reactor train to determine heat input and the heat added to the process in each heater combined with the steam production to determine heat recovery. Thermal efficiency will be calculated using the parameters described above and equation G-1 from American Petroleum Institute (API) methods 560 (4th ed.) Annex G.
l. The Permittee shall maintain a minimum thermal overall efficiency of 87% on a 12-month rolling average basis, calculated monthly, for the process heaters in each reaction train (PDH-H101, H201, H301, H401, H201, H202, H203, H204) including periods of start-up, shutdown, and maintenance.
m. The heaters shall be tuned annually consisting of a flame pattern inspection and adjustment for CO concentration.
n. Permittee shall calculate, on a monthly basis, the amount of CO_2 emitted from combustion of natural gas and process gas in tons/yr using equation C-5 in 40 CFR Part 98 Subpart C, converted to short tons. Compliance shall be based on a 12-month rolling basis to be updated by the last day of the following month.
o. 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-8b of 40 CFR Part 98, converted to short tons.
p. Permittee shall calculate the CO_2e emissions on a 12-month rolling basis, not to exceed 230,308 TPY CO_2e per train based on the procedures and Global Warming Potentials (GWP) contained in Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, effective January 1, 2014 (79 FR 3907, Table 1-A). The record shall be updated by the last day of the following month.

3. Boilers (PDH-BOILERS)

a. Boilers shall be equipped with ultra low NO_x burners using flue gas recirculation and utilize fuel as in Section III.A.1.
b. Permittee shall utilize insulation materials to minimize heat loss and maintain energy efficiency of the boilers as indicated in the permit application.

c. Boiler design will incorporate monitoring to minimize the blowdown to the sewer and recovery of the condensate for boiler feedwater.
d. Boiler design will incorporate an economizer that will be used to preheat boiler feedwater.
e. Permittee shall install, operate, and maintain an O_2 analyzer on the boiler flue gas at a location downstream of the radiant sections of the boilers. Excess O_2 shall be controlled to less than 3% when the operating load is 75% or greater to ensure efficiency on a 12-month rolling average basis.
f. The oxygen analyzer shall continuously monitor and record the excess oxygen concentration in the combustion gases. The monitoring data shall be reduced to daily average concentrations at least once every day using a minimum of four equally spaced data points over each one-hour period.
g. Permittee shall perform preventative maintenance check of the oxygen analyzer and document quarterly.
h. A relative accuracy test audit (RATA) is required once every four quarters in accordance with 40 CFR Part 60, Appendix F, Procedure 1, § 5.1.1.
i. The oxygen analyzers shall be quality-assured quarterly using cylinder gas audits (CGAs) in accordance with 40 CFR Part 60, Appendix F, Procedure 1, § 5.1.2.The Permittee shall validate the oxygen analyzer with zero and span gas at least weekly to maintain 1% accuracy based on full scale.
j. Each boiler shall not exceed the one-hour maximum firing rate of 615 MMBtu/hr. The one-hour maximum firing rates shall be determined daily to demonstrate compliance with the firing rate condition.
k. The stack exhaust temperature, fuel temperature, ambient temperature, and excess oxygen will be continuously monitored and averaged on a monthly basis to be used to calculate the thermal efficiency of each boiler.
l. Thermal efficiency will be calculated using the parameters described above and equation G-1 from American Petroleum Institute (API) methods 560 (4th ed.) Annex G.
m. The Permittee shall maintain a minimum overall efficiency of 82% on a 12-month rolling average basis, calculated monthly, for the boilers (PDH-BOILERS) including periods of start-up, shutdown, and maintenance.
n. The boilers shall be tuned annually consisting of a flame pattern inspection and adjustment for CO concentration.
o. In accordance with 40 CFR § 75.13(c), C3P will determine hourly CO_2 concentration and mass emissions with a flow monitoring system; a continuous O_2 concentration monitor; fuel F and Fc factors; and, where O_2 concentration is measured on a dry basis (or where Equation F-14b in Appendix F to 40 CFR Part 75 is used to determine CO_2 concentration), either a continuous moisture monitoring system, as specified in 40 CFR § 75.11(b)(2), or a fuel-specific default moisture percentage, as defined in 40 CFR § 75.11(b)(1); and by using the methods and procedures specified in Appendix F to 40 CFR Part 75.
p. Permittee shall calculate, on a monthly basis, the CO_2 emission rate and mass emission rate from the boilers using the oxygen monitor and the procedures in 40 CFR Part 75, Appendix F. Compliance shall be based on a 12-month rolling basis to be updated by the last day of the following month.

q. 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 CH4 and N2O emissions limits contained in this section using the default CH4 and N_2O emission factors contained in Table C-2 and equation C-8b of 40 CFR Part 98, converted to short tons.

r. Permittee shall calculate the CO_2e emissions on a 12-month rolling basis, not to exceed 330,055 TPY on a 12 month rolling average and based on the procedures and Global Warming Potentials (GWP) contained in Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1, as effective on January 1, 2014 (79 FR 3907, Table 1-A). The record shall be updated by the last day of the following month.

4. Continuous Catalyst Regeneration (CCR) Vents (CCR-1 and CCR-2)

a. Permittee shall only use nitrogen as a purge gas for the CCR units.
b. Permittee shall sample the catalyst and analyze for percent carbon using an EPA approved method. The catalyst sampling protocol for the CCR vents should be submitted and approved by EPA prior to startup of the plant
c. Catalyst sampling and analysis as described in III.A.4.b above will occur at least twice per week.
d. The catalyst sample will be collected from Lift Engager #4 as it reaches the regeneration tower.
e. Permittee shall calculate, on a monthly basis, the amount of CO_2 emitted from CCR vents in short tons/yr. Compliance shall be based on a 12-month rolling basis to be updated by the last day of the following month.

5. Process Fugitives (PDH-FUG)

a. The Permittee shall implement the TCEQ 28VHP and 28 CNTQ leak detection and repair (LDAR) programs for fugitive emissions of methane.
b. The Permittee shall implement an as-observed AVO program to monitor for fugitive emissions between instrumented monitoring as required in III.A.5.a above.
c. The Permittee shall use high quality components and materials of construction that is compatible with the service in which they are employed.
d. The Permittee will install "leakless" pumps and compressors equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal.
e. Permittee will amend the permit if the fugitive equipment count and emission estimates if the count/emission estimate exceeds representations in the application.

6. Flare (PDH-FLARE)

a. The non-assisted ground flare will have 11 stages and shall be designed to achieve a minimum destruction and removal efficiency of 98% VOC/CH_4 during all times when waste gas is combusted.

b. The only plant process gases that may flow continuously to the flare are: pilot gas, sweep gas (natural gas or nitrogen), process analyzer vents, process safety valve fugitives and storage tank vents.
c. The flare shall be used during maintenance, startup and shutdown activities and also during upset conditions.
d. The flare shall be designed to achieve a minimum destruction and removal efficiency
(DRE) of 98% for CH4 based on flow rate and gas composition measurements.
e. The flare shall be operated with a flame present at all times and/or have a constant pilot flame. The pilot flame shall be continuously monitored by a thermocouple or an infrared monitor. The time, date, and duration of any loss of pilot flame shall be recorded.
f. The flare system shall be designed such that the combined assist natural gas and waste stream meets the 40 CFR § 60.18 specifications of minimum heating value and maximum tip velocity under normal, and MSS conditions.
g. The permit holder shall install a continuous flow monitor and composition analyzer that provides a record of the vent stream flow and composition to the flare.
h. The flow monitor sensor and analyzer sample points shall be installed in the flare header near as possible to the flare inlet such that the total vent stream to the flare is measured and analyzed. Readings shall be taken at least once every 15 minutes and the average hourly values of the flow and composition shall be recorded each hour.
i. The flow monitor and composition analyzer shall be calibrated to meet the following accuracy specifications: the flow monitor shall be ±5.0%, temperature monitor shall be ±2.0% at absolute temperature, and pressure monitor shall be ±5.0 mm Hg.
j. The monitoring system must be capable of measuring the entire gas stream flow to the flare at all operating conditions and may consist of one or more flow measurements at the flare header location. Flow rate should be corrected to standard conditions defined at 68 °F and 760 mm Hg, temperature and pressure.
k. All monitors and analyzer shall be operational at least 95% of the time based on a 12 month rolling average, during the flow of waste gases.
l. Permittee must record the time, date, HHV in MMBtu/hr and duration of each MSS event. The records must include hourly CH_4 emission levels as measured by the in-line gas analyzer (Gas chromatograph or equivalent with volumetric stack gas flowrate) and the calculations based on the actual heat input for the CO_2, N_2O, and CH_4 emissions during each MSS event. These records must be kept for five years following the date of each event.
m. CO_2 emissions shall be calculated using equation Y-1a found in 40 CFR §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, site specific analysis of waste gas and the actual heat input (HHV).
n. Compliance with the annual emission limit shall be determined on a 12-month rolling basis.

7. **Maintenance, Startup, and Shutdown (PDH-MSS)**

a. The Permittee shall depressurize sections of pipe and equipment to the flare or other parts of the process prior to performing MSS activities.
b. MSS emissions that cannot be controlled by the flare are vented to the atmosphere. Venting to the atmosphere shall only occur when the hydrocarbon concentration in process vessels is below 10,000 ppmv, as determined by a Lower Explosive Limit (LEL) meter or Organic Vapor Analyzer.
c. C3P will plan maintenance activities in a manner to minimize the venting of emissions to the atmosphere.
d. Records of MSS activities shall be maintained to include the date, time, and estimated volume of each MSS event.
e. For MSS emissions that are released to atmosphere, the Permittee shall also include a record of the hydrocarbon concentration as measured by the LEL meter or Organic Vapor Analyzer with the records required in III.A.6.b.

8. Cooling Tower (PDH-CT)

a. As a surrogate for CH_4, the Permittee shall implement a leak detection program for the cooling tower consistent with 30 TAC Chapter 115 Subchapter H Division 2. It will be assumed that 5% of any VOC detected utilizing this method will be CH_4.
b. The Permittee will calibrate the continuous flow monitor on the inlet of the cooling tower to within ± 5.0% on an annual basis.
c. The Permittee shall calibrate the continuous monitoring system for total strippable VOC at least weekly and maintain a monitor drift of less than 5.0%.
d. Each continuous monitoring system shall be operational at least 95% of the time that the cooling tower is operational.
e. The Permittee will maintain records of cooling tower monitoring and corrective actions taken consistent with 30 TAC § 115.766.
f. A unit shutdown will be triggered by a cooling water VOC concentration of 0.08 ppmw VOC or greater.

B. Continuous Emissions Monitoring Systems (CEMS)

1. As an alternative to Special Conditions III.A.2 and III.A.3 to show compliance with the annual CO_2 emission limits in Table 1, Permittee may install 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

2. 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 operating days or 180 calendar days after the date the plant commences operation.

3. 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.

4. The CEMS and stack gas flow monitors shall achieve 95% on-stream time or greater when the heaters/ boilers are operational.

C. Parametric Emission Monitoring Systems (PEMS) and Analyzers' Specifications

1. All analyzers and PEMS shall have a 95% onstream factor and be maintained according to the specified requirements as in the above sections.

2. The analyzers and PEMS will be calibrated and quality assured as indicated in the specific condition of this permit and appropriate EPA requirements.

3. Analyzers and PEMS outages will be recorded and reported.

D. RECORDKEEPING AND REPORTING

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 (except flare pilot gas);
   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);
   d. Semi-annual fuel sampling for natural gas, daily averages of the continuous plant gas composition analyzer to meet the frequencies as allowed by 40 CFR § 98.34(b)(3); and
   e. Records of the fuel usage, including heating values, both HHV and LHV, total mass fuel usage, and composition shall be maintained for a minimum period of five years.

2. Permittee shall maintain a file of all records, data, measurements, reports, and documents related to the operation of the facility, including, but not limited to, the following: all records or reports pertaining to significant maintenance performed on any system or device at the plant; duration of startup, shutdown; the initial startup period for the emission units; pollution control 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. The file 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 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: Permittee shall maintain records and submit a written report of all GHG 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;
d. Any failure to conduct any required source testing, monitoring, or other compliance activities; and
e. Any violation of limitations on operation.

4. Excess emissions shall be defined as any period in which the facility emissions exceed a maximum emission limit set forth in this permit, or a malfunction occurs causing an emissions exceedance.

5. Excess emissions indicated by GHG emission performance testing or compliance monitoring shall be considered violations of the applicable emission limit for the purpose of this permit.

6. Instruments and monitoring systems required by this PSD permit shall have a 95% on- stream time on an annual basis.

7. 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.

8. Continuously means individual measurement no less frequent than once every 15 minutes. Electronic data may be reduced to hourly averages for recordkeeping purposes.

E. INITIAL PERFORMANCE TESTING REQUIREMENTS

IV. 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 Process Heaters (PDH-H101, H102, H103, H104, H201, H202, H203, H204), Boilers (PDH-BOILERS), and CCR Vents (CCR-1 and CCR-2) to determine the initial compliance with the CO_2 emission limits and thermal efficiencies 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.

a. Multiply the CO_2 hourly average emission rate determined under maximum operating test conditions by 8,760 hours for the combustion turbines.
b. If the above calculated CO_2 emission total does not exceed the tons per year (TPY) specified in Table 1, no compliance strategy needs to be developed.
   If the above calculated CO_2 emission total exceeds the tons per year (TPY) specified in Table 1, the facility shall:

   a. Document the potential to exceed 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.

V. No later than 180 days after initial start-up, or restart after modification of the facility, performance test(s) must be conducted and a written report of the performance testing results furnished to the EPA with 60 days after the testing is completed. During subsequent operations, stack sampling shall be performed within 120 days if current production rates exceed the production rate during stack testing by 10 percent or greater, additional sampling may be required by TCEQ or EPA.

VI. 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.

VII. 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.

VIII. 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.

IX. 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.

X. 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.

XI. 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.

A. 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 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