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-1336-GHG
PERMITTEE:	Enterprise Products Operating LLC P.O. Box 4324 Houston, TX 77210
FACILITY NAME:	Propane Dehydrogenation Unit
FACILITY LOCATION:	10207 FM 1942 Mont Belvieu, Chambers County, Texas 77017

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 Enterprise Products Operating LLC (Enterprise) for Greenhouse Gas (GHG) emissions. This permit applies to the construction of a new propane dehydrogenation unit adjacent to their existing facility near Mont Belvieu, Texas.

Enterprise is authorized to construct the new PDH Unit with the equipment 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) new source review (NSR) permits 107523, PSD-TX-1336, and N-174 (Non-Attainment). 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 Enterprise 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), this PSD permit becomes effective 30 days after the service of notice of this final decision unless review is requested on the permit pursuant to 40 CFR § 124.19.

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Wren Stenger, Director
Multimedia Planning and Permitting Division

Date

Enterprise Products Operating LLC (PSD-TX-1336-GHG)
Prevention of Significant Deterioration Permit
For Greenhouse Gas Emissions
Draft Permit Conditions

PROJECT DESCRIPTION

Enterprise Products Operating LLC (Enterprise) proposes to construct a new propane dehydrogenation (PDH) unit in Chambers County adjacent to its existing oil and gas production facility near Mont Belvieu, Texas. The project will utilize catalytic reactors to convert propane into propylene (the primary product) and hydrogen (a secondary stream). Enterprise expects the unit to be capable of producing in excess of 1.6 billion pounds of propylene each year when operational.

The Enterprise facility will consist of ten catalytic reactors, in parallel, to convert the propane feed stock into propylene and hydrogen; a reactor charge heater to bring the incoming feed stock up to reaction temperature; a regenerative air heater to devolve coke from the catalyst in the reaction vessels; two gas air combustion turbines and two regenerative air compressors set up in parallel to provide air to the regenerative air heater; a waste heat boiler to recover heat and develop steam, as well as help control emissions of Carbon Monoxide (CO), Volatile Organic Compounds (VOC) and Nitrogen Oxides (NO_{x}); a compression and cooling system to cool the product stream and remove condensable fluids; a propylene compression system to isolate the propylene product and move it off the plant site; a pressure swing adsorption/hydrogen recovery unit (PSA) to isolate the hydrogen product stream and move the majority of it off the plant site; two auxiliary boilers to develop additional steam for the process, when needed; a cooling tower to control excess heat from the process; ancillary tankage and pumps needed to run the facility; a process flare to provide a safe method to combust feedstock and pressured fuel sources when needed; a wastewater treatment plant to strip out VOCs from waters used in the process; and plant fugitive emissions. The plant will utilize vacuum circuit breakers for their electrical supply which will eliminate the need to keep sulfur hexafluoride on site.

EQUIPMENT LIST

The following devices and emission points are subject to this GHG PSD permit.

FIN	EPN	Description
HR15.101	HR15.101	Reactor Charge Heater
HR15.102	DW37.101	Regeneration Air Heater
HR15.103	DW37.101	Waste Heat Boiler Combustion Unit (Duct Burners)
GT26.101A	DW37.101	Regeneration Air Compressor Gas Turbine A
GT26.101B	DW37.101	Regeneration Air Compressor Gas Turbine B
BO10.101	DW37.101	Reactor Evacuation Ejector Effluent to Waste Heat Boiler
GT26.101A and GT26.101B MSS	GT26.101A and GT26.101B (Common By Pass Stack)	Regeneration Air Compressor Gas Turbines A and B MSS
BO10.103A	BO10.103A	Auxiliary Boiler A
BO10.103B	BO10.103B	Auxiliary Boiler B
SK25.801 and SK25.801MSS	SK25.801	Process Flare, Routine Operation
		Process Flare, MSS Operation
FUG-PDH	FUG-PDH	Process Fugitive Emissions
FUG-NGAS	FUG-NGAS	Natural Gas Pipeline Fugitive Emissions
PM18.803	PM18.803	Fire Water Pump Engine
PM18.850C	PM18.850C	Raw Water Pump Engine

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 satisfactory showing, in writing, that an extension is justified.

B. PERMIT NOTIFICATION REQUIREMENTS

Enterprise 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, Enterprise 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 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. Enterprise 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., Enterprise 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. Enterprise 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

Enterprise shall construct this project in compliance with this PSD permit, the application on which this permit is based, the TCEQ's PSD-TX-1336, NNSR Permit N174 and minor NSR permit No. 107523, and all other applicable federal, state, and local air quality regulations. This PSD permit does not release Enterprise from any liability for compliance with other applicable federal, state and local environmental laws and regulations, including the Clean Air Act.

ACRONYMS AND ABBREVIATIONS

AVO	Auditory, Visual, and Olfactory
BACT	Best Available Control Technology
CAA	Clean Air Act
CCS	Carbon Capture and Sequestration
CGA	Cylinder Gas Audit
CEMS	Continuous Emissions Monitoring System
GC	Gas Chromatograph
CFR	Code of Federal Regulations
CH_4	Methane
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
dscf	Dry Standard Cubic Foot
EPN	Emission Point Number
FIN	Facility Identification Number
FR	Federal Register
GCV	Gross Calorific Value
GHG	Greenhouse Gas
gr	Grains
GWP	Global Warming Potential
hr	Hour
LAER	Lowest Achievable Emission Rate
lb	Pound
LDAR	Leak Detection and Repair
MMBtu	Million British Thermal Units
NNSR	Non-Attainment New Source Review
NSR	New Source Review
MSS	Maintenance, Start-up and Shutdown
N_2O	Nitrous Oxides
PSD	Prevention of Significant Deterioration
QA/QC	Quality Assurance and/or Quality Control
TCEQ	Texas Commission on Environmental Quality
TPY	Tons per Year
VOC	Volatile Organic Compound
WHB	Waste Heat Boiler

II. **Annual Emission Limits**

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

EPN	FIN	Description	GHG Mass Basis TPY[1]		TPY CO_2e[1,2]	BACT Requirements
HR15.101	HR15.101	Reactor Charge Heater	CO_2	280,394	281,558	BACT limit of 131.4 when burning recovered process fuel gas. Maintain 85% thermal efficiency of heater. See permit conditions III.A.3.a-u.
			CH_4	14.1		
			N_2O	2.82		
DW37.101	HR15.102	Regeneration Air Heater	CO_2	650,930	1,034,695[3]	See permit conditions III.A.2 and III.A.4.a-j.
			CH_4	23.9		
			N_2O	5.86		
	HR15.103	Waste Heat Boiler Combustion Unit (Duct Burners)	CO_2	19,540		See permit conditions III.A.2 and III.A.5.f-n.
			CH_4	0.98		
			N_2O	0.2		
	GT26.101A	Regeneration Air Compressor Gas Turbine A	CO_2	124,931		See permit conditions III.A.2 and III.A.6.a-j.
			CH_4	2.32		
			N_2O	0.23		
	GT26.101B	Regeneration Air Compressor Gas Turbine B	CO_2	124,931		See permit conditions III.A.2 and III.A.6.a-j.
			CH_4	2.32		
			N_2O	0.23		
	BO10.101	Reactor Evacuation Ejector Effluent to Waste Heat Boiler	CO_2	111,627		Waste Heat Boiler - Meet BACT limit of no greater than 126.5 lb CO_2/MMBtu See permit condition III.2 a-f.
			CH_4	1.12		
			N_2O	0.09		
BO10.103A BO10.103B	BO10.103A BO10.103B	Auxiliary Boiler A and B	CO_2	16,335	16,405[4]	See permit condition III.A.7 a-s.
			CH_4	0.82		
			N_2O	0.16		
SK25.801	SK25.801 SK25.801MSS	Flare	CO_2	7,244	7,258	See permit condition III.A.8.a-e.
			CH_4	0.2		
			N_2O	0.03		

EPN	FIN	Description	GHG Mass Basis TPY[1]		TPY CO_2e[1,2]	BACT Requirements
FUG-PDH	FUG-PDH	Process Fugitive Emissions	CH_4	No Numerical Limit Established [5]	No Numerical Limit Established [5]	Implementation of TCEQ 28LAER/MID directed maintenance and inspection program. See permit condition III.A.9.
FUG-NGAS	FUG-NGAS	Natural Gas Fugitives	CH_4	No Numerical Limit Established [5]	No Numerical Limit Established [5]	Implement AVO LDAR. See permit condition III.A.9.
PM18.803	PM18.803	Fire Water Pump Engine	CO_2	16	16	Operation limited to 52 hours per year or during plant fire emergencies. See permit condition III.A.10 a-c, e-g.
			CH_4	No Numerical Limit Established[6]		
			N_2O	No Numerical Limit Established[6]		
PM18.850C	PM18.850C	Raw Water Make Up Pump	CO_2	8	8	Use of Good Combustion Practices. Operation limited to 52 hours per year or during plant fire emergencies. See permit condition III.A.10 a-b, d -g
			CH_4	No Numerical Limit Established[6]		
			N_2O	No Numerical Limit Established[6]		
Totals[7]			**CO_2**	**1,338,692**	**CO_2e 1,342,659**	
			CH_4	**45.8**		
			N_2O	**9.47**		

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 = 25, N_2O = 298
3. This value is for the total emissions from the WHB stack (DW37.101) including the two combustion turbines (GT26.101A and GT26.101B), the regeneration air heater (HR10.102), the waste heat boiler combustion unit (HR10.103), and the coke burn and off-gassing from the catalyst regeneration process.
4. This value is for operation one of both Auxiliary Boilers and cannot be exceeded for both units combined.
5. Fugitive emission values are estimates based on work practices standards and not enforceable emission limits. Compliance with the emission limit will be determined by compliance with the work practice standard specified in the permit conditions. Fugitive potential to emit from process gas sources are estimated to be 0.25TPY of CH_4, equivalent to 6 TPY of CO_2e. Fugitive potential to emit from natural gas sources are estimated to be 13.04TPY of CH_4, equivalent to 326 TPY of CO_2e.
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. 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. Fuel Monitoring

a. All fuel combustion units identified in this permit, the natural gas input to the catalyst regeneration process and the reactor reduction system effluent input to the WHB shall have fuel metering for each fuel used, and Enterprise 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), lower heat value (LHV), carbon content, and, if applicable, molecular weight shall be determined, at a minimum, monthly by the procedures contained in 40 CFR § 98.34(b)(3). 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. Upon request, Enterprise 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.

b. Enterprise shall calibrate and perform preventative maintenance checks of the fuel gas flow meters and document annually.

2. Waste Heat Boiler Stack (DW37.101)

a. The emissions exiting the waste heat boiler stack (DW37.101) shall be no greater than 126.5 lb CO_2/MMBtu. The emissions shall be determined using the total CO_2 emissions exiting the stack and heat input from all fuel flowing into the waste heat boiler, including, but not limited to, natural gas input into the reactor regeneration process, natural gas firing the regeneration air compressor turbines (GT26.101A and GT26.101B), natural gas and/or fuel gas firing the regeneration air heater (HR15.102), natural gas and/or fuel gas firing the Waste Heat Boiler Duct Burner (HR15.103), and the heat value measured in MMBtu/hr of the coke and effluent entering the WHB (BO10.101) from the reactor reduction system. Enterprise shall demonstrate compliance with the mass emission limits in Section II of this permit by determining the 12-month rolling total of emissions using the method described in III.A.2.b.

b. Enterprise shall determine the CO_2 hourly emission rate and CO_2 mass emissions exiting the WHB stack (DW37.101) using an O_2 monitor and the procedures in 40 CFR Part 75, Appendix F. In accordance with 40 CFR § 75.13(c), Enterprise shall 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 (if applicable), 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.

c. If special condition III.A.2.b is utilized for compliance, 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). Enterprise may comply with the quality assurance provisions of 40 CFR Part 75, Appendix B, in lieu of complying with the provisions of 40 CFR Part 60, Appendix F.

d. As an alternative to special condition III.A.2.b, the Enterprise may install a CO_2 CEMS and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measure and recording CO_2 emissions discharged to the atmosphere.

e. If special condition III.A.2.d is utilized, Enterprise shall ensure the required CO_2 monitoring system and associated equipment are installed and fully operational at the time of the initial unit start up 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 initial operation.

f. Enterprise 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.

g. Enterprise shall calculate the CH_4 and N_2O emissions on a 12-month rolling total basis. Enterprise shall determine compliance with the CH_4 and N_2O emissions limits contained in this permit 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.

h. Enterprise shall calculate the CO_2e emissions on a 12-month rolling total 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 amended on November 29, 2013 (78 FR 71903).

3. Reactor Charge Heater (FIN/EPN: HR15.101)

a. Enterprise shall determine the CO_2 hourly emission rate and CO_2 mass emission exiting the Reactor Charge Heater stack (HR15.101) using an O_2 monitor and the procedures in 40 CFR Part 75, Appendix F. In accordance with 40 CFR § 75.13(c), Enterprise shall 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 (if applicable), 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.

b. If special condition III.A.3.a is utilized for compliance, the oxygen analyzers shall be quality-assured at least quarterly using 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). Enterprise may comply with the quality assurance provisions of 40 CFR Part 75, Appendix B, in lieu of complying with the provisions of 40 CFR Part 60, Appendix F.

c. As an alternative to special condition III.A.3.a, the Enterprise may install a CO_2 CEMS and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measure and recording CO_2 emissions discharged to the atmosphere.

d. If special condition III.A.3.c is utilized, Enterprise shall ensure the required CO_2 monitoring system and associated equipment are installed and fully operational at the time of the initial unit start up 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 initial operation.

e. If special condition III.A.3.c is utilized, Enterprise 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.

f. Enterprise shall calculate the CH_4 and N_2O emissions on a 12-month rolling total basis. Enterprise shall determine compliance with the CH_4 and N_2O emissions limits contained in this permit 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.

g. Enterprise shall calculate the CO_2e emissions on a 12-month rolling total 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 amended on November 29, 2013 (78 FR 71903).

h. Enterprise shall maintain a Charge Heater efficiency of greater than 85%, based on a 12-month rolling average basis, excluding malfunction and maintenance periods.

i. Enterprise shall demonstrate heater efficiencies by monitoring the exhaust temperature, fuel temperature, ambient temperature, and excess oxygen. Thermal efficiency will be calculated for each operating hour from these parameters using equation G-1 from American Petroleum Institute (API) methods 560 (4^{th} ed.) Annex G.

j. The charge gas heater (HR15.101) shall meet a BACT limit of 131.4 lb CO_2/MMBtu when burning recovered process fuel gas. Compliance will be based on a 12-month rolling average basis.

k. Fuel for the charge gas heater (HR15.101) shall be limited to process fuel gas, ethane and/or 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) and 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 § 98.34(a)(6), and records shall be maintained of the semiannual fuel GCV for a period of five years. Upon request, Enterprise 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.

l. Enterprise shall install and maintain an operational non-resettable flow meter for the charge gas heater (HR15.101). The flow meters must be calibrated on an annual basis.

m. The flow rate of the fuel combusted in the charge gas heater (HR15.101) shall be measured and recorded using an operational totalizing fuel flow meter at each inlet.

n. Enterprise shall perform a visual inspection of the burners annually. Enterprise shall conduct a physical inspection and cleaning of the burner tips and convection tubes approximately every three years during a unit turnaround or as necessary to maintain good combustion practices.

o. Enterprise shall install, operate and maintain an O_2 analyzer on the charge gas heater (HR15.101).

p. Oxygen analyzers shall continuously monitor and record oxygen concentration in the charge gas heater (HR15.101). Enterprise shall reduce the oxygen readings to an averaging period of 15 minutes or less and record it at that frequency.

q. 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.

r. 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.

s. Enterprise shall ensure the reactor feed stream is preheated using the heated product stream from the reaction vessels.

t. Enterprise shall install, operate and maintain an automated air/fuel control system.

u. Enterprise shall calibrate and perform preventative maintenance on the air/fuel control analyzers once per quarter, at a minimum.

4. Regeneration Air Heater (FIN: HR15.102; EPN: DW37.101)

a. During normal operation, the regeneration air heater (HR15.102) shall vent through the reactor regeneration process to the waste heat boiler (BO10.101) for heat recovery before entering the atmosphere through the boiler stack (DW37.101).

b. Fuel for the heater shall be limited to pipeline quality natural gas with 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 GCV and LHV 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 § 98.34(a)(6), and records of such shall be maintained for a period of five years. Upon request, Enterprise 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. Enterprise shall install and maintain an operational non-resettable flow meter for the heater. The flow meter must be calibrated on an annual basis.
d. The flow rate of the fuel combusted in natural gas or plant process fuel fired combustion emission units identified in this section shall be measured and recorded using an operational totalizing fuel flow meter at each inlet.
e. Enterprise shall perform a visual inspection of the burners annually. Enterprise shall conduct a physical inspection and cleaning of the burner tips approximately every three years during a unit turnaround or as needed to maintain good combustion practice.
f. Enterprise 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 patterns that would indicate poor combustion. Records of these inspections must be maintained and corrective actions, if necessary, completed and documented.
g. Enterprise shall calculate the CH_4 and N_2O emissions on a 12-month rolling total basis. Enterprise shall determine compliance with the CH_4 and N_2O emissions limits contained in this permit 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.
h. Enterprise shall calculate the CO_2e emissions on a 12-month rolling total 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 amended on November 29, 2013 (78 FR 71903).
i. Enterprise shall install, operate and maintain an automated air/fuel control system.
j. Enterprise shall calibrate and perform preventative maintenance on the air/fuel control analyzers once per quarter, at a minimum.

5. Waste Heat Boiler (WHB) and WHB Duct Burner (FIN: BO10.101/HR15.103; EPN: DW37.101)

a. As described in III.A.2.b-h, Enterprise shall install and operate an O_2 monitor or 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 III.A.2.a of this permit for the WHB stack (DW37.101).
b. Enterprise shall ensure the required O_2 or CO_2 monitoring system and associated 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. Enterprise 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. Enterprise shall calculate the CH_4 and N_2O emissions on a 12-month rolling total basis. Enterprise 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. Enterprise shall calculate the CO_2e emissions on a 12-month rolling total 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 amended on November 29, 2013.

f. The waste heat boiler burner (HR15.103) shall meet an operational limit of 118.5 lb CO_2/MMBtu, HHV, heat input when burning natural gas or 131.5 lb CO_2/MMBtu heat input when burning recovered process fuel gas as calculated on a 12-month rolling average basis. Compliance with the operational burner limit shall be demonstrated on a 12-month rolling average basis, calculated in accordance with 40 CFR Part 98 Subpart C, including 40 CFR § 98.33(a)(2)(iii). CO_2 emissions shall be calculated using the metered fuel usage, calculated Btu values, fuel composition and mass balance, and using equation C-5 of 40 CFR Part 98 Subpart C, converted to pounds CO_2.

g. Fuel for the waste heat boiler duct burners shall be limited to pipeline quality natural gas with 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) and 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 § 98.34(a)(6), and records shall be maintained of the semiannual fuel GCV for a period of five years. Upon request, Enterprise 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. Enterprise shall install and maintain an operational non-resettable flow meter for the waste heat boiler burner (HR15.103). The flow meters must be calibrated on an annual basis.

i. The flow rate of the fuel combusted in the waste heat boiler (WHB) burner (HR15.103) shall be measured and recorded using an operational totalizing fuel flow meter at each inlet.

j. Enterprise shall perform a visual inspection of the burners annually and conduct a physical inspection and cleaning of the burner tips approximately every three years during a unit turnaround or as needed to maintain good combustion practice.

k. The Waste Heater Boiler Duct burner (HR15.103) is limited to 5% of the overall heat input needs of the Waste Heat Boiler (BO10.101)

l. A BACT limit of 126.5 lb CO_2/MMBtu shall apply to operation of the waste heat boiler as determined in Section III.A.2.a of this permit.

m. Enterprise shall install, operate, and maintain an automated air/fuel control system.
n. Enterprise shall calibrate and perform preventative maintenance on the air/fuel control analyzers once per quarter, at a minimum.

6. Combustion Turbines (FINs: GT26.101A and GT26.101B; EPN: DW37.101)

a. The combustion turbines shall combust only 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) and 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 § 98.34(a)(6), and records shall be maintained of the semiannual fuel GCV for a period of five years. Upon request, Enterprise 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. The combustion turbines shall each meet an operational limit of 118.5 lb CO_2/MMBtu heat input during normal operations. Compliance with the operational limit shall be demonstrated for each turbine on a 12-month rolling average basis, calculated in accordance with 40 CFR Part 98 Subpart C, including 40 CFR § 98.33(a)(2)(i). CO_2 emissions shall be calculated using the metered fuel usage, calculated Btu values, fuel composition and mass balance, and using equation C-5 of 40 CFR Part 98 Subpart C, converted to pounds CO_2.
c. Enterprise shall calculate the CH_4 and N_2O emissions on a 12-month rolling total basis. Enterprise shall determine compliance with the CH_4 and N_2O emissions limits contained in this permit 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.
d. Enterprise shall calculate the CO_2e emissions on a 12-month rolling total 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 amended on November 29, 2013 (78 FR 71903).
e. During normal operations, the combustion turbines shall vent to the WHB (BO10.101) for heat recovery and out the common WHB stack (DW37.101).
f. Enterprise shall not divert the combustion turbine exhaust from the WHB except during times of start up of the plant. Bypass of the WHB of the heat recovery process will not occur during normal operational periods and is limited to 21 hours per year calculated on a 12-month rolling total basis.
g. During times of MSS, the combustion turbines shall each meet an BACT limit of 118.5 lb CO_2/MMBtu heat input.
h. Compliance with the MSS BACT limit shall be demonstrated for each turbine on a 12-month rolling average basis, calculated in accordance with 40 CFR Part 98 Subpart C, including 40 CFR § 98.33(a)(2)(i). CO_2 emissions shall be calculated using the metered

fuel usage, calculated Btu values, fuel composition and mass balance, and using equation C-5 of 40 CFR Part 98 Subpart C, converted to pounds CO_2.

i. During normal operation, a BACT limit of 126.5 lb CO_2/MMBtu shall apply to operation of the combustion turbines as determined in Section III.A.2.a of this permit.

j. Enterprise shall follow the preventive maintenance schedule provided by the compressor vendor and shall tune air flow in the turbines and clean the compressor burner tips on a schedule recommended by the vendor in order to maintain optimum efficiency.

7. Auxiliary Boilers (FIN/EPN: BO10.103A and BO10.103B)

a. Each boiler shall combust only pipeline quality natural gas, ethane and/or plant fuel gas.

b. The combined firing rate of the two boilers shall not exceed 248,500 MMBtu/yr, HHV, on a 12-month rolling average.

c. Each boiler is limited to 310 hours per year operation at full operational mode.

d. The maximum firing rate for the auxiliary boiler shall not exceed 420 MMBtu/hr.

e. Enterprise shall measure and record the fuel flow rate using an inline flow meter and automatically record the data with a data acquisition and handling system.

f. Enterprise shall calibrate and perform preventative maintenance check of the fuel gas flow meters and document annually.

g. Enterprise shall measure and record the composition of the fuel gas firing each boiler.

h. Enterprise shall perform cleaning of the burner tips annually, at a minimum.

i. Enterprise shall perform cleaning of the convection section tubes annually, at a minimum.

j. A rolling 12-month fuel usage record, including fuel composition, average hourly firing rate and the one-hour maximum firing rate, shall be calculated to demonstrate compliance with the conditions III.7. a., b., c., and d, above.

k. Enterprise shall install, operate and maintain an automated air/fuel control system.

l. Enterprise shall calibrate and perform preventative maintenance on the air/fuel control analyzers once per quarter, at a minimum.

m. Enterprise shall install, operate and maintain an O_2 analyzer on the boiler.

n. Oxygen analyzers shall continuously monitor and record oxygen concentration in the boiler. Enterprise shall reduce the oxygen readings to an averaging period of 6 minutes or less and record it at that frequency.

o. 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.

p. 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.

q. CO_2 emissions shall be calculated using the metered fuel usage, calculated Btu values, fuel composition and mass balance, and using equation C-5 of 40 CFR Part 98 Subpart C, converted to short tons CO_2.

r. Enterprise shall calculate the CH_4 and N_2O emissions on a 12-month rolling total basis. Enterprise shall determine compliance with the CH_4 and N_2O emissions limits contained in this permit 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.

s. Enterprise shall calculate the CO_2e emissions on a 12-month rolling total 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 amended on November 29, 2013 (78 FR 71903).

8. Flare (FIN/EPN: SK25.801 and SK25.801MSS)

a. The flare shall have a minimum destruction and removal efficiency (DRE) of 99% for methane based on flow rate and gas composition measurements as specified in 40 CFR Part 98 Subpart W, including 40 CFR § 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, including 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.

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.

9. **Fugitive Process Emissions (FIN/EPN:FUG-PDH and FUG-NGADS)**

a. Enterprise shall implement an auditory/visual/olfactory (AVO) monitoring program for detection of leaks in any line or component containing 10%, or greater, methane service. AVO monitoring shall be performed daily.
b. Enterprise shall comply with the Texas Commission Environmental Commission's Intensive Directed Maintenance – 28 LAER fugitive leak detection and repair requirements for any line or component in VOC service.
c. Any component found to be leaking during the directed leak detection and maintenance or AVO monitoring programs shall be repaired within 15 days.
d. Records of fugitive monitoring by the directed leak detection and maintenance or AVO monitoring programs must be maintained on site.

10. **Pump Engines (FIN/EPN: PM 18.803 and PM 18.850C)**

a. The engines shall be diesel fired. Fuel used in the engines will meet the requirements of 40 CFR § 80.510(b) regarding sulfur content (15 ppmw maximum) and a minimum Cetane Index of 40 or maximum aromatic content of 35% by volume.
b. The Permittee shall install a non-resettable hour meter prior to start-up of each engine.
c. The emergency firewater pump engine (PM18.803) shall be certified to meet the applicable emission standards of 40 CFR § 60.4205(c).
d. The raw water engine pump (PM18.580C) shall be certified to meet the applicable emission standards of 40 CFR § 60.4205(b).
e. Each engine may be operated for the purpose of maintenance checks and readiness testing for up to one hour for each week of the year for a total of 52 hours per year per engine.
f. The emission limit in Table 1 is based on each emergency generator engine operating 52 hours a year for maintenance and testing.
g. Compliance with the Annual Emission Limit shall be demonstrated on a 12-month rolling total calculated in accordance with 40 CFR Part 98 Subpart C § 98.33(a)(1)(i) converted to short tons.

IV. Recordkeeping and Reporting

A. Records

1. In order to demonstrate compliance with the GHG emission limits in Section II of this permit, Enterprise 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), and 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, including 40 C.F.R. § 98.34(b)(3).

2. Enterprise 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 and 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. Enterprise shall maintain records of all GHG emission units and CO_2 emission certification tests and monitoring and compliance information required by this permit.
4. Enterprise 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:

   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, i.e., 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. Enterprise 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 Reactor Charge Heater (HR15.101) and Waste Heat Boiler (DW37.101), the Auxiliary Boilers (BO10.103A and BO10.103B) and the Process Flare (SK25.801) 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. Enterprise 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 Reactor Charge Heater (HR15.101), the Regeneration Air Compressor Combustion Turbines (GT26.101 A and GT26.101B), Regeneration Air Heater (HR15.102), the reactor regeneration process, and Waste Heat Boiler (BO10.101) shall operate at representative production rates during emission testing on the Waste Heat Boiler stack (DW37.101).

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 EPA such records as may be necessary to determine the conditions of the performance tests.

F. The owner or operator must provide EPA at least 30 days prior notice of any performance test, except as specified under other subparts, to afford 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, 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. Agency Notifications

Enterprise 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

Enterprise 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