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-1398-GHG

PERMITTEE: Magellan Processing, L.P.
(Along with its affiliates)

FACILITY NAME: Condensate Splitter Plant
Corpus Christi Terminal

FACILITY LOCATION: 1802 Poth Ln
Corpus Christi, TX 78407

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 Magellan Processing, L.P. (along with its affiliates, "Magellan") for Greenhouse Gas (GHG) emissions. The permit applies to the construction of a new condensate splitter at their existing facility located in Corpus Christi, Nueces County, Texas.

Magellan is authorized to construct a new condensate splitter 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-1398. 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 CAA. This PSD permit does not relieve Magellan 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.

Bill Luthans
for Wren Stenger, Director
Multimedia Planning and Permitting Division

Dec. 4, 2014
Date

Magellan Processing, L.P. (along with its affiliates)
Prevention of Significant Deterioration Permit (PSD-TX-1398-GHG)
For Greenhouse Gas Emissions
Permit Conditions

PROJECT DESCRIPTION

Following the construction authorized by this permit, Magellan Processing, L.P. (along with its affiliates, "Magellan") will add a new 100,000 barrels per day (bbl/day) condensate splitter plant to their existing Corpus Christi Terminal in Corpus Christi, Nueces County, Texas. The existing Corpus Christi Terminal is a for-hire bulk petroleum storage terminal. Petroleum products and specialty chemicals are stored in various storage tanks and transferred in and out of the terminal tankage for external customers via pipeline, tank truck, railcar, and marine vessel. Magellan will construct the proposed condensate splitter plant in two phases. The proposed plant will have two trains each of which will process 50,000 bbl/day of hydrocarbon condensate material to obtain products suitable for commercial use including propane, butanes, light naphtha, heavy naphtha, kerosene, distillate, and resid (oil gas) product for sale to customers. The proposed plant will consist of a pre-fractionator column, a main fractionation column, heaters, a flare, vapor combustors, emergency engines, and 27 storage tanks.

EQUIPMENT LIST

The following devices are subject to this GHG PSD permit.

FIN	EPN	Description
H-1A H-2A	H-1A H-2A	Two fractionator heaters (Combustion Units). Each unit has a maximum firing rate of 128.9 MMBtu/hr and an annual average heat input rate of 117.2 MMBtu/hr and is fired with natural gas and fuel gas.
H-1B H-2B	H-1B H-2B	Two hot oil heaters (Combustion Units). Each unit has a maximum firing rate of 105.8 MMBtu/hr and an annual average input rate of 96.2 MMBtu/hr and is fired with natural gas and fuel gas.
H-4	H-4	One tank heater (Combustion Unit). The unit has a maximum and an annual average input rates of 16 MMBtu/hr and is fired with natural gas.
FL-1	FL-1	One flare (Combustion Unit). Used for control of routine, maintenance, startup and shutdown emissions and for emergency releases.
FWP1 FWP2	FWP1 FWP2	Two diesel-powered firewater pump engines (617 hp) for firewater pump. In addition to emergency fire suppression activities, each of the units is limited to 100 hours per 12-month rolling basis for maintenance and testing.
EMGEN1 EMGEN2	EMGEN1 EMGEN2	Two diesel-powered emergency generators (100 kW and 500 kW). In addition to emergency outages, each of the units is limited to 100 hours per 12-month rolling basis for maintenance and testing.
FUG-1	FUG-1	Process fugitives
MSSVCU	MSSVCU	One Maintenance, Startup and Shutdown vapor combustor (Combustion Unit)

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 VI.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 in writing or by electronic 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 Section 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-1398 (when issued) and all other applicable federal, state, and local air quality regulations. This PSD permit does not release the Permittee from any liability for compliance with other applicable federal, state and local environmental laws and regulations, including the Clean Air Act.

I. ACRONYMS AND ABBREVIATIONS

API	American Petroleum Institute
BACT	Best Available Control Technology
CAA	Clean Air Act
CC	Carbon Content
CCS	Carbon Capture and Sequestration
CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
CH_4	Methane
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
DIB	Deisobutanizer
dscf	Dry Standard Cubic Foot
EF	Emission Factor
EPN	Emission Point Number
FIN	Facility Identification Number
FR	Federal Register
GHG	Greenhouse Gas
gr	Grains
GWP	Global Warming Potential
HHV	High Heating Value
hr	Hour
LAER	Lowest Achievable Emission Rate
lb	Pound
LDAR	Leak Detection and Repair
MMBtu	Million British Thermal Units
MSS	Maintenance, Start-up and Shutdown
NNSR	Nonattainment New Source Review
N_2O	Nitrous Oxides
NSPS	New Source Performance Standards
PSD	Prevention of Significant Deterioration
QA/QC	Quality Assurance and/or Quality Control
SCFH	Standard Cubic Feet per Hour
SCR	Selective Catalytic Reduction
TAC	Texas Administrative Code
TCEQ	Texas Commission on Environmental Quality
TPY	Tons per Year
USC	United States Code
VCU	Vapor Combustion Unit
VOC	Volatile Organic Compound
VRU	Vapor Recovery Unit

II. ANNUAL EMISSION LIMITS

Table 1. Annual Emission Limits
Annual emissions, in tons per year (TPY) on a 365-day, rolling total, shall not exceed the following

FIN	EPN	Description	GHG Mass Basis		CO_2e[1,2] (TPY)	BACT Requirements
				TPY[1]		
H-1A	H-1A	Fractionator Heater - Train 1	CO_2	60,049	60,111	Minimum thermal efficiency of 85%. See permit condition III.B.1.o.
			CH_4	1.13		
			N_2O	0.11		
H-1B	H-1B	Hot Oil Heater - Train 1	CO_2	49,289	49,340	Minimum thermal efficiency of 85%. See permit condition III.B.1.o.
			CH_4	0.93		
			N_2O	0.09		
H-2A	H-2A	Fractionator Heater – Train 2	CO_2	60,049	60,111	Minimum thermal efficiency of 85%. See permit condition III.B.1.o.
			CH_4	1.13		
			N_2O	0.11		
H-2B	H-2B	Hot Oil Heater – Train 2	CO_2	49,289	49,340	Minimum thermal efficiency of 85%. See permit condition III.B.1.o.
			CH_4	0.93		
			N_2O	0.09		
H-4	H-4	Tank Heater	CO_2	4,099	4,103	Design thermal efficiency of 85%. Not to exceed 4,380 hours of equivalent full load operation on a 12-month rolling basis. See permit condition III.B.1.r
			CH_4	0.075		
			N_2O	No Numerical Limit Established[3]		
FL-1	FL-1	Flare	CO_2	576	577	Good combustion practices. See permit condition III.B.2.
			CH_4	0.02		
			N_2O	No Numerical Limit Established[3]		
FWP1 FWP2	FWP1 FWP2	Diesel-powered Fire Water Pumps	CO_2	64	64	Limit hours of non-emergency operation and good combustion practices. See permit condition III.B.5.
			CH_4	No Numerical Limit Established[3]		
			N_2O	No Numerical Limit Established[3]		
EMGEN 1 EMGEN 2	EMGEN1 EMGEN2	Diesel-powered Emergency Generators	CO_2	47	47	Limit hours of non-emergency operation and good combustion practices. See permit condition III.B.5.
			CH_4	No Numerical Limit Established[3]		
			N_2O	No Numerical Limit Established[3]		
MSSVC U	MSSVCU	MSS Vapor Combustion Unit	CO_2	2,645	2,648	Maintain a minimum combustion temperature. See permit condition III.B.4.
			CH_4	0.056		
			N_2O	No Numerical Limit Established[3]		

Table 1. Annual Emission Limits Annual emissions, in tons per year (TPY) on a 365-day, rolling total, shall not exceed the following						
FIN	EPN	Description	GHG Mass Basis		CO_2e[1,2] (TPY)	BACT Requirements
				TPY[1]		
FUG-1	FUG-1	Components Fugitive Leak Emissions	CH_4	No Numerical Limit Established[4]	No Numerical Limit Established[4]	See permit condition III.B.3.
Totals[5]			CO_2	**226,106**	**CO_2e 226,502[6]**	
			CH_4	**10.565**		
			N_2O	**0.426**		

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): CO_2=1, CH_4 = 25, N_2O = 298, SF_6=22,800
3. 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.
4. Fugitive process emission from FUG-1 are estimated to be 6.42 TPY of CH_4 and 160 TPYCO_2e.
5. The total emissions for CH4 and CO_2 e include the PTE for process fugitive emissions of CH4. The total emissions for CO_2e, also, include PTE emission of an existing tank heater (H-3). These totals are given for informational purpose only and do not constitute emission limits.
6. Two existing marine vessel loading vapor combustion units (EPNs: VCU1 and VCU2) and one existing tank heater (EPN: H-3) at the Corpus Christi Terminal will be used as part of the condensate splitter process but are not being physically modified themselves. They have a total estimated GHG emissions of 15,723 tpy CO_2e. As explained in the GHG Permitting Guidance, for the purposes of determining whether a PSD permits is required, the EPA requires a permitting authority to look beyond the emissions unit that is modified (across the entire source) to determine the extent of emission increases that result from the modification. However, the BACT applies only to the emission unit(s) that have been modified or added to the existing facility. See PSD and Title V permitting Guidance for Greenhouse Gases at 23. As a result, any additional GHG emissions from the condensate splitter process have been included in calculating the total tpy CO_2e to determine the PSD applicability. EPA will not, however, conduct a BACT analysis for the existing marine vessel loading vapor combustion units (VCU1 and VCU2) and tank heater (H-3) as part of this permit.

III. SPECIAL PERMIT CONDITIONS

A. Phased Construction

The proposed condensate splitter plant will consist of two trains each of which will process 50,000 bbl/day of hydrocarbon condensate material. Magellan is authorized to construct in two phases. Train 1 and Train 2 will be constructed in Phase 1 and Phase 2, respectively. Construction of the second 50,000 bbl/day train (Train 2) will commence within 18 months of the completion of the first 50,000 bbl/day train. The table below identifies under which phase of construction each emission point will be constructed.

Process Equipment Description	EPN	Construction Phase
Natural Gas Fired Fractionator Heater	H-1A	1
Natural Gas Fired Fractionator Heater	H-2A	2
Hot Oil Heater	H-1B	1
Hot Oil Heater	H-2B	2
Flare	FL-1	1
Tank Heater	H-3	Existing[1]
Tank Heater	H-4	1
Natural Gas Fugitives	FUG-1	1
Fire Water Pump Engine	FWP1	1
Fire Water Pump Engine	FWP2	1
Emergency Generator Engine	EMGEN1	1
Emergency Generator Engine	EMGEN2	1
Marine Vapor Combustor	VCU1	Existing[1]
Marine Vapor Combustor	VCU2	Existing[1]
MSS Vapor Combustor	MSSVCU	1

1. This emission unit is an existing non-modified unit. It is not subject to permit requirements since this unit will not be physically modified.

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

1. Fractionator Heaters, Hot Oil Heaters and Tank Heater (EPNs: H-1A, H-2A, H-1B, H-2B, and H-4)

a. Permittee shall calculate, on a daily basis, the amount of CO_2 emitted from combustion in tons/yr using equation C-5 in 40 CFR Part 98 Subpart C, converted to short tons. Compliance shall be based on a 365-day rolling total basis.

b. Permittee shall calculate the CH_4 and N_2O emissions on a 365-day rolling total basis. Permittee shall determine compliance with the CH_4 and N_2O emissions limits contained in this section using the default CH_4 and N_2O emission factors contained in Table C-2 and equation C-8 of 40 CFR Part 98 and the measured actual heat input (HHV), converted to short tons.

c. Permittee shall calculate the CO_2e emissions on a 365-day 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.
d. Fuel for the heaters shall be limited to pipeline quality natural gas and produced off gas. The fuel gross calorific value (GCV) [high heat value (HHV)] of the fuel shall be determined, at a minimum, semiannually 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, Permittee shall provide a sample and/or analysis of the fuel that is fired in the heaters or shall allow a sample to be taken by EPA for analysis.
e. The flow rate of the fuel combusted in natural gas-fired combustion emission units identified in this section shall be measured and recorded using an operational totalizing fuel flow meter at each inlet.
f. Permittee shall perform cleaning of the burner tips annually, at a minimum.
g. Permittee shall install, operate, and maintain an automated air/fuel control system.
h. Permittee shall calibrate and perform preventative maintenance on the air/fuel control analyzers once per quarter, at a minimum.
i. Permittee shall utilize insulation materials (e.g., ceramic fiber blankets and Kaolite$_{TM}$) where feasible to reduce heat loss.
j. Permittee shall install, operate, and maintain an O_2 analyzer on heaters H-1A, H-1B, H-2A, and H-2B.
k. Oxygen analyzers shall continuously monitor and record oxygen concentration in the heaters. It shall reduce the oxygen readings to an averaging period of 15 minutes or less and record it at that frequency.
l. 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.
m. The oxygen analyzers shall be quality-assured at least quarterly using cylinder gas audits (CGAs) in accordance with 40 CFR Part 60, Appendix F, Procedure 1, § 5.1.2.
n. The annual average firing rate of the fractionator heaters, hot oil heaters and tank heater shall not exceed 117.2 MMBtu/hr, 96.2 MMBtu/hr, and 16 MMBtu/hr, respectively. Compliance shall be based on a 365-day rolling average basis.
o. The Permittee shall maintain a minimum overall thermal efficiency of 85% on a 12-month rolling average basis, calculated monthly, for each fractionator heater and each oil heater (H-1A, H-2A, H-1B, and H-2B) excluding periods of start-up, shutdown, and malfunction.
p. The fractionator heaters and hot oil heaters (H-1A, H-2A, H-1B, and H-2B) will be continuously monitored for exhaust temperature, input fuel temperature, and stack oxygen. Thermal efficiency for emission units will be calculated for each operating hour from these parameters using equation G-1 from American Petroleum Institute (API) methods 560 (4th ed.) Annex G.
q. The heaters are not expected to have GHG emissions in excess of the allowed emission rates during periods of startup, shutdown, or maintenance. The fuel firing rates will be below the maximum rate, and startups will be limited to 12 hours per event.
r. The tank heater (H-4) shall not exceed 4,380 hours of equivalent full load operation on a 12-month rolling basis.

2. **Flare (EPN: FL-1)**

   a. The flare shall only combust pipeline natural gas in the pilots during normal operations.
   b. The flare shall be air assisted.
   c. Permittee shall install, operate, and maintain a flow rate and composition (total VOC or btu content) analyzer to monitor the waste gas combusted by the flare. The flow rate and composition analyzer shall continuously record the molecular weight and mass flow rate of the flare gas.
   d. The flare shall have a minimum destruction and removal efficiency (DRE) of 98 % for VOC and 99% for methane, based on flow rate and gas composition measurements.
   e. Permittee must record the inlet waste gas heat input (HHV) in MMBtu/hr during flare operation. The records must include hourly CH_4 emission levels as measured by the in-line gas analyzer (Gas chromatograph or equivalent with inlet gas flow rate) and the calculations based on the actual heat input for the CO_2, N_2O, and CH_4 emissions. These records must be kept for five years following the date of each event.
   f. 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. An infrared monitor is considered equivalent to a thermocouple for flame monitoring purposes.
   g. Permittee shall calculate the amount of CO_2 emissions 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.

3. **Process Fugitives (EPN: FUG-1)**

   - **Components Fugitive Leaks Work Practice and Operation Requirements:**

   a. The Permittee shall implement TCEQ 28 VHP LDAR program under the permit issued by TCEQ for non-GHG pollutants for fugitive emissions control for process lines in VOC service. The leak thresholds, repair requirements, and record keeping requirements shall be consistent with the TCEQ air permit requirements for VOC emissions.
   b. The Permittee shall implement an audio, visual, and olfactory (AVO) method for detecting leaks in natural gas piping components and fugitive emissions of methane for process lines not in VOC service but containing methane.
   c. The Permittee shall:
      i. Perform the AVO monitoring daily; and
      ii. Maintain a written log of daily inspection identifying the operating area inspected, fuel gas and natural gas equipment inspected (valves, lines, flanges, etc.), whether any leaks were identified by audible, visual or olfactory inspections and corrective actions/repairs taken.
   d. The Permittee shall take for the following action for identified leaks immediately upon detection of the leak:
      i. Tag the leaking equipment device; and

ii. Commence repair or replacement of the leaking component as soon as practicable, but no later than 30 days after detection. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging within 30 days of the detection of the leak. A listing of all components that qualify for delay of repair shall be maintained on a delay of repair list.

4. Maintenance, Startup and Shutdown Vapor Combustion Unit (EPN: MSSVCU)

a. The VCU shall have an initial stack test to verify the proper combustion chamber temperature to ensure a destruction and removal efficiency of at least 99.5%. During subsequent operations, if the waste process gas flow rate to the VCU is greater than that recorded during the test period, stack sampling shall be performed at the new operating conditions within 120 days.

b. For burner combustion, natural gas fuel usage (scf) is recorded using an operational totalizing flow meter at the MSSVCUs.

c. The flow rate of the VOC gas combusted shall be measured and recorded using an operational totalizing flow meter at the MSSVCU.

d. VOC flow to the MSSVCU resulting from MSS activities shall be calculated using the physical and chemical properties of the material being combusted. The data will be used to calculate GHG emissions to show compliance with the limits specified in Table 1.

e. Permittee shall calculate CO_2 emissions, on a monthly basis, using equation C-1 consistent with 40 CFR § 98.33(a)(1)(i).

f. Permittee shall perform periodic maintenance on the MSSVCU annually, at a minimum, or more often as recommended by the manufacturer specifications.

g. Permittee shall maintain the combustion temperature above 1400 °F or the most recent stack temperature in accordance with Special Condition 16 of the TCEQ NSR permit No. 56470. Temperature monitoring of the MSSVCU combustion chamber will ensure proper operation.

h. Permittee shall install and maintain a temperature recording device with an accuracy of the greater of ±0.75 percent of the temperature being measured expressed in degrees Celsius or ±2.5°C.

i. The MSSVCU combustion chamber temperature shall be continuously monitored and recorded when VOC gas is directed to the MSSVCU from MSS activities. The temperature measurement devices shall reduce the temperature readings to an averaging period of 15 minutes or less and record it at that frequency.

5. Diesel-Powered Firewater Pump Engines and Emergency Generators (EPNs: FWP1, FWP2, EMGEN1 and EMGEN2)

a. The firewater pump engines and emergency generators will utilize diesel as fuel.

b. Each of the firewater pump engine and emergency generator shall not exceed 100 hours of non-emergency operation on a 12-month rolling basis and shall be operated and maintained in accordance with the manufacturer's recommendations. Compliance with the 100 hour non-emergency operational requirement is determined on a 12 month rolling basis.

c. Permittee shall install and maintain an operational non-resettable elapse time meter for the firewater pump engines and emergency generators.
d. The engines and generators shall meet the applicable monitoring and recordkeeping requirements as required in 40 CFR Part 60, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.
e. Permittee shall maintain a file of all records, data measurements, reports and documents related to the operation of the firewater pump engines and emergency generators, including, but not limited to, the following: all records or reports pertaining to maintenance performed, all records relating to performance tests and monitoring of the firewater pump engines and emergency generators; fuel usage, and hours of operation required in Special Conditions III.B.5.a and III.B.5.b; 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.

6. Maintenance, Startup, and Shutdown (MSS) Activities (EPN: MSS)

a. Carbon Canisters and/or Scrubbers
   - Carbon canisters and/or scrubbers shall be utilized to control MSS emissions associated with vacuum trucks, frac tanks, and any other process equipment that is not connected to the flare or vapor combustion unit. All the recovered VOC emissions shall be displaced to the flare.

C. Continuous Emissions Monitoring Systems (CEMS)

1. As an alternative to Special Condition III.B.1.a. 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 to show compliance with the annual emission limit in Table 1.
2. If this alternative is adopted, Permittee shall ensure that all required CO_2 monitoring system/equipment are installed and all certification tests are completed on or before the earlier of 90 unit operating days or 180 calendar days after the date the unit commences operation.
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. Permittee shall meet the appropriate quality assurance requirements specified in 40 CFR Part 60, Appendix F for the CO_2 emission monitoring system.

IV. Recordkeeping and Reporting

1. In order to demonstrate compliance with the GHG emission limits in Table 1, Permittee will monitor the following parameters and summarize the data on a calendar month basis.
   a. Operating hours for all air emission sources;
   b. The natural gas 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

c. Annual fuel sampling for natural gas, and quarterly sampling of waste gas at a minimum.

2. Permittee shall maintain 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 maintenance performed on any system or device at the facility; 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 records must be retained for not less than five years following the date of such measurements, maintenance, reports, and/or records.
3. Permittee shall maintain records of all GHG emission units and CO_2 emission certification tests and monitoring and compliance information required by this permit.
4. Permittee shall maintain records and submit a written report of all excess emissions to EPA semi-annually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator or authorized representative, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. The report is due on the 30th day following the end of each semi-annual period and shall include the following:
   a. Time intervals, data and magnitude of the excess emissions, the nature and cause (if known), corrective actions taken and preventive measures adopted;
   b. Applicable time and date of each period during which the monitoring equipment was inoperative (monitoring down-time);
   c. A statement in the report of a negative declaration; that is; a statement when no excess emissions occurred or when the monitoring equipment has not been inoperative, repaired or adjusted; and
   d. Any failure to conduct any required source testing, monitoring, or other compliance activities.
5. Excess emissions shall be defined as any period in which the facility emissions exceed a maximum emission limit set forth in this permit.
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. All records required by this PSD permit shall be retained and remain accessible for not less than 5 years following the date of such measurements, maintenance, and reporting.

V. Initial Performance Testing Requirements:

A. Permittee shall perform an initial stack test to establish the actual quantities of air contaminants being emitted into the atmosphere from emission units (H-1A, H-1B, H-2A, H-2B, and H-4) and to determine the initial compliance with the CO_2 emission limits established in this permit. Sampling shall be conducted in accordance with 40 CFR § 60.8 and EPA Method 3a or 3b, in 40 CFR 60 Appendix B, for the concentration of CO_2 for the heaters.

1. For the Hot Oil, Fractionator and Tank Heaters calculate the CO_2 hourly average emission rate determined under maximum operating test conditions, convert to lbs of CO_2/MMBtu. Use the following equation to calculate the annual emissions.

$$CO_2\ TPY = 2 * (DV) * (8{,}760\ hr/yr) * (lb\ CO_2/MMBtu)$$

Where:

DV = Design annual average furnace firing rate (MMBtu/hr) upon which the emissions in Table 1 were based on.

lb CO_2/MMBtu = Calculated from VI.A.

B. Permittee shall conduct an evaluation of the thermal efficiency of the heaters (H-1A, H-1B, H-2A, and H-2B) to verify compliance with minimal thermal efficiency requirements at III.B.1.n when performing testing as stated in V.A. The results of the thermal efficiency evaluation shall be submitted to the EPA within 30 days of testing.

C. 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 EPA.

D. Permittee shall submit a performance test protocol to EPA no later than 30 days prior to the test to allow review of the test plan and to arrange for an observer to be present at the test. The performance test shall be conducted in accordance with the submitted protocol, and any changes required by EPA.

E. Performance testing must be conducted using flow rates that are comparable to the normal operating flow rates.

F. Fuel sampling for emission unit FL-1 (flare) shall be conducted in accordance with 40 CFR Part 98.

G. Flare compliance determinations shall be made following the requirements in 40 CFR § 65.147(b)(3)(i–iv).

H. The MSS vapor combustion unit will be stack tested in accordance with Special Condition 16 of the TCEQ NSR permit No. 56470. Stack testing will establish the minimum combustion chamber temperature for the VCU. Stack testing will be performed initially and within 120 days of a process flow change. Magellan will provide EPA with a copy of the stack testing results for review and approval.

I. 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.

J. 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.

K. 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.

L. 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 (i.e., 40 CFR § 60.8 and EPA Method 3a or 3b, in 40 CFR 60 Appendix B). For purposes of determining compliance with an applicable standard, the arithmetic mean of the results of the three runs shall apply. Emissions testing, as outlined above, shall be performed within 120 days of a process flow change, to verify continued performance at permitted emission limits.

VII. Agency Notifications

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

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

Permittee shall submit a copy of all 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