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-1306-GHG
PERMITTEE:	Corpus Christi Liquefaction, LLC 700 Milam Street, Suite 800 Houston, TX 77002
FACILITY NAME:	Corpus Christi Liquefaction, LLC LNG Terminal
FACILITY LOCATION:	2 La Quinta Road Gregory, TX 78359

Pursuant to the provisions of the Clean Air Act (CAA), Subchapter I, Part C (42 U.S.C. Section 7470, *et. Seq.*), and the Code of Federal Regulations (CFR) Title 40, Section 52.21, and the Federal Implementation Plan at 40 CFR § 52.2305 (effective May 1, 2011 and published at 76 FR 25178), the U.S. Environmental Protection Agency, Region 6 is issuing a *Prevention of Significant Deterioration* (PSD) permit to Corpus Christi Liquefaction, LLC (CCL) for Greenhouse Gas (GHG) emissions. The Permit for the LNG Terminal applies to the construction of a natural gas liquefaction and export plant and import facilities with regasification capabilities to be located in San Patricio and Nueces Counties, Texas.

CCL is authorized to construct a new liquefaction and export plant and import facilities with regasification capabilities 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-1306. 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 CCL 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.

________________________________ Wren Stenger, Director Multimedia Planning and Permitting Division	__________________ Date

Draft for February 27, 2014 public notice.

Corpus Christi Liquefaction, LLC (PSD-TX-1306-GHG)
Prevention of Significant Deterioration Permit
For Greenhouse Gas Emissions
Draft Permit Conditions

PROJECT DESCRIPTION

Corpus Christi Liquefaction (CCL) is proposing to construct and operate a natural gas liquifaction and export plant and import facilities with regasification capabilities (collectively referred to as the "Project" or the "LNG Terminal"). The LNG Terminal will be capable of processing an annual average of approximately 2.1 billion standard cubic feet per day (BSCFD) of pipeline quality natural gas in liquefaction mode and 0.4 BSCFD in vaporization mode. LNG will be imported or exported via LNG carriers that will arrive at the Project's marine terminal. The facility will have the capability to liquefy natural gas from the pipeline system for export as LNG, or to import LNG and regasify to send it out into the pipeline system.

The LNG terminal will operate three trains each using six gas-fired aeroderivative turbines – for a total of 18 turbines. More specifically, six gas-fired turbines will include two methane, two propane, and two ethylene refrigeration turbines per train. Each of the three trains in the liquefaction process is equipped with an Acid Gas Removal Unit (AGRU). After sulfur removal, the acid gas is controlled by a thermal oxidizer installed on each train. The LNG Terminal will also have four standby emergency generators, three firewater pumps, one marine flare, and two wet/dry gas flares. Each liquefaction train will also include the following equipment:

- Facilities which remove carbon dioxide (CO_2), hydrogen sulfide (H_2S), and sulfur compounds from the feed gas;
- Facilities to remove water and mercury from the feed gas;
- Facilities to remove heavy hydrocarbons (such as benzene, toluene, ethylbenzene, and xylene (BTEX)) from the feed gas to avoid freezing in the liquefaction unit;
- Six gas turbines each with water injection for emission control, and inlet air humidification systems that drive 14 refrigerant compressors;
- Waste heat recovery units for regenerating the gas driers and amine system;
- Induced draft air coolers;
- Miscellaneous storage vessels and tanks;
- Associated fire and gas safety systems;
- Associated control systems and electrical infrastructure;
- Utility connections and distribution systems;
- Soil improvements and paving; and
- Piping, pipe racks, foundation and structures within the LNG train battery limits.

The LNG Terminal will also be equipped with three full containment storage tanks. The tanks will be designed to store a nominal volume of 160,000 m^3 (1,006,400 barrels) of LNG at a temperature of -270 ^oF and a maximum internal pressure of 3.5 pounds per square inch gauge (psig).

EQUIPMENT LIST

The following devices are subject to this GHG PSD permit.

LNG Facility Equipment

FIN	EPN	Description
TRB1 TRB2 TRB3 TRB4 TRB5 TRB6 TRB7 TRB8 TRB9 TRB10 TRB11 TRB12 TRB13 TRB14 TRB15 TRB16 TRB17 TRB18	TRB1 TRB2 TRB3 TRB4 TRB5 TRB6 TRB7 TRB8 TRB9 TRB10 TRB11 TRB12 TRB13 TRB14 TRB15 TRB16 TRB17 TRB18	18 GE LM2500+ G4 aeroderivative gas turbines (Combustion Unit). The exhaust gases from the ethylene refrigeration turbines (TRB3, TRB4, TRB9, TRB10, TRB15, and TRB16) are sent to waste heat recovery units, each having its own flue gas stack.
TO-1 TO-2 TO-3	TO-1 TO-2 TO-3	3 Thermal Oxidizers (Combustion Units).
WTDYFLR1 WTDYFLR2	WTDYFLR1 WTDYFLR2	2 Wet/Dry Flares (Combustion Units).
MRNFLR	MNFLR	1 Marine Flare (Combustion Units).
GEN1 GEN2 GEN3 GEN4	GEN1 GEN2 GEN3 GEN4	4 Emergency Generators (Combustion Units). 2,220 horsepower (hp) each. Diesel Fired Emergency Generators are limited to 27 hours of operation per year for non-emergency activities for each unit.
FWPUMP1 FWPUMP2 FWPUMP3	FWPUMP1 FWPUMP2 FWPUMP3	3 Fire Water Pump Engines (Combustion Units). 422 horsepower (hp) each. Diesel Fired Fire Water Pumps are limited to 52 hours of operation per year for non-emergency activities for each unit.
FUG	FUG	Process Fugitives.

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.C.

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 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 Permits PSD-TX-1306 (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
BOG	Boil-off Gas
BSCFD	Billion Standard Cubic Feet per Day
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
CT	Combustion Turbine
DIB	Deisobutanizer
DLNB	Dry Low-NO_x Burner
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
LNG	Liquid Natural Gas
MMBtu	Million British Thermal Units
MSS	Maintenance, Start-up and Shutdown
mtpa	Million Tons per Annum
NNSR	Nonattainment New Source Review
N_2O	Nitrous Oxides
NO_x	Nitrogen 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
SF_6	Sulfur Hexafluoride
TAC	Texas Administrative Code
TCEQ	Texas Commission on Environmental Quality
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[2]		
TRB1 TRB2 TRB3 TRB4 TRB5 TRB6 TRB7 TRB8 TRB9 TRB10 TRB11 TRB12 TRB13 TRB14 TRB15 TRB16 TRB17 TRB18	TRB1 TRB2 TRB3 TRB4 TRB5 TRB6 TRB7 TRB8 TRB9 TRB10 TRB11 TRB12 TRB13 TRB14 TRB15 TRB16 TRB17 TRB18	Combustion Turbines	CO_2	146,601[4]	146,754[4]	8,041 lb CO_2e/MMscf of LNG produced for each turbine. See Special Conditions III.A.1.i.
			CH_4	2.8[4]		
			N_2O	0.28[4]		
TO-1	TO-1	Thermal Oxidizer 1	CO_2	196,438	196,458	57.8 tons CO_2/MMscf combusted. Good Combustion and Operating Practices. See Special Conditions III.A.2.
			CH_4	0.55		
			N_2O	0.02		
TO-2	TO-2	Thermal Oxidizer 2	CO_2	196,438	196,458	57.8 tons CO_2/MMscf combusted. Good Combustion and Operating Practices. See Special Conditions III.A.2.
			CH_4	0.55		
			N_2O	0.02		
TO-3	TO-3	Thermal Oxidizer 3	CO_2	196,438	196,458	57.8 tons CO_2/MMscf combusted. Good Combustion and Operating Practices. See Special Conditions III.A.2.
			CH_4	0.55		
			N_2O	0.02		
WTDYFLR1	WTDYFLR1	Wet/Dry Gas Flare 1	CO_2	66,670	71,303	Total gas flow rate limited to 340,734 lb/hr. Good Combustion Practices. See Special Condition III.A.3.
			CH_4	184		
			N_2O	0.11		
WTDYFLR2	WTDYFLR2	Wet/Dry Gas Flare 2	CO_2	66,670	71,303	Total gas flow rate limited to 340,734 lb/hr. Good Combustion Practices. See Special Condition III.A.3.
			CH_4	184		
			N_2O	0.11		

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
MRNFLR	MRNFLR	Marine Flare	CO_2	25,932	28,610	Good Combustion Practices. See Special Condition III.A.3.
			CH_4	107		
			N_2O	0.01		
GEN1	GEN1	Emergency Generator 1	CO_2	35	35	Limit operation to no more than 27 hours on a 12-month rolling basis. See Special Condition III.A.4.b.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		
GEN2	GEN2	Emergency Generator 2	CO_2	35	35	Limit operation to no more than 27 hours on a 12-month rolling basis. See Special Condition III.A.4.b.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		
GEN3	GEN3	Emergency Generator 3	CO_2	35	35	Limit operation to no more than 27 hours on a 12-month rolling basis. See Special Condition III.A.4.b.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		
GEN4	GEN4	Emergency Generator 4	CO_2	35	35	Limit operation to no more than 27 hours on a 12-month rolling basis. See Special Condition III.A.4.b.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		
FWPUMP1	FWPUMP1	Fire Water Pump 1	CO_2	13	13	Limit operation to no more than 52 hours on a 12-month rolling basis. See Special Condition III.A.4.c.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		
FWPUMP2	FWPUMP2	Fire Water Pump 2	CO_2	13	13	Limit operation to no more than 52 hours on a 12-month rolling basis. See Special Condition III.A.4.c.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
FWPUMP3	FWPUMP3	Fire Water Pump 3	CO_2	13	13	Limit operation to no more than 52 hours on a 12-month rolling basis. See Special Condition III.A.4.c.
			CH_4	No Emission Limit Established[5]		
			N_2O	No Emission Limit Established[5]		
BOG	BOG	BOG Compressor Venting (MSS)	CH_4	No Emission Limit Established[6]	No Emission Limit Established[6]	Good Operating Practices. See Special Condition III.A.5.
FUG	FUG	Fugitive Process Emissions	CO_2	No Emission Limit Established[7]	No Emission Limit Established[7]	Implementation of LDAR and AVO monitoring program. See Special Condition III.A.6.
			CH_4	No Emission Limit Established[7]		
Totals[8]			**CO_2**	**3,387,583**	**CO_2e 3,413,185**	
			CH_4	**960.8**		
			N_2O	**5.3**		

1. Compliance with the annual emission limits (tons per year) is based on a 12-month rolling total, to be updated the last day of the following month.
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.
3. Global Warming Potentials (GWP): CH_4 = 25, N_2O = 298
4. The values shown are for each turbine. The emissions for all 18 turbines combined are 2,638,818 TPY CO_2, 50 tpy CH_4, 5 tpy N_2O, and 2,641,580 tpy CO_2e.
5. All values indicated as "No Emission 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.
6. BOG compressor Venting from MSS activities released to the atmosphere are estimated to be 0.75 TPY of CH_4 and 19 TPY of CO_2e.
7. Fugitive process emissions from EPN FUG are estimated to be 433 TPY of CH_4, 0.22 TPY CO_2, and 10,825 TPY CO_2e. The emission limit will be a design/work practice standard as specified in the permit.
8. The total emissions for CH_4 and CO_2e include the PTE for process fugitive emissions of CH_4.

III. SPECIAL PERMIT CONDITIONS

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

1. Combustion Turbines (EPNs: TRB1, TRB2, TRB3, TRB4, TRB5, TRB6, TRB7, TRB8, TRB9, TRB10, TRB11, TRB12, TRB13, TRB14, TRB15, TRB16, TRB17, and TRB18)

a. The combustion turbines shall combust boil-off gas (BOG) and 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).

b. The combustion turbines for ethylene refrigeration (TRB3, TRB4, TRB9, TRB10, TRB15, and TRB16) shall each be equipped with a Waste Heat Recovery Unit (WHRU).

c. All fuel combustion units identified in this permit shall have fuel metering for each fuel, and Permittee shall:

   i. Measure and record the fuel flow rate using an operational non-resettable elapsed flow meter 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. Electronic data may be reduced to hourly averages for recordkeeping purposes.

   ii. Record the total fuel combusted for each fuel monthly.

   iii. The fuel gross calorific value (GCV) [high heat value (HHV)] of the fuel shall be determined, at a minimum, annually by the procedures contained in 40 CFR 98.34(a)(6) and records shall be maintained of the annual 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 turbines or shall allow a sample to be taken by EPA for analysis.

   iv. The fuel flow of the fuel fired in the combustion turbines (TRB1, TRB2, TRB3, TRB4, TRB5, TRB6, TRB7, TRB8, TRB9, TRB10, TRB11, TRB12, TRB13, TRB14, TRB15, TRB16, TRB17, and TRB18) shall be continuously monitored and recorded.

d. Permittee shall calibrate and perform preventative maintenance check of the fuel flow meters and document annually.

e. Permittee shall install and operate pressure and vibration monitoring equipment on the combustion turbine packages.

f. The combustion turbines shall be equipped with a control package that monitors the air/fuel ratio in the combustion primary zone.

g. All analyzers identified in this section III.A.1. shall achieve 95% on-stream time or greater.
h. Each combustion turbine shall meet a BACT limit of 8,041 lbs of CO_2e/MMscf of LNG produced, on a 12-month rolling average basis.
i. Permittee shall calculate, on a monthly basis, the amount of CO_2 emitted from combustion in tons/yr using equation C-2a 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.
j. Permittee shall calculate the CH_4 and N_2O emissions on a 12-month rolling basis to be updated by the last day of the following month. Permittee shall determine compliance with the CH_4 and N_2O emissions limits contained in this section using the default CH_4 and N_2O emission factors contained in Table C-2 and equation C-9a of 40 CFR Part 98 and the measured actual heat input (HHV), converted to short tons.
k. Permittee shall calculate the CO_2e emissions on a 12-month rolling basis, based on the procedures and Global Warming Potentials (GWP) contained in Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1, as published on November 29, 2013 (78 FR 71904). The record shall be updated by the last day of the following month.

2. Thermal Oxidizers (EPNs: TO-1, TO-2, and TO-3)

a. Each of the three natural gas liquefaction trains is equipped with a thermal oxidizer (TO1, TO2, and TO3). GHG emissions from the thermal oxidizers result from fuel gas combustion (pipeline quality natural gas or boil-off gas (BOG)) and waste gas combustion (waste gas from acid gas removal units).
b. Each thermal oxidizer is designed to combust low-VOC concentration waste gas from the amine units and has a fuel rating of 23.08 MMBtu/hr when firing natural gas.
c. Each thermal oxidizer shall have an initial stack test, and annual compliance testing, to verify destruction and removal efficiency (DRE) for methane of 99.9%.
d. Each train is equipped with an Acid Gas Removal Unit (AGRU). The waste gas from each AGRU shall be routed to a thermal oxidizer for combustion.
e. For burner combustion, natural gas and BOG fuel usage (scf) shall be recorded using an operational non-resettable elapsed flow meter at each thermal oxidizer.
f. The flow rate of the waste gas combusted shall be measured and recorded using an operational non-resettable elapsed flow meter at each thermal oxidizer.
g. Waste gas will be sampled and analyzed on a quarterly basis for composition. The sampled data will be used to calculate GHG emissions to show compliance with the limits specified in Table 1.
h. Permitee shall calculate CO_2 emissions, on a monthly basis, using equation W-3 consistent with 40 CFR Part 98, Subpart W [98.233(d)(2)].

i. The Permittee shall maintain a BACT limit of 57.8 tons of CO_2/MMscf burned in each thermal oxidizer.
j. Periodic maintenance will help maintain the destruction efficiency of the thermal oxidizer and shall be performed at a minimum annually or more often as recommended by the manufacturer specifications.
k. The thermal oxidizers shall be stack tested annually.
l. The thermal oxidizers' exhaust temperature shall be continuously monitored and recorded when waste gas is directed to the oxidizers. The temperature measurement devices shall reduce the temperature readings to an averaging period of 6 minutes or less and record it at that frequency.
m. The Permittee shall maintain the combustion temperature at a minimum of 1,400 ºF at all times when abating waste gases from the AGRU in the thermal oxidizer. Temperature monitoring of the thermal oxidizer will ensure proper operation. The 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 ±2.5ºC.
n. Oxygen analyzers shall continuously monitor and record oxygen concentration when waste gas is directed to the thermal oxidizers. It 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) of the stack O_2 analyzer 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.

3. Flares (EPNs: WTDYFLR1, WTDYFLR2, and MRNFLR)

a. Flares shall have a minimum destruction and removal efficiency (DRE) of 99% for methane based on flowrate and gas composition measurements as specified in 40 CFR § 98.233(n).
b. Emission Units (WTDYFLR1, WTDYFLR2, and MRNFLR) shall only combust natural gas as a continuous stream for the flare pilot.
c. The wet/dry flares (WTDYFLR1 and WTDYFLR2) are used to control MSS emissions and will have pilot gas emissions 8,760 hours per year.
d. The total hourly gas flow rate to the wet/dry flares (WTDYFLR1 and WTDYFLR2) shall not exceed 341,667 lb/hr and the annual gas flow rate shall not exceed 48,714,426 lbs/yr.
e. The marine flare (MRNFLR) will be used to control ship loading emissions and may operate 8,760 hrs/yr. The flare shall operate no more than 240 hours per year in gas conditioning operations.

f. Permittee must record the time, date, fuel heat input (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.
g. Permittee must record the fuel 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 volumetric stack gas flowrate) 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.
h. Each flare shall be designed and operated in accordance with 40 CFR 60.18 (except during purging of inert gases from LNG carriers) 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.

4. Emergency Generators (EPNs: GEN1, GEN2, GEN3, and GEN4) and Fire Water Pump Generators (EPNs: FWPUMP1, FWPUMP2, and FWPUMP3)

a. The Diesel Fired Emergency Generators (GEN1, GEN2, GEN3, and GEN4) and Diesel Fired Fire Water Pumps (FWPUMP1, FWPUMP2, and FWPUMP3) are authorized to fire diesel fuel containing no more than 0.5 percent sulfur by weight. Upon request, Permittee shall provide a sample and/or an analysis of the fuel-fired in the emission units (GEN1, GEN2, GEN3, GEN4, FWPUMP1, FWPUMP2, and FWPUMP3) or shall allow a sample to be taken by EPA for analysis to demonstrate the percent sulfur of the fuel.
b. The Diesel Fired Emergency Generators are limited to 27 hours of non-emergency operation per year for each unit.
c. The Diesel Fired Fire Water Pump Generators are limited to 52 hours of non-emergency operation per year for each unit.
d. The Diesel Fired Emergency Generators and Diesel Fired Fire Water Pump Generators shall meet the 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 install and maintain an operational non-resettable elapsed time meter for the Diesel Fired Emergency Generators and Diesel Fired Fire Water Pumps.
f. Permittee shall maintain a file of all records, data measurements, reports and documents related to the operation of the Diesel Fired Emergency Generators and Diesel Fired Fire Water Pumps, 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 emergency generator and fire pump equipment; for each diesel fuel oil delivery, documents from the fuel supplier certifying compliance with the fuel sulfur content limit of Special Condition III.A.4.a., hours of operation; 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.

5. BOG Compressor Venting – MSS (BOG)

a. MSS emissions shall be minimized through the implementation of good operational practices.
b. Records of each MSS activity that results in direct venting of emissions to the atmosphere shall be maintained to include the date, time, and duration of each MSS event.

6. Process Fugitives (FUG)

a. The Permittee shall implement the TCEQ 28LAER leak detection and repair (LDAR) program for fugitive emissions of methane for process lines in VOC service (> 10% VOC).
b. The Permittee shall implement the TCEQ 28M leak detection and repair (LDAR) program for fugitive emissions of methane for process lines in methane service (>10% methane).
c. The Permittee shall implement an audio/visual/olfactory (AVO) monitoring program to monitor for leaks in between instrument monitoring required by III.A.5.a. and b.
d. Permittee shall maintain a file of all records, data measurements, reports and documents related to the fugitive emission sources including, but not limited to, the following: all records or reports pertaining to maintenance performed, all records relating to compliance with the Monitoring and Quality Assurance and Quality Control (QA/QC) procedures outlined in 40 CFR 98.304.

B. Continuous Emissions Monitoring Systems (CEMS)

1. As an alternative to Special Conditions III.A.1.l. and III.A.2.h. 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. 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.

IV. 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. The natural gas fuel usage and BOG 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
    c. Annual fuel sampling for natural gas and BOG.

2. Permittee shall implement the TCEQ 28M leak detection and repair (LDAR) program and keep records of the monitoring results, as well as the repair and maintenance records.
3. 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 significant 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.
4. Permittee shall maintain records of all GHG emission units and CO_2 emission certification tests and monitoring and compliance information required by this permit.
5. Permittee shall maintain records and submit a written report of all excess emissions to EPA semi-annually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator or authorized representative, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. The report is due on the 30^{th} day following the end of each semi-annual period and shall include the following:

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

6. Excess emissions shall be defined as any period in which the facility emissions exceed a maximum emission limit set forth in this permit.
7. 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.
8. 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. The holder of this permit shall perform an initial stack test to establish the actual quantities of air contaminants being emitted into the atmosphere from emission units TRB1, TRB2, TRB3, TRB4, TRB5, TRB6, TRB7, TRB8, TRB9, TRB10, TRB11, TRB12, TRB13, TRB14, TRB15, TRB16, TRB17, TRB18, TO-1, TO-2, and TO-3 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 A, for the concentration of CO_2.

1. For each Combustion Turbine, calculate the CO_2 hourly average emission rate determined under maximum operating test conditions, then convert to lb/MMBtu. Use the following equation to calculate the annual emissions.

$$CO_2\,TPY = 286.3\,\frac{MMBtu}{hr} \times 8{,}760\,\frac{hrs}{yr} \times lb\,\frac{CO_2}{MMBtu} \div 2000\,\frac{lb}{ton}$$

Where:

286.3 MMBtu/hr = the annual average firing rate for each combustion turbine upon which the emissions in Table 1 were based.

2. For the Thermal Oxidizer, calculate the CO_2 hourly average emission rate determined under maximum operating test conditions, then convert to lb/scf of acid gas flow. Use the following equation to calculate the annual emissions.

$$CO_2\ TPY = 424{,}092\frac{scf}{hr} \times 8{,}760\frac{hr}{year} \times lb\frac{CO_2}{scf} \div 2{,}000\frac{lb}{ton}$$

Where:

424,092 scf/hr = the waste gas plus pilot gas flow rate to the thermal oxidizers

3. If the above calculated CO_2 emission totals do not exceed the tons per year (TPY) limits specified on Table 1, no compliance strategy needs to be developed.
4. If any of the above calculated CO_2 emission totals exceed the tons per year (TPY) limits specified in Table 1, the facility shall;
   a. Document the predicted 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. During subsequent operations if current Combustion Turbine firing rates exceed the rates during stack testing by 10 percent or greater, stack sampling shall be performed within 120 days. During subsequent operations, if current acid gas flow rate to the RTO exceeds the rates during stack testing by 10 percent or greater, additional sampling may be required by TCEQ or EPA.

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

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

E. Fuel sampling of waste gases for emission unit TO-1, TO-2, and TO-3 shall be conducted in accordance with 40 CFR Part 98.

F. The Permittee shall perform initial performance demonstration testing of the thermal oxidizers (TO) at the site. The TO shall operate at the maximum production rate during stack emissions testing. The Permittee shall measure CH_4 concentrations in the thermal oxidizer inlet and exhaust streams to demonstrate a minimum destruction efficiency of 99.9% by weight at a minimum combustion chamber temperature of 1,400 °F.

G. The Permittee shall record the TO combustion chamber temperature and TO combustion chamber set-point temperature during the performance test. These and any additional operational parameters shall be identified in the test protocol and recorded during testing.

H. For the TO the sampling site and velocity traverse point shall be selected in accordance with EPA Test Method 1or 1A. The gas volumetric flow rate shall be measured in accordance with EPA Test Method 2, 2A, 2C, 2D, 2F, 2G, or 19. The dry molecular weight shall be determined in accordance with EPA Test Method 3, 3A or 3B. The stack gas moisture shall be determined in accordance with EPA Test Method 4. These methods must be performed, as applicable, during each test run.

I. Performance tests must be conducted under such conditions to ensure representative performance of the affected facility. The Permittee must make available to the EPA such records as may be necessary to determine the conditions of the performance tests.

J. The Permittee 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 Permittee 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. Emissions testing, as outlined above, shall be performed every three years, or more frequently if identified above, to verify continued performance at permitted emission limits.

VI. Agency Notifications

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

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