**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-1340-GHG
PERMITTEE:	Natgasoline, LLC
FACILITY NAME:	Natgasoline Gas to Gasoline Plant
MAILING ADDRESS:	P.O. Box 1647 Nederland, TX 77627
FACILITY LOCATION:	Hwy 380 Access Rd & Sulphur Plant Rd Intersection Beaumont, TX 77705

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 Natgasoline LLC (Natgasoline) for Greenhouse Gas (GHG) emissions. The Permit applies to the construction of a new methanol production plant and a motor-grade gasoline production using natural gas as a feedstock in a gas-to-gasoline (GtG) production facility in Beaumont, Texas.

Natgasoline is authorized to construct a new GtG facility 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-1340. 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 Natgasoline 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

Natgasoline, LLC (PSD-TX-1340-GHG)
Prevention of Significant Deterioration Permit
for Greenhouse Gas Emissions
Permit Conditions

PROJECT DESCRIPTION

Pursuant to the provisions of this permit, Natgasoline proposes to construct a new motor-grade gasoline (GtG) facility that will use natural gas as feedstock in Beaumont, Texas. The proposed new facility includes two main process units. The Methanol (MeOH) Unit has a design capacity of 2,478,560 tpy (5,500 metric tons per day) of methanol from natural gas feedstock, and Methanol-to-Gasoline (MtG) Unit has a design capacity of 8,030,000 barrels per year (20,000 barrels per day) of gasoline. The methanol produced in the MeOH Unit is converted into gasoline in the MtG Unit or sold as methanol product.

The proposed GtG facility will include two main process plant operations. The first process is the methanol plant (MeOH), which uses the combined reforming process to synthesize the natural gas (pipeline) feed. The natural gas is pretreated to remove sulfur compounds and mixed with steam and recycled process gas before entering the reformers. The reforming section consists of a gas-fired steam reformer and an auto-thermal reformer (ATR). The reformer feed is heated in catalyst filled tubes in the radiant section of the steam reformer to form a mixture of carbon monoxide (CO), carbon dioxide (CO_2) and hydrogen (H_2) known as synthesis gas (syngas). Steam is produced in the convection section of the steam reformer. The ATR reformer completes the processing of natural gas to syngas using pure oxygen from an air separation unit (ASU). Heat recovery systems convert excess heat generated by the steam reformer and ATR into useful energy for steam generation and process heating.

Syngas is then compressed and sent to the methanol reactors that convert syngas to crude methanol and a water condensate product. The crude methanol from the distillation section is sent to a three-column distillation train. Overhead gases from the first column are routed to the fuel gas system, and remaining liquids are fed to the second column. The bottoms from the second column are fed to the third column for additional methanol purification. The process water stream from the bottom of the third column is recycled to the saturation system. The overhead gases from the second and third columns are condensed into intermediate methanol product, which is sent to intermediate methanol storage.

The water condensate and gases from the distillation process are recycled to be used in various sections of the methanol plant. The final methanol product is sent to storage and can either be sold or used as feed in the methanol-to-gasoline (MtG) plant.

The MtG Unit converts methanol feedstock into motor vehicle gasoline and a liquefied petroleum gas (LPG) mixture. MtG Unit feedstock may include methanol from the MeOH Unit and methanol purchased from off-site manufacturers. The methanol feedstock is converted into gasoline and

LPG in a series of five MtG reactors configured in parallel. The five MtG reactors are supported by five gas-fired MtG reactor heaters to supply heat of reaction. One gas-fired MtG regeneration heater generates heat to periodically combust carbonaceous deposits that accumulate on the reactor catalyst during operation, and the gas from these periodic catalyst regeneration processes vent to atmosphere The reactor effluent is sent to separation where it is separated into three streams: 1) an LPG stream to be sent to pressurized LPG storage, 2) a "light" gasoline stream to be sent to gasoline blending and storage, and 3) a "heavy" gasoline stream to be routed to the MtG Heavy Gasoline Treatment (HGT) Unit for further processing into more valuable hydrocarbons. The MtG HGT Unit includes one reactor supported by one gas-fired HGT heater to supply heat of reaction. The HGT reactor converts some of the "heavy" gasoline feed into converted "heavy" gasoline for mixing with the "light" gasoline to produce the blended gasoline product. Some of the HGT reactor feed is converted into LPG that is sent to pressurized LPG storage.

Steam required for operating the MeOH MtG Units is supplied by heat recovery systems in the MeOH Unit and also by the gas-fired auxiliary boiler. These process units are also supported by a cooling tower. Associated with the project is an ASU that will supply oxygen, nitrogen and instrument air. The ASU will receive steam from the plant and does not emit any GHGs. A common plant flare controls emissions from compressor seals and in cases of upset or emergency and planned MSS activities. MSS emissions that cannot be routed to flare are emitted to atmosphere. A back-up diesel-fired emergency generator is used for back-up power. Two diesel-fired firewater pumps are used if emergency fire water is needed. Piping components from the process equipment described above are also a source of GHG emissions as well as a gas-fired Vapor Combustion Unit that controls emissions from loading product gasoline into rail cars or trucks.

EQUIPMENT LIST

The following devices are subject to this GHG PSD permit.

FIN	EPN	Description
B-01001	B-01001	Reformer (Combustion Unit), 1,552 Million British Thermal Units per Hour (MMBtu/hr). Used to reform natural gas. The reformer will be equipped with a Selective Catalytic Reduction (SCR) system for Oxides of Nitrogen (NOx) control.
B-14001	B-14001	Auxiliary Boiler (Combustion Unit), 950 MMBtu/hr. Used to produce steam. The auxiliary boiler will be equipped with a SCR system for NOx control.
H-REGEN	H-REGEN	Regeneration Heater, 45 MMBtu/hr. Used to regenerate methanol catalyst.
H-RX1 H-RX2 H-RX3 H-RX4 H-RX5	H-RX1 H-RX2 H-RX3 H-RX4 H-RX5	Five Reactor Heaters, 25 MMBtu/hr per heater. Used to supply heat to the reaction at each methanol-to-gasoline reactor.
H-HGT	H-HGT	Heavy Gasoline Heater Treater, 8.0 MMBtu/hr. Used to supply heat to the Heavy Gasoline Treatment feed.

FIN	EPN	Description
S-10001	S-10001	MeOH Flare (Combustion Unit). Used for pilot & normal operations in the methanol production unit.
S-10001(MSS)	F-10001	MeOH Flare (Combustion Unit). Used for MSS venting in the methanol production unit.
VCU-1	VCU-1	Vapor Combustor Unit (Combustion Unit). Used for control on product loading operations.
FUG-MEOH	FUG-MEOH	MeOH Fugitives, process fugitives in the methanol production unit.
FUG-MTG	FUG-MTG	MtG Fugitives, process fugitives in the gasoline production unit.
V-CATREGEN	V-CATREGE	Catalyst Regeneration Vent. Used only during reactor catalyst regeneration events.
H-EMG	H-EMG	Emergency Generator (Combustion Unit). The generator shall be no larger than 2,000 kilo-watt (kW).
H-FWP-1 H-FWP-2	H-FWP-1 H-FWP-2	Two Firewater Pump Engines (Combustion Unit). The engine shall be no larger than 1,000 kW.
T-06001	T-06001	MeOH Cooling Tower. Used to support cooling water needs of methanol and gasoline production units.

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 United States Environmental Protection Agency (US 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 MSS, 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 EPA, which may include, but is not limited to, monitoring results, review of operating and 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 30 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, 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 CAA.

I. ACRONYMS AND ABBREVIATIONS

%	Percent
ATR	Auto-thermal Reformer
AVO	Auditory, Visual, and Olfactory
EPN	Emission Point Number
BACT	Best Available Control Technology
CAA	Clean Air Act
CEMS	Continuous Emissions Monitoring System
CGAs	Cylinder Gas Audits
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
ft^3	Cubic Feet
GCV	Gross Calorific Value
GHG	Greenhouse Gas
gr	Grains
GtG	Gas-to-Gasoline
GWP	Global Warming Potential
HAP	Hazardous Air Pollutant
HHV	High Heating Value
hr	Hour
HRSG	Heat Recovery Steam Generating
kW	Kilo-watt

lb	Pound
LDAR	Leak Detection and Repair
LPG	Liquefied Petroleum Gas
MeOH	Methanol
MtG	Methanol-to-Gasoline
MMBtu/hr	Million British Thermal Units per Hour
MSS	Maintenance, Start-up, and Shutdown
NSR	New Source Review
NNSR	Nonattainment New Source Review
N_2O	Nitrous Oxide
NOx	Oxides of Nitrogen
NSPS	New Source Performance Standards
O_2	Oxygen
PSD	Prevention of Significant Deterioration
PTE	Potential to Emit
RATA	Relative Accuracy Test Audit
QA/QC	Quality Assurance and/or Quality Control
SCFH	Standard Cubic Feet per Hour
SC	Special Condition
SCR	Selective Catalytic Reduction
TAC	Texas Administrative Code
TCEQ	Texas Commission on Environmental Quality
TOC	Total Organic Carbon
TPY	Tons per Year (Short Tons)
USC	United States Code
US EPA	United States Environmental Protection Agency
VOCs	Volatile Organic Compounds

II. Annual Emission Limits

Annual emissions, in TPY on a 12-month rolling basis, shall not exceed the following:

Table 1. Annual Emission Limits [1]

EPN	FIN	Description	GHG Mass Basis		TPY CO_2e [2,3]	BACT Requirements
			Pollutant	TPY [2]		
B-01001	B-01001	Reformer	CO_2	718,867	719,576	Minimum 90 (%) Thermal Efficiency, Maximum 3% oxygen (O_2) in stack gas (normal operation), Maximum 350°F in stack gas (normal operation). See permit condition III.A.1
			CH_4	12.94		
			N_2O	1.29		
B-14001	B-14001	Auxiliary Boiler	CO_2	357,225	357,594	Minimum 77% Thermal Efficiency. See permit condition III.A.2
			CH_4	6.74		
			N_2O	0.67		
H-REGEN	H-REGEN	Regeneration Heater	CO_2	12,733	12,746	Maximum Firing Rate of 45 MMBtu/hr, Gaseous Fuel, Good Combustion Practices. See permit condition III.A.3
			CH_4	0.24		
			N_2O	0.02		
H-RX1 H-RX2 H-RX3 H-RX4 H-RX5	H-RX1 H-RX2 H-RX3 H-RX4 H-RX5	MtG Reactor Heaters	CO_2	52,874[4]	52,929[4]	Maximum Firing Rate of 25 MMBtu/hr, Gaseous Fuel, Good Combustion Practices. See permit condition III.A.3
			CH_4	1.00[4]		
			N_2O	0.10[4]		
H-HGT	H-HGT	MtG Heavy Gasoline Heater Treater	CO_2	3,844	3,850	Maximum Firing Rate of 8 MMBtu/hr, Gaseous Fuel, Good Combustion Practices. See permit condition III.A.3
			CH_4	0.07		
			N_2O	0.01		
S-10001	S-10001	Flare Pilot & Normal Operation	CO_2	2,571	2,735	Good Design and Combustion Practices, Minimize Flaring events. See permit condition III.A.4
			CH_4	6.54		
			N_2O	<0.01		
S-10001 (MSS)	F-10001	Flare MSS Vents	CO_2	16,203	16,497	Good Operational Practices. See permit condition III.A.5
			CH_4	11.43		
			N_2O	0.03		
VCU-1	VCU-1	MtG VCU	CO_2	1,061	1,062	Maintain minimum combustion temperature as determined by testing. Good Combustion Practices. See permit condition III.A.6
			CH_4	0.02		
			N_2O	<0.01		
FUG-MEOH	FUG-MEOH	MeOH Fugitives	CH_4	No Numerical limit is established[5]		Implementation of Leak Detection and Repair (LDAR) Program. See permit condition III.A.7
FUG-MTG	FUG-MTG	MtG Fugitives	CH_4	No Numerical limit is established[5]		Implementation of LDAR Program. See permit condition III.A.7
V-CATREGEN	V-CATREGEN	Catalyst Regeneration Vent	CO_2	5,446	5,446	Proper Operating Techniques. See permit condition III.A.8
H-EMG	H-EMG	Emergency Generator	CO_2	139	140	Proper Operating Techniques Limited Operating Hours. See permit condition III.A.9
			CH_4	0.01		
			N_2O	<0.01		

EPN	FIN	Description	GHG Mass Basis		TPY CO_2e [2,3]	BACT Requirements
			Pollutant	TPY [2]		
H-FWP1 H-FWP2	H-FWP1 H-FWP2	Firewater Pump Engines	CO_2	139	140	Proper Operating Techniques, Limited Operating Hours. See permit condition III.A.9
			CH_4	0.01		
			N_2O	<0.01		
T-06001	T-06001	Cooling Tower	CO_2	-	866	Implementation of Heat Exchanger Leak Monitoring and Repair Program. See permit condition III.A.10
			CH_4	34.65		
			N_2O	-		
Totals [6]			CO_2	1,171,102	1,174,027	
			CH_4	91.49		
			N_2O	2.12		

1. Compliance with the annual emission limits (TPY) is based on a 12-month rolling basis.
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, including MSS activities.
3. Global Warming Potentials (GWP): Methane (CH_4) = 25, Nitrous Oxide (N_2O) = 298
4. The emissions shown for the reactor heaters (H-RX1, H-RX2, H-RX3, H-RX4, and H-RX5) is an emissions cap for all five heaters combined.
5. Fugitive process emissions from EPN FUG-MEOH are estimated to be 10.91 TPY of CH_4 and 273 TPY CO_2e. emissions cap for all five heaters combined. Fugitive process emissions from EPN FUG-MTG are estimated to be 6.93 TPY of CH_4 and 173 TPY CO_2e. In lieu of an emission limit, the emissions will be limited by implementing an LDAR monitoring program.
6. The total emissions for CH_4 and Carbon dioxide equivalent (CO_2e) include the Potential to Emit (PTE) for process fugitive emissions of CH_4. These 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. Reformer (EPN: B-01001)

a. The reformer furnace shall combust pipeline quality natural gas and/or plant produced high hydrogen fuel gas (process fuel gas).

b. The reformer furnace 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. Analyze process gas composition in accordance with 40 CFR § 98.34(b)(3)(ii)(E).

   iv. The fuel gross calorific value (GCV), high heat value (HHV), carbon content and, if applicable, molecular weight, shall be determined, at a minimum, monthly by the procedures contained in 40 CFR § 98.34(b)(3). Records of the fuel GCV shall be maintained for a minimum period of five years. Upon request, Permittee shall provide a sample and/or analysis of the fuel that is fired in any unit covered by this permit at the time of the request, or shall allow a sample to be taken by EPA for analysis.

   v. Pipeline quality natural gas shall be exempt from section III.A.1.b.iii. of this permit provided Permittee receives and maintains quarterly records of the vendor's analysis, and the data is of sufficient quality to yield further analysis as required above.

c. Permittee shall calibrate and perform preventative maintenance checks of the fuel flow meters and document at the minimum frequency established per the manufacturer's recommendation, or at the interval specified per 40 CFR § 98.34(b)(1)(ii).

d. Permittee shall install, operate, and maintain an O_2 analyzer on the furnace flue gas in the stack of the furnace.

e. The O_2 analyzer shall continuously monitor and record the excess O_2 concentration in the combustion gases. The monitoring data shall be reduced to hourly average concentrations at least once every day using a minimum of four equally spaced data points over each one-hour period.

f. Permittee shall perform preventative maintenance check of the O_2 analyzer and document quarterly.

g. 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.

h. The O_2 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.

i. Permittee will validate the O_2 analyzer with zero and span gas at least weekly to maintain 1% accuracy based on full scale.

j. Excess oxygen shall be controlled to less than 3% when the operating load is 75% or greater to ensure efficiency on a 12-month rolling average basis.
k. All analyzers identified in this section III.A.1. shall achieve 95% on-stream time or greater when the reformer is operational.
l. Permittee shall utilize insulation materials where feasible to reduce heat loss.
m. The reformer furnace shall not exceed the one-hour maximum firing rate of 1,552 MMBtu/hr.
n. The one-hour maximum firing rates shall be determined daily to demonstrate compliance with the firing rate condition in III.A.1.m.
o. Permittee shall continuously monitor and record the furnace gas exhaust temperature hourly and limit the temperature to less than or equal to 350 ^{o}F on a 12-month rolling average basis. This stack temperature is for normal operations and does not include commissioning, startup, and shutdown.
p. Permittee shall maintain a minimum overall thermal efficiency of 90% LHV on a 12-month rolling average basis, calculated monthly, for the furnace (B-01001) excluding periods of MSS.
q. The reformer furnace will be continuously monitored for exhaust temperature, input fuel temperature, and stack oxygen. Thermal efficiency for the furnace will be calculated monthly from these parameters on a LHV basis using equation G-1 from American Petroleum Institute methods 560 (4^{th} ed.) Annex G.
r. The furnace shall be tuned annually consisting of a flame pattern inspection and adjustment for CO_2 concentration.
s. Permittee shall calculate, on a monthly basis, the amount of CO_2 emitted from combustion of process gas in tons/yr using equation C-5 in 40 CFR Part 98 Subpart C, converted to short tons. CO_2 emitted from the combustion of natural gas in tons/yr shall be calculated 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.
t. 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-8 (for process gas) and C-9a (for natural gas) of 40 CFR § 98.33 and the measured HHV (for process gas), converted to short tons.
u. Permittee shall calculate the CO_2e emissions on a 12-month rolling basis, based on the procedures and GWP contained in Greenhouse Gas (GHG) Regulations, 40 CFR Part 98, Subpart A, Table A-1. The record shall be updated by the last day of the following month.

2. Auxiliary Boiler (EPN: B-14001)

a. The boiler shall combust pipeline quality natural gas and/or plant produced high hydrogen fuel gas (process gas).
b. The boiler 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. Analyze process gas composition in accordance with 40 CFR § 98.34(b)(3)(ii)(E).
iv. The fuel gross calorific value GCV (HHV), 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 GCV shall be maintained for a minimum period of five years. Upon request, Permittee shall provide a sample and/or analysis of the fuel that is fired in any unit covered by this permit at the time of the request, or shall allow a sample to be taken by EPA for analysis.
v. Pipeline quality natural gas shall be exempt from section III.A.2.b.iii. of this permit provided Permittee receives and maintains quarterly records of the vendor's analysis, and the data is of sufficient quality to yield further analysis as required above.

c. Permittee shall calibrate and perform preventative maintenance checks of the fuel flow meters and document at least annually.
d. Permittee shall install, operate, and maintain an O_2 analyzer on the boiler.
e. The O_2 analyzer shall continuously monitor and record O_2 concentration in the boiler and shall record the O_2 readings to an averaging period of 15 minutes. The required zero and span calibrations will take place weekly.
f. The O_2 analyzer 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).
g. Permittee shall perform a preventative maintenance check or O_2 control analyzers and document quarterly.
h. The maximum firing rate for the boiler shall not exceed 950 MMBtu/hr.
i. Permittee shall maintain a minimum overall thermal efficiency of 77% on a 12-month rolling average basis, calculated monthly using equation G-1 from American Petroleum Institute (API) methods 560 (4^{th} ed.) Annex G, or an equivalent method approved by EPA.
j. Permittee shall calculate, on a monthly basis, the amount of CO_2 emitted from combustion of process gas in tons/yr using equation C-5 in 40 CFR § 98.33, converted to short tons. CO_2 emitted from the combustion of natural gas in tons/yr shall be calculated using equation C-2a in 40 CFR § 98.33, 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.
k. 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-8 (for process gas) and C-9a (for natural gas) of 40 CFR § 98.33 and the measured HHV (for process gas), converted to short tons.

l. Permittee shall calculate the CO_2e emissions on a 12-month rolling basis, based on the procedures and GWP contained in GHG Regulations, 40 CFR Part 98, Subpart A, Table A-1. The record shall be updated by the last day of the following month.

m. Perform boiler inspection every 5 years per manufacturer's recommendations.

3. Heaters (EPNs: H-RX1 through H-RX5, H-REGEN, and H-HGT)

a. The firing rate of heaters H-RX1 through H-RX5 shall not each exceed 25 MMBtu/hr. The firing rate of the regeneration heater (H-REGEN) shall not exceed 45 MMBtu/hr. The firing rate of the heavy gasoline heater treater (H-HGT) shall not exceed 8 MMBtu/hr. The heaters shall combust pipeline quality natural gas and/or plant produced high hydrogen fuel gas (process fuel gas).

b. The heaters 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. Analyze process gas composition in accordance with 40 CFR § 98.34(b)(3)(ii)(E).

   iv. The fuel gross calorific value GCV (HHV), 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 GCV shall be maintained for a minimum period of five years. Upon request, Permittee shall provide a sample and/or analysis of the fuel that is fired in any unit covered by this permit at the time of the request, or shall allow a sample to be taken by EPA for analysis.

   v. Pipeline quality natural gas shall be exempt from section III.A.3.b.iii. of this permit provided Permittee receives and maintains quarterly records of the vendor's analysis, and the data is of sufficient quality to yield further analysis as required above.

c. Permittee shall calibrate and perform preventative maintenance checks of the fuel flow meters and document at the minimum frequency established per the manufacturer's recommendation, or at the interval specified per 40 CFR § 98.34(b)(1)(ii).

d. Permittee shall install, operate, and maintain an automated air/fuel control system to maintain optimal combustion efficiency.

e. Permittee shall calibrate and perform preventative maintenance on the air/fuel control system at least once per quarter, at minimum.

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

g. Permittee shall perform burner clean-up every five years or each unit turnaround (whichever is less) to remove any buildup and maintain heat transfer efficiency. Records shall be kept onsite for a period of five years.
h. The actual firing rate for the heaters shall be calculated to demonstrate compliance with the rate in III.A.3.a.
i. Permittee shall calculate, on a monthly basis, the amount of CO_2 emitted from combustion of process gas in tons/yr using equation C-5 in 40 CFR § 98.33, converted to short tons. CO_2 emitted from the combustion of natural gas in tons/yr shall be calculated using equation C-2a in 40 CFR § 98.33, 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-8 (for process gas) and C-9a (for natural gas) of 40 CFR § 98.33 and the measured HHV (for process gas), converted to short tons.
k. Permittee shall calculate the CO_2e emissions on a 12-month rolling basis, based on the procedures GWP contained in GHG Regulations, 40 CFR Part 98, Subpart A, Table A-1. The record shall be updated by the last day of the following month.

4. MeOH Flare (EPN: S-10001)

a. The flare shall have a minimum destruction and methane removal efficiency (DRE) of 99% (98% for VOC) based on flow rate and gas composition measurements as specified in 40 CFR § 98.253(b).
b. Emissions including CH_4 from compressor seals shall be vented to the flare during normal operations.
c. The flare shall only combust pipeline natural gas as pilot fuel. The only emissions authorized from the flare are from combustion of natural gas, compressor seal gas, and waste gases from MSS activities.
d. Permittee shall record the time, date, and duration of emissions event and each MSS event as described in condition III.A.5.a. These records must be kept for five years following the date of each event.
e. The flare shall be equipped with a flare gas flow meter and a temperature monitor. The flow measurement device and temperature monitor shall be calibrated, at a minimum, on a biannual basis.
f. CO_2 emissions shall be calculated using equation Y-1a or Y-1b in 40 CFR § 98.253(b)(1)(ii)(A). CH_4 and N_2O emissions shall be calculated using equations Y-4 and Y-5 in 40 CFR § 98.253. As an alternative to the carbon content monitored required in § 98.253(b)(1)(ii)(A), carbon content determined by engineering estimates, as allowed in paragraph (iii)(A) may be used with equation Y-3.
g. 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.

5. Maintenance, Startup, and Shutdown (EPN: S-10001 MSS)

a. Permittee shall depressure sections of pipe and equipment to the flare or other parts of the process prior to performing MSS activities.
b. MSS emissions that cannot be controlled by the flare are vented to the atmosphere.
c. Start-up emissions shall be vented to the flare for no more than 160 hours/yr. No more than 91,693 ft^3 of waste gas from equipment clearing shall be routed to the flare each year.
d. Permittee will plan maintenance activities in a manner to minimize the venting of emissions to the atmosphere.
e. Records of MSS activities shall be maintained to include the date, time, and estimated volume of each MSS event.

6. Vapor Combustor Unit (EPN: VCU-1)

a. The Vapor Combustor Unit (VCU) shall serve as a control device for gasoline product loading operations. GHG emissions from the VCU result from fuel gas combustion (pipeline quality natural gas or process fuel gas) and VOC containing gas combustion (gas from the loading operations).
b. The VCU 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. Analyze process gas composition in accordance with 40 CFR §98.34(b)(3)(ii)(E).
    iv. The fuel gross GCV (HHV), 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 GCV shall be maintained for a minimum period of five years. Upon request, Permittee shall provide a sample and/or analysis of the fuel that is fired in any unit covered by this permit at the time of the request, or shall allow a sample to be taken by EPA for analysis.
    v. Pipeline quality natural gas shall be exempt from section III.A.6.b.iii. of this permit provided Permittee receives and maintains quarterly records of the vendor's analysis, and the data is of sufficient quality to yield further analysis as required above.
c. Permittee shall calibrate and perform preventative maintenance checks of the fuel flow meters and document at least annually.
d. The VCU can remain in hot standby with only the pilot combusting fuel.

e. Natural gas or process fuel gas will be used as supplemental fuel, if needed, to maintain combustion temperature for controlling gaseous vent streams.
f. The VCU shall have an initial stack test to verify the proper combustion chamber temperature to ensure a destruction and removal efficiency (DRE) of at least 99% for CH_4 or VOC. During subsequent operations, if the waste gas flow rate to the vapor combustor is greater than that recorded during the test period, stack sampling shall be performed at the new operating conditions within 120 days.
g. VOC emissions resulting from loading activities shall be calculated using the physical and chemical properties of the material being loaded. The data will be used to calculate GHG emissions to show compliance with the limits specified in Table 1.
h. A rolling 12-month average and the one-hour maximum firing rates shall be calculated monthly to demonstrate compliance with the limits specified in Table 1.
i. Periodic maintenance will help maintain the efficiency of the VCU and shall be performed as recommended by the manufacturer specifications.
j. Permittee shall maintain the combustion temperature above the one hour average temperature maintained in the initial stack test, as required by special condition (SC) number (No.) 15 of the Texas Commission on Environmental Quality (TCEQ) New Source Review (NSR) Permit No. 107764 and PSD TX Permit No 1340. Prior to the stack test, the minimum combustion chamber temperature will be 1,400 ^oF. Temperature monitoring of the VCU combustion chamber will ensure proper operation.
k. 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.
l. The VCU combustion chamber temperature shall be continuously monitored and recorded when a vent stream is directed to the VCU. The temperature measurement devices shall reduce the temperature readings to an averaging period of 15 minutes or less and record it at that frequency.
m. The Permittee shall perform burner tune-ups at least annually.
n. Permittee shall calculate, on a monthly basis, the amount of CO_2 emitted from combustion of process gas in TPY using equation C-5 in 40 CFR § 98.33, converted to short tons. CO_2 emitted from the combustion of natural gas in tons/yr shall be calculated using equation C-2a in 40 CFR § 98.33, converted to short tons. Compliance shall be based on a 12-month rolling basis to be updated by the last day of the following month.
o. Permittee shall calculate the CH_4 and N_2O emissions on a 12-month rolling basis to be updated by the last day of the following month. Permittee shall determine compliance with the CH_4 and N_2O emissions limits contained in this section using the default CH_4 and N_2O emission factors contained in Table C-2 and equation C-8 (for process gas) and C-9a (for natural gas) of 40 CFR § 98.33 and the measured HHV (for process gas), converted to short tons.
p. Permittee shall calculate the CO_2e emissions on a 12-month rolling basis, based on the procedures and GWP contained in GHG Regulations, 40 CFR Part 98, Subpart A, Table A-1. The record shall be updated by the last day of the following month.

7. Process Fugitives (EPNs: FUG-MEOH, FUG-MTG)

a. Permittee shall implement the TCEQ 28VHP LDAR program for fugitive emissions of CH_4.

b. Permittee shall implement an as-observed Auditory, Visual, and Olfactory (AVO) program to monitor for fugitive emissions between instrumented monitoring as required in III.A.7.a above.

c. Permittee shall use high quality components and materials of construction that are compatible with the service in which they are employed.

8. V-Catalyst Regeneration Vent (EPNs: V-CATREGEN)

a. The MtG reactor catalyst will be regenerated by removing carbon deposits periodically, when the methanol-to-gasoline conversion efficiency becomes unacceptable for continued process operations as determined by standard operating procedures.

b. Total operating hours devoted to reactor catalyst regeneration venting shall not exceed 1,681 hours per rolling 12-month period. Permittee shall maintain monthly records of the operating hours devoted to catalyst regeneration venting.

c. Permittee shall maintain records necessary to demonstrate compliance with the emission limit on a 12-month rolling average.

d. On or after initial startup Permittee shall not discharge or cause the discharge of emissions from catalyst regeneration in excess of 5,446 tons of CO_2e emissions/year.

9. Emergency Generator (EPN: H-EMG) and Firewater Pump Engines (EPN: H-FWP-1, H-FWP-2)

a. The generator engines purchased will be certified to meet the applicable emission standards of 40 CFR § 60.4205(b).

b. The engine may be operated for the purpose of maintenance checks and readiness testing for up to 100 hours per year on a 365-day rolling total.

c. Permittee shall install a non-resettable hour meter prior to start-up of the engine.

d. Permittee shall implement good combustion practices, including preventative maintenance per manufacturer's recommendations.

e. Permittee shall maintain records of engine maintenance/tune-ups, as well as run times.

f. On or after initial startup, Permittee shall not discharge or cause the discharge of emissions in excess of 280 tons CO_2e/year total from non-emergency use of all three engines, based on a 12-month rolling total.

g. Permittee shall demonstrate compliance with the 12-month rolling total emission limit by using the calculations at 40 CFR Part 98, Subpart C.

10. Cooling Tower (EPN: T-06001)

a. The Permittee shall implement a leak detection program for the cooling tower consistent with 40 CFR Part 63 Subpart F. Total Organic Carbon (TOC) will be substituted for HAP to determine if a GHG leak is present. TOC will be measured utilizing Method 5310 from *Standard Methods for the Examination of Water and*

Wastewater. It will be assumed that any hydrocarbon detected utilizing this method will be CH_4.

b. Leak detection monitoring shall occur monthly for the first 6 months of operation, then on a quarterly basis thereafter pursuant to 40 CFR § 63.104(b).

c. The Permittee shall maintain records of cooling tower monitoring and corrective actions taken consistent with 40 CFR § 63.104(f).

B. Continuous Emissions Monitoring Systems (CEMS)

1. As an alternative to Special Conditions III.A.1.s. through III.A.1.u. , 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 and 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.
4. The 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

A. Records

1. In order to demonstrate compliance with the GHG emission limits in Table 1, the Permittee will monitor the following parameters and summarize the data on a calendar month basis.
   a. Operating hours for all air emission sources;
   b. 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); records of the fuel consumed by each source (except H-EMG, H-FWP-1&2 and flare pilot gas); and
   c. Semi-annual fuel sampling for natural gas, daily fuel sampling of plant fuel gas, or other frequencies as allowed by 40 CFR § 98.34(b)(3).
2. Permittee shall maintain a file of all records, data, measurements, reports, and documents related to the operation of the facility, including, but not limited to, the following: all records or reports pertaining to significant maintenance performed on any system or device at the facility; duration of startup and shutdown; the initial startup period for the emission units; pollution control units; malfunctions; all records relating to performance tests, calibrations, checks, and monitoring of combustion equipment; duration of an inoperative monitoring device and emission units with the required corresponding emission data; and all other information required by this permit recorded in a permanent form suitable for

inspection. The file must be retained for not less than five years following the date of such measurements, maintenance, reports, and/or records.

3. Permittee shall maintain records and submit a written report of all excess emissions to EPA semi-annually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator or authorized representative, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. The report is due on the 30^{th} day following the end of each semi-annual period and shall include the following:
    a. Time intervals, data and magnitude of the excess emissions, the nature and cause (if known), corrective actions taken and preventive measures adopted;
    b. Applicable time and date of each period during which the monitoring equipment was inoperative (monitoring down-time);
    c. A statement in the report of a negative declaration; that is; a statement when no excess emissions occurred or when the monitoring equipment has not been inoperative, repaired or adjusted;
    d. Any failure to conduct any required source testing, monitoring, or other compliance activities; and
    e. Any violation of limitations on operation.
4. Excess emissions shall be defined as any period in which the facility emissions exceed a maximum emission limit set forth in this permit, or a malfunction occurs causing an emissions expedience.
5. Excess emissions indicated by GHG emission performance testing or compliance monitoring shall be considered violations of the applicable emission limit for the purpose of this permit.
6. Instruments and monitoring systems required by this PSD permit shall have a 95% on-stream time on an annual basis.
7. All records required by this PSD permit shall be retained for not less than five years following the date of such measurements, maintenance, and reporting.
8. Continuously means individual measurement no less frequent than once every 15 minutes. Electronic data may be reduced to hourly averages for recordkeeping purposes.

V. Initial Performance Testing Requirements:

A. The Permittee shall perform stack sampling and other testing to establish the actual pattern and quantities of air contaminants being emitted into the atmosphere from the stack of the following:

- Reformer (B-01001) Initial and every five years.
- Auxiliary Boiler (B-14001) Initial and every three years.
- Regeneration Heater (H-REGEN) Initial and every five years.
- Five Reactor Heaters (H-RXH 1-5) Initial and every five years.
- Heavy Gasoline Heater Treater (H-HGT) Initial and every five years.
- Vapor Combustor Unit (VCU-1) Initial and every five years.

Permittee is 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 potential to exceed in the test report; and
    b. Explain within the report how the facility will assure compliance with the CO_2 emission limit listed in Table 1.

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

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 tests must be conducted under such conditions to ensure representative performance of the affected facility for all units. The owner or operator must make available to the EPA such records as may be necessary to determine the conditions of the performance tests. Boiler test must be conducted under maximum production rates. Heaters tests must be conducted under maximum firing rates.

E. 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.

F. 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.

G. 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.

H. Emissions testing, as outlined above, shall be performed every five years, plus or minus 6 months, after the previous performance test is 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

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