Statement of Basis
Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit
for KM Liquids Terminals LLC, Galena Park Terminal

Permit Number: PSD-TX-101199-GHG

March 2013

This document serves as the Statement of Basis (SOB) for the above-referenced draft permit, as required by 40 CFR 124.7. This document sets forth the legal and factual basis for the draft permit conditions and provides references to the statutory or regulatory provisions, including provisions under 40 CFR 52.21, that would apply if the permit is finalized. This document is intended for use by all parties interested in the permit.

I. Executive Summary

On March 23, 2012, KM Liquids Terminals LLC (KMLT) Galena Park Terminal submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions from a proposed modification at an existing stationary source. In connection with the same proposed modification project, KMLT submitted Non-attainment New Source Review (NNSR) and minor New Source Review permit applications for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on February 23, 2012. The project at the Galena Park Terminal proposes to construct a new 100,000 barrels per day (bbl/day) condensate splitter plant at the existing KMLT Galena Park Terminal, to be constructed in two 50,000 bbl/day phases. The condensate splitter plant will consist of a stabilization column, a main fractionation column, heaters, a flare, and storage tanks. The process will take hydrocarbon condensate material and process it to obtain products suitable for commercial use, which includes Y-grade liquids, light naphtha, heavy naphtha, kerosene product, and distillate product for sale to customers. After reviewing the application, EPA Region 6 has prepared the following Statement of Basis (SOB) and draft air permit to authorize modification and construction of air emission sources at the KM Liquids Terminals, Galena Park Terminal.

This SOB documents the information and analysis EPA used to support the decisions EPA made in drafting the air permit. It includes a description of the proposed facility, the applicable air permit requirements, and an analysis showing how the applicant complied with the requirements.

EPA Region 6 concludes that KM Liquids Terminal’s application is complete and provides the necessary information to demonstrate that the proposed project meets the applicable air permit regulations. EPA's conclusions rely upon information provided in the permit application, supplemental information requested by EPA and provided by KMLT, and EPA's own technical analysis. EPA is making all this information available as part of the public record.

II. Applicant

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III. Permitting Authority

On May 3, 2011, EPA published a federal implementation plan that makes EPA Region 6 the PSD permitting authority for the pollutant GHGs. 75 FR 25178 (promulgating 40 CFR § 52.2305).

The GHG PSD Permitting Authority for the State of Texas is:

EPA, Region 6
1445 Ross Avenue
Dallas, TX 75202

The EPA, Region 6 Permit Writer is:
Aimee Wilson
Air Permitting Section (6PD-R)
(214) 665-7596

The Non-GHG PSD Permitting Authority for the State of Texas is:

Air Permits Division (MC-163)
TCEQ
P.O. Box 13087
Austin, TX 78711-3087

IV. Facility Location

The KM Liquids Terminals, Galena Park Terminal is located in Harris County, Texas, and this area is currently designated "nonattainment" for Ozone. The nearest Class 1 area is the Big Bend National Park, which is located well over 100 miles from the site. The geographic coordinates for this facility are as follows:

Latitude: 29º 44' 10" North
Longitude: -95º 13' 07" West

Below, Figure 1 illustrates the facility location for this draft permit.

Figure 1. KM Liquids Terminals, Galena Park Terminal Location

V. Applicability of Prevention of Significant Deterioration (PSD) Regulations

EPA concludes KM Liquids Terminal's application is subject to PSD review for the pollutant GHGs, because the project would lead to an emissions increase of GHGs for a facility as described at 40 CFR § 52.21(b)(49)(v). Under the project, GHG emissions are calculated to increase over zero tpy on a mass basis and to exceed the applicability threshold of 75,000 tpy CO_2e (KMLT calculates CO_2e emissions of 243,545 tpy) at an existing stationary source that emits or has the potential to emit 100,000 tpy CO_2e. EPA Region 6 implements a GHG PSD FIP for Texas under the provisions of 40 CFR § 52.21 (except paragraph (a)(1)). See 40 CFR § 52.2305.

KMLT represents that TCEQ, the permitting authority for regulated NSR pollutants other than GHGs, will issue a minor NSR permit that will limit the emissions of all other pollutants to beneath the significant emission rates found at 40 CFR 52.21(b)(23). These limits must be in place prior to construction under the GHG PSD permit, if it is issued. At this time, TCEQ has not issued the minor NSR permit for the non-GHG pollutants.

EPA Region 6 applies the policies and practices reflected in the EPA document entitled "PSD and Title V Permitting Guidance for Greenhouse Gases" (March 2011). Consistent with that guidance, we have not required the applicant to model or conduct ambient monitoring for GHGs, and we have not required any assessment of impacts of GHGs in the context of the additional impacts analysis or Class I area provisions. Instead, EPA has determined that compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs. The applicant has submitted an analysis to meet the requirements of 40 CFR § 52.21(o), as it may otherwise apply to the project.

VI. Project Description

The proposed GHG PSD permit, if finalized, will allow KM Liquids Terminals (KMLT) to construct a new 100,000 barrels per day (bbl/day) condensate splitter plant at the existing KMLT Galena Park Terminal located in Galena Park, Texas. The Galena Park 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. The existing facility consists of various storage tanks and associated piping, loading, and control equipment. The condensate splitter plant will be constructed in two 50,000 bbl/day phases. The condensate splitter plant will consist of two process trains and will include a stabilization column, a main fractionation column, heaters, flare, and storage tanks. The process will take hydrocarbon condensate material and process it to obtain products suitable for commercial use, which include Y-grade liquids, light naphtha, heavy naphtha, kerosene product, and distillate product for sale to customers.

Stabilization Column

The hydrocarbon condensate is fed from storage tanks to the stabilizer column where the lightest fraction of the condensate is distilled from the overhead at a pressure which will typically permit complete condensation of the overhead product. Any uncondensed off-gas that may be produced intermittently (up to 1% of the total fuel usage) will be used for fuel gas in the heaters. Water present in the feed will be distilled in the stabilizer and produced from the overhead receiver water boot. The overhead liquid product (Y-Grade Liquid) from the stabilizer column will be stored in pressurized storage for transfer to the truck loading rack. The feed to this stabilizer column is preheated with waste heat recovered from hot product streams (from hot oil heaters and the fractionation column) to reduce the amount of fuel fired as heat input required for distillation. The remaining reboiler heat required to achieve the desired separation is provided by circulating hot oil provided by the hot oil heater. The circulating hot oil is heated in a gas fueled direct fired heater. The bottoms stream from the stabilizer column is pressurized through a preheat exchanger that is heated by circulating hot oil into the main fractionation column.

Main Fractionation Column

The main fractionation column splits the bottoms from the stabilizer column into five commercially acceptable streams (Combi Tower Off-Gas, Light Naphtha, Heavy Naphtha, Kerosene, and Distillate Product). Two of these streams are taken off as sidedraws (Heavy Naphtha and Kerosene Product) and fed to the top of individual stripping columns. Lighter material is stripped from the product draw in each of the side columns by introducing heat to the bottom of each stripper column with a reboiler exchanger heated by circulating hot oil. The stripped sidedraw vapors are returned to the main fractionation column from the overhead of each stripper column and the stripped sidedraw products (Heavy Naphtha and Kerosene Product) are used to preheat the feed to the process before final cooling and transfer to storage.

In addition to the sidedraw products, a bottoms product (Distillate Product) and overhead products (Combi Tower Off-Gas and Light Naphtha) are produced from the main fractionation column. These products represent the heaviest fraction and the lightest fractions of the stabilized condensate, respectively. Lighter material is removed from the bottoms product using natural gas for stripping. The overhead condensing system will be operated at the lowest practical pressure to minimize temperatures and improve separation. Both a liquid distillate product (Light Naphtha) and a non-condensable gas stream (Combi Tower Off-Gas) saturated with heavier components will be produced from the overhead vapor along with column reflux. The off-gas will be compressed and cooled to make it suitable for use as a fuel gas and for recovery of light naphtha.

Flare

An elevated flare is provided for use in emergency overpressure situations and during planned maintenance, startup, and shutdown activities to dispose of excess process vapors. This flare utilizes a continuous pilot to ensure that unexpected release events result in safe disposal. The pilot is fueled with natural gas.

Emergency Generator

A standby natural gas fired emergency power generator is also provided to maintain critical electrical services during a power outage and minimize emergency flare loads.

Product Transfer and Loading

The existing docks will be utilized to transfer products offsite. A new tank truck rack for the Y-Grade product loading will be constructed for product transfer. The tank truck loading rack will only have fugitive GHG emissions.

Fugitives

Fugitive emissions of GHG pollutants, including CO_2 and methane, may result from piping equipment leaks. The piping components that may leak include valves, flanges, pump seals, etc. KMLT will implement the TCEQ 28LAER Leak Detection and Repair (LDAR) program for the entire Galena Park Terminal site.

Phased Construction

KMLT proposes to construct the proposed condensate splitter in two phases. The condensate splitter will consist of two process trains (Train 1 and Train 2). Each train will process 50,000 bbl/day of hydrocarbon condensate material. 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. Train 1 will be constructed in Phase 1 and Train 2 will be constructed in Phase 2.

Process Equipment	Included in Construction Phase
F-101 Hot Oil Heater Train 1	1
F-201 Hot Oil Heater Train 2	2

Process Equipment	Included in Construction Phase
FL-101 Flare	1
FUG Fugitives	1 and 2
Tank Truck Loading/Unloading Rack	1 and 2
MSS Maintenance, Startup, and Shutdown	1 and 2
Modification of Marine Vessel Loading VCUs	1

VII. General Format of the BACT Analysis

The BACT analyses for this draft permit is consistent with the statutory requirements of CAA sections 165 (a)(4) and 169(3) and 40 CFR sections 52.21 (b)(12) and 52.21 (j). The analyses are also consistent with recommendations found in EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011), which outlines the steps for conducting a "top-down" BACT analysis. Those steps are listed below.

(1) Identify all potentially available control options;
(2) Eliminate technically infeasible control options;
(3) Rank remaining control technologies;
(4) Evaluate the most effective controls and document the results; and
(5) Select BACT.

VIII. Applicable Emission Units and BACT Discussion

The majority of the contribution of GHGs associated with the project is from combustion sources (i.e., heaters and flare). The site has some fugitive emissions from piping components which contribute a minor amount of GHGs, estimated at 164 tpy of the total project CO_2e emissions of the total CO2e project emission of 243,545 tpy. Stationary combustion sources primarily emit CO_2, and small amounts of N_2O and CH_4. The following devices are subject to this GHG PSD permit:

- Heaters (EPNs: F-101 and F-201)
- Flare (EPN: FL-101)
- Emergency Generator Engine (EPN: EGEN-1)
- MSS Emissions (EPN: MSS)
- Fugitives (EPN: FUG)
- Marine Vessel Loading Vapor Combustion Units (EPNs: SD4-VCU, VCU-1A, VCU-1B, VCU-2A, VCU-2B, and VCU-2C)

IX. Hot Oil Heaters (EPNs: F-101 and F-201)

GHG emissions, primarily CO_2, are generated from the combustion of natural gas in the proposed heaters. The new condensate splitter plant will utilize two hot oil heaters each with a maximum firing rate of 247 MMBtu/hr.

As part of the PSD review, KMLT provides in the GHG permit application a 5-step top-down BACT analysis for the two heaters. EPA has reviewed KMLT's BACT analysis for the heaters, which has been incorporated into this Statement of Basis, and also provides its own analysis in setting forth BACT for this proposed permit, as summarized below.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Fuel Selection* – Use of low carbon fuels results in lower GHG emissions.
- *Carbon Capture and Sequestration (CCS)* – CCS is an available add-on control technology that is applicable for all of the site's affected combustion units.
- *Heater/Process Design* – Good heater design to maximize thermal efficiency.
- *Good Combustion Practices* – The formation of GHGs can be controlled by proper operation and using good combustion techniques.
- *Periodic Burner Tune-up* – Periodically tune-up the heaters to maintain optimal thermal efficiency.
- *Product Heat Recovery* – Hot product streams are cooled with exchange of heat with the colder feed and the distillation column's stripping section to provide process heat in lieu of heat from the furnace.

Carbon Capture and Sequestration (CCS)

Carbon capture and storage is an available GHG control technology for "facilities emitting CO_2 in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing)."[1] CCS systems involve the use of adsorption or absorption processes to remove CO_2 from flue gas, with subsequent desorption to produce a concentrated CO_2 stream. The three main capture technologies for CCS are pre-combustion capture, post-combustion capture, and oxyfuel combustion (IPCC, 2005). Of these approaches, pre-combustion capture is applicable primarily to gasification plants, where solid fuel such as coal is converted into gaseous components by applying heat under pressure in the presence of steam and oxygen (U.S.

[1]U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, *PSD and Title V Permitting Guidance for Greenhouse Gases*, March 2011, <http:/www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf> (March 2011).

Department of Energy, 2011). At this time, oxyfuel combustion has not yet reached a commercial stage of deployment for this type of application. Accordingly, pre-combustion capture and oxyfuel combustion are not considered available control options for this proposed facility; the third approach, post-combustion capture, is applicable to heaters.

With respect to post-combustion capture, a number of methods may potentially be used for separating the CO_2 from the exhaust gas stream, including adsorption, physical absorption, chemical absorption, cryogenic separation, and membrane separation (Wang et al., 2011). Many of these methods are either still in development or are not suitable for treating heater exhaust gas due to the characteristics of the exhaust stream (Wang, 2011; IPCC, 2005).

Once CO_2 is captured from the flue gas, the captured CO_2 is compressed to 100 atmospheres (atm) or higher for ease of transport (usually by pipeline). The CO_2 would then be transported to an appropriate location for underground injection into a suitable geological storage reservoir, such as a deep saline aquifer or depleted coal seam, or used in crude oil production for enhanced oil recovery (EOR). There is a large body of ongoing research and field studies focused on developing better understanding of the science and technologies for CO_2 storage.[2]

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible for this project.[3]

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- Use of low carbon fuels (up to 100% GHG emission reduction for fuels containing no carbon),
- CO_2 capture and storage (up to 90% GHG emission reduction),
- Heater/process design (up to 10% GHG emission reduction),
- Good combustion practices (5 - 25% GHG emission reduction),
- Periodic tune-up (no information for heaters), and
- Product heat recovery (does not directly improve heater efficiency)

It should be further noted that these various control measures are not technically incompatible, but rather can be potentially considered as a suite of potential control measures on which a BACT limit can be based.

[2] U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory *Carbon Sequestration Program: Technology Program Plan*, <http://www.netl.doe.gov/technologies/carbon_seq/refshelf/2011_Sequestration_Program_Plan.pdf>, February 2011

[3] Based on the information provided by KM Liquids and reviewed by EPA for this BACT analysis, while there are some portions of CCS that may be technically infeasible for this project, EPA has determined that overall Carbon Capture and Storage (CCS) technology is technologically feasible at this source.

Virtually all GHG emissions from fuel combustion result from the conversion of the carbon in the fuel to CO_2. Thus, use of a completely carbon-free fuel such as 100% hydrogen, has the potential of reducing CO_2 emissions by 100%. Hydrogen is not produced from the processes at the Galena Park Terminal, and therefore is not a viable fuel. Natural gas is the lowest carbon fuel available at the Galena Park Terminal. Carbon capture and storage (CCS) may be capable of achieving up to 90% reduction of produced CO_2 emissions in some circumstances and thus would be considered the most effective control method.

Good heater design, air/fuel ratio control, and periodic tune-ups are all considered effective and have a range of efficiency improvements which cannot be directly quantified; therefore, the above ranking is approximate only. The estimated efficiencies were obtained from Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy and Plant Managers (Environmental Energy Technologies Division, University of California, sponsored by USEPA, June 2008). Product heat recovery involves the use of heat exchangers to transfer the excess heat that may be contained in product streams to feed streams. Pre-heating of feed streams in this manner reduces the heat requirement of the downstream process unit which reduces the heat required from process heaters. Where the product streams require cooling, this practice also reduces the energy required to cool the product stream.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Use of Low Carbon (Natural Gas) Fuel

Natural gas is the lowest carbon fuel available for use in the proposed heaters. Natural gas is readily available at the Galena Park Terminal and is considered a very cost effective fuel alternative. Natural gas is a very clean burning fuel with respect to criteria pollutants and thus has minimal environmental impact compared to other fuels. The use of produced off-gas stream may be used as a heater fuel source reducing purchased natural gas usage.

Carbon Capture and Sequestration

KMLT developed a cost analysis for CCS that provided the basis for eliminating the technology as a viable control option in step 4 of the BACT process based on economic costs and environmental impacts. The recovery and purification of CO_2 from the stack gases would necessitate significant additional processing, including energy, and environmental/air quality penalties, to achieve the necessary CO_2 concentration for effective sequestration. The additional process equipment required to separate, cool, and compress the CO_2, would require a significant additional and power expenditure.

The majority of the cost was attributed to the capture and compression facilities that would be required. The total annual cost of CCS would be $21,700,000 per year for the two hot oil heaters. EPA Region 6 reviewed KMLT's CCS cost estimate and believes it adequately approximates the cost of a CCS control for this project and demonstrates those costs are prohibitive in relation to the overall cost of the proposed project without CCS, which is estimated at $145,000,000. Based on a 7% interest rate, and 20-year equipment life, this cost equates to an overall annualized cost of about $13,700,000 without CCS. The annualized cost of CCS would result in at least a 158% increase in this cost, and thus CCS has been eliminated as BACT for this project as economically prohibitive.

In addition, there would be additional negative environmental and energy impacts associated with use of CCS for the proposed heaters. The additional process equipment required to separate, cool, and compress the CO_2 would require significant additional power and energy expenditure. This equipment would include amine units, cryogenic units, dehydration units, and compression facilities. The power and energy would be provided from additional combustion units, including heaters, engines, and/or combustion turbines. The additional GHG emissions resulting from additional fuel combustion would either further increase the cost of the CCS system if the emissions were also captured for sequestration or, if not captured, reduce the net amount of GHG emission reduction, making CCS even less cost effective.

Therefore, EPA has determined at this time that for KMLT CCS should be eliminated as BACT for this facility due to the economic impacts and negative environmental and energy impacts.

Heater/Process Design

New heaters will be designed with efficient burners, greater heat transfer efficiency, state-of-the-art refractory and insulation materials in the heater walls, floor, and other surfaces to minimize heat loss and increase overall thermal efficiency. Ceramic fiber blankets and Kaolite™ of various thickness and density will be used where feasible on all heater surfaces. Kaolite™ is a super light low thermal conductivity insulation material consisting of vermiculite and Portland cement that reduces heat transfer producing significant savings in heater fuel consumption.

Hot bottoms from the main distillation column are re-circulated through the stripper columns as a heating media for the column reboilers. The hot bottoms are then circulated through the furnace convection section to recover waste heat from furnace stack effluent. In addition, hot oil is used in a separate furnace to supply heat at a lower temperature to the process to reduce furnace stack gas temperature and, thereby, increase furnace efficiency. Also, an overhead product stream may be used as a heater fuel source for up to 1% of the total heat input, reducing demand for an exogenous source of fuel.

The function and near steady state operation of the proposed heaters allows them to be designed to achieve "near best" thermal efficiency. There are no negative environmental, economic, or energy impacts associated with this control technology.

Good Combustion Practices

Some amount of excess air is required to ensure complete fuel combustion, minimize emissions, and enhance safety. More excess air than needed to achieve these objectives reduces overall heater efficiency. Good fuel/air mixing in the combustion zone will be achieved through the use of oxygen monitors and intake air flow monitors to optimize the fuel/air mixture and limit excess air. Manual or automated air/fuel ratio controls are used to optimize these parameters and maximize the efficiency of the combustion process. Limiting the excess air enhances efficiency and reduces emissions through reduction of the volume of air that needs to be heated in the combustion process. In addition, proper fuel gas supply system design and operation to minimize fluctuations in fuel gas quality, maintaining sufficient residence time to complete combustion, and good burner maintenance and operation are part of KMLT's good combustion practices. There are no negative environmental, economic, or energy impacts associated with this control technology. Good combustion practices could improve efficiency up to 25%.[4]

Periodic Tune-up

Periodic tune-ups of the heaters include:

- Preventative maintenance check of fuel gas flow meters annually,
- Preventative maintenance check of oxygen control analyzers quarterly,
- Cleaning of burner tips on an as-needed basis, and
- Cleaning of convection section tubes on an as-needed basis.

These activities insure that maximum thermal efficiency is maintained; however, it is not possible to quantify an efficiency improvement, although convection cleaning has shown improvements in the 0.5 to 1.5% range, and routine and proper maintenance can theoretically recover up to 10% of the efficiency lost over time to age and wear. There are no negative environmental, economic, or energy impacts associated with this control technology.

[4] The estimated efficiency was obtained from Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy and Plant Managers (Environmental Energy Technologies Division, University of California, sponsored by USEPA, June 2008).

Product Heat Recovery

Rather than increasing heater efficiency, this technology reduces potential GHG emissions by reducing the required heater duty (fuel firing rate), which can substantially reduce overall plant energy requirements. Excess heat in product streams will be used to pre-heat feed streams throughout the process through the use of heat exchangers to transfer the heat from the product stream to the feed stream. This will also reduce the energy requirement (primarily purchased electricity) needed to cool the product streams. There are no negative environmental, economic, or energy impacts associated with this control technology.

Step 5 – Selection of BACT

To date, other similar facilities with a GHG BACT limit are summarized in the table below:

Company / Location	Process Description	BACT Control(s)	BACT Emission Limit / Requirements	Year Issued	Reference
Energy Transfer Company (ETC), Jackson County Gas Plant Ganado, TX	Four Natural Gas Processing Plants 4 Hot Oil Heaters (48.5 MMBtu/hr each) 4 Trim Heaters (17.4 MMBtu/hr each) 4 Molecular Sieve Heaters (9.7 MMBtu/each) 4 Regenerator Heaters (3 MMBtu/hr each)	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT limit for process heaters per plant (one of each heater per plant) of 1,102.5 lbs CO_2/MMSCF 365-day average, rolling daily for each plant	2012	PSD-TX-1264-GHG
Enterprise Products Operating LLC, Eagleford Fractionation Mont Belvieu, TX	NGL Fractionation 2 Hot Oil Heaters (140 MMBtu/hr each) 2 Regenerant Heaters (28.5 MMBtu/hr each	Energy Efficiency/ Good Design & Combustion Practices	Hot Oil Heaters have a minimum thermal efficiency of 85% on a 12-month rolling basis. Regenerant heaters only have good combustion practices.	2012	PSD-TX-154-GHG

Company / Location	Process Description	BACT Control(s)	BACT Emission Limit / Requirements	Year Issued	Reference
Energy Transfer Partners, LP, Lone Star NGL Mont Belvieu, TX	2 Hot Oil Heaters (270 MMBtu/hr each) 2 Regenerant Heaters (46 MMBtu/hr each)	Energy Efficiency/ Good Design & Combustion Practices	Hot Oil Heaters - 2,759 lb CO_2/bbl of NGL processed. Regenerator Heaters - 470 lbs CO_2/bbl of NGL processed. 365-day average, rolling daily	2012	PSD-TX-93813-GHG
Copano Processing L.P., Houston Central Gas Plant Sheridan, TX	2 Supplemental Heaters (25 MMBtu/hr each)	Energy Efficiency/ Good Design & Combustion Practices, and Limited Operation	Each heater will be limited to 600 hours of operation on a 12-month rolling basis.	2013	PSD-TX-104949-GHG

The Enterprise Eagleford Fractionation and Energy Transfer Partners Lone Star NGL are both natural gas liquids (NGL) fractionation facilities. The Lone Star NGL facility produces a higher grade of propane for export purposes that requires a higher heat duty than the Enterprise facility. KMLT has proposed to monitor thermal efficiency of the hot oil heaters. They have proposed to maintain an 85% thermal efficiency which is equal to the thermal efficiency that was proposed by Enterprise Products Operating for their hot oil heaters. The Enterprise heaters are rated at 140 MMBtu/hr and the KMLT heaters are rated at 247 MMBtu/hr. We analyzed the proposed BACT and have determined it is consistent with other BACT determinations for similar units.

The following specific BACT practices are proposed by KMLT for the hot oil heaters:

- *Use of Low Carbon (Natural Gas) Fuel* – Pipeline quality natural gas will be the only purchased fuel fired in the proposed heaters. It is the lowest carbon purchased fuel available.
- *Heater/Process Design* – The heaters shall be designed to maximize heat transfer efficiency and reduce heat loss.
- *Good Combustion Practices* – KMLT will install, utilize, and maintain an automated air/fuel control system to maximize combustion efficiency in the heaters. The heaters will maintain a minimum thermal efficiency of 85%.
- *Periodic Heater Tune-ups* – Maintain analyzers and clean burner tips and convection tubes as needed, but to occur no less frequently than every 12 months.
- *Product Heat Recovery* – Excess heat in product streams will be used to pre-heat feed streams throughout the process through the use of heat exchangers to transfer the heat from the product stream to the feed stream.

BACT Limits and Compliance:

KMLT shall demonstrate compliance with an 85% thermal efficiency on the heaters demonstrated on a 12-month rolling average basis. The heaters will be continuously monitored for exhaust temperature, fuel temperature, ambient temperature, and stack O_2 concentration. Thermal efficiency will be calculated for each operating hour from these continuously monitored parameters using equation G-1 from American Petroleum Institute (API) methods 560 (4^{th} ed.) Annex G. To ensure compliance with the proposed emission limit, KMLT shall not exceed an annual average firing rate of 227 MMBtu/hr for each of the hot oil heaters. Efficient heater design and good combustion practices of the heaters corresponds to an emission limit of 232,392 tpy CO_2e for both heaters.

Both heaters will be designed to incorporate efficiency features, including insulation to minimize heat loss and heat transfer components that maximize heat recovery in order to minimize exogenous fuel use.

KMLT will maintain records of heater tune-ups, burner tip maintenance, O_2 analyzer calibrations and maintenance for all heaters. In addition, KMLT will maintain records of fuel temperature, ambient temperature, and stack exhaust temperature for the heaters.

KMLT will demonstrate compliance with the CO_2 limits for the heaters using the emission factors for natural gas from 40 CFR Part 98 Subpart C, Table C-2. The equation for estimating CO_2 emissions as specified in 40 CFR 98.33(a)(3)(iii) is as follows:

Where:

CO_2 = Annual CO_2 mass emissions from combustion of natural gas (short tons)

Fuel = Annual volume of the gaseous fuel combusted (scf). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to §98.3(i).

CC = Annual average carbon content of the gaseous fuel (kg C per kg of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV at §98.33(a)(2)(ii).

MW = Annual average molecular weight of the gaseous fuel (kg/kg-mole). The annual average molecular weight shall be determined using the same procedure as specified for HHV at §98.33(a)(2)(ii).

MVC = Molar volume conversion factor at standard conditions, as defined in §98.6.

44/12 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion of kg to metric tons.

1.102311 = Conversion of metric tons to short tons.

The proposed permit also includes an alternative compliance demonstration method, in which KMLT may install, calibrate, and operate a CO_2 Continuous Emission Monitoring System (CEMS) and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording CO_2 emissions.

The emission limits associated with the greenhouse gases CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Table C-2 and the actual heat input (HHV). Comparatively, the emissions from CO_2 contribute the most (greater than 99%) to the overall GHG emissions from the heaters and; therefore, additional analysis is not required for CH_4 and N_2O. To calculate the CO_2e emissions, the draft permit requires calculation of the emissions based on the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1, as published on October 30, 2009 (74 FR 56395). Records of the calculations would be required to be kept to demonstrate compliance with the emission limits on a 12-month rolling basis.

An initial stack test demonstration will be required for CO_2 emissions from each emission unit. An initial stack test demonstration for CH_4 and N_2O emissions is not required because the CH_4 and N_2O emission are less than 0.01% of the total CO_2e emissions from the heaters and are considered a *de minimis* level in comparison to the CO_2 emissions, making initial stack testing impractical and unnecessary.

X. Flare (EPN: FL-101)

The new condensate splitter plant will utilize a process flare which is designed for control of venting during planned maintenance and startup/shutdown (MSS) and upset situations. The flare's pilots are fueled by pipeline quality natural gas. The pilot gas flow rate is 150 scfh. The flare will have a hydrocarbon destruction and removal efficiency (DRE) of 98%. This BACT analysis only applies to the firing of natural gas in the pilots. A separate BACT analysis for the emissions generated by this flare when controlling MSS emissions can be found in section XIV below.

Step 1 – Identification of Potential Control Technologies

- *Use of a Thermal Oxidizer/VCU in Lieu of a Flare* – Alternate control technology consideration.
- *Use of a Vapor Recovery Unit (VRU) in Lieu of a Flare* – Alternate control technology consideration.

- *Flaring Minimization* – Minimize the duration and quantity of flaring to the extent possible through good engineering design of the process and good operating practices.
- *Proper Operation of the Flare* – Use of flow and composition monitors to accurately determine the optimum amount of natural gas required to maintain adequate VOC destruction in order to minimize natural gas combustion and the resulting CO_2 emissions.

Flaring minimization and proper flare operation are complementary means of controlling flare-associated GHG emissions.

Step 2 – Elimination of Technically Infeasible Alternatives

The primary reason a flare is considered for control of VOC in the process vent stream is that it can also be used for emergency releases. Although every possible effort is made to prevent such releases, they can occur, and the design must allow for them. A thermal oxidizer/VCU is not capable of handling the sudden large volumes of vapor that could occur during an upset release in this process. A thermal oxidizer/VCU would also not result in a significant difference in GHG emissions compared to a flare. The same constraints exist with a VRU. For this reason, even if a thermal oxidizer/VCU or vapor recovery unit was used for control of routine vent streams, a flare would still be necessary to control emergency releases and would require continuous burning of natural gas in the pilots, which would result in additional CO_2, NO_2, and CO emissions.

For these reasons, the use of either a thermal oxidizer/VCU or VRU is rejected as technically infeasible for the proposed project. Both flaring minimization and proper operation of the flare are technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- Flaring minimization (up to 100% GHG emission reduction depending on activity type), and
- Proper operation of the flare (not directly quantifiable).

Virtually all GHG emissions from fuel combustion result from the conversion of the carbon in the fuel (i.e. the natural gas needed to power the flare) and/or waste gas to CO_2. The proposed condensate splitter plant will be designed to minimize the volume of the waste gas sent to the flare. During routine operation, gas flow to the flare will be limited to pilot and purge gas only. To the extent possible, flaring will be limited to purge/pilot gas, emission events, and MSS activities.

Proper operation of the flare results in a range of efficiency improvements which cannot be directly quantified; therefore, the above ranking is approximate only, and in any case, both of these control technologies are part of the BACT limit. Use of an analyzer to determine the heating value of the flare gas to allow continuous determination of the amount of natural gas needed to maintain a minimum heating value of 300 Btu/scf to ensure proper destruction of VOCs ensures that excess natural gas is not unnecessarily flared.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

Flaring Minimization

The proposed process condensate splitter plant will be designed to minimize the volume of the waste gas sent to the flare. During routine operation, gas flow to the flare will be limited to pilot and purge gas only. Process/waste gases from the proposed condensate splitter plant will be recycled back to the heaters as heat input (i.e., up to 1%) thus reducing the amount of natural gas heat input. There are no negative environmental, economic, or energy impacts associated with this control technology.

Proper Operation of the Flare

Use of an analyzer to determine the heating value of the flare gas to allow for continuous determination of the amount of natural gas needed to maintain a minimum heating value of 300 Btu/scf to ensure proper destruction of VOCs ensures that excess natural gas is not unnecessarily flared. This added advantage of reducing fuel costs makes this control option cost effective as both a criteria pollutant and GHG emission control option. There are no negative environmental, economic, or energy impacts associated with this control technology.

Step 5 – Selection of BACT

The following specific BACT practices are proposed for the low profile flare:

- *Flaring Minimization*– Minimize the duration and quantity of flaring to the extent possible through good engineering design of the process and good operating practice.
- *Proper Operation of the Flare* – The formation of GHGs can be controlled by proper operation and using good combustion practices. Poor flare combustion efficiencies lead to higher methane emissions and higher overall GHG emissions. KMLT will monitor the BTU content on the flared gas minimizing periods of poor combustion. Periodic maintenance will help maintain the efficiency of the flare.

Using these good combustion practices above, along with a DRE of 98%, will result in an emission limit for the flare of 78 tpy CO_2e. The CO_2e emissions, from the combustion of natural gas in the pilots of the flare account for less than 0.01% of the total projects CO_2e emissions.

KMLT will demonstrate compliance with the CO_2 emission limit using the emission factors for natural gas from 40 CFR Part 98 Subpart C, Table C-1, and the site specific fuel analysis for process fuel gas (see Table A-10 of the GHG permit application). The equation for estimating CO_2 emissions as specified in 40 CFR 98.253(b)(1)(ii)(A) is as follows:

Where:

CO_2 = Annual CO_2 emissions for a specific fuel type (short tons/year).
0.98 = Assumed combustion efficiency of the flare.
0.001 = Unit conversion factor (metric tons per kilogram, mt/kg).
n = Number of measurement periods. The minimum value for n is 52 (for weekly measurements); the maximum value for n is 366 (for daily measurements during a leap year).
p = Measurement period index.
44 = Molecular weight of CO_2 (kg/kg-mole).
12 = Atomic weight of C (kg/kg-mole).
$(Flare)_p$ = Volume of flare gas combusted during the measurement period (standard cubic feet per period, scf/period). If a mass flow meter is used, measure flare gas flow rate in kg/period and replace the term "$(MW)_p$/MVC" with "1".
$(MW)_p$ = Average molecular weight of the flare gas combusted during measurement period (kg/kg-mole). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.
MVC = Molar volume conversion factor (849.5 scf/kg-mole).
$(CC)_p$ = Average carbon content of the flare gas combusted during measurement period (kg C per kg flare gas). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.
1.102311 = Conversion of metric tons to short tons.

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98 Subpart C, Table C-2, site specific analysis of process fuel gas, and the actual heat input (HHV).

XI. Process Fugitives (EPN: FUG)

Hydrocarbon emissions from leaking piping components (process fugitives) associated with the proposed project include methane, a GHG. The additional methane emissions from process fugitives have been conservatively estimated to be 163 tpy as CO_2e. Fugitive emissions of methane are thus negligible, accounting for less than 0.01% of the project's total CO_2e emissions.

Step 1 – Identification of Potential Control Technologies for GHGs

The only identified control technology for process fugitive emissions of CO_2e is use of a leak detection and repair (LDAR) program. LDAR programs vary in stringency as needed for control of VOC emissions. Because KMLT is adopting a stringent LDAR program to control fugitive emissions of ozone precursors, and this LDAR program will result in co-control of fugitive GHG emissions, there would be no significant added cost associated with use of that program for GHG fugitive emission control. As such, evaluating the relative effectiveness of different LDAR programs is not warranted.

Step 2 – Elimination of Technically Infeasible Alternatives

LDAR programs are a technically feasible option for controlling process fugitive GHG emissions.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

As stated in Section XI, Step 1, this evaluation does not compare the effectiveness of different levels of LDAR programs.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

Although technically feasible, use of an LDAR program to control the GHG emissions that occur as process fugitives is without significant added cost here, because an LDAR program is being implemented for VOC control purposes, and it will also result in effective control of the small amount of GHG emissions from the same piping components. KMLT will use TCEQ's 28LAER[5] LDAR program at the Galena Park Terminal to minimize process fugitive VOC emissions at the proposed condensate splitter plant, and this program has also been proposed for the additional fugitive VOC emissions associated with this project. 28LAER is TCEQ's most stringent LDAR program, developed to satisfy LAER requirements in ozone non-attainment areas. There are no negative environmental, economic, or energy impacts associated with implementing TCEQ's 28LAER LDAR program to control GHGs, given that the same requirement is being adopted for independent reasons. In addition, EPA finds that an emissions standard to control fugitive emissions would be technically and economically infeasible (virtually by definition, since these emissions are sporadic and unpredictable) so that it is reasonable to adopt a work practice as BACT. See section 52.21 (b)(12).

[5] The boilerplate special conditions for the TCEQ 28LAER LDAR program can be found at http://www.tceq.state.tx.us/assets/public/permitting/air/Guidance/NewSourceReview/bpc_rev28laer.pdf. These conditions are included in the TCEQ issued NSR permit.

Step 5 – Selection of BACT

EPA has reviewed and concurs with KMLT's Fugitive Emission Sources BACT analysis. Based on KMLT's top-down BACT analysis for fugitive emissions, EPA concludes that using the TCEQ 28 LAER[6] leak detection and repair (LDAR) program is the appropriate BACT control technology option. EPA determines that the TCEQ 28LAER work practice standard for fugitives for control of CH_4 emissions is BACT. As noted above, LDAR programs would not normally be considered for control of GHG emissions alone due to the negligible amount of GHG emissions from fugitives, and while the existing LDAR program is being imposed in this instance, the imposition of a numerical limit for control of those negligible emissions is not feasible.

XII. Marine Vessel Loading (EPNs: SD4-VCU, VCU-1A, VCU-1B, VCU-2A, VCU-2B, and VCU-2C)

The new condensate splitter plant will utilize a new tank truck loading rack and existing marine loading facilities to transfer condensate splitter plant product off-site. The existing marine loading facilities are already equipped with vapor combustion units (VCU). The vapor combustion units will be modified to ensure destruction and removal efficiency (DRE) of a minimum of 99.8% for methane. GHG emissions, primarily CO_2, are generated from the combustion of VOC vapors associated with the loading of products from the proposed condensate splitter plant and natural gas used to maintain the required minimum combustion chamber temperature to achieve adequate destruction.

Step 1 – Identification of Potential Control Technologies

The only viable control option for reducing GHG emissions associated with loading vapor control is minimizing the quantity of combusted VOC vapors and natural gas to the extent possible. The available control technologies for marine vessel loading emissions are:

- *Use of a Flare in Lieu of a Thermal Oxidizer/VCU* – Alternate control technology consideration.
- *Use of a Vapor Recovery Unit (VRU) in Lieu of a VCU* – Alternate control technology consideration.
- *Minimization* – Minimize the duration and quantity of combustion to the extent possible through good engineering design of the process and good operating practices.

[6] The boilerplate special conditions for the TCEQ 28LAER LDAR program can be found at http://www.tceq.state.tx.us/assets/public/permitting/air/Guidance/NewSourceReview/bpc_rev28laer.pdf. These conditions are included in the TCEQ issued NSR permit.

- *Proper Operation of the VCU* – Use of flow and composition monitors to accurately determine the optimum amount of natural gas required to maintain adequate VOC destruction in order to minimize natural gas combustion and the resulting CO_2 emissions.

Step 2 – Elimination of Technically Infeasible Alternatives

The primary reason a Vapor Combustion Unit (VCU) is considered for control of VOC in the loading emissions is due to the LAER technology review associated with the pending TCEQ NNSR permit application for non-GHG emissions. VCUs typically achieve higher DREs than flares; therefore, VCUs are often utilized to control loading emissions to achieve emission limits reflecting LAER. Accordingly, in the TCEQ application KMLT has proposed a VCU as LAER for VOC control. The use of a flare would not result in a significant difference in GHG emissions compared to a thermal oxidizer/VCU. In addition, vapor recovery units (VRU) are not technically feasible for this project because they would not be capable of handling the large volumes of vapor associated with marine loading activities.

For these reasons, the use of either a flare or VRU is rejected as technically infeasible for the proposed project. Both minimization and proper operation of the VCU are technically feasible, and are complementary means of control.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- Minimization (up to 80% GHG emission reduction associated with submerged loading of ships), and
- Proper operation of the VCU (not directly quantifiable).

Virtually all GHG emissions from fuel combustion result from the conversion of the carbon in the fuel and/or waste gas to CO_2. The proposed process condensate splitter marine loading facilities will be designed to minimize the volume of the waste gas sent to the VCU. Specifically, the utilization of submerged loading technology equates to a reduction of up to 80% of vapor space concentration during ship loading activities. Proper operation of the VCU results in a range of efficiency improvements which cannot be directly quantified; therefore, the above ranking is approximate only. Use of an analyzer to determine the VCU combustion chamber temperature allows for the continuous determination of the amount of natural gas needed to maintain a minimum the combustion chamber above 1,400^{o}F. Maintaining the combustion chamber above 1,400^{o}F maintains proper destruction of VOCs and ensures that excess natural gas is not unnecessarily combusted.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

Minimization

The proposed process condensate splitter marine loading facilities will be designed to minimize the volume of the waste gas sent to the VCU. Specifically, submerged and/or pressurized loading reduces the volume of waste gas generated during the loading process which in turn reduces the GHG emissions associated with loading VOC vapor controls. There are no negative environmental, economic, or energy impacts associated with this control technology.

Proper Operation of the VCU

Use of an analyzer to determine the VCU combustion chamber temperature allows for the continuous determination of the amount of natural gas needed to maintain the combustion chamber above 1,400^{o}F prior to the stack test performed in accordance with the TCEQ NNSR permit No. 101199. Following the completion of the above referenced stack test, the fifteen minute average temperature shall be maintained above the minimum one hour average temperature maintained during the stack test. Maintaining the VCU combustion chamber temperature at the proper temperature for the destruction of VOCs ensures that excess natural gas is not unnecessarily combusted. This added advantage of reducing fuel costs makes this control option cost effective as both a criteria pollutant and GHG emission control option. There are no negative environmental, economic, or energy impacts associated with this control technology.

Step 5 – Selection of BACT

The following specific BACT practices are proposed for marine vessel loading:

- *Minimization*– Minimize the duration and quantity of combustion to the extent possible through good engineering design of the process and good operating practice.
- *Proper Operation of the VCU* – The formation of GHGs can be controlled by proper operation and using good combustion practices. Poor combustion efficiencies lead to higher methane emissions and higher overall GHG emissions. KMLT will monitor the combustion chamber temperature to ensure the adequate destruction of VOCs and to minimize natural gas combustion and resulting CO_2 emissions.

Using these best operating practices above will result in an emission limit for marine vessel loading of 3,052 tpy CO_2e. Compliance will be demonstrated based on the minimum combustion chamber temperature on a 15 minute average temperature above the one hour average temperature maintained in the initial stack test, which will be 1,400 ^{o}F at a minimum. The stack test shall be repeated when a process change is made, to ensure proper VCU operation and efficiency.

KMLT will demonstrate compliance with the CO_2 emission limit using the emission factors for natural gas from 40 CFR Part 98 Subpart C, Table C-1, and the site specific fuel analysis for process fuel gas. The equation for estimating CO_2 emissions as specified in 40 CFR 98.33(a)(3)(iii) is as follows:

Where:

CO_2 = Annual CO_2 mass emissions from combustion of natural gas (short tons)
Fuel = Annual volume of the gaseous fuel combusted (scf). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to §98.3(i).
CC = Annual average carbon content of the gaseous fuel (kg C per kg of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV at §98.33(a)(2)(ii).
MW = Annual average molecular weight of the gaseous fuel (kg/kg-mole). The annual average molecular weight shall be determined using the same procedure as specified for HHV at §98.33(a)(2)(ii).
MVC = Molar volume conversion factor at standard conditions, as defined in §98.6.
44/12 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion of kg to metric tons.
1.102311 = Conversion of metric tons to short tons.

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Table C-2, site specific analysis of process fuel gas, and the actual heat input (HHV).

XIII. Emergency Generator Engine (EPN: EGEN-1)

The emergency generator engine proposed for use at KMLT will operate at a low annual capacity factor - approximately 500 hours per year in non-emergency use.

Step 1 – Identification of Potential Control Technologies

- *Low Carbon Fuels –* Use of fuels containing lower concentrations of carbon generate less CO_2, than other higher-carbon fuels. Typically, gaseous fuels such as natural gas or high-hydrogen plant tail gas contain less carbon, and thus lower CO_2 emission potential, than liquid or solid fuels such as diesel or coal.

- *Good Combustion Practices and Maintenance* – Good combustion practices include appropriate maintenance of equipment and operating within the recommended air to fuel ratio recommended by the manufacturer.
- *Limited Operation* – Limiting the hours of use during testing and maintenance will reduce the GHG emissions.

These potential control technologies are complementary.

Step 2 – Elimination of Technically Infeasible Alternatives

Use of low carbon fuel, good combustion practices and maintenance, and limited operation are all applicable and feasible, and are not mutually exclusive.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Use of low carbon fuel, limited operation, and good combustion practices and maintenance are all effective in minimizing emissions, but cannot be directly quantified, therefore ranking is not possible. In any case, since these controls are a suite of controls constituting BACT, no ranking is necessary.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Natural gas is the lowest carbon fuel available for use in the proposed emergency generator. Natural gas is readily available at the Galena Park Terminal and is considered a very cost effective fuel alternative. Limited operation is directly applicable to the proposed engine since it is to be utilized for emergency use only, resulting in no emissions at most times. A properly designed and maintained engine constitutes good operating practice for maximizing efficiency of all fuel combustion equipment, including emergency engines.

Step 5 – Selection of BACT

The following specific BACT practices are proposed for the emergency generator:

- *Low Carbon Fuel* – Natural gas will be the only purchased fuel fired by the emergency generator. It is the lowest carbon purchased fuel available for use at the complex.
- *Good Combustion Practices and Maintenance* – Good combustion practices for compression ignition engines include appropriate maintenance of equipment, periodic testing conducted weekly, and operating within the recommended air to fuel ratio, as specified by its design.

- *Limited Operation* – Limiting the hours of use during testing and maintenance will reduce the GHG emissions.

Using the above good combustion practices identified above results in an emission limit of 310 tpy CO_2e. The CO_2e emissions from the emergency engine accounts for less than 0.08% of the total project CO_2e emissions. KMLT will demonstrate compliance with the CO_2 emission limit using the emission factors for natural gas fuel from 40 CFR Part 98 Subpart C, Table C-1. The equation for estimating CO_2 emissions as specified in 40 CFR 98.33(a)(1)(i) is as follows:

Where:

CO_2 = Annual CO_2 mass emissions from combustion of natural gas fuel (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to §98.3(i).
HHV= Default high heat value of the fuel.
0.001 = Conversion of kg to metric tons.
EF = Fuel specific default CO_2 emission factor (kg CO_2/MMBtu).

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Table C-2, and the actual heat input (HHV).

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

GHG emissions, primarily CO_2 are generated from the combustion of VOC vapors associated with maintenance, startup, and shutdown (MSS) activities associated with heaters, storage tanks, frac tanks (portable tanks), other process equipment, and piping at the proposed condensate splitter plant. The MSS emissions are either collected by a vapor collection system and then sent to a flare or a contracted vapor combustion unit (VCU) for control, and/or contracted internal combustion engine (ICE) for control. The flare is the primary control device for process equipment, and the contracted VCUs/ICEs are primarily used to control MSS emissions from portable units and units that may not have large volume MSS streams. In fact, the only GHG emissions associated with the storage tanks and frac tanks are from MSS activities.

Step 1 – Identification of Potential Control Technologies

The only viable control option for reducing GHG emissions associated with MSS vapor control is minimizing the quantity of combusted VOC vapors and natural gas to the extent possible, and to combust these vapors as efficiently as possible. The available control technologies for MSS emissions are:

- *Use of a Vapor Recovery Unit (VRU) in Lieu of a Flare/VCU* – VRU systems (i.e., carbon canister, scrubber, etc.) do not generate GHG emissions and will be utilized to control MSS emissions associated with vacuum trucks, frac tanks, and other process area equipment that are not connected to the flare.
- *Minimization* – Minimize the duration and quantity of combustion to the extent possible through good engineering design of the storage tanks and process equipment and good operating practices.
- *Proper Operation of the Flare/VCU and/or internal combustion engine (ICE)* – Use of flow and composition monitors to accurately determine the optimum amount of natural gas required to maintain adequate VOC destruction in order to minimize natural gas combustion and the resulting CO_2 emissions.

Step 2 – Elimination of Technically Infeasible Alternatives

The use of a VRU, minimization, and proper operation of the flare/VCU/ICE are considered technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- Use of a VRU in lieu of a flare/VCU (up to 100% GHG emission reduction),
- Minimization (not directly quantifiable for MSS activities), and
- Proper operation of the flare/VCU/ICE (not directly quantifiable for MSS activities).

Proper operation of a VRU for MSS VOC emissions control results in GHG emission reductions up to 100%.

The proposed process condensate splitter plant will be designed to minimize the volume of the waste gas sent to the flare and/or VCU, and/or ICE. These improvements cannot be directly quantified; therefore, the above ranking is approximate only. Waste gas volumes will be reduced by reducing storage tank and process equipment vapor space volumes requiring control during MSS activities (i.e., degassing, etc.).

Proper operation of the flare and/or VCU results in a range of efficiency improvements which cannot be directly quantified; therefore, the above ranking is approximate only, and in any case, the technologies are complementary rather than mutually exclusive. Use of an analyzer to maintain the heating value of the flare waste gas above 300 Btu/scf and/or the VCU/ICE combustion chamber temperature above 1,400^{o}F allows for the proper destruction of VOCs and ensures that excess natural gas is not unnecessarily combusted.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

Use of a VRU

Vacuum trucks, frac tanks (portable tanks), and other process area equipment not connected to the flare will utilize VRU technology (i.e., carbon canister, scrubber, etc.) for MSS emissions control. VRU usage is limited to MSS activities where the flow rate and event duration warrant its use. Specifically, a VRU is not capable of handling the sudden large volumes of vapor that could occur during unit turnarounds or storage tank roof landing activities. There are no negative environmental, economic, or energy impacts associated with this control technology.

Minimization

New storage tanks and process equipment are designed such that the vapor space volume requiring control during MSS activities is significantly reduced. The storage tank and process equipment will be subject to LAER control requirements as determined by TCEQ and will be included in the TCEQ NNSR permit No. 101199. Specifically, VOC emissions and the subsequent GHG emissions associated with MSS activities are significantly reduced by limiting the duration of MSS activities, reducing vapor space volume requiring control, painting tanks white, incorporating “drain dry” sumps into the tank design, draining residual VOC material to closed systems, etc. There are no negative environmental, economic, or energy impacts associated with this control technology.

Proper Operation

Use of an analyzer to determine the amount of natural gas needed to maintain the waste gas stream sent to the flare above 300 Btu/scf and/or the VCU/ICE combustion chamber temperature above 1,400^{o}F will ensure proper operation. Maintaining the flare waste gas stream heat content and VCU/ICE combustion chamber temperature at the proper levels for the destruction of VOCs ensures that excess natural gas is not unnecessarily combusted. This added advantage of reducing fuel costs makes this control option cost effective as both a criteria pollutant and GHG emission control option. There are no negative environmental, economic, or energy impacts associated with this control technology.

Step 5 – Selection of BACT

The following specific BACT practices are proposed for controlling MSS emissions from the proposed condensate splitter plant:

- *Use of a VRU in lieu of a Flare/VCU* – VRU systems (i.e., carbon canisters, scrubbers, etc.) will be utilized to control MSS emissions associated with vacuum trucks, frac tanks, and any equipment that is not connected to the flare in the process area or portable VCU.
- *Minimization* – Minimize the duration and quantity of combustion to the extent possible through good engineering design of the storage tanks and process equipment and good operating practice.
- *Proper Operation of the Flare/VCU or ICE* – Use of flow and composition monitors to accurately determine the optimum amount of natural gas required to maintain adequate VOC destruction in order to minimize natural gas combustion and resulting CO_2 emissions.

Using these operating practices above will result in the minimization of MSS emissions. The MSS emissions from the flare are estimated to be 7,282 tpy CO_2e, and 317 tpy CO_2e from the VCU. Compliance will be demonstrated based on the minimum combustion chamber temperature of 1,400^{o}F on a 15 minute average for the VCU. Use of an analyzer to determine the heating value of the waste gas sent to the flare to allow for continuous determination of the amount of natural gas needed to maintain a minimum heating value of 300 Btu/scf to ensure proper destruction of VOCs ensures that excess natural gas is not unnecessarily flared.

XV. Threatened and Endangered Species

Pursuant to Section 7(a)(2) of the Endangered Species Act (ESA) (16 U.S.C. 1536) and its implementing regulations at 50 CFR Part 402, EPA is required to insure that any action authorized, funded, or carried out by EPA is not likely to jeopardize the continued existence of any federally-listed endangered or threatened species or result in the destruction or adverse modification of such species' designated critical habitat.

To meet the requirements of Section 7, EPA is relying on a Biological Assessment (BA) prepared by the applicant and adopted by EPA. Further, EPA designated KM Liquids Terminal, LLC – Galena Park ("KMLT") and its consultant, Whitenton Group ("Whitenton"), as non-federal representatives for purposes of preparation of the BA.

A draft BA has identified eleven (11) species listed as federally endangered or threatened in Harris County, Texas:

Federally Listed Species for Harris County by the U.S. Fish and Wildlife Service (USFWS), National Marine Fisheries Service (NMFS) and the Texas Parks and Wildlife Department (TPWD)	**Scientific Name**
Birds	
Red-cockaded Woodpecker Whooping Crane	*Picoides borealis* *Grus americana*
Amphibians	
Houston Toad	*Bufo houstonensis*
Fish	
Smalltooth Sawfish	*Pristis pectinata*
Mammals	
Louisiana Black Bear Red Wolf	*Ursus americanus luteolus* *Canis rufus*
Plant	
Texas Prairie Dawn Flower	*Hymenoxys texana*
Reptiles	
Green Sea Turtle Kemp's Ridley Sea Turtle Leatherback Sea Turtle Loggerhead Sea Turtle	*Chelonia mydas* *Lepidochelys kempii* *Dermochelys coriacea* *Caretta caretta*

EPA has determined that issuance of the proposed permit will have no effect on any of the eleven (11) listed species, as there are no records of occurrence, no designated critical habitat, nor potential suitable habitat for any of these species within the action area.

Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on listed species. The final draft biological assessment can be found at EPA's Region 6 Air Permits website at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XVI. Magnuson-Stevens Act

Pursuant to Section 305(b)(2) of the Magnuson-Stevens Fishery Conservation and Management Act and implementing regulations at 50 CFR 600.05 – 600.930, EPA is required to consult with NOAA's National Marine Fisheries Service on proposed actions that may adversely affect essential fish habitat (EFH).

To meet the requirements of the Magnuson-Stevens Act, EPA is relying on an EFH Assessment prepared by the applicant and adopted by EPA.

The facility is adjacent to tidally influenced portions of the Houston Ship Channel (HSC), which empties into Galveston Bay system. These tidally influenced portions have been identified as potential habitats of postlarval, juvenile, subadult or adult red drum (*Sciaenops ocellatus*), white shrimp (*Penaeus setiferus*), brown shrimp (*Penaeus aztecus*), pink shrimp (*Penaeus duorarum*), royal red shrimp (*Pleoticus robustus*) and forty-three species of reef fish which include triggerfishes, jacks, wrasses, snappers, tilefishes, and groupers. The EFH information was obtained from the NMFS's website (http://www.habitat.noaa.gov/protection/efh/efhmapper/index.html). Furthermore, these tidally influenced areas have also been identified by NMFS to contain EFH for neonate/young of the year scalloped hammerhead sharks (*Sphyrna lewini*); neonate/young of the year and juvenile blacktip sharks (*Carcharhinus limbatus*), bull sharks (*Carcharhinus leucas*) and bonnethead sharks (*Sphyrna tiburo*); and neonate/young of the year and adult Atlantic sharpnose sharks (*Rhizoprionodon terraenovae*)

Based on the information provided in the EFH Assessment, EPA concludes that the proposed PSD permit allowing KMLT construction of a condensate splitter and associated process equipment within the existing facility property will have no adverse impacts on listed marine and fish habitats, because there are no proposed direct construction impacts or indirect project impacts within the HSC. Further, air modeling indicates that pollutant levels will be below *de minimums* levels over the water. The site storm water system will remain the same, as it exists today; where contact storm water is routed to the Gulf Coast Waste Disposal Authority, a publically owned treatment work (POTW) facility, for treatment and non-contact storm water is routed via storm water outfalls in the Hunting Bayou, a tributary to Buffalo Bayou/Houston Ship Channel. Finally, all wastewater that will be generated as a result of the project will be sent directly via hard pipe to Gulf Coast Waste Disposal Authority for treatment.

Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on listed species. The final essential fish habitat report can be found at EPA's Region 6 Air Permits website at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XVII. National Historic Preservation Act (NHPA)

Section 106 of the NHPA requires EPA to consider the effects of this permit action on properties eligible for inclusion in the National Register of Historic Places. To make this determination, EPA relied on a cultural resource report prepared by Horizon Environmental Services, Inc. ("Horizon") on behalf of Whitenton submitted on December 19, 2012.

For purposes of the NHPA review, the Area of Potential Effect (APE) was determined to be approximately 49 acres of land within and adjacent to the construction footprint of the existing facility. Horizon conducted a field survey of the property and a desktop review on the archaeological background and historical records within a 1-mile radius area of potential effect (APE) which included a review of the National Park Service's National Register of Historic

Places (NRHP). Based on the results of the field survey, no archaeological resources or historic structures were found within the APE. Based on the cultural review, no cultural resource sites were identified within a 1-mile radius of the APE. Based on the desktop review, eight previous cultural surveys were made within a 1-mile radius of the APE. Eleven previously recorded historic or archaeological sites, as well as one cemetery and an isolated grave were identified from those reports, all of which are outside of the APE.

EPA Region 6 determines that because no historic properties are located within the APE and that a potential for the location of archaeological resources is low within the construction footprint itself, issuance of the permit to KMLT will not affect properties on or potentially eligible for listing on the National Register.

On March 7, 2013, EPA sent letters to Indian tribes identified by the Texas Historical Commission as having historical interests in Texas to inquire if any of the tribes have historical interest in the particular location of the project and to inquire whether any of the tribes wished to consult with EPA in the Section 106 process. EPA received no requests from any tribe to consult on this proposed permit. EPA will provide a copy of the report to the State Historic Preservation Officer for consultation and concurrence with its determination. Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on historic properties. A copy of the report may be found at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XVIII. Environmental Justice (EJ)

Executive Order (EO) 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive branch policy on environmental justice. Based on this Executive Order, the EPA's Environmental Appeals Board (EAB) has held that environmental justice issues must be considered in connection with the issuance of federal Prevention of Significant Deterioration (PSD) permits issued by EPA Regional Offices [See, e.g., *In re Prairie State Generating Company*, 13 E.A.D. 1, 123 (EAB 2006); *In re Knauf Fiber Glass*, Gmbh, 8 E.A.D. 121, 174-75 (EAB 1999)]. This permitting action, if finalized, authorizes emissions of GHG, controlled by what we have determined is the Best Available Control Technology for those emissions. It does not select environmental controls for any other pollutants. Unlike the criteria pollutants for which EPA has historically issued PSD permits, there is no National Ambient Air Quality Standard (NAAQS) for GHG. The global climate-change inducing effects of GHG emissions, according to the "Endangerment and Cause or Contribute Finding", are far-reaching and multi-dimensional (75 FR 66497). Climate change modeling and evaluations of risks and impacts are typically conducted for changes in emissions that are orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible [PSD and Title V Permitting Guidance for GHGs at 48]. Thus, we conclude it would not be meaningful to evaluate impacts of GHG emissions on a local community in the context of a single permit. Accordingly, we have determined an environmental justice analysis is not necessary for the permitting record.

XIX. Conclusion and Proposed Action

Based on the information supplied by KM Liquids Terminals, our review of the analyses contained in the TCEQ minor NSR Permit Application and the GHG PSD Permit Application, and our independent evaluation of the information contained in our Administrative Record, it is our determination that the proposed facility would employ BACT for GHGs under the terms contained in the draft permit. Therefore, EPA is proposing to issue KM Liquids Terminals a PSD permit for GHGs for the facility, subject to the PSD permit conditions specified therein. This permit is subject to review and comments. A final decision on issuance of the permit will be made by EPA after considering comments received during the public comment period.

APPENDIX

Annual Facility Emission Limits

Annual emissions, in tons per year (TPY) on a 365-day total, rolled daily, shall not exceed the following:

Table 1. Facility Emission Limits[1]

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
F-101	F-101	Naphtha Stabilizer Hot Oil Heater - Train 1	CO_2	116,083	116,191	Minimum thermal efficiency of 85%. See permit condition III.B.1.o.
			CH_4	2.2		
			N_2O	0.2		
F-201	F-201	Naphtha Stabilizer Hot Oil Heater - Train 2	CO_2	116,083	116,191	Minimum thermal efficiency of 85%. See permit condition III.B.1.o.
			CH_4	2.2		
			N_2O	0.2		
FL-101	FL-101	Flare	CO_2	78	78	Good combustion practices. See permit condition III.B.2.
			CH_4	No Numerical Limit Established[4]		
			N_2O	No Numerical Limit Established[4]		
SD4-VCU VCU-1A VCU-1B VCU-2A VCU-2B VCU-2C	SD4-VCU VCU-1A VCU-1B VCU-2A VCU-2B VCU-2C	Marine Vessel Loading Vapor Combustion Units	CO_2	3,042	3,051	Maintain a minimum combustion temperature as determined by stack testing. See permit condition III.B.4.i.
			CH_4	0.12		
			N_2O	0.02		
EGEN-1	EGEN-1	Emergency Generator	CO_2	309	309	Limit hours of operation and good combustion practices. See permit condition III.B.5.
			CH_4	0.01		
			N_2O	No Numerical Limit Established[4]		
MSS	MSS	MSS Emissions from Flare and Portable Vapor Control Units	CO_2	7,561	7,561	Good combustion practices. See permit condition III.B.6.
			CH_4	0.01		
			N_2O	No Numerical Limit Established[4]		
FUG	FUG	Process Fugitive Emissions	CH_4	No Numerical Limit Established[5]	No Numerical Limit Established[5]	Implementation of LDAR Program. See permit condition III.B.3.
Totals[5]			**CO_2**	**243,156**	**CO_2e 243,545**	
			CH_4	**12.3**		
			N_2O	**0.42**		

1. Compliance with the annual emission limits (tons per year) is based on a 365-day total, rolled daily.
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 = 21, N_2O = 310
4. 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.
5. Fugitive process emissions from EPN FUG are estimated to be 7.8 TPY of CH_4, and 164 TPY CO_2e.
6. The total emissions for CH_4 and CO_2e include the PTE for process fugitive emissions of CH_4. These totals are given for informational purposes only and do not constitute emission limits.