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McKee Refinery • Diamond Shamrock Refining Company, L.P., a Valero Company • 6701 FM 119 • Sunray, TX 79086-2013 • Telephone (806) 935-2141

December 1, 2011

Mr. Jeff Robinson
Chief, Air Permits Section
U.S. EPA Region 6, 6PD
1445 Ross Avenue, Suite 1200
Dallas, TX 75202-2733

RE: Application for a Prevention of Significant Deterioration Air Quality Permit for
Greenhouse Gas Emissions – Crude Expansion Project
Diamond Shamrock Refining Company, L.P., a Valero Company
Valero McKee Refinery
Sunray, Moore County, Texas

Dear Mr. Robinson:

The Diamond Shamrock Refining Company, L.P., a Valero Company (Valero) is hereby submitting the attached application for a Prevention of Significant Deterioration (PSD) air quality permit for greenhouse gas emissions for the planned Crude Expansion Project at the Valero McKee Refinery in Moore County, Texas. The U.S. Environmental Protection Agency's (EPA) document *PSD and Title V Permitting Guidance for Greenhouse Gases, Nov. 2010*, was utilized as a guide for preparation of the attached application.

The application is submitted to EPA under authority EPA has asserted through its Interim Final and Proposed Federal Implementation Plan (FIP) for the regulation of greenhouse gases. The State of Texas and other petitioners have challenged EPA's FIP, claiming that EPA's FIP action is unlawful. The case is currently pending in the United States Court of Appeals for the D.C. Circuit. Valero takes no position on whether EPA's imposition of the challenged FIP is lawful, and its application is not an admission that the authority EPA asserts is consistent with the Federal Clean Air Act."

Since preparing the reviewing PSD applications for greenhouse gas emissions is new for both permit writers and permit applicants, Valero is committed to working closely with EPA Region 6 to have the application review completed in a timely manner.

Should you have any questions regarding this application, please contact me at (806) 935-1354 or email me at Shelly.Williamson@valero.com.

Sincerely,



Shelly Williamson
Environmental Manager

Enclosures

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Jeff Saitas, West Capitol
Joe J. Ibanez, Sage Environmental Consulting, L.P.



**Diamond Shamrock Refining Company, L.P.,
a Valero Company**

**Greenhouse Gas
Prevention of Significant Deterioration
Permit Application for Crude Expansion Project**

**Valero McKee Refinery
Sunray, Texas**

December 2011

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SECTION 1 INTRODUCTION

Diamond Shamrock Refining Company, L.P., a Valero Company (Valero), owns and operates a crude oil refinery located in Sunray, TX. Crude oil is delivered to the Valero McKee Refinery via pipeline and trucks, then processed and refined into various petrochemical products and commercial petroleum products such as propane, gasoline, jet fuel, diesel fuel, and asphalt. Valero is hereby requesting an authorization to modify certain equipment at the Valero McKee Refinery which will allow for an increase in the overall processing of crude oil, herein referred to as the Crude Expansion Project.

1.1 Purpose of Request

The Valero McKee Refinery is a land-locked facility without access to waterborne crude sources or major pipelines. The majority of crude processed at the refinery has typically been supplied from local gathering systems in the Texas Panhandle. Recent development of local gathering systems in the eastern Texas Panhandle, Oklahoma Panhandle, and southwestern Kansas has ramped up in an effort to supply more high quality local crude to the nearby refineries. Over the past year, these gathering system improvements have created an economic incentive for Valero to make certain modifications to the refinery to increase its overall crude oil processing capacity.

The proposed project is not a major expansion project involving the addition of new processing units; but rather, it involves making several changes to existing process units to debottleneck the refinery's existing crude processing capacity. More specifically, installation and modification of equipment will be made inside the Nos. 1 and 2 Crude Units, the Nos. 1 and 2 Vacuum Units, the Refinery Light Ends Unit (RLE) Unit, the No. 4 Naphtha Fractionator, the refinery Dehexanizer (a Naphtha Fractionator Tower), the Hydrocracking Unit (HCU), the Turbine Fuel Merox Unit, and the Diesel Hydrotreater. In addition to changes at these process units, new piping will be added to re-route certain process streams to accommodate the increased crude processing and account for certain operational constraints within the refinery. A more detailed description of these changes is provided in Section 2 of the application.

Valero is an existing major source as defined within the Federal Prevention of Significant Deteriorations (PSD) Permit Program. Therefore, physical and operational changes at the refinery are potentially subject to PSD permitting requirements. The Crude Expansion Project will trigger PSD review for Greenhouse Gas (GHG) and non-GHG criteria pollutants. This permit application is intended to satisfy the requirements of the GHG Tailoring Rule issued in May 2010.

EPA Region 6 is the current permitting authority for processing GHG permit applications in Texas. Therefore, the GHG portion of the PSD application is being submitted to EPA Region 6. The criteria pollutant portion of the permit application is being submitted to the Texas Commission on Environmental Quality (TCEQ) under a separate cover.

1.2 Facility Information

The Valero McKee Refinery is located on FM 119, approximately 5 miles southwest of Sunray, Texas in Moore County. Moore County is designated as attainment or unclassified for all criteria pollutants. Figure 1-1 at the end of this section presents the facility location relative to nearby topographic features. This map is based on a United States Geological Survey (USGS) quadrangle map. Figure 1-2, also located at the end of this section, is the facility plot plan showing the location of the emission points associated with the Crude Expansion Project.

1.3 Federal GHG Permitting Applicability

Under the GHG Tailoring Rule issued in May 2010, GHG emissions from the largest stationary sources will, for the first time, be covered by the PSD rule beginning January 2, 2011. Specifically under Step 2 of this rule, PSD applies to the GHG emissions from a proposed modification to an existing source if any of the following is true:

- PSD for GHGs would be required under Tailoring Rule Step 1.

Or both:

- The existing source’s potential-to-emit (PTE) for GHGs is equal to or greater than 100,000 TPY on a CO₂ equivalent (CO₂e) basis and is equal to or greater than 100/250 TPY (depending on the source category) on a mass basis, and
- The emissions increase and the net emissions increase of GHGs from the modification would be equal to or greater than 75,000 TPY on a CO₂e basis and greater than zero TPY on a mass basis.

The Valero McKee Refinery is an existing major source for all criteria pollutants and has a PTE for GHGs greater than 100,000 TPY on a CO₂e basis and greater than 100 TPY on a mass basis. GHG emissions from the proposed Crude Expansion Project including Carbon Dioxide (CO₂), Methane (CH₄), and Nitrous Oxide (N₂O) are provided in the following table and are expressed as CO₂e. As shown, the project increase in GHG emissions expressed as CO₂e is greater than 75,000 TPY and therefore, the project triggers a PSD review for GHG emissions.

Table 2-1 Project GHG Emission Summary

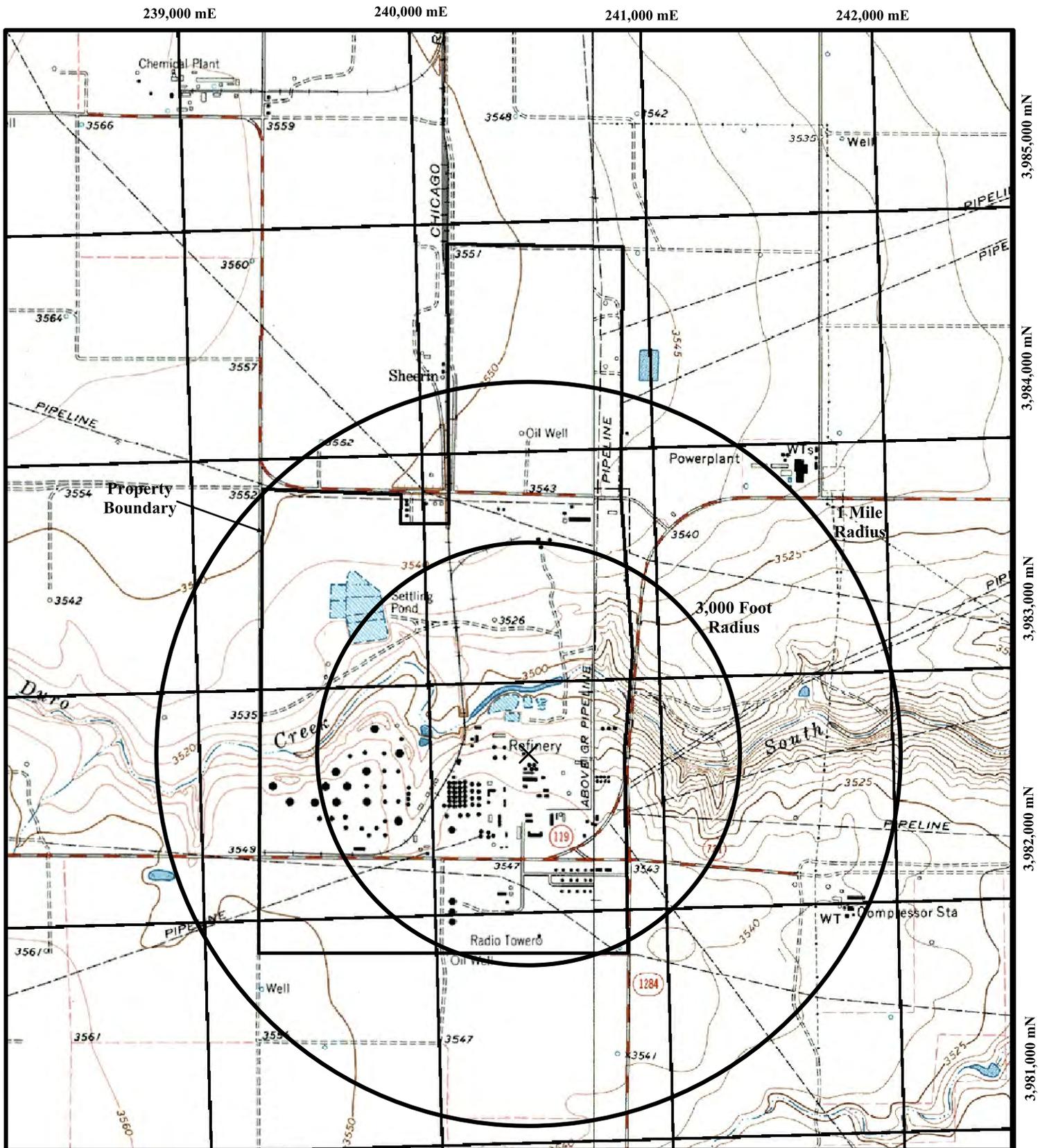
POLLUTANT*	PROJECT GHG NET EMISSION INCREASES TPY
CO ₂ , CH ₄ , N ₂ O expressed as CO ₂ e	507,726

* Note: No other emissions of GHG regulated pollutants (hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) nor sulfur hexafluoride (SF₆)) are emitted as part of the Crude Expansion Project.

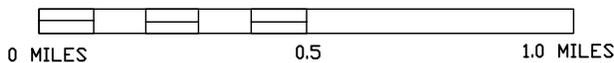
1.4 Application Contents

Key components of this application are organized as follows:

- An area map and plot plan are provided at the end of Section 1;
- Project and Process description is included in Section 2;
- Emission rate calculation methodologies are discussed in Section 3;
- Best Available Control Technology (BACT) analysis is discussed in Section 4;
- Netting Emissions Considerations are discussed in Section 5;
- Appendix A contains Administrative Forms; and
- Appendix B includes Emission Calculations tables.



SCALE 1:24,000



U.S.G.S. 7.5 MINUTE SERIES
DUMAS NORTH, TEXAS QUADRANGLE
DUMAS NE, TEXAS QUADRANGLE

THE UTM GRID IS IN NAD27

NORTH

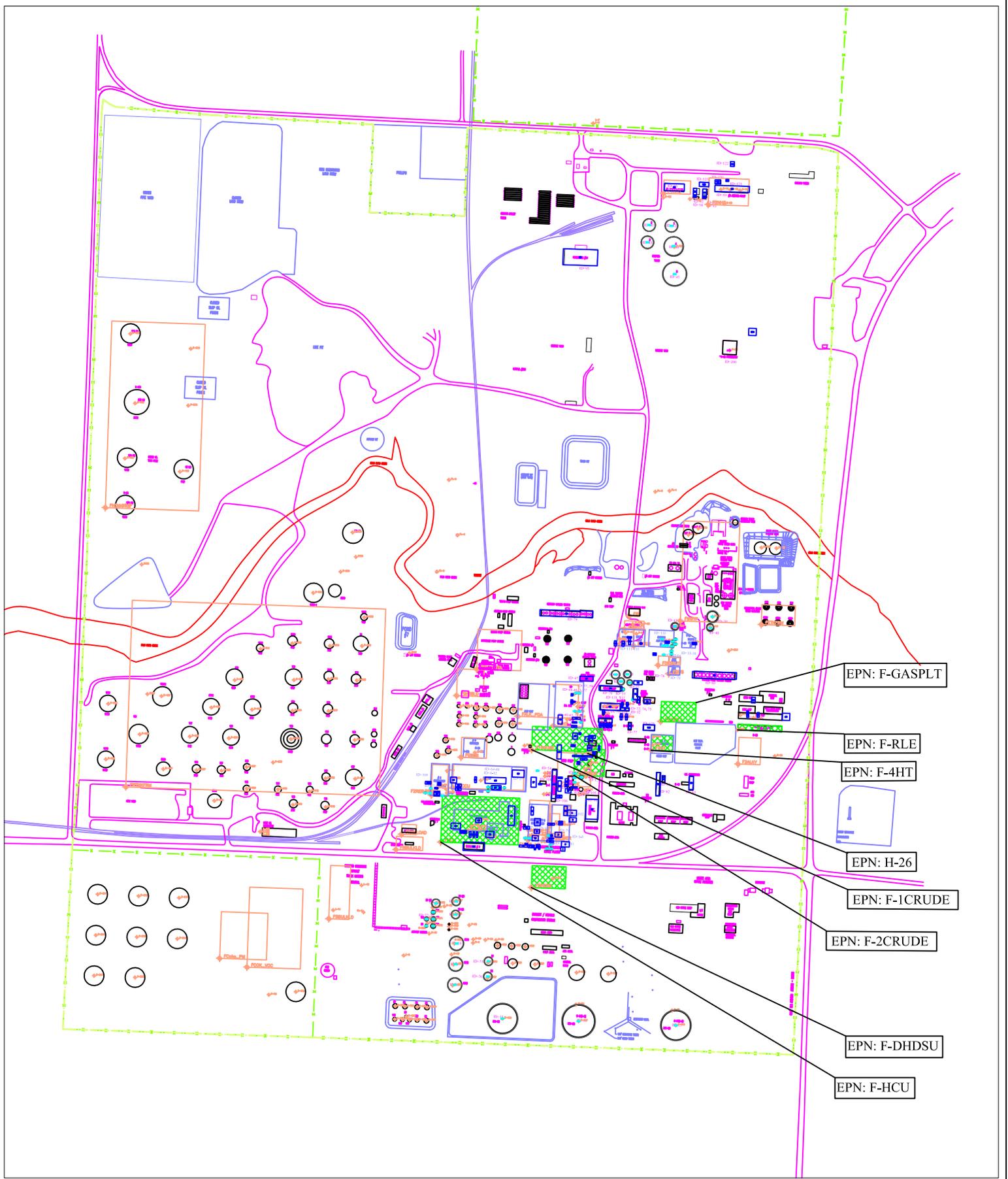


FIGURE 1-1 AREA MAP

Diamond Shamrock Refining Co., L.P., a Valero Company
Site Location on USGS Map
6701 FM 119 Sunray, Texas 79086

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DATE: December 2011
PROJ. # 25-01-122
FILE NAME: Area Map.dwg



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Drawing:	Plot Plan.dwg
Revision #:	1
Date:	December 2011
Project #:	25-1-122

Figure 1-2
Refinery Plot Plan
Dimond Shamrock Refining Co.,
Valero McKee Refinery

SECTION 2

PROJECT DESCRIPTION

This section provides a simplified process description of the Valero McKee Refinery. A simplified block flow diagram, Figure 2-1, is included at the end of this section. This section also provides a description of the proposed modification activities associated with the Crude Expansion Project and their implication on NSR PSD permitting requirements including an evaluation of upstream and downstream effects.

2.1 Overview of Existing Refining Operations

The Valero McKee Refinery processes crude oil to produce petrochemical products and commercial petroleum products. Crude oil is blended at a separate facility and transferred to the Valero McKee Refinery by pipeline and trucks. The crude oil is then processed and refined into various petrochemical products and commercial petroleum products such as propane, gasoline, jet fuel, diesel fuel, and asphalt.

2.2 Crude Expansion Project

The proposed Crude Expansion Project will debottleneck parts of the refinery to allow for additional crude processing. The proposed changes involve the installation and modification of equipment at several existing process units such as the Nos. 1 and 2 Crude Units, the Nos. 1 and 2 Vacuum Unit, the Refinery Light Ends Unit (RLE) Unit, the No. 4 Naphtha Fractionator, the Dehexanizer Tower (a Naphtha Fractionator), the Hydrocracking Unit (HCU), the Turbine Fuel Merox Unit, and the Diesel Hydrotreater. The following sections provide a brief description of each process unit and a detailed description of the proposed changes

2.2.1 Nos. 1 and 2 Crude Units

The Nos. 1 and No.2 Crude Units separate desalted crude oil into its primary boiling range products. This type of separation is accomplished by vaporizing the majority of the crude oil in a charge heater and fractionating it in a distillation tower. In the distillation tower, the vaporized portion of the feed rises and is separated into naphtha, turbine fuel, diesel, and gas oil products. Naphtha and light gasoline vapors from the top of the columns are condensed in air and water-cooled heat exchangers before further processing. Non-condensable vapors are processed in the RLE Unit and the heavy bottoms (referred to as “reduced crude”) are typically charged to the Vacuum Units. The refinery currently has the capability to bypass the Vacuum Units and process reduced crude at the refinery’s Fluidized Catalytic Cracking Unit (FCCU).

As part of this project, the existing crude charge pumps will be replaced with larger pumps, new crude desalter feed cross effluent exchangers will be added, existing gas oil/product pumps at No. 2 Crude Unit will be replaced, and new fin fan product

coolers will be installed. Valero also proposes to replace the existing reduced crude pipeline (which bypasses the Vacuum Units) with a larger pipeline and associated pumps to allow for an incremental increase in processing reduced crude at the FCCU. This incremental increase is going to be offset by shifting gas oil from the FCCU to the HCU. Therefore, there is no increase in throughput or emissions at the FCCU.

The following are the existing emission sources associated with the No. 1 and No. 2 Crude Units:

- No. 1 Crude Charge Heater (EPN: H-1)
- No. 2 Crude Charge Heater - Anderson (EPN: H-11)
- No. 2 Crude Charge Heater - Born (EPN: H-41)
- No. 2 Crude Charge Heater - Petrochem (EPN: H-9)
- No. 1 Crude Unit Fugitives (EPN: F-1CRUDE)
- No. 2 Crude Unit Fugitives (EPN: F-2CRUDE)

The process heaters will not require a physical change or an increase in their current permitted emission rates to accommodate the additional processing of crude at the No. 1 and No. 2 Crude Units. However, since the actual fuel firing rates for each process heater may increase with increased throughputs, they are considered affected sources. See Section 2.3 below regarding affected sources. Only new fugitive emissions will be added according to the previously described changes.

2.2.2 No. 1 Vacuum Unit

The No. 1 Vacuum Unit processes reduced crude from the No. 1 Crude Unit and fractionates it into light and heavy gas oils and vacuum gas residual (pitch). The additional crude processing is projected to increase the Vacuum Crude Unit feed rates. The increased feed rate will result in a firing rate increase at the No. 1 Vacuum Unit Charge Heater (EPN: H-2) but will not require an increase in its current represented firing rate. This heater is considered an affected emission source. New fugitive emissions will be added with the new pump and associated ancillary piping at the No. 1 Vacuum Unit (EPN: F-1CRUDE).

2.2.3 No. 2 Vacuum Unit

Reduced crude from the No. 2 Crude Unit is largely fed to the No. 2 Vacuum Unit where a vacuum distillation column separates the reduced crude into two main fractions. These two main fractions include light and heavy gas oils and vacuum gas residual (pitch). The gas oils are transferred to the FCCU and Hydrocracking Unit (HCU) for cracking into lighter components and the pitch is transferred to the Propane Deasphalting Unit (PDA) to produce asphalt for sale.

The proposed Crude Expansion Project will increase the No. 2 Vacuum Unit feed rate. Therefore, Valero McKee Refinery proposes to extend the No. 2 Vacuum heater and install a new ejector to the existing ejector system to accommodate this change.

The following are the existing emission sources associated with the No. 2 Vacuum Unit:

- No. 2 Vacuum Charge Heater (EPN: H-26)
- No. 2 Vacuum Unit Fugitives (EPN: F-2CRUDE)

The No. 2 Vacuum heater will require physical modifications but will not require an increase in its current permitted emission rates to accommodate the proposed changes. New fugitive emissions will be added with the new ejector and associated ancillary piping, pumps and equipment at the No. 2 Vacuum Unit.

2.2.4 Refinery Light Ends Unit

Gaseous overheads from the Nos.1 and 2 Crude Units are transferred to the RLE Unit where hydrogen sulfide (H₂S), water, and mercaptans are removed from the overheads. The RLE Unit also receives Liquefied Petroleum Gas (LPG) streams from the refinery debutanizers, Hydrocracking Unit, and the Naphtha Reformers and distills the liquid to produce light ends gas, which is used as refinery fuel gas. The RLE Unit also produces propane, n-butane and iso-butane as final products for sale. Some of the iso-butane is transferred to the Alkylation Unit for further processing.

With increased crude processing at the No. 1 and No. 2 Crude Units, additional overhead gases from the crude towers and LPG from the debutanizers will require more processing at the RLE Unit. Valero proposes to modify the RLE Unit to accommodate this additional processing by installing a new higher pressure De-Ethanizer, cooling water exchangers for overhead cooling, and a steam reboiler. The inlet to the new De-Ethanizer will have a caustic treater, amine treater, and a sand tank. Other changes include adding a new pump to move liquid feed to the new De-Ethanizer, and adding a new charge pump on the Low Temp Depropanizer Charge Drum, and other minor piping changes may also be required.

There are no existing combustion emission sources associated with the RLE Unit. Only new fugitives emissions will be added to the RLE Unit in accordance with the described changes (EPN: F-RLE)

2.2.5 Naphtha Fractionators

Light straight run (LSR) naphtha from the Crude Units is fed to the Naphtha Fractionators. Using heat supplied by the Naphtha Reboilers, the Naphtha Fractionators separate the LSR naphtha into heavier naphtha and gaseous overheads. The overheads are fed to the RLE Unit for further processing as described above, while the heavier naphtha is transferred to the refinery Hydrotreaters to remove sulfur.

As part of the proposed project, new overhead fans will be installed on the No. 4 Naphtha Fractionator, parallel to the existing fans that currently cool the gaseous

overheads sent to the RLE unit. Other changes to the naphtha fractionators include adding a new reboiler to the Dehexanizer (which actually operates as a naphtha fractionator). The reboiler return nozzle on the Dehexanizer will be raised and some trays will be removed to allow for more circulation through the reboiler.

Furthermore, to account for the incremental increase in naphtha produced from increased crude processing at the crude units, new piping, pumps and control instrumentation will be installed to transfer the additional naphtha to the existing FCC Gasoline Hydrogen Desulfurization (HDS) Unit. The FCC Gasoline HDS Unit currently hydrotreats gasoline produced from the FCCU, similar to the Naphtha Hydrotreaters, and currently has the capacity to process the increased naphtha without modifications.

There are no existing combustion emission sources associated with the No. 4 Naphtha Fractionator or Dehexanizer. Only new fugitives emissions will be added in accordance with the described changes (EPN: F-4HT and F-1CRUDE, respectively).

2.2.6 Hydrocracking Unit

The HCU uses hydrogen to sweeten and crack gas oil over a fixed bed of catalyst. Product composition can vary depending on operating parameters, feedstock composition, and catalyst type; however, primary products include LPG, LSR, Naphtha, Turbine Fuel and Diesel. The HCU recycles the excess hydrogen produced at the Reformers by treating and re-heating (EPN: H-42) the hydrogen prior to mixing it with gas oil and reacting. Desulfurization, denitrogenation, hydrogenation and cracking occur primarily in the first reactor and cracking and final hydrotreating in the second reactor. Subsequently, a high pressure and low pressure separator are used to remove and recycle hydrogen, remove light gases sent to the RLE Unit, and separate liquids sent to a debutanizer. Liquid from the low pressure separator is charged to the debutanizer. A process heater (EPN: H-43) provides heat to reboil the debutanizer. Debutanizer overhead gas and liquid are sweetened in the RLE Unit. Debutanizer bottoms liquid is heated in the HCU Fractionator Charge Heater (EPN: H-8) and charged to the HCU fractionator. Overhead gas from the fractionator is treated in RLE Unit, and sour water is charged to the sour water strippers. Sweet products from the fractionator include light straight run (LSR), naphtha, turbine fuel, distillate, and gas oil. The products are stored in tanks or sent to other units for further processing.

The Crude Expansion Project will increase the amount of gas oil processed at the HCU; therefore, the associated process heaters are expected to increase firing. These sources are considered affected emission sources.

Minor piping and ancillary equipment changes/addition will be made to accommodate the increase in feed rate to the unit associated with the increased crude processing.

2.2.7 Turbine Fuel Merox Unit

Turbine fuel produced from the Crude Units is treated to remove sulfur using the Turbine Fuel Merox Unit. The Turbine Fuel Merox Unit sweetens turbine fuel by converting mercaptan sulfur compounds to disulfide sulfur compounds. In the Merox process, hydrocarbon is mixed with air and passed over a Merox catalyst. In the presence of air, the Merox catalyst reacts with mercaptan sulfur in the hydrocarbon to form disulfides and water. The Merox catalyst requires periodic saturation with caustic to remain active, so caustic is occasionally circulated over the catalyst to maintain activity. There are no existing combustion emission sources associated with this unit.

Minor piping and ancillary equipment changes/addition will be made to accommodate the increase in feed rate to the unit associated with the increased crude processing.

2.2.8 Diesel Hydrotreater

Diesel produced from the Crude Units is treated to remove sulfur using the Diesel Hydrotreater. The Diesel Hydrotreater uses hydrogen to sweeten diesel by converting sulfur compounds to hydrogen sulfide over a catalyst. Prior to reacting with hydrogen, the sour diesel is heated using the Diesel Hydrogen Desulfurization (DHDS) Unit Charge Heater (EPN: H-48).

Minor piping and ancillary equipment changes/addition will be made to accommodate the increase in feed rate to the unit associated with the increased crude processing.

2.3 Downstream and Upstream Effects

Project emission increases are calculated for the purpose of determining PSD applicability. According to the PSD regulations, project emission increases must include potential emission increases from sources that will be modified as part of a project. PSD guidance indicates that sources upstream and downstream of the project changes must also be evaluated for potential effects on actual emission rates, and these potential actual emissions increases must also be included in the determination of total project emissions increase.

The McKee Refinery is an integrated petroleum refinery. As such, changes at one refinery operating unit may affect the operation of other units that are upstream or downstream of the unit that was changed. If any changes associated with the Crude Expansion Project increase emission rates from downstream or upstream unit operations, then evaluation of PSD applicability must include those ancillary emission increases.

The following subsections document Valero's evaluation of potential project effects on key upstream and downstream operating units including a brief description of each process and how the unit and associated emissions sources may be affected by the proposed changes. A block flow diagram of the refining process is included at the end of this section as Figure 2-1 to facilitate review of this discussion.

2.3.1 Gas Oil Fractionator

The Gas Oil Fractionator (GOF) is used as a swing unit in processing crude, gas oil, or diesel. The GOF separates the feed material into two fractions depending on the feed material. Purchased gas oil, a mixture of gas oil and diluent, produces finished gas oil and naphtha/LSR. Crude oil is fractionated into a LSR-diesel fraction and a gas oil and heavier products.

In each operating scenario, the feed material is heated by exchanger, desalted and then passed through the GOF Charge Heater (EPN: H-13), where it is heated and the lighter materials are vaporized. With the planned increase in crude processing, the production rates for the GOF are expected to increase. The increased feed rate will result in a firing rate increase at the GOF Charge Heater, but will not require an increase in its current permitted emission rate. Therefore, the GOF and associated charge heater are considered affected by this project.

2.3.2 Naphtha Fractionators and Debutanizers

Three naphtha fractionation towers separate lighter components from a mixture of LSR and naphtha. Naphtha feed from the crude units is first filtered and heated in a feed/effluent exchanger before charged to the fractionation tower. Unstable LSR containing lighter products is drawn off the top of the tower and pumped to the LSR debutanizers. Naphtha from the bottom of the fractionation tower is sent to the naphtha hydrotreaters.

Three debutanizers separate liquid petroleum gas (LPG) from LSR gasoline. LPG is removed from LSR to lower its vapor pressure so that it can be blended into gasoline. Before blended, the stabilized LSR product is then processed in the No.4 Hydrotreater.

The proposed Crude Expansion Project will result in increase yields of naphtha from the No. 1 and No.2 Crude towers to the Naphtha Fractionators and Debutanizers.

However, there are no existing combustion emission sources associated with the Naphtha Fractionators or the Debutanizers. The only changes that will be made to the naphtha processing units and associated emission sources were described in Section 2.2.5.

2.3.3 C5/C6 Splitter

The sour LSR from the Naphtha Fractionators is hydrotreated at the No. 4 Hydrotreater (to remove sulfur) prior to being sent to the C5/C6 Splitter. The Splitter tower is designed to separate pentanes (C5) from hexanes (C6) contained in the LSR. The sweetened C5 stream is transferred to an existing pressurized storage tank and used in gasoline blending. The C6 stream is further processed at the Penex Unit where the hexanes are isomerized before blended with gasoline.

The proposed Crude Expansion Project will result in increased production of LSR which can be processed at the C5/C6 Splitter. However, there are no emission sources associated with this unit other than fugitives and no required physical modification necessary to accommodate additional production.

2.3.4 Penex (Isomerization) Unit

The Penex Unit is a catalytic process, which upgrades the octane of low octane naphtha by converting normal paraffins to their isomers. The chemical reactions of this process are enhanced by adding a chloriding agent, which converts it to gaseous Hydrogen Chloride (HCl) in the process. The off gases of the Penex Isomerization Unit are neutralized and scrubbed before they are routed to the refinery gas system.

The proposed Crude Expansion Project will result in increased production of normal C5/C6 which can be processed at the Isomerization Unit. However, there are no emission sources associated with this unit other than fugitives and no required physical modification necessary to accommodate additional production. Therefore, this unit is not considered affected.

2.3.5 Naphtha Reformers

The refinery includes a Continuous Catalyst Regeneration (CCR) Reformer (No. 1 Reformer) and a semi-regenerative Rheniformer (No. 2 Reformer). The reformers further process naphtha by removing additional LPG and reacting the naphtha with hydrogen to form reformate. Primary reactions include dehydrogenation and cyclization of paraffins, dehydrogenation of naphthenes, and isomerization of paraffins. The reformate largely consists of aromatic compounds boiling in the 100°F to 400°F range. Excess hydrogen produced during the dehydrogenation process is further compressed and used for hydrotreating and hydrocracking at other process units within the refinery.

The CCR design requires a catalyst regenerator and stacked reactor configuration. Coke collects on the catalyst in the reactors, thus reducing its activity. Activity is restored in the regenerator by burning the coke off the catalyst, redistributing the active metal with a chloriding agent, and reducing the catalyst with hydrogen. Chlorides are removed from the catalyst as coke is burned in the regenerator and a caustic wash column is used to remove chlorides from the regeneration vent gas prior to being vented to the atmosphere (EPN: V-18). The No. 2 Reformer operates similar to the No. 1 Reformer, except that the catalyst is not regenerated on a continuous basis and only requires regeneration once or twice a year. Semi-regeneration consists of burning the coke off the catalyst by circulating nitrogen with a small amount of oxygen through the reactors at controlled temperature followed by reduction with hydrogen. Combustion products are scrubbed and then purged through a vent pipe for approximately two days (EPN: V-21). VOC emissions from depressurization and purging steps are controlled by the FCCU Flare or the HCU Flare (EPNs: FL-3 and FL-4, respectively.)

The process heaters associated with the No. 1 Reformer (EPNs: H-18, H-34, H-46) and the No. 2 Reformer (EPNs: H-38 and H-39) are used as charge heaters, reactor interheaters, and a stabilizer reboiler. The incremental increase in naphtha produced with the additional crude processing will be further processed at the No. 2 Reformer. Therefore, the No. 2 Reformer and associated emission sources are considered affected, but will not require an increase in the current permitted emission rates. The No. 1 Reformer is not considered affected since the production rate is not expected to exceed the rates that have been previously accommodated for this unit.

2.3.6 Hydrogen Plant

Hydrogen is produced by the new Hydrogen Plant, the No. 1 Reformer, and the No. 2 Reformer. When the Hydrogen Plant was permitted, the refinery took limits of combined H₂ production (67.86 MMSCFD on an annual basis and 80.86 MMSCFD on an hourly basis) to keep other H₂ consuming units in the refinery (hydrotreaters and hydrocracker) from being affected. All of these units are now affected by the Crude Expansion Project and are included as part of the PSD analysis. Therefore, there is no further purpose for the combined H₂ production limits, so they can be removed.

The Hydrogen Plant is expected to produce up to its full capacity of 30 MMSCFD as a result of the Crude Expansion Project. But the Hydrogen Plant is a new source that will have less than two years in service, so its baseline emissions are considered to be its allowable emissions. As a result, the Hydrogen Plant is not considered to be an affected source.

2.3.7 Fluid Catalytic Cracking Unit

The refinery currently operates a Fluidized Catalytic Cracking Unit (FCCU) to further refine gas oils separated at the crude units into lighter products.

The FCCU includes a high temperature regenerator for complete CO combustion. In catalytic cracking, large molecules in heavy distillate feedstock are broken down into a variety of smaller molecules. Reactor products are separated in a series of distillation operations, and coke is burned off the spent catalyst in the regenerator (EPN: V-20). The Crude Expansion Project will not increase the amount of gas oil processed at the FCCU above rates that have been previously accommodated for this unit. Therefore, the FCCU is not considered affected by the Crude Expansion Project.

2.3.8 Heavy Oil Processing

The heavy oil (Vacuum Resid or Pitch) processing will be accomplished with the existing PDA. The PDA Unit extracts gas oil in vacuum tower bottoms by contacting it with a light hydrocarbon solvent such as propane. The vacuum tower bottoms and solvent are brought together in countercurrent flow in a liquid-liquid extraction tower. Gas oil in the vacuum tower bottoms is extracted by the solvent and the gas oil/solvent mix rises to the top of the extractor. The remainder of the vacuum tower

bottoms stream containing asphalt and some solvent leave the bottom of the extractor. The separated gas oil and asphalt streams then pass through a series of process heaters (EPNs: H-6, and H-40) and towers where the hydrocarbon solvent is flashed off and recovered for reuse. The asphalt is blended and stored in heated tanks prior to sales.

With the planned increase in crude processing, the production rates for the PDA are expected to increase. Therefore, the PDA and associated process heaters are considered affected by this project. The increased processing rate will result in a firing rate increase at the associated heaters, but will not require an increase in its current represented firing rate. The heaters used to heat the asphalt storage tanks are not considered affected by the increased production since they run near steady state and are not operationally dependant on the tank throughputs.

2.3.9 Hydrotreating and Other Desulfurization Units

The refinery currently uses multiple hydrotreating and other desulfurization units to remove sulfur from distilled products such as naphtha, gasoline, turbine fuel and diesel.

The No. 1 Hydrotreater, No. 2 Hydrotreater, and the Unifiner uses hydrogen to sweeten sour naphtha by converting sulfur compounds to H₂S over a catalyst. The sweet naphtha can then be charged to the reforming units. The No. 4 Hydrotreater treats stabilized LSR product from the three refinery debutanizers discussed in Section 2.3.3. Prior to reacting with hydrogen, the sour feeds are heated using the following process heaters:

- No. 1 Naphtha Hydrotreater Charge Heater (EPN: H-45)
- No. 2 Naphtha Hydrotreater Charge Heater (EPN: H-36)
- Unifiner Charge Heater (EPN: H-14)

The Nos. 1 and No. 2 Naphtha Hydrotreaters also use fired heaters (EPNs: H-15 and H-36, respectively) for reboiling at the unit's stabilizer towers.

Gasoline produced from the FCCU is treated to remove sulfur using the FCC Gas Hydrogen Desulfurization (HDS) Unit. The FCC Gas HDS Unit, similar to the hydrotreaters, uses hydrogen to sweeten gasoline by converting sulfur compounds to H₂S over a catalyst. Prior to reacting with hydrogen, the sour gasoline is heated using the Gasoline Desulfurization Unit (GDU) Charge Heater (EPN: H-80). As previously mentioned in Section 2.2.5, piping will be added as part of this project to route some naphtha from the naphtha header to the FCC Gas HDS Unit.

The proposed Crude Expansion Project will result in increased production of naphtha, gasoline, turbine fuel, and diesel among other products. This increased production may increase the fuel firing of the before mentioned heaters that support the refineries hydrotreating processes. As such, these process heaters are considered affected

emissions sources; however, the proposed changes will not require any physical changes to these sources and will not require an increase in their currently represented firing rates.

2.3.10 Amine Treating and Sulfur Recovery Units

Amine treating is used to separate light organic gases (fuel gas) from the acid gas streams generated at the refinery hydrotreating process units. The No. 1 and No. 2 Sulfur Recovery Units (SRUs) are used to extract elemental sulfur from treated acid gas streams. The SRUs consist of a straight-through Claus process. Amine acid gas, sour water stripper gas, and recycle acid gas from the tail gas unit are charged to the reactor furnace. A blower provides air to burn approximately one third of the H_2S to SO_2 . The reactor products are cooled and passed through a sulfur condenser. The remaining vapors are heated and passed through a separate catalytic reactor which produces additional elemental sulfur.

The tail gas from the Claus process is directed to tail gas treating units (TGTU) consisting of a treating unit and incinerator. The treating units are designed to reduce the sulfur in the tail gas to H_2S . The H_2S is then absorbed and stripped before being sent back to the Claus units for further sulfur recovery. The remaining gases are incinerated, and vented out to the atmosphere (EPNs: V-5 and V-16, respectively).

With the planned increase in crude processing, acid gas production is expected to increase. Some of the additional acid gas may be processed at the SRUs; therefore, the No. 1 SRU and No. 2 SRU and their associated TGTU incinerator process vents are considered affected. The additional processing of acid gas will not require any physical modifications to these units and will not require an increase in their currently represented capacities.

2.3.11 Iso-Octene Unit

The Iso-Octene Unit is currently used to process an isobutylene rich stream from the FCC Depropanizer Bottoms to produce a C_4 raffinate (a gasoline blending component) and a C_5 Iso-Octene. The unit consists of three sections, a polymerization section, a fractionation section, and an alcohol recovery section. A resin catalyst is used for the polymerization section.

The water washed C_4 (B-B) feed from the FCC unit is sent to the polymerization reactor section. The stream is mixed with recycled alcohol and sent to the two polymerization reactors in series. The purpose of the alcohol is to attenuate the resin catalyst. The net product from the polymerization reactor section is sent to the debutanizer column which separates unconverted feed (net C_4 raffinate) from the C_5+ material. The C_4 raffinate is sent to the downstream alkylation unit via storage. The debutanizer bottoms product is sent to an alcohol extractor column for alcohol removal. The alcohol from the extractor bottoms is recovered in a stripper column; with a portion recycled to the polymerization section and a portion leaving the unit as a net stream to prevent contaminant buildup.

Since the proposed Crude Expansion Project will not increase production of isobutylene (B-B) from the FCCU, the Iso-Octene Unit, which processes this B-B, is not considered affected.

2.3.12 Alkylation Unit

The Alkylation Unit produces a high octane, branched paraffinic alkylate blendstock by reacting C3 or C4 olefins and iso-butane together in the presence of sulfuric acid. The Alkylation units consist of three primary sections: The first section consists of caustic treating and diolefin hydrogenation facilities to prepare olefins. The Alkylation Unit consists of Stratco designed effluent refrigerated contactors, acid settlers, compressors, and fractionation facilities. An independent section for treating propane/propylene (P/P) consists of amine and caustic treating and a pair of dehydrators.

Since the proposed Crude Expansion Project will not increase production of paraffin from the FCCU, the Alkylation Unit, which processes this paraffin, is not considered affected.

2.3.13 Acid Plant

The Sulfuric Acid Plant serves as a process unit to reduce SO₂ emissions and produces sulfuric acid used in the Alkylation Units. Sulfuric acid regeneration requires thermal decomposition ("burning") of the acid to SO₂, and remaking the acid through chemical reaction.

Acid gas and air is fed into a combustion chamber. The SO₂ and other products from the combustion of spent acid and H₂S with undried atmospheric air are passed through gas cleaning and mist removal equipment. The gas stream then passes through a drying tower which discharges the sulfur dioxide gas to the sulfur trioxide converter. The sulfur trioxide gas from the converter flows to an absorption tower where sulfur trioxide is absorbed in 93 to 98 percent sulfuric acid spray. The sulfur trioxide combines with the water in the acid and forms more sulfuric acid. SO₂ and acid mist are released at the top of the absorber to a scrubber before released to the atmosphere (EPN: V-29).

With the planned increase in crude processing, the acid gas production is expected to increase. Some of the additional acid gas may be processed at the Sulfuric Acid Plant; however, since this process unit does not emit GHG emissions, it is not considered affected.

2.3.14 Crude and Product Storage

The Crude Expansion Project will result in increase in crude throughput and production of many intermediate and final products at the refinery, including but not limited to the following: Naphtha, LSR, Gasoline, Turbine Fuel, Jet Fuel, Diesel, Gas Oil, Vacuum Resid, Slop Oils, Sour Water, Reformate, Alkylate, LPG, Propanes, and Butanes.

LPG, Propanes, and Butanes are stored in pressurized tanks and do not emit under normal circumstances. Therefore, these storage tanks are not considered affected sources. CH₄ can be expected to be emitted from crude oil storage tanks, but not from the products tanks other than LPG, Propanes, and Butanes. Therefore, only crude oil storage tanks are considered affected sources. The Crude Expansion project will not require the addition of any new storage tanks or physical changes to existing storage tanks.

2.3.15 Product Loading

The McKee Refinery transfers most refinery products via trucks, railcars and pipeline for off-site sales. With increased production of motor fuels, turbine fuel, and diesel associated with this project, product loading is expected to increase and is therefore affected. However, the increase will not require any new loading racks or an increase in the currently permitted emission rates for the current loading racks, except for the truck loading rack (EPN: L-11) and the diesel railcar loading racks (EPNs: L-5 and L-13). Given this fact and since product loading is more driven by local economics rather than increased production, all loading operations other than the truck loading rack and the diesel railcar loading racks are not considered affected sources of the Crude Expansion project. The truck loading rack and the diesel railcar loading rack (EPN: L-13) are controlled by a vapor combustion, therefore, the truck rack and the diesel railcar loading rack (EPN: L-13) are considered affected.

2.3.16 Steam Production

Process equipment utilizes steam produced by existing boilers and steam produced by heat recovery from certain refinery processes. Based on review of the proposed process changes and steam balance information, Valero has concluded that the proposed project will result in an incremental increase of steam usage equivalent to approximately 20 MMBtu/hr (annual average) of 300 psi or 150 psi steam from the existing boilers. Therefore, the existing boilers are considered upstream affected units. No new boilers will be added to the refinery associated with this project.

2.3.17 Waste Gas Flaring

The refinery currently operates four process unit flares (EPNs: FL-1, FL-3, FL-4, FL-8) that receive routine and non-routine vent streams from multiple process units throughout the refinery. With increased crude processing, there is an expected increase in waste gas that may be generated during routine operations. However, the refinery plans to have installed by the end of 2011 a flare gas recovery system that will recover and process the current and future waste gas streams that may be generated from this project. As such, there will be no increase in actual emissions from the flares associated with this project.

2.3.18 Wastewater Treatment

Wastewater streams from the various refinery operations are routed to the on-site wastewater operations for treatment and disposal. Wastewater may be stored in several wastewater tanks (EPNs: S-184, S-195, S-196, S-197 and S-199) before being routed to wastewater treatment. Oily wastewater is processed through the API Separator to separate free oil from the wastewater. Slop oil from the API Separator is routed to the slop oil tanks and then returned back to the refinery processes for recovery. The API Separator is enclosed, and vapors from this unit are routed to the Wastewater Flare (EPN: FL-6). The water from the API Separator is deep well injected.

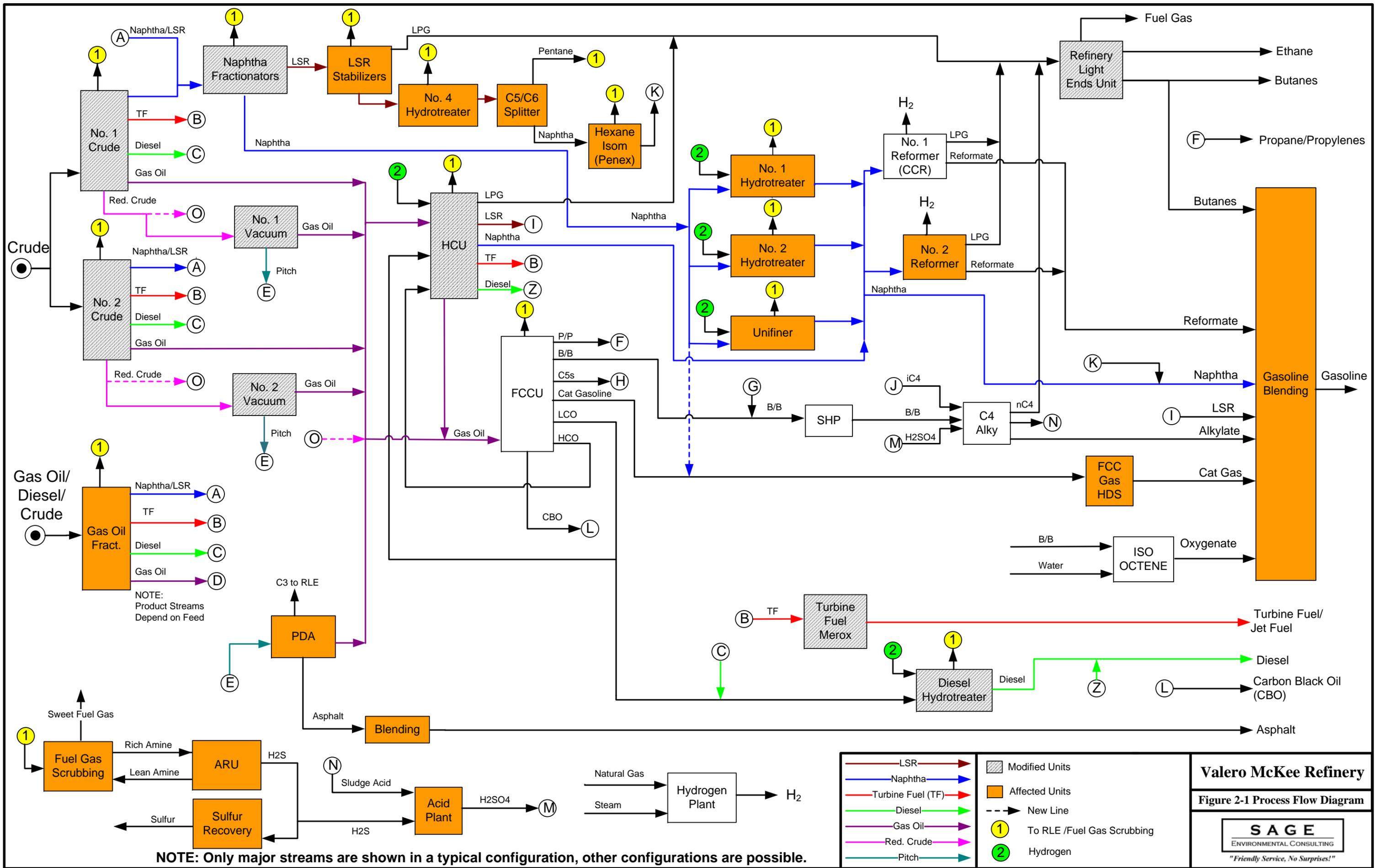
The Crude Expansion Project may increase wastewater production flow and therefore, the wastewater storage tanks and Wastewater Flare are considered affected emission sources. However, there are no new wastewater drains or sumps expected to be added with this project.

2.3.19 Cooling Towers

It is not anticipated that the Crude Expansion Project will affect actual emission rates from any cooling towers.

2.3.20 Planned Maintenance, Start-Up, and Shutdown Activities

Planned Maintenance, Start-Up, and Shutdown (MSS) emissions associated with the refinery are already authorized under the existing state NSR Permit No. 9708. No increase in GHG MSS emissions are being requested as a result of this project.



Valero McKee Refinery
Figure 2-1 Process Flow Diagram

"Friendly Service, No Surprises!"

SECTION 3

GHG EMISSION CALCULATION METHODOLOGY

This section describes the emission calculation methodologies used to calculate annual GHG emission rates for the emission sources associated with the Crude Expansion Project. Detailed emission calculations are provided in the tables located in Appendix B of this application. The calculation tables in this appendix are intended to be self-explanatory; therefore, the following discussion is limited to a general description of calculation methodologies and a summary of key assumptions and calculation basis data.

3.1 New and Modified Emissions Sources

There are no new emissions sources associated related to the Crude Expansion Project. The new fugitive components added to the Nos. 1 and 2 Crude Units, the Nos. 1 and 2 Vacuum Units, the Refinery Light Ends Unit (RLE) Unit, the No. 4 Naphtha Fractionator, the Dehexanizer Tower, the HCU, the Turbine Merox Unit, and the Diesel Hydrotreater making these units modified. In addition, the No. 2 Vacuum Heater will be modified as described in Section 2.

New Fugitive Equipment Leaks:

Fugitive emission rates of VOC from the piping components and ancillary equipment were estimated using the methods outlined in the TCEQ's *Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000*.

Each fugitive component was classified first by equipment type (valve, pump, relief valve, etc.) and then by material type (gas/vapor, light liquid, heavy liquid). An uncontrolled emission rate was obtained by multiplying the number of fugitive components of a particular equipment/material type by the appropriate emission factor per the TCEQ guidance document. The refinery fugitive emission factors were used for all refinery units. To obtain controlled fugitive emission rates, the uncontrolled rates were multiplied by a control factor, which was determined by the LDAR program employed for that source type. For the proposed CH₄ emissions from added fugitive components, the CH₄ emissions were calculated by multiplying the estimated average CH₄ concentration for the additional fugitive components by the estimated controlled fugitive emissions rates. The CH₄ emissions which are also expressed as CO₂e for the added fugitive components from the modified units in summarized in Table B-2 of Appendix B.

Modified Process Heater Emissions:

CO₂ emissions from firing refinery fuel gas and/or purchased natural gas at the No. 2 Vacuum heater (EPN: H-26) are conservatively estimated by using Equation C-5 from the Federal GHGMRR 40 CFR 98 Subpart C - General Stationary Fuel Combustion Sources, the fuel annual usage rate, and the fuel's annual average carbon content.

CH₄ and N₂O emissions from the No. 2 Vacuum Heater were calculated based on the emission factor of 3×10^{-3} kg-CH₄/MMBtu and 6×10^{-4} kg- N₂O / MM Btu (40 CFR 98 Subpart C Table C-2), respectively.

The PTE or proposed allowable emissions of CO₂, CH₄, and N₂O expressed as CO₂e for the modified No. 2 Vacuum Heater associated with the Crude Expansion Project are presented in Table B-12 in Appendix B.

3.2 Upstream and Downstream Affected Source Emissions Increases

Upstream and downstream operational impacts were considered for the reasons discussed in Section 2.3 of this application. The upstream and downstream emissions sources determined to be potentially affected by the proposed changes include multiple gas-fired process heaters, boilers, storage tanks, loading, wastewater and process flares, sulfur recovery units, and several process vents. Table B-1 in Appendix B provides a complete list of emissions sources considered affected by the Crude Expansion project including the predicted emission increases by sources.

The following subsections summarize the methods used to calculate GHG emission rates from each emission source type.

Process Heaters and Boilers:

The baseline and projected CO₂ emissions from modified and affected process heaters and boilers are fired with refinery fuel gas and/or purchased natural gas and emissions are calculated using Equation C-5 from the Federal GHGMRR 40 CFR 98 Subpart C - General Stationary Fuel Combustion Sources, the respective baseline and projected annual fuel usage rates, and the respective fuel's annual average carbon content.

CH₄ and N₂O emissions from the affected heaters and boilers were calculated based on the emission factor of 3×10^{-3} kg-CH₄/MMBtu and 6×10^{-4} kg- N₂O / MM Btu (40 CFR 98 Subpart C Table C-2), respectively.

The increase in CO₂, CH₄ and N₂O emissions were calculated as the difference between the projected and baseline annual emissions rates for each heater and boiler.

Tables B-10 and B-11 of Appendix B present the PTE and the baseline emissions for all modified and affected heaters and boilers associated with the project.

No. 2 Reformer Vent:

CO₂ emissions from the No. 2 Reformer Vent were calculated using Equation Y-11 of the Federal GHGMRR 40 CFR 98 Subpart Y – Petroleum Refineries, and converting from metric tons to U.S. tons.

CH₄ emissions from the Reformer are calculated based on 40 CFR 98 Subpart Y Equation Y-9 and converting from metric tons to U.S. tons. N₂O emissions from the Reformer are calculated based on 40 CFR 98 Subpart Y Equation Y-10 and converting from metric tons to U.S. tons. Reformer are calculated based on 40 CFR 98 Subpart Y Equation Y-10 and converting from metric tons to U.S. tons.

The increases in CO₂, CH₄ and N₂O emissions were calculated as the difference between the projected and baseline annual emissions rates for each incinerator vent. Table B-13 of Appendix B presents the PTE and the baseline emissions for the No. 2 Reformer vent.

Sulfur Recovery Units:

CO₂ emissions from the SRU Incinerators (EPNs: V-5 and V-16) were calculated using Equation Y-12 of the Federal GHGMRR 40 CFR 98 Subpart Y – Petroleum Refineries, and converting from metric tons to U.S. tons.

The increases in CO₂ emissions were calculated as the difference between the projected and baseline annual emissions rates for each incinerator vent. Tables B-14 and B-15 of Appendix B presents the PTE and the baseline emissions for each SRU Incinerator.

Wastewater Flare FL-6 and Vapor Combustor FL-7

CO₂ emissions from the Wastewater Flare FL-6 (EPN: FL-6) were calculated using Equation Y-3 of the Federal GHGMRR 40 CFR 98 Subpart Y – Petroleum Refineries, and converting from metric tons to U.S. tons.

CH₄ emissions from Flare FL-6 were calculated based on 40 CFR 98 Subpart Y Equation Y-4 and converting from metric tons to U.S. tons. N₂O emissions from the flare were calculated based on 40 CFR 98 Subpart Y Equation Y-5 and converting from metric tons to U.S. tons.

The increases in CO₂, CH₄ and N₂O emissions for the flare were calculated as the difference between the projected and baseline annual emissions rates. Table B-16 of Appendix B presents the PTE and the baseline emissions for the Wastewater Flare.

Vapor Combustor FL-7

CO₂ emissions from the loading rack vapor combustor (EPN: FL-7) were calculated using Equation Y-3 of the Federal GHGMRR 40 CFR 98 Subpart Y – Petroleum Refineries, and converting from metric tons to U.S. tons.

CH₄ emissions from the vapor combustor FL-7 were calculated based on 40 CFR 98 Subpart Y Equation Y-4 and converting from metric tons to U.S. tons. N₂O emissions from the vapor combustor were calculated based on 40 CFR 98 Subpart Y Equation Y-5 and converting from metric tons to U.S. tons.

The increases in CO₂, CH₄ and N₂O emissions for the vapor combustor were calculated as the projected incremental increase associated with the Crude Expansion Project. Table B-17 of Appendix B presents the incremental increase of GHG from the vapor combustor FL-7.

Storage Tanks:

The Crude Expansion Project will increase throughputs at the crude oil storage tanks, and the wastewater storage tanks. The increase in CH₄ emissions from the crude oil storage tanks and wastewater storage tanks were calculated using Equation Y-22 from Federal GHGMRR 40 CFR 98 Y – Petroleum Refineries, and the projected increase in the crude oil annual throughput associated with the Crude Expansion Project. The emissions were converted from metric tons to U.S. tons.

Table B-18 of Appendix B presents the PTE and the baseline emissions for the affected storage tanks.

CO₂e Emissions

CO₂e emissions are defined as the sum of the mass emissions of each individual GHG adjusted for its global warming potential (GWP). Valero has used the GWP values in Table A-1 of the GHG MRR Rule (40 CFR Part 98, Subpart A, Table A-1) to calculate CO₂e emissions from estimated emissions of CO₂, CH₄, and N₂O by multiplying the individual GHG pollutant rates by their applicable GWP provided in Table 3-1 below.

Table 3-1 GWP Table

POLLUTANT	GWP
CO ₂	1
CH ₄	21
N ₂ O	310

SECTION 4

GHG BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

The increases in potential GHG emissions associated with this project are above the PSD threshold. Subsequently, any new or modified affected emissions unit where a net increase in CO₂, CH₄, and N₂O emissions has occurred is subject to the application of BACT. The sources that will be new or modified that are subject to BACT review includes the No. 2 Vacuum Unit Heater and fugitive components (Equipment Leaks). All other equipment affected by this project do not meet the definition of modified and therefore are not subject to a BACT analysis.

4.1 BACT Analysis Methodology

BACT is defined in 40 CFR 52.21(b)(12) of the PSD regulations as “..an emission limitation based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any...source...which on a case-by-case basis is determined to be achievable taking into account energy, environmental and economic impacts and other costs”. In the EPA guidance document titled *PSD and Title V Permitting Guidance for Greenhouse Gases*, EPA recommended the use of the Agency's five-step "top-down" BACT process to determine BACT for GHGs. In brief, the top-down process calls for all available control technologies for a given pollutant to be identified and ranked in descending order of control effectiveness. The permit applicant should first examine the highest-ranked ("top") option. The top-ranked options should be established as BACT unless the permit applicant demonstrates to the satisfaction of the permitting authority that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the top ranked technology is not "achievable" in that case. If the most effective control strategy is eliminated in this fashion, then the next most effective alternative should be evaluated, and so on, until an option is selected as BACT. The five basic steps of a top-down BACT analysis are listed below:

- Step 1: Identify potential control technologies.
- Step 2: Eliminate technically infeasible options.
- Step 3: Rank remaining control technologies.
- Step 4: Evaluate the most effective controls and document results.
- Step 5: Select the BACT.

The first step is to identify potentially “available” control options for each emission unit triggering PSD, for each pollutant under review. Available options should consist of a comprehensive list of those technologies with a potentially practical application to the emission unit in question. The list should include lowest achievable emission rate (LAER) technologies, innovative technologies, and controls applied to similar source categories. For

this analysis, the following sources are typically consulted when identifying potential technologies:

- EPA's New Source Review Website,
- U.S. EPA's RACT/BACT/LAER Clearinghouse (RBLC) Database,
- Engineering experience with similar control applications,
- Various state air quality regulations and websites, and
- Guidance Documents and Reports including:
 - "Available And Emerging Technologies For Reducing Greenhouse Gas Emissions From The Petroleum Refining Industry" published by EPA Office of Air and Radiation; and
 - "Report of the Interagency Task Force on Carbon Capture and Storage" obtained from http://www.epa.gov/climatechange/policy/ccs_task_force.html.

After identifying potential technologies, the second step is to eliminate technically infeasible options from further consideration. To be considered feasible, a technology must be both available and applicable. A control technology or process is only considered available if it has reached the licensing and commercial sales phase of development and is "commercially available". It is important, in this step, that the technical basis for eliminating a technology from further consideration be clearly documented based on physical, chemical, engineering, and source-specific factors related to safe and successful use of the controls.

The third step is to rank the technologies not eliminated in Step 2 in order of descending control effectiveness for each pollutant of concern.

The fourth step entails an evaluation of energy, environmental, and economic impacts for determining a final level of control. The evaluation begins with the most stringent control option and continues until a technology under consideration cannot be eliminated based on adverse energy, environmental, or economic impacts.

The fifth and final step is to select as BACT the most effective of the remaining technologies under consideration for each pollutant of concern.

4.2 No. 2 Vacuum Heater - GHG BACT

The Valero McKee Refinery's Crude Expansion Project will modify the No. 2 Vacuum Heater (H-26) that burns refinery fuel gas. This process heater will emit three GHGs: CH₄, CO₂, and N₂O. CO₂ will be emitted from the heater because it is a combustion product of any carbon-containing fuel. CH₄ will be emitted from the heater as a result of any incomplete combustion of refinery fuel gas and/or natural gas. N₂O will be emitted from the heater in trace quantities due to partial oxidation of nitrogen in the air which is used as the oxygen source for the combustion process.

All fossil fuels contain significant amounts of carbon but the refinery fuel gas and natural gas combusted in this heater is a low carbon fuel. One of the useful byproducts produced by the petroleum refining process is refinery fuel gas. This gas is generally similar to natural gas but contains less methane and more hydrogen and ethane than natural gas does. In the combustion of a fossil fuel, the fuel carbon is oxidized into CO and CO₂. Full oxidation of fuel carbon to CO₂ is desirable because CO has long been a regulated pollutant with established adverse environmental impacts, and because full combustion releases more useful energy within the process. In addition, emitted CO gradually oxidized to CO₂ in the atmosphere. CO₂ emissions are generated and emitted from the modified No. 2 Vacuum Unit Heater and exhausted to the atmosphere from the heater stack.

4.2.1 Step 1 - CO₂ Control Technologies

The following technologies were identified as CO₂ control options for refinery process heaters based on available information and data sources:

- Use of low carbon fuels;
- Use of good combustion practices;
- Energy efficient design;
- Pre-Combustion Carbon Capture and Storage (CCS); and
- Post-Combustion CCS.

4.2.1.1 Low Carbon Fuels

The following table presents the amount of CO₂ formed when combusting fossil fuels, including some of the fuels that will be used by the No. 2 Vacuum Unit Heater.

Table 4-1 CO₂ Emission Factors¹

Fuel Type	Default CO₂ Emission Factor
Coal and coke	kg CO ₂ /mmBtu
Anthracite	103.54
Bituminous	93.40
Subbituminous	97.02
Lignite	96.36
Coke	102.04
Natural gas	kg CO ₂ /mmBtu
(Weighted U.S. Average)	53.02

Fuel Type	Default CO₂ Emission Factor
Distillate Fuel Oil No. 1	73.25
Distillate Fuel Oil No. 2	73.96
Distillate Fuel Oil No. 4	75.04
Residual Fuel Oil No. 5	72.93
Residual Fuel Oil No. 6	75.10
Used Oil	74.00
Kerosene	75.20
Liquefied petroleum gases (LPG)	62.98
Propane	61.46
Propylene	65.95
Ethane	62.64
Ethanol	68.44
Ethylene	67.43
Isobutane	64.91
Isobutylene	67.74
Butane	65.15
Butylene	67.73
Naphtha (<401 deg F)	68.02
Natural Gasoline	66.83
Other Oil (>401 deg F)	76.22
Pentanes Plus	70.02
Petrochemical Feedstocks	70.97
Petroleum Coke	102.41
Special Naphtha	72.34
Unfinished Oils	74.49
Heavy Gas Oils	74.92
Lubricants	74.27
Motor Gasoline	70.22
Aviation Gasoline	69.25
Kerosene-Type Jet Fuel	72.22
Asphalt and Road Oil	75.36

Fuel Type	Default CO₂ Emission Factor
Other fuels-solid	kg CO ₂ /mmBtu
Municipal Solid Waste	90.7
Tires	85.97
Plastics	75.00
Petroleum Coke	102.41
Other fuels—gaseous	kg CO ₂ /mmBtu
Blast Furnace Gas	274.32
Coke Oven Gas	46.85
Propane Gas	61.46
Fuel Gas	59.00
Biomass fuels—solid	kg CO ₂ /mmBtu
Wood and Wood Residuals	93.80
Agricultural Byproducts	118.17
Peat	111.84
Solid Byproducts	105.51
Biomass fuels—gaseous	kg CO ₂ /mmBtu
Biogas (Captured methane)	52.07
Biomass Fuels—Liquid	kg CO ₂ /mmBtu
Ethanol	68.44
Biodiesel	73.84
Biodiesel (100%)	73.84
Rendered Animal Fat	71.06
Vegetable Oil	81.55

Obtained from 40CFR98, Subpart C, Table C-1

As shown in the table above, the use of natural gas and refinery fuel gas reduces the production of CO₂ from combustion of fuel relative to burning solid fuels (e.g. coal or coke) and liquid fuels (i.e., distillate or residual oils).

4.2.1.2 *Good Combustion Practices*

Good combustion practices for process heaters fired with refinery fuel gas include the following:

- Good air/fuel mixing in the combustion zone;
- Sufficient residence time to complete combustion;
- Proper fuel gas supply system design and operation in order to minimize fluctuations in fuel gas quality;
- Good burner maintenance and operation;
- High temperatures and low oxygen levels in the primary combustion zone; and
- Overall excess oxygen levels high enough to complete combustion while maximizing thermal efficiency.

4.2.1.3 *Energy Efficient Design*

When possible based on existing refinery design and operation, the use of the following can provide an energy efficient design for process heaters minimizing the required fuel combustion for process heaters.

- Combustion Air Preheat;
- Use of Process Heat to Generate Steam;
- Process Integration and Heat Recovery;
- Increase radiant tube surface area when modifying existing heaters;
- Excess Combustion Air Monitoring and Control; and
- Cogeneration as a CO₂ Reduction Technique.

4.2.1.4 *Pre-Combustion or Post-Combustion Carbon Capture and Storage (CCS)*

Pre-combustion carbon capture for fuel gas combustion involves substituting pure oxygen for air in the combustion process, resulting in a concentrated CO₂ exhaust stream so it may be captured more effectively. The oxygen may be isolated from air using a number of technologies, including cryogenic separation and membrane separation. Post-combustion carbon capture for fuel gas combustion is applied to conventional combustion techniques using air and carbon-containing fuels in order to isolate CO₂ from the combustion exhaust gases. There are a number of methods and processes that could be used to capture CO₂ from the dilute exhaust gases produced by the process heater. These capture technologies include separation with solvent or physical filters, cryogenic separation to condense the CO₂, and membrane separation technologies.

In order to provide effective reduction of CO₂ emissions, efficient methods of compression, transport, and storage would also be required. This would require transporting the captured CO₂ to a suitable geological storage formation including the following:

- Depleted oil and gas reservoirs,
- Unmineable coal seams,
- Saline formations,
- Basalt formations, and
- Terrestrial ecosystems.

There are several major unresolved issues with respect to CO₂ sequestration including the legal process for closing and remediating sequestration sites and liability for accidental releases from these sites.

4.2.2 Step 1 - CH₄ and N₂O Control Technologies

The following technologies were identified as CH₄ and N₂O control options for refinery process heaters based on available information and data sources (see Section 6.1)

- Use of low carbon fuels;
- Use of good combustion practices;
- Energy efficient design; and
- Oxidation catalysts (CH₄ Control Only).

4.2.2.1 Low Carbon Fuels

The following table presents the default emission factors of CH₄ and/or N₂O formed when combusting fossil fuels, including some of the fuels that will be used by the process heater.

Table 4-2 CH₄ and N₂O Emission Factors²

Fuel type	Default N ₂ O emission factor (kg CH ₄ /mmBtu)	Default CH ₄ emission factor (kg CH ₄ /mmBtu)
Coal and Coke (All fuel types in Table C-1)	1.6×10^{-03}	1.1×10^{-02}
Natural Gas	1.0×10^{-04}	1.0×10^{-03}
Petroleum (All fuel types in Table C-1)	6.0×10^{-04}	3.0×10^{-03}
Municipal Solid Waste	4.2×10^{-03}	3.2×10^{-02}
Tires	4.2×10^{-03}	3.2×10^{-02}

Fuel type	Default N ₂ O emission factor (kg CH ₄ /mmBtu)	Default CH ₄ emission factor (kg CH ₄ /mmBtu)
Blast Furnace Gas	1.0×10^{-04}	2.2×10^{-05}
Coke Oven Gas	1.0×10^{-04}	4.8×10^{-04}
Biomass Fuels—Solid (All fuel types in Table C-1)	4.2×10^{-03}	3.2×10^{-02}
Biogas	6.3×10^{-04}	3.2×10^{-03}
Biomass Fuels—Liquid (All fuel types in Table C-1)	1.1×10^{-04}	1.1×10^{-03}

²Obtained from 40CFR98, Subpart C, Table C-2.

As shown in the table, the use of natural gas and refinery fuel gas reduces the production of CH₄ and N₂O from combustion of fuel relative to burning solid fuels (e.g. coal or coke) and liquid fuels (i.e., distillate or residual oils).

4.2.2.2 Good Combustion Practices

Good combustion practices for process heaters fired with refinery fuel gas include the following:

- Good air/fuel mixing in the combustion zone;
- Sufficient residence time to complete combustion;
- Proper fuel gas supply system design and operation in order to minimize fluctuations in fuel gas quality;
- Good burner maintenance and operation;
- High temperatures and low oxygen levels in the primary combustion zone; and
- Overall excess oxygen levels high enough to complete combustion while maximizing thermal efficiency.

4.2.2.3 Energy Efficient Design

When possible based on existing refinery design and operation, the use of the following can provide an energy efficient design for process heaters minimizing the required fuel combustion for process heat.

- Combustion Air Preheat;
- Use of Process Heat to Generate Steam;
- Process Integration and Heat Recovery;
- Increase radiant tube surface area when modifying existing heaters; and
- Excess Combustion Air Monitoring and Control.

4.2.2.4 *Oxidation Catalysts*

Oxidation catalyst has been widely applied as a control technology for CO and VOC emissions from natural gas-fired combined cycle gas turbines and would also provide reduction in CH₄ emissions. This technology utilizes excess air present in the combustion exhaust and the activation energy required for the reaction to lower CH₄ concentration in the presence of a catalyst. The optimum temperature range for these systems is approximately 850°F to 1,100°F. No chemical reagent addition is required.

4.2.3 Step 2 - Eliminate Technically Infeasible Options

This step of the top-down BACT analysis eliminates any control technology that is not considered technically feasible unless it is both available and applicable.

4.2.3.1 *Lower Carbon Fuels*

The process heaters at the refinery combust refinery fuel gas which is a low-carbon fuel. The only identified fuels with lower CO₂ formation rates are syngas, pressure swing adsorption ("PSA") tail gas, and natural gas. Production of additional syngas or PSA tail gas would lead to overall increases in GHG emissions from the refinery and do not represent options for reducing GHG emission. Natural gas is commercially available and would yield slightly reduced CO₂ emission rates from the process heaters, but displacing refinery fuel gas from use as fuel in the process heaters would necessitate disposal of this fuel gas by combustion elsewhere at the refinery, such as by flaring, which would increase overall CO₂ emissions from the site. Thus there are no control options involving the use of low-carbon fuels in process heaters that are technically feasible for reducing GHG emissions relative to the proposed use of refinery fuel gas.

4.2.3.2 *Carbon Capture and Storage*

The pre-combustion technique for CO₂ separation involves substituting pure oxygen for air in the combustion process, resulting in a concentrated CO₂ exhaust stream. This "oxyfuel" process has not yet been tested or demonstrated in a project such as process heaters at a petroleum refinery. However, for purposes of BACT analysis, it is assumed that this technology would be technically feasible since it is both available and applicable.

There are a number of methods and processes that could be used to capture CO₂ from the dilute exhaust gases produced by the process heater. These capture technologies include separation with solvent or physical filters, cryogenic separation to condense the CO₂, and membrane separation technologies.

4.2.3.2.1 Separation with Solvent Scrubbers

There are many solvents under development for the separation of CO₂ from combustion of flue gases through chemical absorption. The most commercially developed of these processes use monoethanolamine (MEA) as the solvent. MEA has the advantage of fast reaction with CO₂ at low partial pressure. The primary concern with MEA is corrosion in the presence of O₂ and other impurities, high solvent degradation rates due to reactions with SO₂ and NO_x, and the energy requirements for solvent regeneration. Solvent scrubbing has been used in the chemical industry for separation of CO₂ in exhaust streams and is a technically feasible technology for this application; however, it has not been demonstrated in large scale industrial process applications.

4.2.3.2.2 Cryogenic Separation

The cryogenic CO₂ capture process includes the following steps:

- Dry and cool the combustion flue gas;
- Compress the flue gas;
- Further cool the compressed flue gas by expansion which precipitates the CO₂ as a solid;
- Pressurize the CO₂ to a liquid; and
- Reheat the CO₂ and remaining flue gas by cooling the incoming flue gases.

The final result is the CO₂ in a liquid phase and a gaseous nitrogen stream that can be vented through a gas turbine for power generation. The CO₂ capture efficiency depends primarily on the pressure and temperature at the end of the expansion process. However, this process has not been commercially demonstrated on gas streams with low CO₂ concentrations such as the process heaters at a petroleum refinery. To date there is insufficient data available to accurately complete cost analyses for this developmental technology.

4.2.3.2.3 Membrane Separation

This method is commonly used for CO₂ removal from natural gas at high pressure and high CO₂ concentration. Membrane-based capture uses permeable or semi-permeable materials that allow for selective transport/separation of CO₂ from flue gas. It has been estimated that 80 percent of the CO₂ could be captured using this technology. The captured CO₂ would then be purified and compressed for transport. Membrane technology is not fully developed for CO₂ concentration and gas flow such as process heaters at a petroleum refinery. To date there is insufficient data available to accurately complete cost analyses for this developmental technology.

4.2.3.2.4 Carbon Transport and Storage

There are available technically feasible methods for compression, transport, and storage of concentrated CO₂ streams. Options for capturing emissions from process heaters fired with refinery fuel gas, which would be required as an element of CCS as a GHG emission control option, were discussed in the preceding three subsections under carbon capture and storage.

4.2.3.3 Oxidation Catalysts

Oxidation catalysts are not technically feasible. The typical oxidation catalyst for CH₄-containing exhaust gases is rhodium or platinum (noble metal) catalyst on an alumina support material. This catalyst is installed in an enlarged duct or reactor with flue gas inlet and outlet distribution plates. Acceptable catalyst operating temperatures range from 400 to 1250 °F, with the optimal range being 850 to 1,100 °F. Below approximately 600 °F, a greater catalyst volume would be required to achieve the same reductions. To achieve this temperature range in process heaters fired with refinery fuel gas, the catalyst would need to be installed in the heater upstream of any waste heat recovery or air preheat equipment.

Installation of oxidation catalyst in flue gas containing more than trace levels of SO₂ will result in poisoning and deactivation of the catalyst by sulfur-containing compounds, as well as increasing the conversion for SO₂ to SO₃. The increased conversion of SO₂ to SO₃ will increase condensable particulate matter emissions and increase flue gas system corrosion rates. For these reasons, catalytic oxidation of CH₄ is not considered technically feasible for the refinery fuel gas fired process heaters.

4.2.3.4 Good Combustion Practices

Good combustion practices for process heaters fired with refinery fuel gas are technically feasible and are inherent in the design of the No. 2 Vacuum Heater.

4.2.4 Step 3 - Rank Remaining Control Technologies

The following technologies and control efficiencies were identified as technically feasible for CO₂ control options for refinery process heaters based on available information and data sources:

- Post-Combustion CCS (assumed 93% control efficiency);
- Pre-Combustion CCS (assumed 87% control efficiency);
- Use of low carbon fuels (control efficiency is not available);
- Use of good combustion practices (efficiency is not available); and
- Energy efficient design (efficiency is not available).

4.2.5 Step 4 - Evaluate the Most Effective Controls and Document Results

4.2.5.1 *Use of Low Carbon Fuels, Good Combustion Practices, and Energy Efficient Design*

The use of low carbon fuels and good combustion practices are inherent in the design and operation of the No. 2 Vacuum Unit Heater at the Valero McKee Refinery. As part of the proposed project, the No. 2 Vacuum Unit Charge Heater will be modified to increase the radiant section of the heater, thereby reducing the overall skin temperature of the internal tubes and decreasing coking potential. This additional surface area will improve energy efficiency by reducing the heater's heat flux. Other energy efficient designs will be incorporated as feasible, depending on the existing heater configuration; specifically, the use of Combustion Air Preheat, Process Heat to Generate Steam, Process Integration and Heat Recovery, and Excess Combustion Air Monitoring and Control.

4.2.5.2 *Carbon Capture Systems*

4.2.5.2.1 **Pre-Combustion Carbon Capture**

The CO₂ emissions increases from the No. 2 Vacuum Unit Heater are 11,173 tons per year. The pre-combustion technique for CO₂ separation involves substituting pure oxygen for air in the combustion process, resulting in a concentrated CO₂ exhaust stream. The oxygen may be isolated from air using a number of technologies, including cryogenic separation and membrane separation. The concentrated CO₂ streams would then need to be dried, compressed from low pressure up to 2,000 psi and transported by pipeline to an appropriate storage site.

The estimated increase in capital costs for the CCS equipment needed for capture and compression would be up to approximately 25 percent¹, if the plant were built new. The costs are expected to be higher for a modified source due to issues associated with pre-existing piping and infrastructure issues. Pipeline transportation and injection/storage are estimated to be \$1.5 - \$23 per tonne CO₂² and are highly dependent on distance to nearest available carbon storage facility, terrain the pipeline must pass through, type of storage reservoir, existing infrastructure, regional factors, etc. In addition, adding the CCS would result in some energy penalty of up to 15%³ simply because the CCS process will use energy produced by the plant resulting in a loss of efficiency which may in turn potentially increase the natural gas fuel use of the plant to overcome these efficiency losses. These adverse energy, environmental, and economic impacts are significant combined with the fact that oxy-combustion process has not been demonstrated in practice⁴, outweigh the environmental benefit of

¹ "Report of the Interagency Task Force on Carbon Capture and Storage", August 2010, pg 33 (http://www.epa.gov/climatechange/policy/ccs_task_force.html)

² "Report of the Interagency Task Force on Carbon Capture and Storage", August 2010, pgs 37, 44 (http://www.epa.gov/climatechange/policy/ccs_task_force.html)

³ "Report of the Interagency Task Force on Carbon Capture and Storage", August 2010, pg A-14 (http://www.epa.gov/climatechange/policy/ccs_task_force.html).

⁴ "Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry", October 2010, pg 13 (<http://www.epa.gov/nsr/ghgdocs/refineries.pdf>).

CCS. Therefore, Pre-Combustion Carbon Capture and Storage does not represent BACT for the #2 Vacuum Unit Heater at the Valero McKee Refinery.

4.2.5.2.2 Post-Combustion Carbon Capture

For the purposes of the following analysis of CCS, chemical absorption using MEA based solvents is assumed to represent the best post-combustion CO₂ capture option. This control option is assumed to be 93 percent effective. The CO₂ emissions increases from the #2 Vacuum Heater are 11,173 tons per year. The CO₂ rich solvent from the scrubber would then be pumped to a regeneration system for CO₂ removal and reuse. The CO₂ would need to be dried, compressed from low pressure up to 2,000 psi and transported by pipeline to an appropriate storage site.

The estimated increase in capital costs for the CCS equipment needed for capture and compression would be up to approximately 80 percent⁵, if the plant were built new. As stated in subsection 4.2.5.2.1, the costs are expected to be higher for a modified source due issues associated with pre-existing piping and infrastructure issues. Pipeline transportation and injection/storage are estimated to be \$1.5 - \$23 per tonne CO₂ and are highly dependent on distance to nearest available carbon storage facility, terrain the pipeline must pass through, type of storage reservoir, existing infracture, regional factors, etc. In addition, adding the CCS would result in some energy penalty of up to 15% simply because the CCS process will use energy produced by the plant resulting in a loss of efficiency which may in turn potentially increase the natural gas fuel use of the plant to overcome these efficiency losses. These adverse energy, environmental, and economic impacts are significant and outweigh the environmental benefit of CCS. Therefore, CCS does not represent BACT for the No. 2 Vacuum Unit Heater at the Valero McKee Refinery.

4.2.5.2.3 Carbon Transport and Storage

In addition to the adverse economic impacts that show CCS is not a viable option for this project, the use of CCS for the No. 2 Vacuum Unit Heater at the Valero McKee Refinery would entail significant adverse energy and environmental impacts due to increased fuel usage in order to meet the steam and electric load requirements of these systems. In order to capture, dry, compress, and transport to a suitable enhanced oil recovery (EOR) site, the CO₂ available for capture from the process heater would require excessive amounts of additional electric power and steam generation capacity. The generation of the steam and electric power required by the project would itself result in GHG emissions, which would offset some of the net GHG reduction achieved by capturing and storing the CO₂ emitted by the process heaters.

⁵ "Report of the Interagency Task Force on Carbon Capture and Storage", August 2010, pg 33 (http://www.epa.gov/climatechange/policy/ccs_task_force.html)

4.2.6 Step 5 - Selection of BACT

The use of CO₂ capture at the Valero McKee Refinery would entail significant adverse energy and environmental impacts due to increased fuel usage in order to meet the steam and electric load requirements of these systems. In addition to the adverse impacts from steam and electricity generation that will be needed, the capital cost of the equipment to capture, dry, compress, and transport CO₂ make it economically infeasible. The adverse energy, environmental, and economic impacts are significant and outweigh the environmental benefit of CO₂ capture for this project and does not represent BACT for the process heater.

The Valero McKee Refinery will incorporate the use of low carbon fuels (refinery fuel gas and natural gas), good combustion practices, and energy efficient design where possible for the No. 2 Vacuum Heater to meet BACT.

4.3 Equipment Fugitives

The Valero McKee Refinery Crude Expansion project will include new and modified piping including pumps, valves, and connectors for movement of gas and liquid raw materials, intermediates, and feedstocks. These components are potential sources of CH₄ emissions due to leakage from rotary shaft seals, connection interfaces, valves stems, and similar points.

4.3.1 Step 1 - CO₂ Control Technologies

The only identified available control technology for process fugitive emissions of CO₂e are use of a leak detection and repair (LDAR) program. LDAR programs are designed to control VOC emissions and vary in stringency.

4.3.2 Step 2 - Eliminate Technically Infeasible Options

The only identified available control technology for process fugitive emissions of CO₂e is the use of a LDAR program and is technically feasible.

4.3.3 Step 3 - Rank Remaining Control Technologies

Because there is only one available control technology, ranking is not required.

4.3.4 Step 4 - Evaluate the Most Effective Controls and Document Results

Current LDAR programs only focus on VOC emissions. Valero McKee proposes using the existing LDAR program at the site to minimize GHGs measured as CH₄ as applicable. Valero proposes to define that equipment in GHG service is a piece of equipment that contains a liquid (gas or liquid) that is at least 5 percent by weight of methane. The percent value is based on the percent value deemed to be in organic hazardous air pollutant service as defined in 40 CFR 63.161.

4.3.5 Step 5 - Selection of BACT

Valero McKee Refinery proposes to use a LDAR program that incorporates GHG monitoring as needed.

SECTION 5

CONTEMPORANEOUS NETTING

PSD applicability is based on a two step process for modified sources of GHGs. After July 1, 2011, PSD applies to GHGs if the existing source has a PTE equal to or greater than 100,000 TPY CO₂e and 100/250 TPY mass basis for “one of the 28 listed source categories” or for “any air pollutant,” respectively. Step 1 determines if the modification to the facility by itself results in a significant emissions increase. If there is a significant increase from this modification, the Step 2 applies which includes accounting for creditable emissions increases and decreases at the source over a “contemporaneous period” or contemporaneous netting. If the modification shows to have GHG emissions increase and net emissions increase of 75,000 TPY CO₂e or more and greater than zero TPY GHG mass basis as shown through contemporaneous netting, then PSD is applicable.

Contemporaneous netting for GHG is not completed since there were no credible emission reductions claimed during the contemporaneous period for this project. Based on the GHG emission changes in the contemporaneous period, it was determined that a PSD review for GHGs will be required for the Crude Expansion Project.

SECTION 6

OTHER PSD REQUIREMENTS

6.1 Equipment Fugitives

An impacts analysis is not being provided with this application in accordance with EPA's recommendations:

“Since there are no NAAQS or PSD increments for GHGs, the requirements in sections 52.21(k) and 51.166(k) of EPA's regulations to demonstrate that a source does not contribute to a violation of the NAAQS are not applicable to GHGs. Therefore, there is no requirement to conduct dispersion modeling or ambient monitoring for CO₂ or GHGs.”

6.2 GHG Preconstruction Monitoring

A pre-construction monitoring analysis for GHG is not being provided with this application in accordance with EPA's recommendations:

“EPA does not consider it necessary for applications to gather monitoring data to assess ambient air quality for GHGs under section 52.21(m)(1)(ii), section 51.166(m)(1)(ii), or similar provision that may be contained in state rules based on EPA's rules. GHGs do not affect “ambient air quality” in the sense that EPA intended when these parts of EPA's rules were initially drafted. Considering the nature of GHG emissions and their global impacts, EPA does not believe it is practical or appropriate to expect permitting authorities to collect monitoring data for purpose of assessing ambient air impacts of GHGs.”

6.3 Additional Impacts Analysis

A PSD additional impacts analysis is not being provided with this application in accordance with EPA's recommendations:

“Furthermore, consistent with EPA's statement in the Tailoring Rule, EPA believes it is not necessary for applications or permitting authorities to assess impacts for GHGs in the context of the additional impacts analysis or Class I area provisions of the PSD regulations for the following policy reasons. Although it is clear that GHG emissions contribute to global warming and other climate changes that result in impacts on the environment, including impacts on Class I areas and soils and vegetation due to the global scope of the problem, climate change modeling and evaluations of risks and impacts of GHG emissions is typically conducted for changes in emissions order of magnitude larger than the emissions for 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 with current climate change modeling. Given these considerations, GHG emissions would serve as the more appropriate and credible proxy for assessing the impact of a given facility. Thus, EPA believes that the most practical way to address the considerations reflected in the Class I area and additional impacts analysis is to focus on reducing GHG emissions to the maximum extent. In light of these analytical challenges, 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 GHG.”

6.4 Endangered Species

Impacts from GHG emissions associated with the Crude Expansion Project will be submitted subsequent to this application.

APPENDIX A ADMINISTRATIVE FORMS

The following forms are included in this appendix in the following order:

- Table PSD-1: PSD Air Quality Applicability Supplement
- Table PDS-2: Combustion Source Calculations

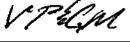
Texas Natural Resource Conservation Commission
Prevention of Significant Deterioration (PSD) Review
TABLE PSD-1
PSD AIR QUALITY APPLICABILITY SUPPLEMENT

TO BE COMPLETED BY APPLICANT AT TIME OF APPLICATION

A permit applicant must complete this table if PSD netting is required or if requested by permit engineer. This is not a stand-alone document. Please refer to the TNRCC PSD Air Quality Guidance Document for specific details regarding information required by this form. For additional information regarding PSD applicability and review, please refer to 40 CFR Part 52 Section 21 and EPA's Draft New Source Review Workshop Manual of October 1990 which provides examples for illustration.

Permit Application No. TBD
Company Diamond Shamrock Refining Co., L.P., a Valero Co. Air Quality Account I.D. MR-0008-T
Company Contact Shelly Williamson Phone Number 806-935-1354
Facility Location or Street Address 6701 FM 119
City Sunray County Moore
Permitted Unit I.D. and Name Crude Expansion Project – affects multiple permitted units
Activity: New Major Source Major Modification
Project or Process Description Crude Expansion Permit Project – Refer to Section 3 for a description of the proposed projects to be included.
Operating Schedule: _____ hrs/day _____ days/wk _____ wks/hr _____ hrs/yr Continuous
Or throughput _____

The information provided on this form (and Tables PSD-2 and PSD-3, if applicable) is true and correct.

 _____ Signature	 _____ Title	<u>29-Nov-2011</u> _____ Date
---	---	-------------------------------------

If Prevention of Significant Deterioration (PSD) review is required, then the applicant must send a complete application to EPA Region 6 at the address below. EPA Region 6 must also receive copies of all subsequent correspondence.

EPA Region 6
New Source Review Section
1445 Ross Avenue
Dallas, TX 75202-2733

LIST RELEVANT DATES:

- A. 01 / 01 / 13 Estimated start of construction.
- B. 01 / 01 / 8 5 years prior to estimated start of construction.
- C. 06 / 01 / 13 Estimated start of operation.

DEFINE CONTEMPORANEOUS PERIOD (from B to C): 01 / 01 / 08 to 06 / 01 / 13
From 5 years prior to estimated start of construction through estimated start of operation.

	Yes	No	Regulated Pollutant ¹						
			GHG						
Existing site potential to emit² (tpy)			>100,000						
Proposed project increases² (tpy)			507,726						
Nonattainment New Source Review Applicability: If the proposed project will be located in an area that is designated nonattainment for any pollutants, place a check to the right in the column under that pollutant(s) and complete a Table 1N.			N/A	N/A	N/A	N/A	N/A	N/A	N/A
Is the existing site one of the 28 named sources? ³	X								
Is the existing site a major source? ⁴	X								
Existing site is a major source:									
Is netting required? If "Yes" attach Tables PSD-2 and PSD-3. ⁵	X								
Significance level as defined in 40 CFR 52.21(b)(23) ⁶			75,000						
Net contemporaneous change from Table PSD-2 (tpy)			>75,000						
Is PSD review applicable? Answer "Yes" or "No" under each applicable pollutant.			Yes						
Existing site is NOT a major source:									
Is the proposed project by itself one of the 28 named sources ³									
Is the proposed project a major source by itself? (No consideration is given to any emissions decreases.) ⁴									
Once the project is considered major all other pollutants are compared to their respective significance levels. ⁶ Netting is not allowed. Is PSD review applicable? Answer "Yes" or "No" under each applicable pollutant.									

¹ Regulated pollutants include criteria pollutants (pollutants for which a National Ambient Air Quality Standard [NAAQS] exists) and noncriteria pollutants (pollutants regulated by EPA for which no NAAQS exists).
² Defined in Part A of the TNRCC *PSD Air Quality Guidance Document*.
³ The 28 named source categories are listed in 40 CFR 52.21(b)(1) and Table A of the TNRCC *PSD Air Quality Guidance Document*.
⁴ Refer to Part C "major source determination" of the TNRCC *PSD Air Quality Guidance Document*.
⁵ Refer to Part E2 of the TNRCC *PSD Air Quality Guidance Document*.
⁶ Significant emissions are defined in 40 CFR 52.21(b)(23) and Table B of the TNRCC *PSD Air Quality Guidance Document*.

US EPA ARCHIVE DOCUMENT

**TABLE PSD-2
PROJECT CONTEMPORANEOUS CHANGES¹**

Company: Diamond Shamrock Refining Co., L.P.

Permit Application No. TBD

Regulated Pollutant **GHG (CO₂e)**

	PROJECT DATE ²	EMISSION UNIT AT WHICH REDUCTION OCCURRED ³		PERMIT NO.	PROJECT NAME OR ACTIVITY	A	B	C	CREDITABLE DECREASE OR INCREASE ⁶	REASON CODE ⁷
		ALLOWABLE EMISSIONS AFTER THE ACTIVITY ⁴ (tons/year)	ACTUAL EMISSIONS PRIOR TO THE ACTIVITY ⁴ (tons/year)			(tons/year) DIFFERENCE (A-B) ⁵				
		FIN	EPN							
1	See Table B-1 in Appendix B for a list of emission changes associated with this project.									
2										
3										
4										
5										-
6										-
7										-
8										-
9										-
10										-
11										-
12										-
13										-
14										-
									PAGE SUBTOTAL ⁸	>75,000 tpy
Summary of Contemporaneous Changes						TOTAL				

* - Noted increases and decreases are not creditable for this project because they were relied upon to issue a previous PSD permit.

APPENDIX B

GHG EMISSION CALCULATIONS

The following tables are included in this appendix in the following order:

- Table B-1 – Emission Crude Expansion Project PSD Analysis;
Fugitives
- Table B-2 – Fugitive Emission Increase Summary;
- Table B-3 – Increased Process Fugitive Calculations: No. 1 Crude Unit
- Table B-4 – Increased Process Fugitive Calculations: Dehexanizer;
- Table B-5 – Increased Process Fugitive Calculations: No. 2 Crude Unit;
- Table B-6 – Increased Process Fugitive Calculations: RLE Unit;
- Table B-7 – Increased Process Fugitive Calculations: No. 4 Naphtha Fractionator;
- Table B-8 – Increased Process Fugitive Calculations: Hydrocracker;
- Table B-9 – Increased Process Fugitive Calculations: Diesel Hydrodesulfurization Unit and Turbine Merox Unit;

Heaters and Boilers

- Table B-10 – Modified and Affected Heater Emissions - Potential to Emit;
- Table B-11 – Modified and Affected Heater Emissions - Baseline Emissions;
- Table B-12 – Modified No. 2 Vacuum Heater Emissions Calculations;

Process Vents

- Table B-13 – No. 2 Reformer Regeneration Vent Emission Calculations;
- Table B-14 – No. 1 Sulfur Recovery Unit Potential to Emit;
- Table B-15 – No. 2 Sulfur Recovery Unit Potential to Emit;

Wastewater Flare & Vapor Combustor

- Table B-16 – Wastewater Flare Emissions Emission Calculations;
- Table B-17 – Vapor Combustor Emissions Emission Calculations;

Storage Tanks

- Table B-18 – Storage Tank Increased Emissions Calculations.

Table B-1
Valero McKee Refinery
Crude Expansion Project PSD Analysis - December 2011

EPN	Unit #	Unit	Description	New, Modified or Affected?	GHG CO ₂ e		
					Baseline Emissions (tpy)	PTE (tpy)	PTE - Baseline (tpy)
Multiple	Multiple	Multiple	Additional Fugitive Components	Modified			2.08
H-1	110	No. 1 Crude	No. 1 Crude Charge Heater (ULN, CUB-LE)	Affected	109,162	154,858	45,696
H-2	210	No. 1 Vacuum	No. 1 Vacuum Heater	Affected	26,705	39,473	12,768
H-6	250	PDA	DAGO Heater	Affected	3,708	14,152	10,445
H-8	430	Hydrocracking Unit	HCU Fractionator Charge Heater (ULN, LE)	Affected	24,117	44,224	20,107
H-9	120	No. 2 Crude	No. 2 Crude Heater-PetroChem (raw gas burners)	Affected	18,021	44,224	26,204
H-11	120	No. 2 Crude	No. 2 Crude Charge Anderson (ULN, LE)	Affected	33,075	46,090	13,014
H-13	230	GO Fractionator	GO Fractionator Heater	Affected	5,022	27,206	22,184
H-14	390	Unifiner	Unifiner Charge Heater	Affected	5,563	13,268	7,705
H-15	350	#1 Nap Hydrotreater	No. 1 Nap. Hydrotreater DeS2 Reboiler	Affected	11,358	18,077	6,720
H-26	220	No. 2 Vacuum	No. 2 Vacuum Charge Heater (ULN, SMR)	Modified	34,997	46,170	11,173
H-36	370	#2 Nap Hydrotreater	No. 2 Nap. Hydrotreater Charge Heater (ULN, LE)	Affected	9,660	28,746	19,086
H-38	375	#2 Reformer	No. 2 Reformer Charge & InterHeater (ULN, SMR)	Affected	78,147	123,218	45,071
H-39	375	#2 Reformer	No. 2 Reformer Stab. Reboiler	Affected	8,419	12,162	3,744
H-40	250	PDA	No. 1 PDA Asphalt Heater (Asphalt-South) (LN)	Affected	11,667	33,169	21,503
H-41	120	No. 2 Crude	No. 2 Crude Charge-Born (ULN, SMR)	Affected	112,277	137,156	24,879
H-45	350	#1 Nap Hydrotreater	No. 1 Nap. Hydrotreater Charge Heater (ULN, SMR)	Affected	9,785	35,069	25,285
H-48	150	TFHDSU	DHDS Charge Heater (ULN, CUB-L)	Affected	10,425	65,952	55,526
H-64	395	#4 HDS/Isom	No. 4 Hydrotreater Charge Heater	Affected	6,240	16,640	10,400
H-42	370	Hydrocracking Unit	HCU Recycle Gas Heater, (ULN, LE)	Affected	26,303	44,426	18,122
H-43	370	Hydrocracking Unit	HCU DeC4 Reboiler Heater (ULN, LE)	Affected	23,317	43,563	20,246
H-80	400	FCC HDS	GDU HDS Charge Heater (ULN, Free Jet)	Affected	0	49,227	49,227
H-37	370	#2 Nap Hydrotreater	No. 2 NHT DeSulfur Reboiler Heater	Affected	16,148	31,942	15,794
B-4	Utilities	Boiler	No. 11 Boiler	Affected			10,006
B-6	Utilities	Boiler	No. 13 Boiler	Affected			
B-8	Utilities	Boiler	No. 15 Boiler	Affected			
B-9	Utilities	Boiler	No. 16 Boiler	Affected			
B-10	Utilities	Boiler	No. 18 Boiler	Affected			
B-11	Utilities	Boiler	No. 19 Boiler	Affected			
B-12	Utilities	600# Boiler	600# Boiler	Affected			

**Table B-1
Valero McKee Refinery
Crude Expansion Project PSD Analysis - December 2011**

EPN	Unit #	Unit	Description	New, Modified or Affected?	GHG CO ₂ e		
					Baseline Emissions (tpy)	PTE (tpy)	PTE - Baseline (tpy)
S-184	Tank Farm	Tank Farm	Tank 940T1 (Sour Water)	Affected	13.54	17.75	4.20
S-195	Tank Farm	Tank Farm	Tank T101 (Sour Water)	Affected			
S-196	Tank Farm	Tank Farm	Tank T102 (Sour Water)	Affected			
S-197	Tank Farm	Tank Farm	Tank T109 (Sour Water)	Affected			
S-199	Tank Farm	Tank Farm	Tank T115 (Sour Water)	Affected			
S-022	Tank Farm	Tank Farm	Tank 120M2 (Crude Oil (RVP 7))	Affected			
S-023	Tank Farm	Tank Farm	Tank 120M3 (Crude Oil (RVP 7))	Affected			
S-183	Tank Farm	Tank Farm	Tank 120M4 (Crude Oil (RVP 7))	Affected			
S-186	Tank Farm	Tank Farm	Tank 80M1 (Crude Oil (RVP 7))	Affected			
S-176	Tank Farm	Tank Farm	Tank 200M1 (Crude Oil (RVP 7))	Affected			
FL-6	Wastewater	Wastewater	Wastewater Flare	Affected	7,779	8,062	283
FL-7	Multiple	Loading	Loading Rack Vapor Combustor	Affected			392
V-21	375	#2 Reformer	No. 2 Reformer Cat Regenerator Vent	Affected	20	50	30
V-5	820	#1 SRU	SRU No. 1 Incinerator	Affected	2,395	8,643	6,247
V-16	830	#2 SRU	SRU No. 2 Incinerator	Affected	8,994	14,862	5,868
Project Increases Only					507,726		
PSD Significance Levels					75,000		
Triggers Contemporaneous Netting					Y		

Note:

1. Only GHG incremental increase from boilers and the vapor combustor included in the project increase total.

**Table B-2
Fugitive GHG (Methane) Increase Summary
Valero McKee Refinery**

EPN	Process Unit	Total Methane	Total CO ₂ e
		TPY	TPY
F-1CRUDE	#1 Crude Unit	0.0002	0.0050
F-1CRUDE	Dehexanizer	0.0020	0.0411
F-2CRUDE	#2 Crude Unit	0.0004	0.0090
F-RLE	RLE	0.0312	0.6554
F-4HT	#4 Fractionator	0.0064	0.1336
F-HCU	Hydrocracker	0.0586	1.2298
F-DHDSU	Diesel Hydrodesulfurization Unit and Turbine Merox Unit	0.0004	0.0088
Total		0.04	2.08

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**Table B-3
Increased Fugitive GHG (Methane) Emissions Calculations
Valero McKee Refinery - No. 1 Crude
EPN: F-1CRUDE**

Component	Service	Comp. Count	Emission Factor ¹ (lb/hr/source)	Control Efficiency ² (percent)	Emissions ⁴ (lb/hr)	Emissions ⁵ (ton/yr)
Valves	Gas	15	0.05900	97	0.03	0.12
	LL	65	0.02400	97	0.05	0.20
	HL	0	0.00051	30	0.00	0.00
Pump Seals	LL	4	0.25100	85	0.15	0.66
	HL	0	0.04600	30	0.00	0.00
Agitators	Gas	0	0.25100	85	0.00	0.00
Connectors (flanges)	All	99	0.00055	30	0.04	0.17
Compressor seals		0	1.39900	95	0.00	0.00
PRVs		1	0.35000	97	0.01	0.05
Open-ended lines		0	0.00510	100	0.00	0.00
Sampling connections		0	0.03300	97	0.00	0.00
Total					0.27	1.19

Compound	Wt % ³			Emissions	
	GV	LL	HL	lb/hr	ton/yr
Methane	0.02	0.02	0.00	5.45E-05	2.39E-04

Notes:

¹ Emission factors taken from TCEQ Technical Guidance Package for Chemical Sources "Equipment Leak Fugitives" dated October 2000 (Draft).

² 28 VHP Control efficiencies taken from TCEQ Technical Guidance Package for Chemical Sources "Equipment Leak Fugitives" dated October 2000 (Draft) for all components except for compressor seals which uses 28MID control credit.

³Wt % of Methane was determined using Heat and Material Balance Data Sheet

⁴ lb/hr = (count)(factor)(1-efficiency)

⁵ ton/yr = (lb/hr)(8760 hr/yr)/(2000 lb/ton)

**Table B-4
Increased Fugitive GHG (Methane) Emissions Calculations
Valero McKee Refinery - Dehexanizer
Part of EPN: F-1CRUDE**

Component	Service	Comp. Count	Emission Factor ¹ (lb/hr/source)	Control Efficiency ² (percent)	Emissions ⁴ (lb/hr)	Emissions ⁵ (ton/yr)
Valves	Gas	0	0.05900	97	0.00	0.00
	LL	7	0.02400	97	0.01	0.02
	HL	0	0.00051	30	0.00	0.00
Pump Seals	LL	0	0.25100	85	0.00	0.00
	HL	0	0.04600	30	0.00	0.00
Agitators	Gas	0	0.25100	85	0.00	0.00
Connectors (flanges)	All	15	0.00055	30	5.78E-03	0.03
Compressor seals		0	1.39900	95	0.00	0.00
PRVs		0	0.35000	97	0.00	0.00
Open-ended lines		0	0.00510	100	0.00	0.00
Sampling connections		0	0.03300	97	0.00	0.00
Total					0.01	0.05

Compound	Wt % ³			Emissions	
	GV	LL	HL	lb/hr	ton/yr
Methane	4.13	4.13	0.00	4.47E-04	1.96E-03

Notes:

¹ Emission factors taken from TCEQ Technical Guidance Package for Chemical Sources "Equipment Leak Fugitives" dated October 2000 (Draft).

² 28 VHP Control efficiencies taken from TCEQ Technical Guidance Package for Chemical Sources "Equipment Leak Fugitives" dated October 2000 (Draft) for all components except for compressor seals which uses 28MID control credit.

³Wt % of Methane was determined using Heat and Material Balance Data Sheet

⁴ lb/hr = (count)(factor)(1-efficiency)

⁵ ton/yr = (lb/hr)(8760 hr/yr)/(2000 lb/ton)

**Table B-5
Increased Fugitive GHG (Methane) Emissions Calculations
Valero McKee Refinery - No. 2 Crude
EPN: F-2CRUDE**

Component	Service	Comp. Count	Emission Factor ¹ (lb/hr/source)	Control Efficiency ² (percent)	Emissions ⁴ (lb/hr)	Emissions ⁵ (ton/yr)
Valves	Gas	0	0.05900	97	0.00	0.00
	LL	63	0.02400	97	0.05	0.20
	HL	24	0.00051	30	0.01	0.04
Pump Seals	LL	6	0.25100	85	0.23	0.99
	HL	5	0.04600	30	0.16	0.71
Agitators	Gas	0	0.25100	85	0.00	0.00
Connectors (flanges)	All	125	0.00055	30	0.05	0.21
Compressor seals		0	1.39900	95	0.00	0.00
PRVs		0	0.35000	97	0.00	0.00
Open-ended lines		0	0.00510	100	0.00	0.00
Sampling connections		0	0.03300	97	0.00	0.00
Total					0.49	2.14

Compound	Wt % ³			Emissions	
	GV	LL	HL	lb/hr	ton/yr
Methane	0.02	0.02	0.02	9.78E-05	4.28E-04

Notes:

¹ Emission factors taken from TCEQ Technical Guidance Package for Chemical Sources "Equipment Leak Fugitives" dated October 2000 (Draft).

² 28 VHP Control efficiencies taken from TCEQ Technical Guidance Package for Chemical Sources "Equipment Leak Fugitives" dated October 2000 (Draft) for all components except for compressor seals which uses 28MID control credit.

³ Wt % of Methane was determined using Heat and Material Balance Data Sheet

⁴ lb/hr = (count)(factor)(1-efficiency)

⁵ ton/yr = (lb/hr)(8760 hr/yr)/(2000 lb/ton)

**Table B-6
Increased Fugitive GHG (Methane) Emissions Calculations
Valero McKee Refinery - RLE
EPN: F-RLE**

Component	Service	Comp. Count	Emission Factor ¹ (lb/hr/source)	Control Efficiency ² (percent)	Emissions ⁴ (lb/hr)	Emissions ⁵ (ton/yr)
Valves	Gas	1	0.05900	97	1.77E-03	0.01
	LL	5	0.02400	97	3.60E-03	0.02
	HL	0	0.00051	30	0.00	0.00
Pump Seals	LL	4	0.25100	85	0.15	0.66
	HL	0	0.04600	30	0.00	0.00
Agitators	Gas	0	0.25100	85	0.00	0.00
Connectors (flanges)	All	43	0.00055	30	0.02	0.07
Compressor seals		0	1.39900	95	0.00	0.00
PRVs		0	0.35000	97	0.00	0.00
Open-ended lines		0	0.00510	100	0.00	0.00
Sampling connections		0	0.03300	97	0.00	0.00
Total					0.17	0.76

Compound	Wt % ³			Emissions	
	GV	LL	HL	lb/hr	ton/yr
Methane	4.13	4.13	0.00	0.01	0.03

Notes:

¹ Emission factors taken from TCEQ Technical Guidance Package for Chemical Sources "Equipment Leak Fugitives" dated October 2000 (Draft).

² 28 VHP Control efficiencies taken from TCEQ Technical Guidance Package for Chemical Sources "Equipment Leak Fugitives" dated October 2000 (Draft) for all components except for compressor seals which uses 28MID control credit.

³ Wt % of Methane was determined using Heat and Material Balance Data Sheet

⁴ lb/hr = (count)(factor)(1-efficiency)

⁵ ton/yr = (lb/hr)(8760 hr/yr)/(2000 lb/ton)

**Table B-7
Increased Fugitive GHG (Methane) Emissions Calculations
Valero McKee Refinery - #4 Fractionator
EPN: F-4HT**

Component	Service	Comp. Count	Emission Factor ¹ (lb/hr/source)	Control Efficiency ² (percent)	Emissions ⁴ (lb/hr)	Emissions ⁵ (ton/yr)
Valves	Gas	14	0.05900	97	0.02	0.11
	LL	0	0.02400	97	0.00	0.00
	HL	0	0.00051	30	0.00	0.00
Pump Seals	LL	0	0.25100	85	0.00	0.00
	HL	0	0.04600	30	0.00	0.00
Agitators	Gas	0	0.25100	85	0.00	0.00
Connectors (flanges)	All	27	0.00055	30	1.04E-02	0.05
Compressor seals		0	1.39900	95	0.00	0.00
PRVs		0	0.35000	97	0.00	0.00
Open-ended lines		0	0.00510	100	0.00	0.00
Sampling connections		0	0.03300	97	0.00	0.00
Total					0.04	0.15

Compound	Wt % ³			Emissions	
	GV	LL	HL	lb/hr	ton/yr
Methane	4.13	4.13	0.00	1.45E-03	6.36E-03

Notes:

¹ Emission factors taken from TCEQ Technical Guidance Package for Chemical Sources "Equipment Leak Fugitives" dated October 2000 (Draft).

² 28 VHP Control efficiencies taken from TCEQ Technical Guidance Package for Chemical Sources "Equipment Leak Fugitives" dated October 2000 (Draft) for all components except for compressor seals which uses 28MID control credit.

³Wt % of Methane was determined using Heat and Material Balance Data Sheet

⁴ lb/hr = (count)(factor)(1-efficiency)

⁵ ton/yr = (lb/hr)(8760 hr/yr)/(2000 lb/ton)

**Table B-8
Increased Fugitive GHG (Methane) Emissions Calculations
Valero McKee Refinery - Hydrocracker
EPN: F-HCU**

Component	Service	Comp. Count	Emission Factor ¹ (lb/hr/source)	Control Efficiency ² (percent)	Emissions ⁴ (lb/hr)	Emissions ⁵ (ton/yr)
Valves	Gas	203	0.05900	97	0.36	1.57
	LL	115	0.02400	97	0.08	0.36
	HL	64	0.00051	30	0.02	0.10
Pump Seals	LL	2	0.25100	85	0.08	0.33
	HL	3	0.04600	30	0.10	0.42
Agitators	Gas	0	0.25100	85	0.00	0.00
Connectors (flanges)	All	955	0.00055	30	0.37	1.61
Compressor seals		1	1.39900	95	0.07	0.31
PRVs		0	0.35000	97	0.00	0.00
Open-ended lines		0	0.00510	100	0.00	0.00
Sampling connections		0	0.03300	97	0.00	0.00
Total					1.07	4.71

Compound	Wt % ³			Emissions	
	GV	LL	HL	lb/hr	ton/yr
Methane	1.40	1.40	0.00	1.34E-02	5.86E-02

Notes:

¹ Emission factors taken from TCEQ Technical Guidance Package for Chemical Sources "Equipment Leak Fugitives" dated October 2000 (Draft).

² 28 VHP Control efficiencies taken from TCEQ Technical Guidance Package for Chemical Sources "Equipment Leak Fugitives" dated October 2000 (Draft)

³ Wt % of Methane was determined using Heat and Material Balance Data Sheet.

⁴ lb/hr = (count)(factor)(1-efficiency)

⁵ ton/yr = (lb/hr)(8760 hr/yr)/(2000 lb/ton)

**Table B-9
Increased Fugitive GHG (Methane) Emissions Calculations
Valero McKee Refinery - Diesel Hydrodesulfurization Unit and Turbine Merox Unit
EPN: F-DHDSU**

Component	Service	Comp. Count	Emission Factor ¹ (lb/hr/source)	Control Efficiency ² (percent)	Emissions ⁴ (lb/hr)	Emissions ⁵ (ton/yr)
Valves	Gas	147	0.05900	97	0.26	1.14
	LL	108	0.02400	97	0.08	0.34
	HL	194	0.00051	30	0.07	0.30
Pump Seals	LL	2	0.25100	85	0.08	0.33
	HL	4	0.04600	30	0.13	0.56
Agitators	Gas	0	0.25100	85	0.00	0.00
Connectors (flanges)	All	1113	0.00055	30	0.43	1.88
Compressor seals		1	1.39900	95	0.07	0.31
PRVs		4	0.35000	97	0.04	0.18
Open-ended lines		0	0.00510	100	0.00	0.00
Sampling connections		0	0.03300	97	0.00	0.00
Total					1.15	5.04

Compound	Wt % ³			Emissions	
	GV	LL	HL	lb/hr	ton/yr
Methane	0.01	0.01	0.00	9.54E-05	4.18E-04

Notes:

¹ Emission factors taken from TCEQ Technical Guidance Package for Chemical Sources "Equipment Leak Fugitives" dated October 2000 (Draft).

² 28 VHP Control efficiencies taken from TCEQ Technical Guidance Package for Chemical Sources "Equipment Leak Fugitives" dated October 2000 (Draft) for all components except for compressor seals which uses 28MID control credit.

³ Wt % of Methane is conservatively assumed to be 0.01.

⁴ lb/hr = (count)(factor)(1-efficiency)

⁵ ton/yr = (lb/hr)(8760 hr/yr)/(2000 lb/ton)

Table B-10
Modified and Affected Heater Emissions - Potential to Emit
Valero McKee Refinery

FIN	EPN	Description	Annual Average Firing Rate MMBtu/hr	CO ₂ e	CO ₂ e	CH ₄	CH ₄	N ₂ O	N ₂ O	CO ₂	CO ₂
				Max Hourly Emission (lb/hr)	Annual Average Emission (tpy)	Max Hourly Emission (lb/hr)	Annual Average Emission (tpy)	Max Hourly Emission (lb/hr)	Annual Average Emission (tpy)	Max Hourly Emission (lb/hr)	Annual Average Emission (tpy)
H-1	H-1	No. 1 Crude Charge Heater (ULN, CUB-LE)	265.2	30,291.73	132,677.76	1.75	7.68	0.35	1.54	30,146.11	132,039.98
H-2	H-2	No. 1 Vacuum Heater	75.1	8,582.66	37,592.03	0.50	2.18	0.10	0.44	8,541.40	37,411.33
H-6	H-6	DAGO Heater	28.3	3,231.12	14,152.29	0.19	0.82	0.04	0.16	3,215.59	14,084.26
H-8	H-8	HCU Fractionator Charge Heater (ULN, LE)	88.4	8,834.79	38,696.38	0.51	2.24	0.10	0.45	8,792.32	38,510.37
H-9	H-9	No. 2 Crude Heater-PetroChem (raw gas burners)	88.4	5,427.66	23,773.14	0.31	1.38	0.06	0.28	5,401.57	23,658.86
H-11	H-11	No. 2 Crude Charge Anderson (ULN, LE)	77.4	8,835.09	38,697.68	0.51	2.24	0.10	0.45	8,792.62	38,511.66
H-13	H-13	GO Fractionator Heater	40.3	4,606.87	20,178.08	0.27	1.17	0.05	0.23	4,584.72	20,081.08
H-14	H-14	Unifiner Charge Heater	26.5	3,029.17	13,267.78	0.18	0.77	0.04	0.15	3,014.61	13,204.00
H-15	H-15	No. 1 Nap. Hydrotreater DeS2 Reboiler	36.1	4,127.25	18,077.34	0.24	1.05	0.05	0.21	4,107.41	17,990.45
H-26	H-26	No. 2 Vacuum Charge Heater (ULN, SMR)	81.8	10,541.12	46,170.11	0.54	2.37	0.11	0.47	10,496.22	45,973.46
H-36	H-36	No. 2 Nap. Hydrotreater Charge Heater (ULN, LE)	57.5	4,165.11	18,243.19	0.24	1.06	0.05	0.21	4,145.09	18,155.50
H-37	H-37	No. 2 NHT DeSulfur Reboiler Heater	36.5	6,562.99	28,745.88	0.38	1.66	0.08	0.33	6,531.44	28,607.70
H-38	H-38	No. 2 Reformer Charge & InterHeater (ULN, SMR)	246.3	22,719.17	99,509.98	1.32	5.76	0.26	1.15	22,609.96	99,031.64
H-39	H-39	No. 2 Reformer Stab. Reboiler	24.3	2,776.74	12,162.13	0.16	0.70	0.03	0.14	2,763.39	12,103.66
H-40	H-40	No. 1 PDA Asphalt Heater (Asphalt-South) (LN)	66.3	7,572.93	33,169.44	0.4	1.9	0.1	0.4	7,536.5	33,010.0
H-41	H-41	No. 2 Crude Charge-Born (ULN, SMR)	274.2	35,340.35	154,790.72	2.05	8.96	0.41	1.79	35,170.47	154,046.64
H-42	H-42	HCU Recycle Gas Heater, (ULN, LE)	85.1	9,718.60	42,567.45	0.56	2.47	0.11	0.49	9,671.88	42,362.83
H-43	H-43	HCU DeC4 Reboiler Heater (ULN, LE)	87.1	9,945.78	43,562.53	0.58	2.52	0.12	0.50	9,897.97	43,353.13
H-45	H-45	No. 1 Nap. Hydrotreater Charge Heater (ULN, SMR)	70.1	8,006.71	35,069.38	0.46	2.03	0.09	0.41	7,968.22	34,900.80
H-48	H-48	DHDS Charge Heater (ULN, CUB-L)	105.0	10,095.76	44,219.43	0.58	2.56	0.12	0.51	10,047.23	44,006.87
H-64	H-64	No. 4 Hydrotreater Charge Heater	33.3	3,799.09	16,640.00	0.22	0.96	0.04	0.19	3,780.83	16,560.01
H-80	H-80	GDU HDS Charge Heater (ULN, Free Jet)	98.4	11,239.09	49,227.20	0.65	2.85	0.13	0.57	11,185.06	48,990.57
B-4	B-4	No. 11 Boiler	20.0	1,713.28	7,504.15	0.10	0.43	0.02	0.09	1,705.04	7,468.07
B-6	B-6	No. 13 Boiler	20.0	1,713.28	7,504.15	0.10	0.43	0.02	0.09	1,705.04	7,468.07
B-8	B-8	No. 15 Boiler	20.0	1,713.28	7,504.15	0.10	0.43	0.02	0.09	1,705.04	7,468.07
B-9	B-9	No. 16 Boiler	20.0	1,713.28	7,504.15	0.10	0.43	0.02	0.09	1,705.04	7,468.07
B-10	B-10	No. 18 Boiler	20.0	1,713.28	7,504.15	0.10	0.43	0.02	0.09	1,705.04	7,468.07
B-11	B-11	No. 19 Boiler	20.0	1,713.28	7,504.15	0.10	0.43	0.02	0.09	1,705.04	7,468.07
B-12	B-12	600# Boiler	20.0	1,713.28	7,504.15	0.10	0.43	0.02	0.09	1,705.04	7,468.07

Note: Boiler emissions represent incremental increases only.

Table B-11
Modified and Affected Heater Emissions - Baseline Emissions
Valero McKee Refinery

FIN	EPN	Description	Annual Average Firing Rate MMBtu/hr	CO _{2e}	CO _{2e}	CH ₄	CH ₄	N ₂ O	N ₂ O	CO ₂	CO ₂
				Max Hourly Emission (lb/hr)	Annual Average Emission (tpy)	Max Hourly Emission (lb/hr)	Annual Average Emission (tpy)	Max Hourly Emission (lb/hr)	Annual Average Emission (tpy)	Max Hourly Emission (lb/hr)	Annual Average Emission (tpy)
H-1	H-1	No. 1 Crude Charge Heater (ULN, CUB-LE)	218.2	24,922.91	109,162.35	1.4	6.3	0.3	1.3	24,803.11	108,637.61
H-2	H-2	No. 1 Vacuum Heater	53.4	6,097.07	26,705.16	0.4	1.5	0.1	0.3	6,067.76	26,576.79
H-6	H-6	DAGO Heater	7.4	846.48	3,707.60	0.0	0.2	0.0	0.0	842.42	3,689.78
H-8	H-8	HCU Fractionator Charge Heater (ULN, LE)	48.2	5,506.20	24,117.16	0.3	1.4	0.1	0.3	5,479.73	24,001.23
H-9	H-9	No. 2 Crude Heater-PetroChem (raw gas burners)	36.0	4,114.30	18,020.62	0.2	1.0	0.0	0.2	4,094.52	17,933.99
H-11	H-11	No. 2 Crude Charge Anderson (ULN, LE)	66.1	7,551.47	33,075.42	0.4	1.9	0.1	0.4	7,515.17	32,916.43
H-13	H-13	GO Fractionator Heater	10.0	1,146.57	5,021.97	0.1	0.3	0.0	0.1	1,141.06	4,997.83
H-14	H-14	Unifiner Charge Heater	11.1	1,270.06	5,562.87	0.1	0.3	0.0	0.1	1,263.96	5,536.13
H-15	H-15	No. 1 Nap. Hydrotreater DeS2 Reboiler	22.7	2,593.09	11,357.72	0.2	0.7	0.0	0.1	2,580.62	11,303.12
H-26	H-26	No. 2 Vacuum Charge Heater (ULN, SMR)	70.0	7,990.21	34,997.12	0.5	2.0	0.1	0.4	7,951.80	34,828.89
H-36	H-36	No. 2 Nap. Hydrotreater Charge Heater (ULN, LE)	19.3	2,205.54	9,660.25	0.1	0.6	0.0	0.1	2,194.94	9,613.82
H-37	H-37	No. 2 NHT DeSulfur Reboiler Heater	32.3	3,686.67	16,147.60	0.2	0.9	0.0	0.2	3,668.95	16,069.98
H-38	H-38	No. 2 Reformer Charge & InterHeater (ULN, SMR)	156.2	17,841.77	78,146.95	1.0	4.5	0.2	0.9	17,756.00	77,771.30
H-39	H-39	No. 2 Reformer Stab. Reboiler	16.8	1,922.05	8,418.59	0.1	0.5	0.0	0.1	1,912.81	8,378.13
H-40	H-40	No. 1 PDA Asphalt Heater (Asphalt-South) (LN)	23.3	2,663.61	11,666.61	0.2	0.7	0.0	0.1	2,650.81	11,610.53
H-41	H-41	No. 2 Crude Charge-Born (ULN, SMR)	224.4	25,633.91	112,276.54	1.5	6.5	0.3	1.3	25,510.69	111,736.82
H-42	H-42	HCU Recycle Gas Heater, (ULN, LE)	52.6	6,005.35	26,303.41	0.3	1.5	0.1	0.3	5,976.48	26,176.97
H-43	H-43	HCU DeC4 Reboiler Heater (ULN, LE)	46.6	5,323.50	23,316.91	0.3	1.4	0.1	0.3	5,297.91	23,204.83
H-45	H-45	No. 1 Nap. Hydrotreater Charge Heater (ULN, SMR)	19.6	2,233.93	9,784.60	0.1	0.6	0.0	0.1	2,223.19	9,737.57
H-48	H-48	DHDS Charge Heater (ULN, CUB-L)	20.8	2,380.21	10,425.31	0.1	0.6	0.0	0.1	2,368.77	10,375.19
H-64	H-64	No. 4 Hydrotreater Charge Heater	12.5	1,424.73	6,240.32	0.1	0.4	0.0	0.1	1,417.88	6,210.32
H-80	H-80	GDU HDS Charge Heater (ULN, Free Jet)	NA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Note: 1) Baseline emissions for boilers are not presented, because increased emissions from boilers are incremental.
 2) H-80 was not operating during the baseline period.

**Table B-12
GHG Emission Calculations - Modified No. 2 Vacuum Heater (EPN H-26)
Valero McKee Refinery**

Baseline Emissions

EPN	Pollutant	Fuel Flowrate scf/yr	Heating Value BTU/scf	Fuel Carbon Content kg C/kg fuel	Fuel MW kg/kgmol	GHG Mass Emissions tpy	Global Warming Potential	CO ₂ e tpy
H-26	CO ₂	638,744,206	959	0.66	15.43	34,828.89	1	34,828.89
H-26	CH ₄	638,744,206	959	-	-	2.03	21	43
H-26	N ₂ O	638,744,206	959	-	-	0.41	310	126
Total								34,997.12

Project Potential To Emit

EPN	Pollutant	Fuel Flowrate scf/yr	Heating Value BTU/scf	Fuel Carbon Content kg C/kg fuel	Fuel MW kg/kgmol	GHG Mass Emissions tpy	Global Warming Potential	CO ₂ e tpy
H-26	CO ₂	746,643,391	959	0.66	15.43	45,973.46	1	45,973.46
H-26	CH ₄	746,643,391	959	-	-	2.37	21	50
H-26	N ₂ O	746,643,391	959	-	-	0.47	310	147
Total								46,170.11

Equation C-5 from 40CFR98, Subpart C

$$CO_2 = (44/12) \times \text{Fuel} \times CC \times (\text{MW}/\text{MVC}) \times 0.001$$

Equation C-8 from 40CFR98, Subpart C

$$CH_4 = 0.001 \times \text{Fuel} \times \text{HHV} \times \text{EF}$$

$$N_2O = 0.001 \times \text{Fuel} \times \text{HHV} \times \text{EF}$$

Factors/Conversions

- 3.67 Ratio of Molecular Weights (CO₂: C)
- 849.5 Molar Volume Conversion at 68F (MVC)
- 1.1025 US Ton/Metric Ton
- 0.003 kg CH₄/MMBtu
- 0.0006 kg N₂O/MMBtu

Table B-13
GHG Emission Calculations - No. 2 Reformer Regeneration Vent
Valero McKee Refinery
EPN: V-21

Baseline Emissions

EPN	Pollutant	Coke Production (CBQ) lb/regen	Regeneration Cycle	Carbon Content lb C/lb Coke	GHG Mass Emissions tpy	Global Warming Potential Factor	CO ₂ e tpy
V-21	CO ₂	11,758	1	0.94	20.26	1	20.26
V-21	CH ₄	-	-	-	0.002	21	0.05
V-21	N ₂ O	-	-	-	0.000	310	0.10
Total							20.41

Project Potential To Emit

EPN	Pollutant	Coke Production (CBQ) lb/regen	Regeneration Cycle hrs	Carbon Content lb C/lb Coke	GHG Mass Emissions tpy	Global Warming Potential Factor	CO ₂ e tpy
V-21	CO ₂	14,400	2	0.94	49.63	1	49.63
V-21	CH ₄	-	-	-	0.01	21	0.11
V-21	N ₂ O	-	-	-	0.001	310	0.24
Total							49.98

Equation Y-11 from 40CFR98, Subpart Y

$$CO_2 = \text{sum} ((CBQ)_n \times CC \times 44/12 \times 0.001)$$

Equation Y-9 from 40CFR98, Subpart Y

$$CH_4 = CO_2 \times (EmF_2 / EmF_1)$$

Equation Y-10 from 40CFR98, Subpart Y

$$N_2O = CO_2 \times (EmF_3 / EmF_1)$$

Factors/Conversions

- 2000 lb/US ton
- 8760 hours/year
- 3.67 Ratio of Molecular Weights (CO₂: C)
- 102.41 EmF₁ - Coke CO₂ Emission Factor from Table C-1 in 40CFR98
- 0.011 EmF₂ - Coke CH₄ Emission Factor from Table C-2 in 40CFR98
- 0.0016 EmF₃ - Coke N₂O Emission Factor from Table C-2 in 40CFR98

Table B-14
GHG Emission Calculations - No. 1 SRU Incinerator
Valero McKee Refinery
EPN: V-5

Baseline Emissions

EPN	Pollutant	F _{SG} (Vol Flow Rate of Feed) scf/yr	MFC mole frac of Carbon in feed	GHG Mass Emissions tpy	Global Warming Potential Factor	CO ₂ e tpy
V-5	CO ₂	209,726,097	0.20	2,395.25	1	2,395.25

Project Potential To Emit

EPN	Pollutant	F _{SG} (Vol Flow Rate of Feed) scf/yr	MFC mole frac of Carbon in feed	GHG Mass Emissions tpy	Global Warming Potential Factor	CO ₂ e tpy
V-5	CO ₂	756,743,648	0.20	8,642.64	1	8,642.64

Equation Y-12 from 40CFR98, Subpart Y

$$CO_2 = F_{SG} \times (44/MVC) \times MFC \times 0.001$$

Factors/Conversions

- 849.5 Molar Volume Conversion at 68F (MVC)
- 1.1025 US Ton/Metric Ton
- 0.003 kg CH₄/MMBtu
- 0.0006 kg N₂O/MMBtu

Table B-15
GHG Emission Calculations - No. 2 SRU Incinerator
Valero McKee Refinery
EPN: V-16

Baseline Emissions

EPN	Pollutant	F _{SG} (Vol Flow Rate of Feed) scf/yr	MFC mole frac of Carbon in feed	GHG Mass Emissions tpy	Global Warming Potential Factor	CO ₂ e tpy
V-16	CO ₂	787,499,908	0.20	8,993.91	1	8,993.91

Project Potential To Emit

EPN	Pollutant	F _{SG} (Vol Flow Rate of Feed) scf/yr	MFC mole frac of Carbon in feed	GHG Mass Emissions tpy	Global Warming Potential Factor	CO ₂ e tpy
V-16	CO ₂	1,301,294,258	0.20	14,861.87	1	14,861.87

Equation Y-12 from 40CFR98, Subpart Y

$$CO_2 = F_{SG} \times (44/MVC) \times MFC \times 0.001$$

Factors/Conversions

- 849.5 Molar Volume Conversion at 68F (MVC)
- 1.1025 US Ton/Metric Ton
- 0.003 kg CH₄/MMBtu
- 0.0006 kg N₂O/MMBtu

Table B-16
GHG Emission Calculations - Wastewater Flare
Valero McKee Refinery
EPN: FL-6

Baseline Emissions

EPN	Pollutant	Flare _{Norm} (Annual Flare Gas Volume) MMscf/yr	Emission Factor (EmF, EmF _{CH4} , EmF _{N2O})	HHV (High Heating Value) Btu/scf	GHG Mass Emissions tpy	Global Warming Potential Factor	CO ₂ e tpy	
FL-6	CO ₂	300.51	60.00	408.035	7,210.04	1	7,210	
FL-6	CH ₄	300.51	3.00E-03	408.035	21.76	21	457	
FL-6	N ₂ O	300.51	6.00E-04	408.035	0.36	310	112	
Total								7,779

Project Potential To Emit

EPN	Pollutant	Flare _{Norm} (Annual Flare Gas Volume) MMscf/yr	Emission Factor (EmF, EmF _{CH4} , EmF _{N2O})	HHV (High Heating Value) Btu/scf	GHG Mass Emissions tpy	Global Warming Potential Factor	CO ₂ e tpy	
FL-6	CO ₂	330.56	60.00	408.035	7,931.05	1	7,931	
FL-6	CH ₄	330.56	3.00E-03	408.035	0.40	21	8	
FL-6	N ₂ O	330.56	6.00E-04	408.035	0.40	310	123	
Total								8,062

Equation Y-3 from 40CFR98, Subpart Y

$$CO_2 = .98 \times .001 \times (\text{Flare}_{\text{Norm}} \times \text{HHV} \times \text{EmF})$$

Equation Y-4 & Y-5 from 40CFR98, Subpart Y

$$CH_4 = (CO_2 \times \text{EmF}_{CH_4} / \text{EmF}_{CO_2}) + CO_2 \times (.02 / .98) \times (16 / 44) \times f_{CH_4}$$

$$N_2O = (CO_2 \times (\text{EmF}_{N_2O} / \text{EmF}))$$

Factors/Conversions

- 849.5 Molar Volume Conversion at 68F (MVC)
- 1.1025 US Ton/Metric Ton
- 0.003 kg CH₄/MMBtu
- 0.0006 kg N₂O/MMBtu
- 0.4 f_{CH₄}

Table B-17
Increase in GHG Emissions - Vapor Combustor
Valero McKee Refinery
EPN: FL-7

Projected Increase Emissions

EPN	Pollutant	Increased Flare _{Norm} (Annual Flare Gas Volume)	Emission Factor (EmF, EmF _{CH4} , EmF _{N2O})	HHV (High Heating Value)	GHG Mass Emissions	Global Warming Potential Factor	CO ₂ e
		MMscf/yr	Kg/MMBtu	Btu/scf	tpy		tpy
FL-7	CO ₂	5.84	60.00	1,020	385.96	1	386
FL-7	CH ₄	5.84	3.00E-03	1,020	0.02	21	0
FL-7	N ₂ O	5.84	6.00E-04	1,020	0.02	310	6
						Total	392

Equation Y-3 from 40CFR98, Subpart Y

$$CO_2 = .98 \times .001 \times (Flare_{Norm} \times HHV \times EmF)$$

Equation Y-4 & Y-5 from 40CFR98, Subpart Y

$$CH_4 = (CO_2 \times EmF_{CH_4}/EmF_{CO_2}) + CO_2 \times (.02/.98) \times (16/44) \times f_{CH_4}$$

$$N_2O = (CO_2 \times (EmF_{N_2O}/EmF))$$

Factors/Conversions

- 849.5 Molar Volume Conversion at 68F (MVC)
- 1.1025 US Ton/Metric Ton
- 0.003 kg CH₄/MMBtu
- 0.0006 kg N₂O/MMBtu
- 0.4 f_{CH₄}

Table B-18
GHG Emission Calculations - Storage Tanks
Valero McKee Refinery

EPNs: S-022, S-023, S-183, S-186, S-176, S-184, S-195, S-196, S-197, and S-199

Baseline Emissions

EPNs	Pollutant	Crude Oil Throughput (Q _{Ref}) MMbbl/yr	GHG Mass Emissions tpy	Global Warming Potential Factor	CO ₂ e tpy
S-022	CH ₄	58.49	0.64	21	13.54
S-023					
S-183					
S-186					
S-176					
S-184					
S-195					
S-196					
S-197					
S-199					

Project Potential To Emit

EPNs	Pollutant	Crude Oil Throughput (Q _{Ref}) MMbbl/yr	GHG Mass Emissions tpy	Global Warming Potential Factor	CO ₂ e tpy
S-022	CH ₄	76.65	0.85	21.00	17.75
S-023					
S-183					
S-186					
S-176					
S-184					
S-195					
S-196					
S-197					
S-199					

Equation Y-22 from 40CFR98, Subpart Y

$$CH_4 = 0.1 \times Q_{Ref}$$

Factors/Conversions

0.01 metric tons CH₄/MMbbl

1.1025 US Tons/Metric Tons