APPLICATION FOR A U.S. ENVIRONMENTAL PROTECTION AGENCY GREENHOUSE GAS AIR QUALITY PERMIT FOR A NEW CONDENSATE SPLITTER FACILITY

Prepared for

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Revised March 2014

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LIST OF ACRONYMS

BACT	Best Available Control Technology
bbl	barrel
BPD	barrels per day
CCI	CCI Corpus Christi LLC
CCS	Carbon Dioxide Capture and Sequestration
CF	Condensate Fractionator
CFR	Code of Federal Regulations
CH_4	methane
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
CSFP	Condensate Splitter Facility
DOE	U.S. Department of Energy
DRE	destruction removal efficiency
EPA	United States Environment Protection Agency
EPN	Emission Point Number
GHG	greenhouse gas
GWP	global warming potential
HFCs	hydrofluorocarbons
IR	infrared
LDAR	leak detection and repair
MMBtu/hr	10^6 British Thermal Units per hour
MVCU	Marine Vapor Control Units
MMgal/yr	10^6 gallons per year
MSS	Maintenance, Startup, and Shutdown
N_2O	nitrous oxide
NAAQS	National Ambient Air Quality Standards
PFCs	perflurocarbons
PSD	Prevention of Significant Deterioration
RBLC	Reasonably Available Control Technology / Best Available Control Technology Lower Achievable Emission Rate Clearinghouse
SOCMI	Synthetic Organic Chemical Manufacturing Industry

Revised March 2014

LIST OF ACRONYMS (CONTINUED)

tpy	short ton (i.e., 2,000 lb) per year
VCU	vapor combustion unit
VFR	vertical fixed roof
VOCs	volatile organic compounds
VRU	vapor recovery units

1. INTRODUCTION

CCI Corpus Christi LLC (CCI) proposes to construct a new Condensate Splitter Process Facility referred to as Phase I and to construct and operate a bulk petroleum terminal referred to as Phase II. Both Phase I and Phase II will be constructed concurrently at the same location in Corpus Christi, Nueces County, Texas. Both Phase I and Phase II operations will be referenced together in this application as the Condensate Splitter Facility Project (CSFP).

With this application, CCI requests a Greenhouse Gas (GHG) air quality permit authorization to construct the proposed new CSFP in Corpus Christi, Texas. This initial GHG permit application is provided consistent with the requirements in Title 40 of the Code of Federal Regulations, Part 52 (40 CFR 52) and specifically with §52.21, "Prevention of Significant Deterioration (PSD)" requirements.

An area map showing the location of the proposed new CSFP is included in this section as **Figure 1-1**. A plot plan for the proposed new CSFP is included as **Figure 1-2**.

1.1 PROJECT OVERVIEW

Phase I of the proposed CSFPP will consist of two identical fractionation trains each capable of processing 50,000 ballers per day (BPD) of hydrocarbon condensate material for a total processing capacity of 100,000 BPD. The product slate will consist of mixed light hydrocarbons (Y-grade), combined naphtha (consisting of heavy stripped naphtha and light naphtha), jet fuel, marine diesel, and heavy gas oil/bottoms. Process equipment associated with Phase I includes heaters/boilers combustions sources, flare, cooling tower, storage tanks, wastewater treatment system, and marine loading with associated piping and other fugitive equipment.

In Phase II of the CSFP, CCI is requesting to authorize loading 500,000 BPD of condensate/crude at two planned marine loading docks. Additional process equipment associated with Phase II includes six storage tanks.

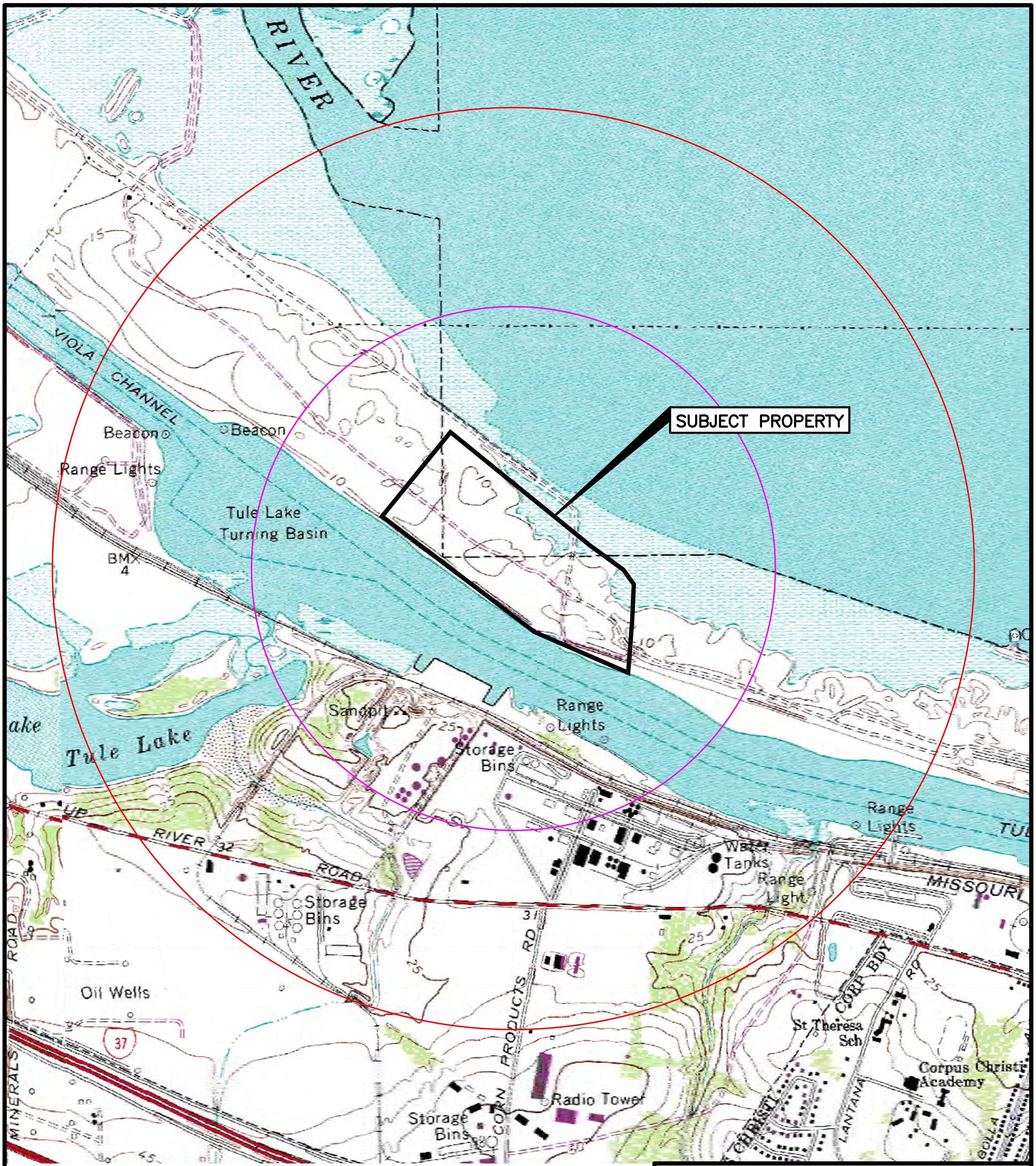
1.2 PSD APPLICABILITY EVALUATIONS

This application is provided to the EPA to request PSD permit authorization as required under 40 CFR §52.21 for constructing a new major stationary source of regulated GHG air pollutants. Construction of the new CSFP will occur after 1 July 2011, and the associated GHG potential to emit for the entire facility is greater than 100,000 tons per year (tpy) of carbon dioxide equivalent (CO_2e). Therefore, a PSD permit appears to be required for GHG emissions as specified in §52.21(b)(49).

PSD applicability tables are included in **Appendix C** to document the determination that the proposed CSFP construction is subject to PSD permitting requirements for GHG emissions. Project-related GHG potential to emit calculations are included in **Appendix D**. Because this is a proposed new stationary source, and there are no contemporaneous projects to evaluate, PSD netting tables are not included in **Appendix C**. **Table D-1** (in **Appendix D**) summarizes the project-related GHG potential emissions, and **Appendix C** provides additional PSD emission summaries and PSD applicability analysis information.

Based on §52.21 and related EPA guidance documents, CCI understands the following with regard to other evaluations required for PSD permitting of regulated GHG pollutants:

- EPA has not established NAAQS specific to regulated GHG pollutants.
- Air dispersion modeling of the regulated GHG pollutants is not required under §52.21(k) at this time.
- Preconstruction air quality monitoring of regulated GHG pollutants is not required under §52.21(m)(1)(ii) at this time.
- Additional impacts analysis of regulated GHG pollutants on designated Class I areas is not required under §52.21(o) at this time.



LEGEND

- 3,000–FOOT RADIUS
- 1–MILE

SOURCE: USGS 7.5' MINUTE SERIES TOPOGRAPHIC, ANNAVILLE AND CORPUS CHRISTI, TEXAS (1975).

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FIGURE 1–1

AREA MAP

CCI CORPUS CHRISTI LLC
CORPUS CHRISTI, TX

DATE	PROJECT NO.	SCALE
DEC 2013	13844.058.001.0002	AS SHOWN

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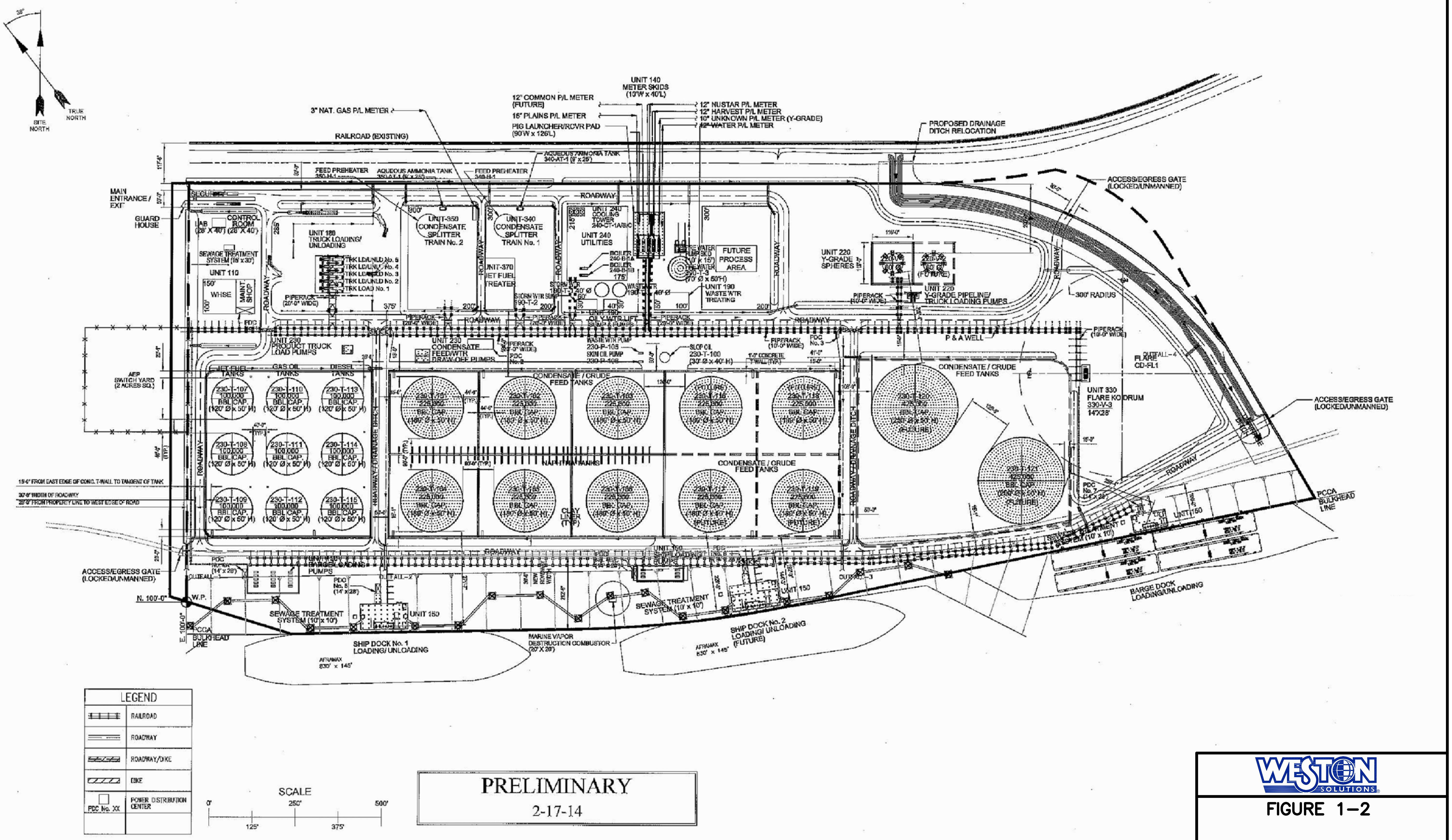

SOURCE:
BASE MAP PROVIDED BY CCI, LLC
FROM WILLBROS ENGINEERS DRAWING
NO. 100-A-02-0001.

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FIGURE 1–2

PLOT PLAN

CCI CORPUS CHRISTI LLC
CORPUS CHRISTI, TX

DATE	PROJECT NO.	SCALE
MAR 2014	13844.058.001.0002	AS SHOWN

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2. PROCESS DESCRIPTION

The proposed site will support both Phase I and Phase II operations. A simplified Process Flow Diagram is provided in Figure 2-1.

2.1 PHASE I CONDENSATE SPLITTER FACILITIES

Phase I will be comprised of two identical parallel fractionation trains. Each train will be capable of processing 50,000 BPD of hydrocarbon condensate feedstock for a total processing capability of 100,000 BPD. The facility will produce a product slate consisting of Y-grade, naphtha, jet fuel, diesel, and heavy gas oil/bottoms. The jet fuel is intended to meet Jet A-1 and JP-45 colonial specifications while the diesel is intended to meet marine diesel grade requirements.

Condensate/Crude feedstock will be received by pipeline or barge and will be stored in various storage tanks (Emission Point Number [EPNs]: TK-101 through TK-104). The feedstock will be fed to a series of heat exchangers and a pre-flash drum before fractionation. The majority of the heat required for the fractionation process will be supplied by direct fired charge heaters (EPNs: H-1 and H-2) using natural gas as the primary fuel. A boiler (EPNs: BL-1 or BL-2) will be utilized to provide process steam requirements. The boiler will utilize natural gas as the primary fuel.

The fractionation column will split the treated feedstock into the commercially acceptable product slate. Final Y-grade product will be stored in pressurized vessels (EPNs: V-1 and V-2), final naphtha, jet fuel, diesel, and heavy gas oil/bottoms products will be stored in vertical fixed roof (VFR) tanks (EPNs: TK-105 through TK-115). Y-grade product will be exported off-site by either pipeline or trucks. Naphtha product will be exported off-site by ship and/or barge. Final jet fuel, diesel, and heavy gas oil/bottoms will be exported off-site by barge, ship, and/or truck.

Other support processes will be required for proper and safe operation of the condensate splitter process. An elevated flare will be used for emergency or upset conditions and certain planned maintenance activities. A Selective Catalytic Reduction (SCR) will be installed on the charge heater (EPNs: H-1 and H-2). The SCR will utilize aqueous ammonia injection and catalyst reactions to control NO_x emissions. Additionally there are two ship loading docks and a barge loading dock for product exported off-site. The marine loading docks will be serviced with a marine vapor combustion system.

The primary fuel for normal operation of the boilers and heaters will include approximately 5 percent (%) produced gas. The fuel gas system includes a mix drum and a liquid knock out drum to mix the gases and remove any condensable liquids before the blended fuel is used in the combustion units. The fuel gas system is an enclosed process that does not produce any waste gases or air pollution emissions during operations.

2.2 PHASE II BULK PETROLEUM TERMINAL

Phase II will receive unrefined condensate/crude by pipeline and barge. The unrefined condensate/crude will be stored in one of several storage tanks (EPNs: TK-116 through TK-121) and will be shipped off-site by ships. The marine loading docks will be supported with a common marine vapor combustion unit (MVCU) to control captured loading vapors.

2.3 SUPPORTING OPERATIONS

This section includes brief descriptions of key utility and other operations that serve to support the Phase I process operations.

2.3.1 Cooling Water System

A circulating cooling water system with a cooling water tower (EPN: CTW) will provide cooling for process operations. About 600,000 gallons per hour of water will be circulated through the cooling water tower. The heated water from the process units will be returned to the cooling tower risers. The cooling water tower will be equipped with mist eliminators and induced air flow fans for each cell.

2.3.2 Flare System

A process flare (EPN: FL-1) will control routine gas venting and emissions associated with planned maintenance, start-up, and shutdown (MSS) activities and upset events. During normal operations, the process flare will control streams from safety relief and pressure control valves from process equipment, pressurized storage tanks, etc. that are closed during normal operations.

During planned MSS operations, the process flare will be used to control gases generated from equipment clearing.

The flare system will be equipped with a flare knock-out drum to prevent liquids from passing to the flare tip and the waste stream flow monitor. The flare will operate with a continuous pilot flame and will be equipped with a continuous pilot flame monitor.

Process upset events are not proposed for permit authorization.

2.3.3 Wastewater Management System

Process wastewater will be generated from various process operations within Phase I. The individual process wastewater streams will be collected and combined in an enclosed wastewater gathering system or process sewer. The wastewater gathering system will include typical sewer components such as drains, pipes, and junction boxes (e.g., manholes). The combined wastewater from the gathering system will be processed in a wastewater treatment system. The treatment system will include oil-water separation, pH neutralization, other physical/chemical pretreatment operations, aerobic biological treatment, and secondary clarification. The treated wastewater will be discharged to the Tule Lake Channel (part of the Nueces Bay system) consistent with a Texas Pollutant Discharge Elimination System Permit to be issued by TCEQ.

2.3.4 Planned Maintenance, Startup, and Shutdown Activities

Planned MSS activities will occur in order to ensure the continued and proper operation of the CSFP. Such activities will require shutdown of the processes and subsequent start-up to return to normal operations. The process flare (EPN: FL-1) will control emissions from planned MSS activities, including combustion of fuel gas and/or gases from equipment clearing. Other MSS activities will include maintenance of the storage tanks, including tank degassing, cleaning, and refilling. Emissions from tank degassing will be routed to a temporary control device (regenerative thermal oxidizer) for control.

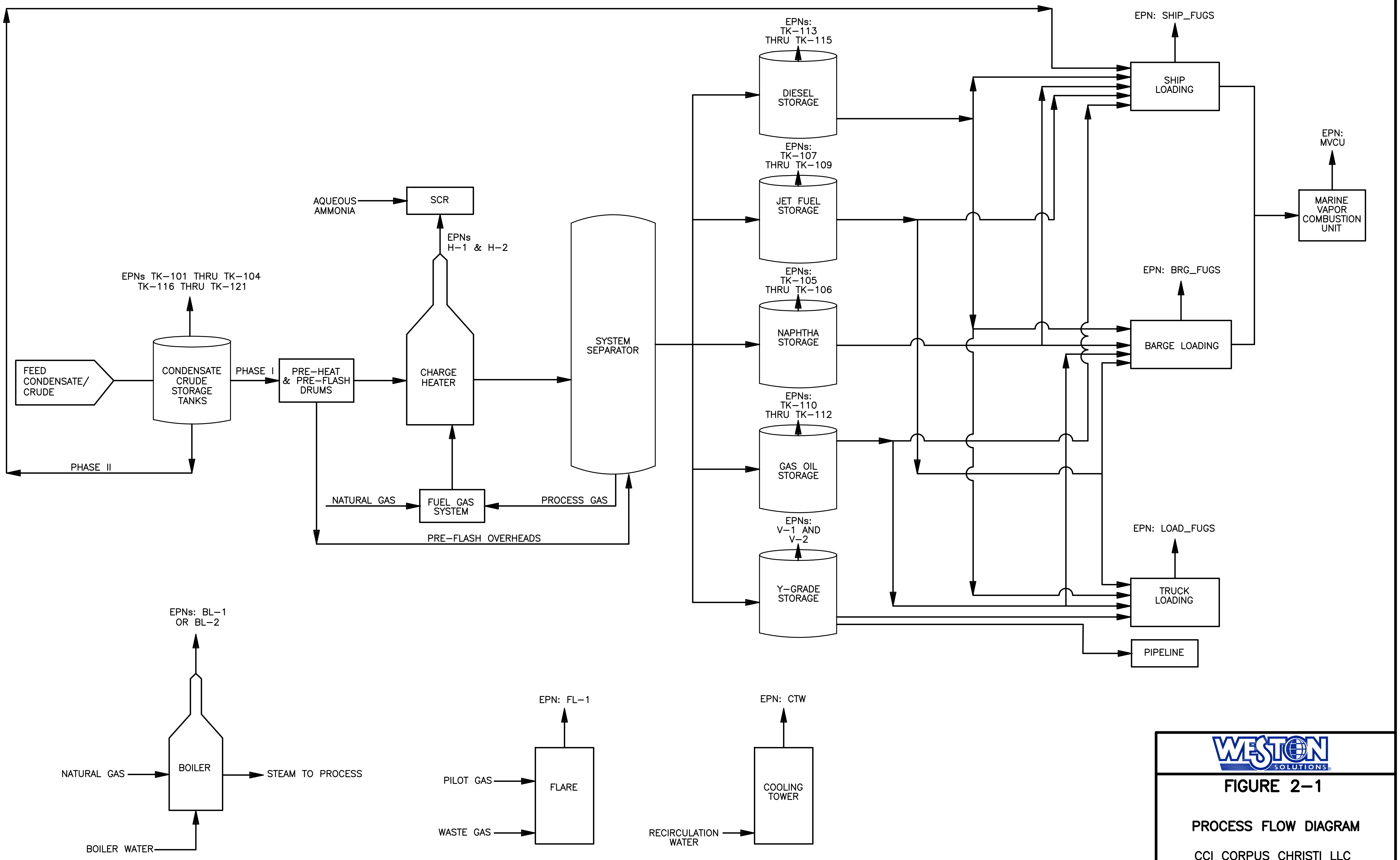

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FIGURE 2−1

PROCESS FLOW DIAGRAM

CCI CORPUS CHRISTI LLC
CORPUS CHRISTI, TX

DATE	PROJECT NO.	SCALE
DEC 2013	13844.058.001.0002	NOT TO SCALE

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3. EMISSION SOURCES AND CALCULATION METHODOLOGIES

The quantity of GHG emissions is the sum of six individual compounds emitted from an emission source on both a mass basis and a carbon dioxide equivalent (CO_2e) basis. The CO_2e emission rates are based on the mass emission rates of each applicable GHG compound multiplied by the global warming potential (GWP) of the corresponding compound as per 40 CFR Part 98, Subpart A, Table A-1. The GHGs emitted from the proposed facilities include carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). CCI does not expect emissions of hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), or sulfur hexafluoride (SF_6) from the proposed facilities.

This section describes the GHG emission calculation methods applied to each source type included in this application. A summary of GHG emissions may be found in **Table D-1** of **Appendix D**.

3.1 HEATERS

The new CSFP will utilize two fuel gas fired heaters (EPNs H-1 and H-2). GHG emissions from the two combustion units were calculated using the proposed maximum hourly and average annual firing rates and GHG emission factors for fuel gas combustion from 40 CFR Part 98, Subpart C, Tables C-1 and C-2. Detailed GHG emission calculations are provided in **Table D-2** in **Appendix D**.

3.2 AUXILARY BOILER

The new CSFP will utilize two fuel gas fired boilers (EPNS H-1 and H-2). GHG emissions from the boiler were calculated using the proposed maximum hourly and average annual firing rates and GHG emission factors for fuel gas combustion from 40 CFR Part 98, Subpart C, Tables C-1 and C-2. Detailed GHG emission calculations are provided in **Table D-2** in **Appendix D**.

3.3 FLARE

A process flare (EPN FL-1) will be utilized to safely manage combustible gases generated during planned MSS activities or upset events. Upset events are not being proposed for permit authorization. During normal operations, only natural gas as pilot fuel will be burned in the plant flare. GHG emissions from the flare during normal operations will include unburned CH_4 and small amounts of CO_2 and N_2O from the combustion process of pilot fuel. GHG emissions for normal flare operations were calculated using the estimated maximum hourly and average annual pilot gas flow rates and the appropriate emission factors. The CO_2 emissions were based on the factor from U.S. EPA's AP-42 Table 1.4-2 (July 1998). The CH_4 and N_2O emission factors were based on 40 CFR Part 98 Subpart C, Table C-2. Detailed GHG emission calculations from the plant flare are provided in Table **D-3** in **Appendix D**.

3.4 FUGITIVE COMPONENTS

Fugitive emissions of methane were calculated based on the calculated fugitive emission rate and a conservative estimate of methane content. The calculated fugitive emission rate was calculated using the number of fugitive components by service and Synthetic Organic Chemical Manufacturing Industry (SOCMI) "without ethylene" emission factors from TCEQ's *Technical Guidance Package for Equipment Leak Fugitives* (November, 2000). The monitoring credits were applied based on TCEQ's 28VHP leak detection and repair (LDAR) program. In the absence of detailed stream speciation, the CH_4 concentration is conservatively assumed to be 20%. Detailed GHG emission calculations for fugitive components are provided in Table **D-7** in **Appendix D**.

3.5 MARINE VAPOR CONTROL UNITS

A Marine Vapor Control Unit (EPN MVCU) will control vapors associated with marine loading activities. During product loading, natural gas will be used as fuel for the pilot and for enrichment gas. GHG emissions generated from the combustion of collected loading vapors were calculated using the loading vapor loss equations described in U.S. EPA's AP-42, Section 5.2 (June 2008), CO_2 emission factors derived from U.S. EPA's AP-42 Table 1.4-2 (September 1998) and CH_4/N_2O emission factors from 40 CFR, Part 98, Subpart C, Table C-1 and C-2.

Detailed GHG emission calculations from the MVCU are provided in **Table D-8** located in **Appendix D**.

3.6 EMERGENCY GENERATOR AND FIREWATER PUMP ENGINES

There will be one emergency generator (EPN EMGEN) and two firewater pumps (EPNS FW-1 and FW-2). GHG emissions from these sources were calculated using the proposed maximum hourly and average annual firing rates and GHG emission factors for distillate fuel oil no.2 from 40 CFR Part 98, Subpart C, Tables C-1 and C-2. Detailed GHG emission calculations are provided in **Table D-9** in **Appendix D**.

3.7 PLANNED MAINTENANCE, STARTUP, AND SHUTDOWN EMISSIONS

The following MSS activities may result in GHG emissions:

- Start-up and shutdown of heaters;
- MSS Vapor Control;
- Clearing of process vessels and equipment;
- Storage tanks degassing; and
- Vacuum trucks.

3.7.1 Start-up and Shutdown of Heaters

The proposed natural gas fired heaters are expected to operate within the GHG emission rates discussed in **Section 3.1** during start-up and shutdown periods, and no additional GHG emissions are included in this application for heater MSS.

3.7.2 MSS Vapor Control

GHG emissions will be generated from the control of vapors associated with various MSS activities. The new CSFPP will utilize the process flare discussed in **Section 3.2** to control VOC emissions associated with MSS activities. Flaring will occur during planned plant turnarounds and equipment clearing for maintenance purposes. Annual GHG flare emissions were conservatively calculated based on the number of planned plant shutdowns in a 12-month period and the total equipment volume capacity at the CSFP. Detailed GHG emission calculations from MSS are provided in Table **D-4** located in **Appendix D**.

3.7.3 Clearing of Process Vessels and Equipment

GHG emissions will be generated from the clearing of process vessels and equipment. Emissions from equipment clearing will be routed to the flare for control. GHG flare emissions from equipment clearing were calculated based on the calculated heat input to the flare for each material and the corresponding CO_2, CH_4, and N_2O emission factors from 40 CFR Part 98 Subpart C, Table C-1 and C-2. Detailed GHG emission calculations from equipment clearing are provided in Table **D-5** located in **Appendix D**.

3.7.4 Tank Degassing and Vacuum Trucks

GHG emissions will be generated from tank maintenance. Tanks are emptied to the extent possible using vacuum trucks before opening the tank to the atmosphere. Emissions from vacuum tucks and tank degassing are routed to a regenerative thermal oxidizer (RTO) for control. The GHG emissions from the RTO are based on the duration of each event and the mass of material routed to the RTO. Detailed GHG emission calculations from the RTO are provided in Table **D-6** located in **Appendix D**.

4. BEST AVAILABLE CONTROL TECHNOLOGY

New sources subject to PSD regulations require that Best Available Control Technology (BACT) be applied to each facility with the potential to emit an air pollutant for which a significant net emissions increase will occur. GHG is the only pollutant addressed in this application and will be produced by individual sources of CO_2, CH_4, and N_2O and addressed as CO_2e emissions that include combustion units and potential fugitive component leaks.

The EPA recommends the five-step "top-down" BACT analysis methodology for GHG sources as outlined in *PSD and Title V Permitting Guidance for Greenhouse Gases* (EPA-457/B-11-001, March 2011). This methodology calls for identification of all available control technologies for a given pollutant and ranks these technologies in descending order of control effectiveness to determine the most stringent control available for a similar or identical emission source. This analysis is based on a case-by-case basis with consideration to technical practicability and economic reasonableness. The EPA has outlined this process in the following five steps:

Step 1: *Identify all available control technologies.*

Step 2: *Eliminate technically infeasible options.*

Step 3: *Rank remaining control technologies based on control effectiveness.*

Step 4: *Evaluate control technologies for cost-effectiveness, energy and environmental impacts.*

Step 5: *Select the BACT.*

The "top-down" approach as described above has been followed in this BACT analysis for the following plant-wide GHG emitting sources:

- Process Heaters;
- Boiler;
- Flare;
- Marine Vapor Control unit;
- Process Fugitives; and
- Emergency Equipment

The following resources were utilized to perform the BACT analysis.

- EPA's Reasonably Available Control Technology / Best Available Control Technology / Lower Achievable Emission Rate Clearinghouse (RBLC) database;

- Approved GHG permit applications for similar source types in the state of Texas;
- EPA's *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry*, November 2010 (referred to herein as GHG BACT for Refineries);
- Department of Energy's *Report of the Interagency Task Force on Carbon Capture and Storage*, October 2010; and
- Ernest Orlando Lawrence Berkeley National Laboratory's *Energy Efficiency Improvement and Cost Savings for the Petrochemical Industry*, July 2008.

4.1 PLANT-WIDE SOURCES

Step 1 – Identification of Potential Control Technologies

Carbon Dioxide Capture and Sequestration (CCS): CCS technologies involve the separation, collection, and compression of CO_2 gas from point source emissions, transportation of the compressed CO_2 gas to an on-site or off-site storage facility, and sequestering of the CO_2 in a viable storage facility.

The proposed CSFP will emit CO_2 from a number of different processes and emission points throughout the facility. The consideration of the CCS at this site would likely be limited to the larger CO_2-emitting stacks, such as the process heaters and the auxiliary boiler. The capture of the CO_2 gas emissions would require separation of the CO_2 gas from the combined combustion exhaust flows using a CO_2 separation process.

The proposed facility will not have on-site CO_2 storage. Therefore, any CO_2 captured and compressed would need to be transported off-site via a third party CO_2 pipeline system. The United States already presently has more than 3,000 miles of CO_2 pipelines used to transport CO_2 for Enhanced Oil Recovery (EOR).

Captured, compressed, and transported CO_2 may be stored or sequestered by means of currently available methods, including storage in geologic formations, EOR, and injection of CO_2 into an active oil reserve, brine aquifer, un-mined coal seam, basalt rock formation, or an organic shale bed. The U.S. Department of Energy (DOE) has been supporting Regional Partnerships that are initiating large-scale tests to determine how geologic storage reservoirs and their surrounding environments respond to large amounts of injected CO_2 in a variety of geological formations and regions across the United States. Because CO_2 storage is still an emerging technology, regulations and standards have not been developed.

Step 2 – Elimination of Technically Infeasible Options

The process of CO_2 capture concentrates the CO_2 stream so it can be transported and/or stored. To date, successful CCS implementation has only involved highly concentrated CO_2 streams for practical and economic reasons.

The CO_2 must be separated from the combustion flue gas by a complex process that 1) filters out particulates, 2) cools the flue gas, and 3) compresses and separates the CO_2 (most likely via an amine absorption system). This process would require the installation of equipment that would otherwise not be used at the facility. For example, the separated CO_2 stream requires large compression equipment, capable of acidic gas handling (since CO_2 is highly corrosive), and high energy consumption to pressurize the gas for pipeline transportation. The energy demand required to operate a carbon capture system would potentially require the construction and operation of a cogeneration unit (cogen unit). A cogen unit could be associated with a significant amount of emissions of GHGs and other regulated pollutants that would require additional controls. Although a CCS system would be technically challenging, it may not be infeasible and therefore needs to be considered in Step 3 of the top-down BACT analysis.

Step 3 – Ranking of Remaining Technologies Based on Control Effectiveness

The economic reasonableness assessment is based on a 90% capture efficiency of the following CO_2-emitting sources at the site:

- Two Charge Heaters (EPNs: H-1 and H-2);
- Auxiliary Boilers (EPNs: BL-1 and BL-2).

These sources contribute 85% to the total CO_2e emissions. Therefore, a CCS system for these sources would be the most effective method of controlling site-wide CO_2 emissions.

Step 4 – Evaluate Control Technologies for Cost-Effectiveness, Energy and Environmental Impacts

A search of the EPA RBLC database revealed no facilities listed as using CCS for BACT. However, though some aspects of CCS may prove it to be technically challenging, economics is the primary consideration in the BACT analysis. The cost of the CCS for the project is not considered effective for GHG control and, if required, would make the entire proposed project economically unviable. Therefore, CCS is not selected as a control option, and no further analysis will be considered in this permit application.

4.2 PROCESS HEATERS

Step 1 – Identification of Potential Control Technologies

Energy Efficiency Design Technologies

As described below, there are several available energy efficiency technologies for controlling GHG emissions from the charge heaters:

1. Efficient Burner Design: The heaters will have efficient burners designed with improved fuel mixing capabilities. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from ICI Boilers, November 2010*).
2. Increased Heat Transfer: The heaters will have state-of-the-art refractory and insulation materials to minimize heat loss and increase overall thermal efficiency. *(Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Process Heaters, November 2010).*
3. Air Preheat System: Combustion air is preheated prior to combustion; this reduces the required heat load for the heaters, increases thermal efficiency, and reduces GHG emissions. *(Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Process Heaters, November 2010).*
4. Heat Recovery System: The flue gas from the heaters is routed through a heat recovery system that reduces the exit flue gas temperature and increases the thermal efficiency of the combustion source. *(Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Process Heaters, November 2010).*
5. Product Heat Recovery: Hot product streams are cooled in heat exchangers transferring heat to the process feedstock and stripping processes reducing the heat load requirement from the heaters and GHG emissions. *(Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Process Heaters, November 2010).*

Best Operational Practices

As detailed below, there are several best practices that can be incorporated into the operation or design of the process heaters:

1. Fuel Selection: Firing natural gas as a fuel will result in lower GHG emissions as demonstrated in 40 CFR Part 98, Subpart C, "General Stationary Fuel Combustion

Sources" Table C-1. Natural Gas has the lowest carbon intensity of any other available fuel.

2. Good Combustion Practices: Oxygen and intake air flow monitors can be used to optimize fuel/air mixing and limit excess air. The excess air should be limited to 2-3% oxygen for best combustion efficiency resulting in reduced GHG emissions. *(Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Process Heaters, November 2010, Energy Efficiency Improvement and Cost Savings for the Petrochemical Industry, July 2008).*
3. Periodic Maintenance: Development of a maintenance program with documented procedures and scheduling of routine inspections and evaluations will result in increased thermal efficiency, energy savings, and reduced GHG emissions.

Step 2 – Elimination of Technically Infeasible Options

All options identified in Step 1 are considered technically feasible and therefore need to be considered in Step 3 of the top-down BACT analysis.

Step 3 – Ranking of Remaining Technologies Based on Control Effectiveness

The control technologies outlined in Step 1 above are all effective control technologies, and the use of one technology does not preclude the use of any other control technology. Combining available control technologies and operation practices will greatly improve energy efficiency. Technically feasible control technologies and their corresponding control efficiencies are provided in **Table 4-1**.

Table 4-1
Process Heater BACT Control Efficiencies

Control Technology Description	Typical Overall Control Efficiency (%)	Source
Fuel Selection	40	40 CFR Part 98, Subpart C, Table C-1, "Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel"
Efficient Burner Design	N/A	GHG BACT for Refineries (Heat Recovery – Air Preheater)
Air Preheat System	10-15	GHG BACT for Refineries (Heat Recovery – Air Preheater)
Heat Recovery System	2-4	GHG BACT for Refineries (Recover Heat from Process Fuel Gas)
Increased Heat Transfer	5-10	Energy Efficiency Improvement (Section 8)
Good Combustion Practices	1-3	GHG BACT for Refineries (Combustion Air Controls-Limitations on Excess Air)
Periodic Maintenance	1-10	GHG BACT for Refineries (Improved Maintenance)

Step 4 – Evaluate Control Technologies for Cost-Effectiveness, Energy and Environmental Impacts

All of the GHG control technologies listed in **Table 4-1** above are economically reasonable and technically feasible for construction of a new facility.

Step 5 – Selection of BACT

CCI proposes that all the control options listed in **Table 4-1** as BACT for controlling GHG emissions from the two heaters.

4.3 AUXILLARY BOILER

Step 1 – Identification of Potential Control Technologies

Energy Efficiency Design Technologies

As detailed below, there are several energy efficiency technologies that can be incorporated into the design of the auxiliary boiler:

1. Air Preheat System: The combustion air is preheated prior to combustion, which reduces the required heat load and increases thermal efficiency. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from ICI Boilers, November 2010).*
2. Efficient Burner Design: New burner designs have improved fuel mixing capabilities, which increases the burner efficiency and reduce GHG emissions. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from ICI Boilers, November 2010).*
3. Boiler Insulation: Insulating the outside surface area of the boiler reduces heat loss, which reduces the required heat load for the boiler and decreases potential GHG emissions. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from ICI Boilers, November 2010).*
4. Economizer: An economizer recovers heat from the boiler stack flue gas and preheats the boiler feed water, which reduces the required heat load for the boiler and decreases potential GHG emissions. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from ICI Boilers, November 2010).*
5. Condensate Return System: Hot condensate is returned to the boiler system to be used as boiler feed water, which reduces the required heat load for the boiler and decreases potential GHG emissions. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from ICI Boilers, November 2010).*
6. Refractory Material Selection: Use of refractory materials that provide the highest insulating capacity reduces heat loss and increases the energy efficiency of the boiler.

(*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from ICI Boilers, November 2010).*

Best Operational Practices

As detailed below, there are several best practices that can be incorporated into the operation or design of the auxiliary boiler:

1. Combustion Air Controls (Limitations on Excess Air/Oxygen): Oxygen monitors and intake air flow monitors can be used to optimize the fuel-to-air ratio and limit excess air, which results in increased combustion efficiency and decreased GHG emissions. Excess air should be limited to approximately 10-15% or lower for a natural gas-fired boiler. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Process Heaters, November 2010, Energy Efficiency Improvement and Cost Savings for the Petrochemical Industry, July 2008).*
2. Periodic Maintenance: Maintaining the combustion sources through a maintenance program results in increased average thermal efficiency and energy savings. Maintenance activities include regular calibrations of fuel flow meters and gas composition analyzers and regular cleaning of fouled or dirty parts. A maintenance plan that contains official documented procedures and a schedule for routine inspections and evaluations can be developed. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Improved Maintenance, November 2010).*
3. Fuel Selection: Firing natural gas or other gaseous fuels results in lower potential GHG emissions, as demonstrated by Table C-1 in 40 CFR Part 98, Subpart C for "General Stationary Fuel Combustion Sources."

Step 2 – Elimination of Technically Infeasible Options

All options identified in Step 1 are considered technically feasible and therefore need to be considered in Step 3 of the top-down BACT analysis.

Step 3 – Ranking of Remaining Technologies Based on Control Effectiveness

The control technologies specified in Step 1 above are all top-ranked control technologies for industrial boilers. The use of one technology does not preclude the use of any other control technology, and the combination of control technologies and practices will result in higher energy efficiency than any one. However, in order for completeness, the following table lists the technically feasible control technologies and their typical control efficiencies where they are available:

Table 4-2
Auxiliary Boiler BACT Control Efficiencies

Item No.	Control Technology Description	Typical Overall Control Eff. (%)	Source
1	Air Pre-Heat System	10-15	GHG BACT for Refineries (Heat Recovery – Air Preheater)
2	Efficient Burner Design	N/A	GHG BACT for ICI Boilers (Replace/Upgrade Burners)
3	Boiler Insulation	6-26	Energy Efficiency Improvement (Section 7.1)
4	Economizer	2-4	GHG BACT for Refineries (Recover Heat from Process Flue Gas)
5	Condensate Return System	1-10% of steam energy use	GHG BACT for Refineries (Install Steam Condensate Return Lines)
6	Refractory Material Selection	N/A	GHG BACT for ICI Boilers (Refractory Material Selection)
7	Combustion Air Controls (Limits on Excess Air)	1-3	GHG BACT for Refineries (Combustion Air Controls – Limitations on Excess Air)
8	Periodic Maintenance	1-10	GHG BACT for Refineries (Improved Maintenance)
9	Fuel Selection	40	40 CFR Part 98, Subpart C, Table C-1, "Default CO emission Factors and High Heat Values for Various Types of Fuel"

Step 4 – Evaluate Control Technologies for Cost-Effectiveness, Energy and Environmental Impacts

All the aforementioned control technologies are considered economically reasonable since this will be a brand new site with the most current technology. The potential control technologies listed will not result in any adverse environmental impacts.

Step 5 – Selection of BACT

CCI proposes that BACT for the auxiliary boilers (EPNs: BL-1 and BL-2) is the combination of all the BACT options listed in Step 1.

4.4 PROCESS FLARE

GHG emissions, primarily CO_2, are generated from the combustion of natural gas in maintaining the flare pilot flame. The flare will be utilized to control VOC emissions generated during certain events such as MSS activities and emergency or upset events. CO_2e emissions will be generated during flaring operations.

Step 1 – Identification of Potential Control Technologies

Alternative control technologies for controlling VOC emissions include thermal oxidizers or vapor combustion units (VCU) and vapor recovery units (VRU). The available control technologies for flare operations include the following:

1. Fuel Selection: Firing of natural gas to maintain a pilot flame or as supplemental fuel during VOC control results in lower GHG emissions as demonstrated in 40 CFR Part 98, Subpart C, Table C-1.
2. Proper Flare Operation: The use of flow and composition monitors to determine the optimum amount of supplemental natural gas required to maintain adequate VOC control will minimize natural gas combustion to reduce CO_2 emissions. *(Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Flares, November 2010).*
3. Flare Minimization: Minimize the duration and quantity of flaring associated with MSS activities to the extent practicable through good design and operating practices will result in lower GHG emissions.

Step 2 – Elimination of Technically Infeasible Options

A primary reason in consideration of a flare as a control of VOC emissions is that a flare may also be used in emergency or upset events. Neither a thermal oxidizer nor a VCU are capable of safely handling the potentially high vapor flow rates, high heat inputs, and rapidly changing conditions that are inherent during emergency and upset events. It is not technically feasible to use a thermal oxidizer or VCU as an alternative to a flare. In addition, the use of a thermal oxidizer or VCU will not significantly reduce the amount of GHG emissions as compared to the use of a flare.

Since there will not be any gases routed to the flare from process vents during normal operations, the same technical and safety constraints apply to the use of a VRU as an alternative control device to the flare.

Step 3 – Ranking of Remaining Technologies Based on Control Effectiveness

The technologies applicable to the proposed flare and their typical control efficiencies where available are indicated in the following table:

Table 4-3
Flare BACT Control Efficiencies

Control Technology Description	Typical Overall Efficiency (%)	Source
Fuel Selection	40	40 CFR Part 98, Subpart C, Table C-1 "Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel"
Proper Flare Operation	N/A	GHG BACT for Refineries (Proper Flare Operations)
Flare Minimization	N/A	Up to 100% GHG emission reduction depending on activity type

All the technologies listed in **Table 4-3** above are top-ranked control technologies for flares, and the use of one of these technologies does not preclude the use of any other. A combination of these technologies and practices will achieve a higher reduction of GHG than the use of any one of these control technologies or practices.

Step 4 – Evaluate Control Technologies for Cost-Effectiveness, Energy and Environmental Impacts

All technically feasible control options listed in Step 3 are considered economically reasonable, as the CSFP will be a new source and will be able to incorporate into the design the most current technology. The control technologies previously discussed will not have any adverse environmental, economic, or energy impacts.

Step 5 – Selection of BACT

CCI proposes that BACT for the flare consist of a combination of the options listed in **Table 4-3**, which includes the following:

- Fuel Selection: Firing of natural gas to maintain a pilot flame or as supplemental fuel during VOC control;
- Proper Flare Operation: The use of flow and composition monitors to determine the optimum amount of supplemental natural gas required to maintain adequate VOC control;
- Flare Minimization: Minimize the duration and quantity of flaring associated with MSS activities to the extent practicable through good design and operating practices.

4.5 MARINE VAPOR CONTROL UNIT

GHG emissions will be generated from the combustion of VOC vapors captured during the loading of products into marine ships and barges and from supplemental natural gas fuel used to maintain adequate combustion chamber temperature for the required destruction efficiency.

Step 1 – Identification of Potential Control Technologies

The only viable control option for reducing GHG emissions generated during marine/barge loading operations is to minimize the amount of controlled VOC vapors and supplemental gas to the extent possible. Available control technologies for marine vessel loading emissions include:

1. Use of a flare in lieu of a VCU is an alternate control consideration;
2. Use of a VRU in lieu of a VCU is an alternate control consideration;
3. Minimize the duration and quantity of combustion through good engineering design (e.g., submerged loading) and best management practices; and
4. Proper operation and the use of flow and composition monitors to determine the optimum amount of natural gas to maintain adequate VOC destruction efficiency.

Step 2 – Elimination of Technically Infeasible Options

A VCU for control of VOC vapors associated with marine vessel loading operations is being considered primarily due to the higher destruction removal efficiency (DRE) that a VCU is able to achieve (i.e., 99%) over a flare (i.e., 98%). The higher DRE would be required by the TCEQ as BACT for control of non-GHG emissions. Also, it should be noted that the use of a flare for controlling marine vessel loading emissions would not result in a significant reduction of GHG emissions as opposed to the use of a VCU.

VRUs are not capable of handling the large volumes of vapors generally associated with marine vessel loading operations. Therefore, a VRU is a technically infeasible alternative to the use of a VCU for marine loading.

For the reasons discussed above, the use of a flare or VRU are rejected for being technically infeasible control options for marine vessel loading operations. Both minimization and proper operation of the VCU are technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Control Effectiveness

The remaining technologies available for control of vapors generated during marine vessel loading operations from most effective to least effective include:

1. Good engineering design and best operational practices, such as utilizing submerged loading of marine vessels, can reduce GHG emissions;
2. The reduction of GHG emissions resulting from proper operation of the VCU is not directly quantifiable.

CO_2 is the primary GHG resulting from fuel combustion in the VCU. The marine vessel loading facilities will be designed to minimize the volume of loading vapors routed to the VCU. The facilities will utilize submerged loading technology as opposed to splash loading which can equate to up to an 80% concentration reduction in the marine vessel vapor space.

Proper operation will enhance the combustion efficiency of the VCU, resulting in lower GHG emissions; however, this cannot be directly quantified, and the ranking of this technology is an approximation. The use of a thermocouple in the combustion chamber to continuously monitor the chamber temperature will allow instantaneous adjustments to the natural gas fuel supply required to maintain an adequate combustion chamber temperature for proper VOC destruction, ensuring that excess fuel is unnecessarily combusted.

Step 4 – Evaluate Control Technologies for Cost-Effectiveness, Energy and Environmental Impacts

The proposed marine loading facilities will be designed to minimize the volume of vapors routed to the VCU. This will be accomplished through utilization of submerged and/or pressurized loading technologies. There are no adverse environmental, economic, or energy impacts associated with this control technology.

The use of combustion chamber temperature monitors will allow accurate determinations of the required natural gas fuel to maintain the proper temperature necessary for efficient VOC destruction while keeping excess natural gas fuel to a minimum. This will provide the added advantage of reducing fuel costs, thus making this control technology cost effective as both a GHG emission control and a viable control for VOC emissions. There are no adverse environmental, economic, or energy impacts associated with this control technology.

Step 5 – Selection of BACT

CCI proposes that BACT for marine loading is a vapor combustor. GHG emissions from the VCU will be minimized using good engineering design and best operational practices.

4.6 FUGITIVE EMISSIONS

Emissions from leaking piping components (process fugitives) can potentially include methane. The contribution of GHG emissions from process fugitives has conservatively been estimated to be 96.68 tpy which is a negligible amount to the total site GHG emissions. For completeness, GHG process fugitives are included in this BACT analysis.

Step 1 – Identification of Potential Control Technologies

1. Installation of Leakless Technology: The utilization of leakless technology components such as welded components would eliminate the potential of GHG emissions from process fugitives.
2. Implementation of a Leak Detection and Repair (LDAR) Program: The use of a portable organic vapor detector that meets the specifications and performance criteria specified in 40 CFR, Part 60, Appendix A, Test Method 21 in to monitor piping components for leaks will result in decreased emissions of GHG as well as other criteria pollutant emissions. As LDAR programs are not considered as control options for GHG emissions alone, and due to the negligible contribution of GHG emissions from leaking components, an evaluation of the relative effectiveness of various LDAR programs is not warranted. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Fuel Gas System, November 2010*).
3. Alternative Monitoring Using Infrared Technology: This control technology is similar to an LDAR program; however, a sensitive infrared (IR) camera to detect piping component leaks is used in lieu of a portable organic vapor detector.
4. Compressor Selection: The use of dry-seal compressors rather than wet-seal compressors and rod packing for reciprocating compressors will result in reduced GHG emissions. (*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry – Fuel Gas System, November 2010*).

Step 2 – Elimination of Technically Infeasible Options

All control technologies identified in Step 1 are technically feasible options for controlling GHG emissions and are considered in Step 3 below.

Step 3 – Ranking of Remaining Technologies Based on Control Effectiveness

Leakless Technology

Installation of leakless technology would result in 100% control of GHG emissions from piping components and is the most effective control technology.

LDAR Program

LDAR programs are generally designed for control of VOC emissions from leaking piping components and piping components in natural gas service where methane is the primary GHG constituent and have not historically been required for monitoring under existing LDAR Programs. As such, there is no information relating to the effectiveness of an LDAR program in controlling GHG, so the same control efficiencies applied to the control of VOC emissions with a given LDAR program have been applied to the efficiency of control for GHG. As stated in Step 1, a comparative evaluation of the effectiveness of various LDAR programs available is not warranted in this BACT analysis.

Alternative Monitoring

The use of an IR camera for piping component leak detection is considered by the United States Environment Protection Agency (EPA) to be a partial alternative monitoring technology to Test Method 21. This may be interpreted that the monitoring methods are equivalent if, in addition to IR monitoring, piping components are also monitored as specified in Test Method 21 annually. The control effectiveness of an alternative monitoring technology alone may be assumed to be 75% based on TCEQ's 28VHP LDAR program for connector monitoring.

Compressor Selection

The use of dry-seal compressors and rod packing for reciprocating compressors are considered effective means of controlling GHG emissions; however, there is no available data to support specific control effectiveness.

Step 4 – Evaluate Control Technologies for Cost-Effectiveness, Energy and Environmental Impacts

Leakless Technology

Although leakless technology is the most effective means of controlling potential emissions from fugitive components, it has not been adopted as BACT for any sources to date. In addition, the installation of leakless technologies in any process would create increased collateral emissions associated with maintenance activities that require replacement or repair of vessels or piping. The use of leakless technology is not a cost-effective means for controlling fugitive emissions as it would increase costs for controlling emissions associated with maintenance activities. The control of maintenance-related emissions would require a higher energy demand and would increase the potential of adverse environmental impacts.

LDAR Program

Though it is technically feasible to use an LDAR program to control the negligible amount of GHG emissions that occur as leaks from process fugitive components, it is also cost prohibitive if used solely for the control of GHG emissions. However, the implementation of an LDAR program for control of VOC emissions from process fugitive components will result in the added control of GHG emissions from those same process fugitive components. The use of an LDAR program for controlling GHG emissions would not impose an additional cost, require higher energy demand, or result in adverse environmental impacts.

Compressor Design

The use of dry-seal compressors and rod packing for reciprocating compressors are cost effective means for controlling GHG emissions as well as emissions from other criteria pollutants. This control technology would not impose an adverse impact on energy demand or the environment.

Step 5 – Selection of BACT

Because of the negligible amount of GHG emissions from process fugitive components, the implementation of an LDAR program strictly for control of GHG emissions is cost prohibitive. However, CCI proposes the implementation of an appropriate LDAR program to control VOC emissions, which would also decrease GHG emissions. The TCEQ has determined that the appropriate LDAR program to meet BACT for VOC emissions at the proposed CSFP is the 28VHP, and CCI will implement this program. CCI will also install compressors that meet seal and rod packing requirements.

4.7 EMERGENCY GENERATOR AND FIREWATER PUMP ENGINES

Step 1 – Identification of Potential Control Technologies

As detailed below, there are several energy efficiency technologies and best practices that can be incorporated into the design and operation of the emergency generator and firewater pump engines:

1. Vendor-Certified Tier 4 and Clean Burn Engine: The U.S. EPA has set stringent emission standards for non-road diesel engines in accordance with 40 CFR Part 60, Subpart IIII. Compliance with these standards will result in lower potential GHG emissions.
2. Fuel Selection: Firing natural gas or other gaseous fuels results in lower potential GHG emissions as demonstrated by Table C-1 in 40 CFR Part 98, Subpart C for "General Stationary Fuel Combustion Sources."
3. Operation Restriction: Dedication to emergency service will limit the total hours of operation as well as GHG emissions. Operating hours can be monitored with the use of a run-time meter in conjunction with administrative controls to reduce engine use.

Step 2 – Elimination of Technically Infeasible Options

During emergency conditions, non-volatile fuel (such as diesel or other heavy oils) is required to be used and readily available. Natural gas or other gaseous fuels would not be available during certain emergency events; therefore, these lower carbon fuels are not technically feasible options for emergency engines. All remaining options identified in Step 1 are considered technically feasible and therefore need to be considered in Step 3 of the top-down BACT analysis.

Step 3 – Rank remaining control technologies based on control effectiveness

The control technologies specified in Step 1 above are all top-ranked control technologies for emergency engines, with the exception of low carbon fuel selection. The use of one technology or practice does not preclude the use of any other control technology or practice, and the combination of control technologies and practices will result in higher energy efficiency than any one.

Step 4 – Evaluate most effective controls in terms of economic, energy and environmental impacts and document results

Except for low carbon fuel selection, all the aforementioned control technologies are considered economically reasonable. These listed potential control technologies will not result in any adverse environmental impacts.

Step 5 – Selection of BACT

CCI proposes that BACT for the emergency generator engine and the firewater pump engines is the combination of all the BACT options listed in Step 1, with the exception of low carbon fuel selection.

APPENDIX A
ADMINISTRATIVE INFORMATION

Administrative Information

I. Applicant Information		
A. Company or Other Legal Name: **CCI Corpus Christi, LLC**		
Texas Secretary of State Charter/Registration Number (if applicable):		
B. Company Official Contact Name: **Brad Burmaster**		
Title: **Vice President**		
Mailing Address: **811 Main St, Suite 3500**		
City: **Houston**	State: **Texas**	ZIP Code: **77002**
Telephone No.: **(281)378-1190**	Fax No.:	E-mail Address:**Brad.burmaster@cci.com**
C. Technical Contact Name: **Leann Plagens**		
Title: Director of Regulatory Compliance		
Company Name: **CCI Corpus Christi, LLC**		
Mailing Address: **811 Main St, Suite 3500**		
City: **Houston**	State: **Texas**	ZIP Code: 77002
Telephone No.: **(281)378-1257**	Fax No.:	E-mail Address:**Leann.plagens@cci.com**
D. Site Name: **CCI Corpus Christi Condensate Splitter Facility**		
E. Area Name/Type of Facility: **Condensate Splitter**		☒ Permanent ☐ Portable
F. Principal Company Product or Business: **Refined Petroleum Products**		
Principal Standard Industrial Classification Code (SIC): **2911**		
Principal North American Industry Classification System (NAICS): **324110**		
G. Projected Start of Construction Date: **November 2014**		
Projected Start of Operation Date: **June 2015**		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: **4820 E. Navigation Boulevard (Carbon Plant Rd.)**		
City/Town: **Corpus Christi**	County: **Nueces**	ZIP Code: **78402**
Latitude (nearest second):	Longitude (nearest second):	

APPENDIX B
TECHNICAL APPLICATION TABLES

CCI Corpus Christi LLC
Table 1(a) Emission Point Summary (Revised March 2014)

Date: 3/7/2014	**Permit No.:** TBD	**Regulated Entity No.:**	TBD
Area Name: CCI Corpust Christi		**Customer Reference No.:**	TBD

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

AIR CONTAMINANT DATA						EMISSION POINT DISCHARGE PARAMETERS										
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate		4. UTM Coordinates of Emissions Point			Source							
									5. Building Height (Ft.)	6. Height Above Ground (Ft.)	7. Stack Exit Data			8. Fugitives		
(A) EPN	(B) FIN	(C) Name		(A) Pound Per Hour	(B) TPY	Zone	East (Meters)	North (Meters)			(A) Diameter (Ft.)	(B) Velocity (FPS)	(C) Temperature (°F)	(A) Length (Ft.)	(B) Width (Ft.)	(C) Axis Degrees
H-1	340-H1	Charge Preheater 1	CO_2	19,855.75	78,271.36	14	649,294	3,079,041	--	TBD	TBD	TBD	TBD	--	--	--
			CH_4	0.34	1.33											
			N_2O	0.03	0.13											
			CO_2e	19,874.19	78,344.06											
H-2	350-H1	Charge Preheater 2	CO_2	19,855.75	78,271.36	14	649,347	3,079,000	--	TBD	TBD	TBD	TBD	--	--	--
			CH_4	0.34	1.33											
			N_2O	0.03	0.13											
			CO_2e	19,874.19	78,344.06											
BL-1	240-B1	Boiler 1	CO_2	4,722.06	18,372.50	14	649,379	3,078,926	--	TBD	TBD	TBD	TBD	--	--	--
			CH_4	0.08	0.31											
			N_2O	0.01	0.03											
			CO_2e	4,726.44	18,389.56											
BL-2	240-B2	Boiler 2	CO_2	4,722.06	18,372.50	14	TBD	TBD	--	TBD	TBD	TBD	TBD	--	--	--
			CH_4	0.08	0.31											
			N_2O	0.01	0.03											
			CO_2e	4,726.44	18,389.56											
FL-1	330-FL1	Flare	CO_2	542.77	2,161.22	14	649,643	3,078,574	--	TBD	TBD	TBD	TBD	--	--	--
			CH_4	1.50	5.98											
			N_2O	<0.01	<0.01											
			CO_2e	580.63	2,312.00											

CCI Corpus Christi LLC
Table 1(a) Emission Point Summary (Revised March 2014)

Date: 3/7/2014	**Permit No.:** TBD	**Regulated Entity No.:** TBD
Area Name: CCI Corpust Christi		**Customer Reference No.:** TBD

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

AIR CONTAMINANT DATA						EMISSION POINT DISCHARGE PARAMETERS										
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate		4. UTM Coordinates of Emissions Point			Source							
									5. Building Height (Ft.)	6. Height Above Ground (Ft.)	7. Stack Exit Data			8. Fugitives		
(A) EPN	(B) FIN	(C) Name		(A) Pound Per Hour	(B) TPY	Zone	East (Meters)	North (Meters)			(A) Diameter (Ft.)	(B) Velocity (FPS)	(C) Temperature (°F)	(A) Length (Ft.)	(B) Width (Ft.)	(C) Axis Degrees
FL-MSS	330-FL1	Flare-MSS	CO_2	183,036.68	1,911.91	14	649,643	3,078,574	--	TBD	TBD	TBD	TBD	--	--	--
			CH_4	18.01	0.20											
			N_2O	0.46	<0.01											
			CO_2e	183,624.20	1,917.98											
TK-MSS	Multiple FINS	Tank MSS (RTO emissions from degassing Tank)	CO_2	8,988.73	36.88	14	TBD	TBD	--	TBD	TBD	TBD	TBD	--	--	--
			CH_4	0.36	<0.01											
			N_2O	0.07	<0.01											
			CO_2e	9,019.34	37.01											
FUGS	FUGS	Fugitives	CO_2	-	-	14	TBD	TBD	--	TBD	TBD	TBD	TBD	--	--	--
			CH_4	1.10	4.84											
			N_2O	-	-											
			CO_2e	27.60	120.88											
MVCU	150-FL2	Marine Vapor Combustion Unit	CO_2	23,301.13	29,022.70	14	649,252	3,078,668	--	TBD	TBD	TBD	TBD	--	--	--
			CH_4	0.92	1.12											
			N_2O	0.18	0.22											
			CO_2e	23,377.28	29,116.27											
EMGEN	EMGEN	Emergency Generator	CO_2	2,446.23	122.31	15	TBD	TBD	--	TBD	TBD	TBD	TBD	--	--	--
			CH_4	0.10	<0.01											
			N_2O	0.02	<0.01											
			CO_2e	2,454.62	122.73											

CCI Corpus Christi LLC
Table 1(a) Emission Point Summary (Revised March 2014)

Date:	3/7/2014	**Permit No.:** TBD	**Regulated Entity No.:**	TBD
Area Name:	CCI Corpust Christi		**Customer Reference No.:**	TBD

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

AIR CONTAMINANT DATA						EMISSION POINT DISCHARGE PARAMETERS										
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate		4. UTM Coordinates of Emissions Point			Source							
									5. Building Height (Ft.)	6. Height Above Ground (Ft.)	7. Stack Exit Data			8. Fugitives		
(A) EPN	(B) FIN	(C) Name		(A) Pound Per Hour	(B) TPY	Zone	East (Meters)	North (Meters)			(A) Diameter (Ft.)	(B) Velocity (FPS)	(C) Temperature (°F)	(A) Length (Ft.)	(B) Width (Ft.)	(C) Axis Degrees
FW-1	FW-1	Firewater Pump 1	CO_2	815.41	40.77	16	TBD	TBD	--	TBD	TBD	TBD	TBD	--	--	--
			CH_4	0.03	<0.01											
			N_2O	0.01	<0.01											
			CO_2e	818.21	40.91											
FW-2	FW-2	Firewater Pumpu 2	CO_2	815.41	40.77	17	TBD	TBD	--	TBD	TBD	TBD	TBD	--	--	--
			CH_4	0.03	<0.01											
			N_2O	0.01	<0.01											
			CO_2e	818.21	40.91											

EPN = EMISSION POINT NUMBER

FIN = FACILITY IDENTIFICATION NUMBER

This form designed to correspond with TCEQ - 10153 (Revised 04/08) Table 1(a).

APPENDIX C
PSD TABLES

TCEQ

TABLE 1F
AIR QUALITY APPLICATION SUPPLEMENT

Permit No.:	Application Submittal Date: ***TBD***
Company: ***CCI Corpus Christi, LLC***	
RN:	Facility Location: ***From Interstate 37 South exit onto Co Rd 55B/Carbon Plant Rd. Proceed for approximately 6.8 miles to the proposed site on the right***
City: ***Corpus Christi***	County: ***Nueces***
Permit Unit I.D.:	Permit Name:
Permit Activity: ☒ New Source ☐ Modification	

Complete for all Pollutants with a Project Emission Increase.	**POLLUTANTS**							
	Ozone							
	VOC	**NO_x**	**CO**	**PM_{10}**	**$PM_{2.5}$**	**NO_X**	**SO_2**	**Other**[1] CO_2e
Nonattainment?								No
PSD?								Yes
Existing site PTE (tpy)?								NA
Proposed project emission increases (tpy from 2F[2])?								227,175.94
Is the existing site a major source?								NA
If not, is the project a major source by itself?								Yes
If site is major source, is project increase significant?								Yes
If netting required, estimated start of construction: ***November 2014***								
5 years prior to start of construction: ***November 2009***								contemporaneous
Estimated start of operation: ***June 2015***								period
Net contemporaneous change, including proposed project, from Table 3F. (tpy)								***NA***
Major NSR Applicable?								***Yes***

Signature	***Title***	***Date***

---

[1] Other pollutants. [Pb, H_2S, TRS, H_2SO_4, Fluoride excluding HF, etc.]

[2] Sum of proposed emissions minus baseline emissions, increases only.

The representations made above and on the accompanying tables are true and correct to the best of my knowledge.

TABLE 2F (Revised March 2014)

PROJECT EMISSION INCREASE

Pollutant[(1)]:	CO_2e	**Permit:**	TBD
Baseline Period:	**Not applicable (proposed new stationary source)**		

					A	B				
	Affected or Modified Facilities[(2)]		**Permit No.**	**Actual Emissions[(3)]**	**Baseline Emissions[(4)]**	**Proposed Emissions[(5)]**	**Projected Actual Emissions**	**Difference (B-A)[(6)]**	**Correction[(7)]**	**Project Increase[(8)]**
	FIN	**EPN**								
1	H-1	340-H1	TBD	-	-	78,344.06	-	78,344.06		78,344.06
2	H-2	350-H1	TBD	-	-	78,344.06	-	78,344.06		78,344.06
3	BL-1	240-B1	TBD	-	-	18,389.56	-	18,389.56		18,389.56
4	BL-2	240-B2	TBD	-	-	18,389.56	-	18,389.56		18,389.56
5	FL-1	330-FL1	TBD	-	-	2,312.00	-	2,312.00		2,312.00
6	FL-MSS	330-FL1	TBD	-	-	1,917.98	-	1,917.98		1,917.98
7	TK-MSS	Multiple FINS	TBD	-	-	37.01	-	37.01		37.01
8	FUGS	FUGS	TBD	-	-	120.88	-	120.88		120.88
9	MVCU	150-FL2	TBD	-	-	29,116.27	-	29,116.27		29,116.27
10	EMGEN	EMGEN	TBD	-	-	122.73	-	122.73		122.73
11	FW-1	FW-1	TBD	-	-	40.91	-	40.91		40.91
12	FW-2	FW-2	TBD	-	-	40.91	-	40.91		40.91
								Page Subtotal[(9)]	0.00	227,175.94

All emissions must be listed in tons per year (tpy). The same baseline period must apply for all facilities for a given NSR pollutant.

1. Individual Table 2Fs should be used to summarize the project emission increase for each criteria pollutant.
2. Emission Point Number as designated in NSR Permit or Emissions Inventory.
3. All records and calculations for these values must be available upon request.
4. Correct actual emissions for currently applicable rule or permit requirements, and periods of non-compliance. These corrections, as well as any MSS previously demonstrated under 30 TAC 101, should be explained in the Table 2F supplement.
5. If projected actual emission is used it must be noted in the next column and the basis for the projection identified in the Table 2F supplement.
6. Proposed Emissions (column B) minus Baseline Emissions (column A).
7. Correction made to emission increase for what portion could have been accommodated during the baseline period. The justification and basis for this estimate must be provided in the Table 2F supplement.
8. Obtained by subtracting the correction from the difference. Must be a positive number.
9. Sum all values for this page.
10. Type of note. Generally would be baseline adjustment, basis for projected actual, or basis for correction (what could have been accommodated).

APPENDIX D
EMISSION CALCULATIONS

Table D-1 (Revised March 2014)
Summary of Potential to Emit
CCI Corpus Christi LLC

A. Annual Potential to Emit (PTE) Summary

Emission Source Description	Potential Annual Emissions (tons/year) [1]				Reference Table
	CO_2	CH_4	N_2O	CO_2e	
Charge Heater (H-1)	78,271.36	1.33	0.13	78,344.06	D-2
Charge Heater (H-2)	78,271.36	1.33	0.13	78,344.06	D-2
Boiler (BL-1)	18,372.50	0.31	0.03	18,389.56	D-2
Boiler (BL-2)	18,372.50	0.31	0.03	18,389.56	D-2
Flare (FL-1)	2,161.22	5.98	<0.01	2,312.00	D-3
Flare-MSS (FL-MSS)	1,911.91	0.20	<0.01	1,917.98	D-4 & D-5
Temporary Control Device (TK-MSS)	36.88	<0.01	<0.01	37.01	D-6
Fugitives (FUGS)	-	4.84	-	120.88	D-7
Marine Vapor Combustion Unit (MVCU)	29,022.70	1.12	0.22	29,116.27	D-8
Emergency Generator (EMGEN)	122.31	<0.01	<0.01	122.73	D-9
Fire Water Pump (FW-1)	40.77	<0.01	<0.01	40.91	D-9
Fire Water Pump (FW-2)	40.77	<0.01	<0.01	40.91	D-9
Total Proposed PTE	**226,624.28**	**15.43**	**0.56**	**227,175.94**	
Major Source Threshold	NA	NA	NA	75,000	
Triggers Major Source Permitting?	**NA**	**NA**	**NA**	**Yes**	

Notes:

(1) All sources associated with this project are new sources; therefore, baseline emissions are zero and the total emissions increases for purposes of federal applicability are equal to the PTEs.

Table D-1 (Revised March 2014)
Summary of Potential to Emit
CCI Corpus Christi LLC

B. Hourly Potential To Emit (PTE) Summary

Emission Source Description	Potential Hourly Emissions (lb/hour)				Reference Table
	CO_2	CH_4	N_2O	CO_2e	
Charge Heater (H-1)	19,855.75	0.34	0.03	19,874.19	D-2
Charge Heater (H-2)	19,855.75	0.34	0.03	19,874.19	D-2
Boiler (BL-1)	4,722.06	0.08	0.01	4,726.44	D-2
Boiler (BL-2)	4,722.06	0.08	0.01	4,726.44	D-2
Flare (FL-1)	542.77	1.50	<0.01	580.63	D-3
Flare-MSS (FL-MSS)	183,036.68	18.01	0.46	183,624.20	D-4 & D-5
Temporary Control Device (TK-MSS)	8,988.73	0.36	0.07	9,019.34	D-6
Fugitives (FUGS)	-	1.10	-	27.60	D-7
Marine Vapor Combustion Unit (MVCU)	23,301.13	0.92	0.18	23,377.28	D-8
Emergency Generator (EMGEN)	2,446.23	0.10	0.02	2,454.62	D-9
Fire Water Pump (FW-1)	815.41	0.03	0.01	818.21	D-9
Fire Water Pump (FW-2)	815.41	0.03	0.01	818.21	D-9
Total Proposed PTE	269,101.97	22.90	0.83	269,921.35	

Table D-2 (Revised March 2014)
Charge Heaters and Boilers - Potential Emissions
CCI Corpus Christi LLC

A. Emission Factors (1) and Global Warming Potential (GWP) Equivalency Factors (2)

CO_2	59 kg CO_2/MMBtu	&	**CO_2**	=	1 ton of CO2 equivalent
CH_4	0.001 kg CH_4/MMBtu	&	**CH_4**	=	25 tons of CO2 equivalent
N_2O	0.0001 kg N_2O/MMBtu	&	**N_2O**	=	298 tons of CO2 equivalent

B. Emission Calculations

Emission Source	Design Firing Rate (3)		CO_2 Emissions (4,5)		CH_4 Emissions (4,5)		N_2O Emissions (4,5)		CO_2e Emissions (6)	
	Maximum MMBtu/hr	Average MMBtu/hr	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
Charge Heater (H-1)	152.6	137.4	19,856	78,271	0.34	1.33	0.03	0.13	19,874	78,344
Charge Heater (H-2)	152.6	137.4	19,856	78,271	0.34	1.33	0.03	0.13	19,874	78,344
Boiler (BL-1)	36.3	32.2	4,722	18,372	0.08	0.31	0.01	0.03	4,726	18,390
Boiler (BL-2)	36.3	32.2	4,722	18,372	0.08	0.31	0.01	0.03	4,726	18,390
Subtotal			49,156	193,288	0.83	3.28	0.08	0.33	49,201	193,467

Notes:

(1) Emission factors are based on 40 CFR Part 98 Subpart C. CO_2 emission factor is based on Table C-1 for fuel gas, CH_4 and N_2O emission factors are based on Table C-2 for natural gas. The fuel gas is 95% natural gas and 5% process gas.

(2) Global warming potential factors are based on the November 2013 revised Table A-1 of 40 CFR Part 98 Subpart A.

(3) Maximum and average heating values are fuel heat input values as fired on a higher heating value (HHV) basis.

(4) Hourly emissions are based on the emission factor * max. hourly firing rate * 2.205 lb/kg.

(5) Annual emissions are based on the emission factor * average hourly firing rate * 2.205 lb/kg * 8,760 hours/year / 2000 lb/ton

(6) CO_2e emissions are based on the sum of the CO_2, CH_4, and N_2O emissions times their respective GWP factors.

Table D-3 (Revised March 2014)
Flare - Pilot and Normal Operation Emission Calculations
CCI Corpus Christi LLC

A. Pilot Gas Emissions

Parameter Name & Variable		Value & Units		Basis/Calculations/Notes
1. General Values and Calculations				
Hourly Flow Rate	F_H	451	scf/hr	Based on process knowledge
Annual Flow Rate	F_A	3,592,000	scf/yr	Based on process knowledge
Heat Content	H	1,020	Btu/scf	Typical heat content for natural gas
2. CO_2 Emission Rate Calculations				
CO_2 Emission Factor	F_{CO2}	116.91	lb/MMBtu	40 CFR Part 98, Subpart C, Table C-1 for natural gas converted to lb/MMBtu
CO_2 Hourly Emission Rate	$ER_{CO2,H}$	**53.78**	**lb/hr**	= F_H x (H / 1,000,000 Btu/MMBtu) x F_{CO2}
CO_2 Annual Emission Rate	$ER_{CO2,A}$	**214.17**	**tpy**	= F_A x (H / 1,000,000 Btu/MMBtu) x F_{CO2} / 2,000 lb/ton
3. CH_4 Emission Rate Calculations				
CH_4 Emission Factor	F_{CH4}	0.00221	lb/MMBtu	40 CFR Part 98, Subpart C, Table C-2 for natural gas converted to lb/MMBtu
CH_4 Hourly Emission Rate	$ER_{CH4,H}$	**<0.01**	**lb/hr**	= F_H x (H / 1,000,000 Btu/MMBtu) x F_{CH4}
CH_4 Annual Emission Rate	$ER_{CH4,A}$	**<0.01**	**tpy**	= F_A x (H / 1,000,000 Btu/MMBtu) x F_{CH4} / 2,000 lb/ton
Hourly Global Warming Potential	$GWP_{CH4,H}$	0.03	lb/hr	= $ER_{CH4, H}$ * 25 CO_2e
Annual Global Warming P	$GWP_{CH4, A}$	0.10	tpy	= $ER_{CH4, A}$ * 25 CO_2e
4. N_2O Emission Rate Calculations				
N_2O Emission Factor	F_{N2O}	0.00022	lb/MMBtu	40 CFR Part 98, Subpart C, Table C-2 for natural gas converted to lb/MMBtu
N_2O Hourly Emission Rate	$ER_{N2O, H}$	**<0.01**	**lb/hr**	= F_H x (H / 1,000,000 Btu/MMBtu) x F_{N2O}
N_2O Annual Emission Rate	$ER_{N2O, A}$	**<0.01**	**tpy**	= F_A x (H / 1,000,000 Btu/MMBtu) x F_{N2O} / 2,000 lb/ton
Hourly Global Warming Potential	$GWP_{N2O, H}$	0.03	lb/hr	= $ER_{N2O, H}$ * 298 CO_2e
Annual Global Warming Potential	$GWP_{N2O, A}$	0.12	tpy	= $ER_{N2O, A}$ * 298CO_2e
5. Total CO_2e Emission Rates				
Hourly Global Warming Potential	-	**53.84**	**lb/hr**	= $ER_{CO2, H}$ + $GWP_{CH4, H}$ + $GWP_{N2O, H}$
Annual Global Warming Potential	-	**214.39**	**tpy**	= $ER_{CO2, H}$ + $GWP_{CH4, H}$ + $GWP_{N2O, H}$

B. Combined Gas Composition (Natural Gas and Produced Gas)

Constituent	Volume %	MW (lb/lb-mol)	Mass %	Constituent Type	Number of Carbons
Water	0.04	18.02	0.04	NA	0
Methane	93.90	16.04	85.30	GHG	1
Ethane	2.70	30.07	4.60	NA	2
Propane	1.80	44.10	4.50	VOC	3
n-Butane	1.20	58.12	3.95	VOC	4
n-Pentane	0.20	72.15	0.82	VOC	5
n-Hexane	0.16	86.18	0.80	VOC	6
Total	**100.00**	**17.66**	**100.00**	-	-

Table D-3 (Revised March 2014)
Flare - Pilot and Normal Operation Emission Calculations
CCI Corpus Christi LLC

C. Normal Flare Emissions (Natural Gas and Produced Gas)

Parameter Name & Variable		Value & Units	Basis/Calculation/Notes
1. General Values and Calculations			
Hourly Vapor Volume to Flare	Q_H	3,850.00 scf/hr	Based on process knowledge
Annual Vapor Volume to Flare	Q_A	30.66 MMscf/yr	Based on process knowledge
MW of Combined Gas	MW	17.62 lb/lb-mol	Based on heat and material balance of stream
Heat Content of Combined Gas	H_V	1,091.30 Btu/scf	Based on heat and material balance of stream
Hourly Vapor Mass to Flare	M_H	176.02 lb/hr	= Q_H x MW / 385 scf/lb-mol
Annual Vapor Mass to Flare	M_A	1,401,721.53 lb/year	= Q_A /1,000,000 x MW / 385 scf/lb-mol
Max. Hourly Vapor Heat Input to Flare	H_H	4.20 MMBtu/hr	= Q_H x H_V / 1,000,000
Annual Vapor Heat Input to Flare	H_A	33,459.26 MMBtu/yr	= Q_A x H_V
2. CO_2 Emission Rate Calculations			
Carbon Content	CC	0.76 -	= Σ (No. of Carbons$_i$ * 12 lb C/lb-mol C * Mass%$_i$ / MW$_i$)
CO_2 Hourly Emission Rate	$ER_{CO2,H}$	**488.99 lb/hr**	= 44 lb CO_2/12 lb C * M_H * CC
CO_2 Annual Emission Rate	$ER_{CO2,A}$	**1,947.05 tpy**	=(44 lb CO_2/12 lb C * M_A * CC) / 2000 lb/ton
3. CH_4 Emission Rate Calculations			
CH_4 Weight Percent	W_{CH4}	85.30 %	Based on stream composition
Flare DRE for CH_4	%	99 %	TCEQ Flare Guidance Document (October 2000)
CH_4 Hourly Emission Rate	$ER_{CH4,\ H}$	**1.50 lb/hr**	= W_{CH4} * M_H * (100%-DRE)
CH_4 Annual Emission Rate	$ER_{CH4,\ A}$	**5.98 tpy**	= W_{CH4} * M_A * (100%-DRE) / 2000 lb/ton
Hourly Global Warming Potential	$GWP_{CH4,\ H}$	37.54 lb/hr	= $ER_{CH4,\ H}$ * 25 CO_2e
Annual Global Warming Potential	$GWP_{CH4,\ A}$	149.46 tpy	= $ER_{CH4,\ A}$ * 25 CO_2e
4. N_2O Emission Rate Calculations			
N_2O Emission Factor	F_{N2O}	0.00022 lb/MMBtu	40 CFR Part 98, Subpart C, Table C-2
N_2O Hourly Emission Rate	$ER_{N2O,\ H}$	**<0.01 lb/hr**	= H_H * F_{N2O}
N_2O Annual Emission Rate	$ER_{N2O,\ A}$	**<0.01 tpy**	= H_A * F_{N2O} / 2000 lbs/ton
Hourly Global Warming Potential	$GWP_{N2O,\ H}$	0.28 lb/hr	= $ER_{N2O,\ H}$ * 298 CO_2e
Annual Global Warming Potential	$GWP_{N2O,\ A}$	1.10 tpy	= $ER_{N2O,\ A}$ * 298 CO_2e
5. Total CO_2e Emission Rates			
Hourly Global Warming Potential	-	**526.80 lb/hr**	= $ER_{CO2,\ H}$ + $GWP_{CH4,\ H}$ + $GWP_{N2O,\ H}$
Annual Global Warming Potential	-	**2,097.61 tpy**	= $ER_{CO2,\ A}$ + $GWP_{CH4,\ A}$ + $GWP_{N2O,\ A}$

D. Total Flare Emissions (Pilot Gas and Normal)

Pollutants	Pilot Gas Emissions		Normal Flare Emissions		Total Emissions	
	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
CO_2	53.78	214.17	488.99	1,947.05	542.77	2,161.22
CH_4	<0.01	<0.01	1.50	5.98	1.50	5.98
N_2O	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01
CO_2e	53.84	214.39	526.80	2,097.61	580.63	2,312.00

Table D-4 (Revised March 2014)
Flare - Startup/Shutdown Flaring MSS Emission Calculations
CCI Corpus Christi LLC

A. Gas Composition

Constituent	Volume %	MW (lb/lb-mol)	Mass %	HHV (Btu/scf)	No. of C
Water	3.57	18.02	1.21	0.00	0
Methane	10.65	16.04	3.22	1,012.00	1
Ethane	5.14	30.07	2.91	1,783.00	2
Propane	20.94	44.10	17.40	2,557.00	3
Isobutane	11.54	58.12	12.64	3,354.00	4
n-butane	20.28	58.12	22.21	3,369.00	4
Isopentane	9.53	72.15	12.95	4,001.00	5
n-pentane	7.62	72.15	10.36	4,009.00	5
Methylcyclopentane	0.34	84.16	0.54	4,501.20	6
Cyclohexane	0.36	84.16	0.57	4,481.70	6
Cyclopentane	0.79	70.10	1.04	3,763.70	5
Benzene	0.34	78.11	0.50	3,741.80	6
C6+	8.90	86.18	14.45	4,755.90	6
Total	100.00	**53.08**	**100.00**	**2,989.06**	-

Table D-4 (Revised March 2014)
Flare - Startup/Shutdown Flaring MSS Emission Calculations
CCI Corpus Christi LLC

B. MSS Flare Emissions

Parameter Name & Variable		Value & Units	Basis/Calculation/Notes
1. General Values and Calculations			
Hourly Vapor Volume to Flare	Q_H	0.38 MMscf/hr	Startup/shutdwon flow rate is based on design
Fuel Heating Value	H_V	2,989.06 Btu/scf	$= \Sigma$ (Volume $\%_i$ * HHV_i)
Molecular Weight	MW	53.08 lb/lb-mol	$= \Sigma$ (Volume $\%_i$ * MW_i)
Flaring Frequency	FF	24.00 hours/year	Based on 3 events/year and 8 hours/event
Annual Vapor Volume to Flare	Q_A	9.19 MMscf/yr	$=Q_H$ x FF
Hourly Vapor Mass to Flare	M_H	52,746.05 lb/hr	$= Q_H$ x 1,000,000 x MW / 385 scf/lb-mol
Annual Vapor Mass to Flare	M_A	1,265,905.29 lb/year	$= Q_A$ x 1,000,000 x MW / 385 scf/lb-mol
Max. Hourly Vapor Heat Input to Flare	H_H	1,144.81 MMBtu/hr	$= Q_H$ x H_V
Annual Vapor Heat Input to Flare	H_A	27,475.40 MMBtu/yr	$= Q_A$ x H_V
2. CO_2 Emission Rate Calculations			
Carbon Content	CC	0.81 -	$= \Sigma$ (No. of $Carbons_i$ * 12 lb C/lb-mol C * $Mass\%_i$ / MW_i)
CO_2 Hourly Emission Rate	$ER_{CO2,H}$	**157,573.19 lb/hr**	= 44 lb CO_2/12 lb C * M_H * CC
CO_2 Annual Emission Rate	$ER_{CO2,A}$	**1,890.88 tpy**	=(44 lb CO_2/12 lb C * M_A * CC) / 2000 lb/ton
3. CH_4 Emission Rate Calculations			
CH_4 Weight Percent	W_{CH4}	3.22 %	Based on stream composition
Flare DRE for CH_4	%	99 %	TCEQ Flare Guidance Document (October 2000)
CH_4 Hourly Emission Rate	$ER_{CH4, H}$	**16.98 lb/hr**	$= W_{CH4}$ * M_H * (100%-DRE)
CH_4 Annual Emission Rate	$ER_{CH4, A}$	**0.20 tpy**	$= W_{CH4}$ * M_A * (100%-DRE) / 2000 lb/ton
Hourly Global Warming Potential	$GWP_{CH4, H}$	424.40 lb/hr	$= ER_{CH4, H}$ * 25 CO_2e
Annual Global Warming Potential	$GWP_{CH4, A}$	5.09 tpy	$= ER_{CH4, A}$ * 25 CO_2e
4. N_2O Emission Rate Calculations			
N_2O Emission Factor	F_{N2O}	0.00022 lb/MMBtu	40 CFR Part 98, Subpart C, Table C-2
N_2O Hourly Emission Rate	$ER_{N2O, H}$	**0.25 lb/hr**	$= H_H$ * F_{N2O}
N_2O Annual Emission Rate	$ER_{N2O, A}$	**<0.01 tpy**	$= H_A$ * F_{N2O} / 2000 lbs/ton
Hourly Global Warming Potential	$GWP_{N2O, H}$	75.22 lb/hr	$= ER_{N2O, H}$ * 298 CO_2e
Annual Global Warming Potential	$GWP_{N2O, A}$	0.90 tpy	$= ER_{N2O, A}$ * 298 CO_2e
5. Total CO_2e Emission Rates			
Hourly Global Warming Potential	-	**158,072.81 lb/hr**	$= ER_{CO2, H} + GWP_{CH4, H} + GWP_{N2O, H}$
Annual Global Warming Potential	-	**1,896.87 tpy**	$= ER_{CO2, A} + GWP_{CH4, A} + GWP_{N2O, A}$

Table D-5 (Revised March 2014)
Equipment Clearing - MSS Potential Emission
CCI Corpus Christi LLC

A. Equipment Clearing Heat Input to Flare

Material	Total Equipment Volume (scf/yr) (1)	Largest Vessel Volume (scf/hr) (2)	MW (lb/lb-mol)	Heating Value (Btu/lb)	Annual Mass to Flare (lb/yr)	Hourly Mass to Flare (lb/hr)	Annual Heat Input to Flare (MMBtu/yr)	Hourly Heat Input to Flare (MMBtu/hr)
	Q_A	Q_H		HHV	M_A (3)	M_H (4)	H_A (5)	H_H (6)
Naphtha	4,004.35	2,401.55	69.00	23,214.29	716.91	429.96	16.64	9.98
Jet Fuel	15,754.89	5,387.83	130.00	19,285.71	5,314.26	1,817.36	102.49	35.05
Diesel	811.12	862.05	130.00	19,295.77	273.60	290.78	5.28	5.61
Condensate	38,271.08	29,575.15	67.00	19,580.00	6,653.18	5,141.45	130.27	100.67
Gas Oil	909.18	862.05	130.00	19,718.31	306.67	290.78	6.05	5.73

Notes:

(1) Annual volume is based on sum of all equipment servicing each material.

(2) Hourly volume is based on largest equipment volume.

(3) $M_A = Q_A \times MW / 385$ scf/lb-mol

(4) $M_H = Q_H \times MW / 385$ scf/lb-mol

(5) $H_A = HHV \times M_A / 1{,}000{,}000$

(6) $H_H = HHV \times M_H / 1{,}000{,}000$

B. GHG Emissions from Equipment Clearing

Material	CO_2 Emission Factor (1)	CO_2 Emissions		CH_4 Emission Factor (2)	CH_4 Emissions		N_2O Emission Factor (2)	N_2O Emissions		CO_2e Emissions (5)	
	kg/MMBtu	lb/hr (3)	TPY (4)	kg /MMBtu	lb/hr (3)	TPY (4)	kg /MMBtu	lb/hr (3)	TPY (4)	lb/hr	TPY
Naphtha	68.02	1,497.01	1.25	0.003	0.07	0.0001	0.0006	0.01	0.00001	1,502.60	1.25
Jet Fuel	72.22	5,581.40	8.16	0.003	0.23	0.0003	0.0006	0.05	0.00007	5,601.01	8.19
Diesel	73.96	915.02	0.43	0.003	0.04	0.00002	0.0006	0.01	0.00000	918.16	0.43
Condensate	74.49	16,535.02	10.70	0.003	0.67	0.0004	0.0006	0.13	0.00009	16,591.36	10.73
Gas Oil	73.96	935.05	0.49	0.003	0.04	0.00002	0.0006	0.01	0.00000	938.26	0.49
Total	**-**	**25,463.50**	**21.03**	**-**	**1.04**	**0.001**	**-**	**0.21**	**0.0002**	**25,551.38**	**21.10**

Notes:

(1) CO_2 emission factor is based on 40 CFR Part 98 Subpart C, Table C-1.

(2) CH_4 and N_2O emission factors are based on 40 CFR Part 98 Subpart C, Table C-2.

(3) Hourly emissions are based on emission factor * hourly heat input (MMBtu/hr) *2.205 lb/kg

(4) Annual emissions are based on the emission factor * annual heat input (MMBtu/yr)* 2.205 lb/kg / 2000 lb/ton

(5) CO_2e emissions are based on the sum of the CO_2, CH_4, and N_2O emissions times their respective GWP factors. GWP factors are based on the November 2013 revised Table A-1 of 40 CFR Part 98 Subpart A. GWP for CO_2, CH_4, and N_2O are 1, 25, and 298 respectively.

Table D-6 (Revised March 2014)
Temporary Control Device Emissions - Potential Emissions
CCI Corpus Christi LLC

A. Input Information for Emission Calculations - Flow Rates and Duration

MSS Activity Routed to Control	Events per Year	Event Duration (hrs/event)	VOC Routed to Control (lb/event)	Hourly Mass Flow Rate (lb/hr)	Annual Mass Flow Rate (lb/yr)	Heat Content (Btu/lb) (1)	Hourly Heat Input (MMBtu/hr)	Annual Heat Input (MMBtu/yr)
Floating Roof Tank Degassing	1	8	22,344.87	2,793.11	22,344.87	19,580.00	54.69	437.51
Fixed Roof Tank Degassing	2	8	154.31	19.29	308.61	19,285.71	0.37	5.95
Floating Roof Vacuum Truck	1	1	278.21	278.21	278.21	19,580.00	5.45	5.45
Fixed Roof Vacuum Truck	2	1	1.17	1.17	2.33	19,285.71	0.02	0.05
						Total (2,3)	**54.69**	**448.96**

Notes:

(1) Floating roof tank emissions are based on storing condensate/crude. Fixed roof tank emissions are based on storing jet fuel. These are the worst case chemicals.

(2) Maximum hourly heat input is based on degassing of floating roof tanks since this activity results in highest heat input to control.

(3) Annual heat input to control is the sum of all activities.

B. GHG Emissions Associated with Tank Maintenance

MSS Activity Routed to Control	CO_2 Emission Factor (1)	CO_2 Emissions		CH_4 Emission Factor (2)	CH_4 Emissions		N_2O Emission Factor (2)	N_2O Emissions		CO_2e Emissions (5)	
	kg/MMBtu	lb/hr (3)	TPY (4)	kg /MMBtu	lb/hr (3)	TPY (4)	kg /MMBtu	lb/hr (3)	TPY (4)	lb/hr	TPY
Floating Roof Tank Degassing	74.54	8,988.73	35.95	0.003	0.36	0.0014	0.0006	0.07	0.0003	9,019.34	36.08
Fixed Roof Tank Degassing	72.22	59.24	0.47	0.003	0.002	0.00002	0.0006	0.0005	0.000004	59.45	0.48
Floating Roof Vacuum Truck	74.54	895.34	0.45	0.003	0.04	0.00002	0.0006	0.01	0.000004	898.39	0.45
Fixed Roof Vacuum Truck	72.22	3.59	0.004	0.003	0.0001	0.0000001	0.0006	0.00003	0.00000003	3.60	0.00
Total (6)	-	**8,988.73**	**36.88**	-	**0.36**	**0.001**	-	**0.072**	**0.0003**	**9,019.34**	**37.01**

Notes:

(1) CO_2 emission factor is based on 40 CFR Part 98 Subpart C, Table C-1.

(2) CH_4 and N_2O emission factors are based on 40 CFR Part 98 Subpart C, Table C-2.

(3) Hourly emissions are based on emission factor * hourly heat input (MMBtu/hr) *2.205 lb/kg

(4) Annual emissions are based on the emission factor * annual heat input (MMBtu/yr)* 2.205 lb/kg / 2000 lb/ton

(5) CO_2e emissions are based on the sum of the CO_2, CH_4, and N_2O emissions times their respective GWP factors. GWP factors are based on the November 2013 revised Table A-1 of 40 CFR Part 98 Subpart A. GWP for CO_2, CH_4, and N_2O are 1, 25, and 298 respectively.

(6) Total hourly emissions (lb/hr) are based on maximum activity. Total annual emissions (tpy)are based on sum of all activities.

Table D-7 (Revised March 2014)
Fugitive Equipment Components - Potential Emissions
CCI Corpus Christi LLC

Component Type and Service	Estimated Number of New Components	USEPA SOCMI w/out C2 Emission Factor (1) (lb/hr-component)	Control Efficiency (2) (percent)	Calculated Emission Rates (3)	
				lb/hour	tpy
Valves					
Gas/Vapor	682	0.0089	97	0.18	0.80
Light Liquid	2,572	0.0035	97	0.27	1.18
Heavy liquid	642	0.0007	0	0.45	1.97
Pumps					
Light Liquid	46	0.0386	85	0.27	1.17
Heavy liquid	11	0.0161	0	0.18	0.78
Flanges/Connectors					
Gas/Vapor	1,202	0.0029	30	2.44	10.69
Light Liquid	3,631	0.0005	30	1.27	5.57
Heavy liquid	908	0.00007	30	0.04	0.19
Relief Valves					
Gas Vapor	39	0.2293	97	0.27	1.18
Compressors					
Gas Vapor	2	0.5027	85	0.15	0.66
			Total Emissions	5.52	24.18
			Total CH_4 (4)	1.10	4.84
			Total CO_2e (5)	**27.60**	**120.88**

Notes:

(1) Air Permit Technical Guidance Package for Chemical Sources - Equipment Leak Fugitives. TCEQ. (October 2000).

(2) Control efficiencies based on TCEQ Leak Detection and Repair Program 28VHP. Relief valves are routed to the flare for control.

(3) Sample Calculations - Fugitive Emissions (Light Liquid Pumps)

lb VOC / hr = 46 heavy liquid valves * 0.0386 lb VOC / hr / component * (100% -85%) = 0.27 lb VOC/hr

tons VOC / yr = 0.27 lb VOC / hr * 8760 hr /yr / 2000 lb/ton = 1.17 tons VOC/yr

(4) Piping components are assumed to contain 20% methane.

(5) Global warming potential factor for CH_4 is 25 as indicated in the November 2013 revised Table A-1 of 40 CFR Part 98 Subpart A.

Table D-8 (Revised March 2014)
Marine Vapor Combustion Unit (MVCU) - Potential Emissions
CCI Corpus Christi LLC

A. Emission Factors (1) and Global Warming Potential (GWP) Equivalency Factors (2)

CO_2 Emission Factor = 53.02 kg CO_2/MMBtu & CO_2 GWP = 1 ton of CO2 equivalent
CH_4 Emission Factor = 0.001 kg CH_4/MMBtu & CH_4 GWP = 25 tons of CO2 equivalent
N_2O Emission Factor = 0.0001 kg N_2O/MMBtu & N_2O GWP = 298 tons of CO2 equivalent

B. Pilot and Enrichment Gas VCU Input Parameters

Pilot Gas Maximum Flow = 99 scf/hr
Enrichment Gas Flow = 19,818 scf/hr
NG Heat Content = 1,020 Btu/scf
Pilot Gas Heat Input = 0.101 MMBtu/hr
Enrichment Gas Heat Input = 20.215 MMBtu/hr

Pilot Gas Average Flow = 867,240 scf/yr
Enrichment Gas Average Flow = 43,402,000 scf/yr
NG Heat Content = 1,020 Btu/scf
Pilot Gas Heat Input = 885 MMBtu/yr
Enrichment Gas Heat Input = 44,270 MMBtu/yr

C. Pilot and Enrichment Gas Emission Calculations (Natural Gas)

Emission Source	CO_2 Emissions		CH_4 Emissions		N_2O Emissions		CO_2e Emissions (3)	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
MVCU-Pilot	11.81	51.71	<0.01	<0.01	<0.01	<0.01	12	52
MVCU-Enrichment Gas	2,363.26	2,587.79	0.04	0.05	<0.01	<0.01	2,366	2,590
Total	2,375.07	2,639.49	0.04	0.05	0.00	0.00	2,377.52	2,642.22

Notes:
(1) Emission factors are based on 40 CFR Part 98 Subpart C, Table C-1 and Table C-2 for natural gas.
(2) Global warming potential factors are based on the November 2013 revised Table A-1 of 40 CFR Part 98 Subpart A.
(3) CO_2e emissions are based on the sum of the CO_2, CH_4, and N_2O emissions times their respective GWP factors.

Table D-8 (Revised March 2014)
Marine Vapor Combustion Unit (MVCU) - Potential Emissions
CCI Corpus Christi LLC

D. MVCU Controlled GHG Emissions

Annual Vapors to Control (1)

Chemical	Annual Loading Rate (gal/yr)	Saturation Factor (2)	Vapor Pressure (psi) (3)	Vapor MW (lb/lb-mol)	Temp (°F)	Loading Loss (lb/10^3 gal) (4)	Annual Vapors Routed MVCU (tpy)	Heat Content (BTU/lb)	Heat Released (MMBtu/yr) (5)
Naphtha	600,844,020	0.50	3.86	69.00	73.50	3.11	887.75	23,214	41,217
Condensate/Crude	5,853,120,000	0.20	8.31	67.00	73.50	2.60	7,237.71	19,580	283,429

Hourly Vapors to Control (1)

Chemical	Hourly Loading Rate (gal/hr)	Saturation Factor (2)	Vapor Pressure (psi) (3)	Vapor MW (lb/lb-mol)	Temp (°F)	Loading Loss (lb/10^3 gal) (4)	Hourly Vapors Routed MVCU (lb/hr)	Heat Content (BTU/lb)	Heat Released (MMBtu/hr) (5)
Naphtha	1,260,000	0.20	5.80	69.00	95.00	1.80	2,153.14	23,214	49.98
Condensate/Crude	1,260,000	0.20	11.58	67.00	95.00	3.49	4,172.95	19,580	81.71

Notes:

(1) Annual: Condensate/crude is only loaded by ships, however, naphtha can be loaded by either barge or ship. Therefore, annual emissions routed to control are based on barge loading for naphtha due to the higher saturation factor of barge loading. Emissions are based on 95% collection efficiency.
Hourly: The pumping capacity of ship loading is six times greater than that of barge loading, therefore, the hourly emissions are based on ship loading with a 95% collection efficiency.

(2) Saturation factors for barge and ship loading are 0.5 and 0.2 respectively (AP-42 Section 5.2-1)
(3)) Annual and hourly vapor pressures are based on Tanks 4.0.9d runs.
(4) Loading loss is calculated based on AP-42 Chapter 5.2, Equation 1.
(5) Heat released for each chemical is calculated using the heat content (btu/lb) and the calculated vapors routed to the MVCU.

Table D-8 (Revised March 2014)
Marine Vapor Combustion Unit (MVCU) - Potential Emissions
CCI Corpus Christi LLC

E. Emission Factors for Loading Material

CO_2 Emission Factor for Naphtha(1) = 68.02 kg CO_2/MMBtu
CO_2 Emission Factor for Condensate(1) = 74.54 kg CO_2/MMBtu
CH_4 Emission Factor for all(1) = 0.003 kg CH_4/MMBtu
N_2O Emission Factor for all(1) = 0.0006 kg N_2O/MMBtu

F. Controlled Loading Emissions

Emission Source	Chemical	CO_2 Emissions		CH_4 Emissions		N_2O Emissions		CO_2e Emissions (4)	
		lb/hr (2)	TPY (3)	lb/hr (2)	TPY (3)	lb/hr (2)	TPY (3)	lb/hr	TPY
MVCU	Naphtha	7,497	3,091	0.33	0.14	0.07	0.03	7,525	3,102
	Condensate	13,429	23,292	0.54	0.94	0.11	0.19	13,475	23,372
Total		**20,926**	**26,383**	**0.87**	**1.07**	**0.17**	**0.21**	**21,000**	**26,474**

Notes:

(1) Naphtha and condensate/crude CO_2 emission factor is based on 40 CFR Part 98 Subpart C, Table C-1 for naphtha and crude oil respectively. CH_4 and N_2O emission factors are based on 40 CFR Part 98 Subpart C, Table C-2.

(2) Hourly emissions are based on emission factor * heat released (MMBtu/hr) *2.205 lb/kg

(3) Annual emissions are based on the emission factor * Heat released (MMBtu/yr)* 2.205 lb/kg / 2000 lb/ton

(4) CO_2e emissions are based on the sum of the CO_2, CH_4, and N_2O emissions times their respective GWP factors.

Table D-9 (Revised March 2014)
Emergency Equipment - Potential Emissions
CCI Corpus Christi LLC

A. Emission Factors and Global Warming Potential (GWP) Equivalency Factors

$CO_2^{(1)}$	73.96 kg CO_2/MMBtu	&	**$CO_2^{(2)}$**	=	1 ton of CO2 equivalent
$CH_4^{(1)}$	0.003 kg CH_4/MMBtu	&	**$CH_4^{(2)}$**	=	25 tons of CO2 equivalent
$N_2O^{(1)}$	0.0006 kg N_2O/MMBtu	&	**$N_2O^{(2)}$**	=	298 tons of CO2 equivalent

B. Emission Calculations

Emission Source	Design Firing Rate		CO_2 Emissions		CH_4 Emissions		N_2O Emissions		CO_2e Emissions $^{(5)}$	
	Maximum MMBtu/hr	Usage (hrs/year)	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
Emergency Generator (EMGEN)	15.0	100	2,446	122	0.10	0.005	0.020	0.001	2,455	123
Fire Water Pump (FW-1)	5.0	100	815	41	0.03	0.002	0.007	0.0003	818	41
Fire Water Pump (FW-2)	5.0	100	815	41	0.03	0.002	0.007	0.0003	818	41
Subtotal			4,077	204	0.165	0.008	0.033	0.002	4,091	205

Notes:

(1) Emission factors are based on 40 CFR Part 98 Subpart C, Table C-1 and Table C-2 for distillate fuel oil no.2

(2) Global warming potential factors are based on the November 2013 revised Table A-1 of 40 CFR Part 98 Subpart A.

(3) Hourly emissions are based on the emission factor * max. hourly firing rate * 2.204 lb/kg.

(4) Annual emissions are based on the emission factor * max.hourly firing rate * 2.204 lb/kg * 100 hours/year / 2000 lb/ton

(5) CO_2e emissions are based on the sum of the CO_2, CH_4, and N_2O emissions times their respective GWP factors.