Statement of Basis

Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit
for CCI Corpus Christi, LLC, Condensate Splitter Facility

Permit Number: PSD-TX-1388-GHG

July 2014

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

I. Executive Summary

On November 4, 2013, CCI Corpus Christi, LLC (CCI) submitted a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions from a new greenfield site to EPA Region 6. On March 13, 2014, EPA Region 6 received an updated application from the company. The updated application provided new information on fuel usage, GHG emission estimates, emission sources, and included the required biological, cultural, and fisheries assessments. The company also submitted additional information in response to technical information requests from EPA on April 28, 2014 and May 21, 2014. In connection with this project, CCI submitted PSD New Source Review (NSR) and state NSR permit applications for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on December 23, 2013. CCI proposes to construct a new 100,000 barrels per day (bbl/day) condensate splitter plant and bulk petroleum terminal near Corpus Christi, Texas. The facility will be constructed in two phases. The first phase includes the condensate splitter plant with its associated equipment. The second phase will be the bulk terminal operation. The bulk terminal phase will include construction of storage tanks and barge/marine loading operations capable of loading 500,000 bbl/day of crude condensate for export from the facility. After reviewing the application, EPA Region 6 has prepared the following Statement of Basis (SOB) and draft air permit to authorize construction of air emission sources at the proposed CCI facility.

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

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

II. Applicant

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Houston, TX 77002

Physical Address:
4820 E. Navigation Boulevard
(Carbon Plant Rd.)
Corpus Christi, TX 78402

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III. Permitting Authority

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

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

EPA, Region 6
1445 Ross Avenue
Dallas, TX 75202

The EPA, Region 6 Permit Writer is:
Robert Todd
Air Permitting Section (6PD-R)
(214) 665-2156

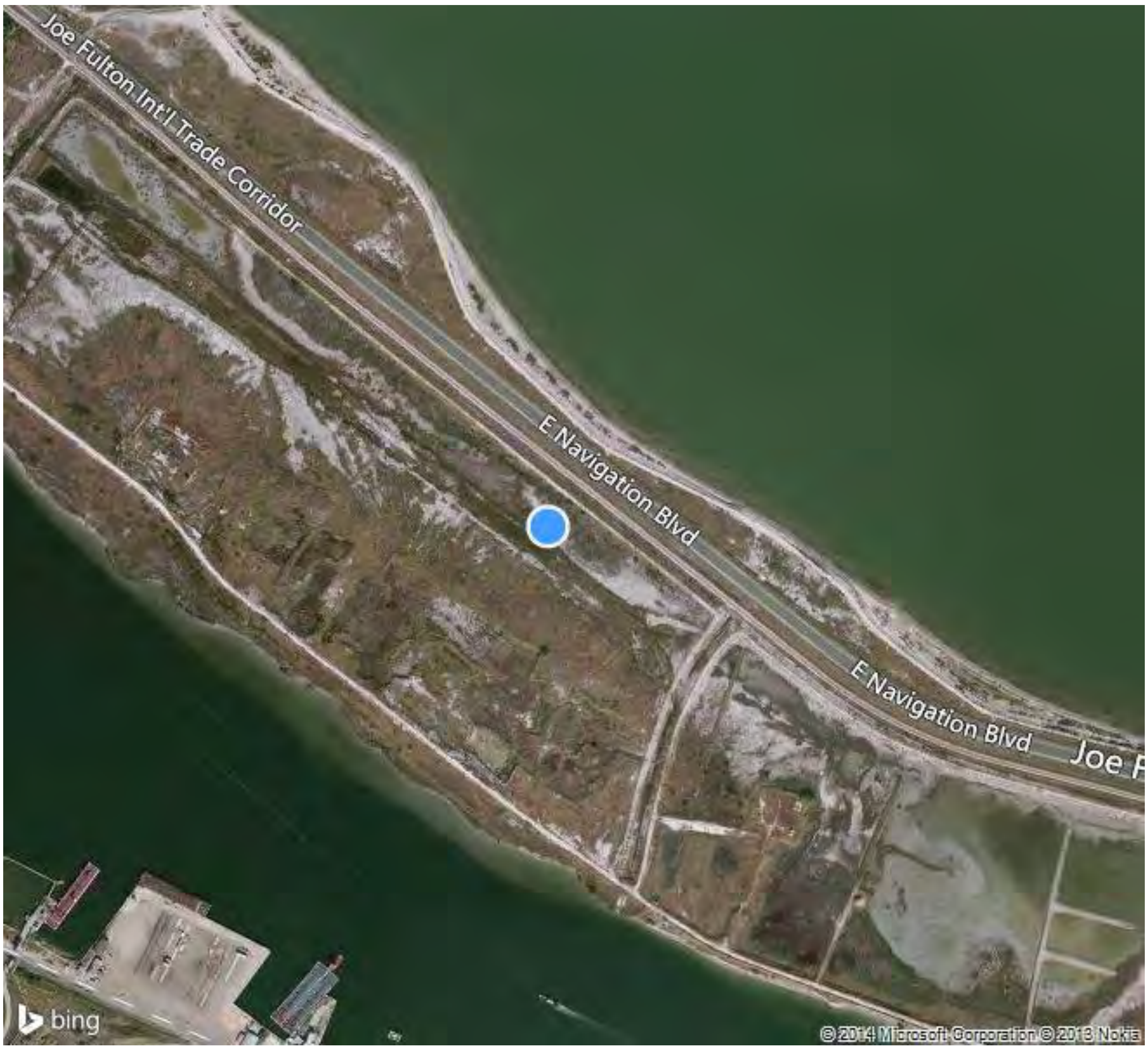
IV. Facility Location

CCI proposes to locate the Condensate Splitter Facility and Bulk Petroleum Terminal in Nueces County, Texas, and this area is currently designated as in attainment or unclassifiable for criteria pollutants. The nearest Class I area is the Big Bend National Park, which is located well over 100 miles from the site. The geographic coordinates for this facility are as follows:

Latitude: 27º 49’ 39.81” North
Longitude: -97º 29’ 02.73” West

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

Figure 1. CCI Corpus Christi, Condensate Splitter and Bulk Terminal Location



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

EPA Region 6 implements a GHG PSD FIP for the State of Texas under the provisions of 40 CFR 52.21 (except paragraph (a)(1)). See 40 CFR § 52.2305. On June 23, 2014, the United States Supreme Court issued a decision addressing the application of stationary source permitting requirements to greenhouse gases (GHG). *Utility Air Regulatory Group (UARG) v. Environmental Protection Agency* (EPA) (No. 12-1146). The Supreme Court said that the EPA may not treat greenhouse gases as an air pollutant for purposes of determining whether a source is a major source required to obtain a Prevention of Significant Deterioration (PSD) or title V permit. However, the Court also said that the EPA could continue to require that PSD permits otherwise required based on emissions of conventional pollutants, contain limitations on GHG emissions based on the application of Best Available Control Technology (BACT). Pending further EPA engagement in the ongoing judicial process before the District of Columbia Circuit Court of Appeals, the EPA is proposing to issue this permit consistent with EPA's understanding of the Court's decision.

The source is a major source because the facility has the potential to emit 672 TPY of volatile organic compounds (VOC). In this case, the applicant represents that TCEQ, the permitting authority for regulated NSR pollutants other than GHGs, has determined the project is subject to PSD review for the conventional regulated NSR pollutant VOC.

The applicant also estimates that this same project emits or has the potential to emit 207,771 TPY CO_2e of GHGs, which well exceeds the 75,000 ton per year CO2e threshold in EPA regulations. 40 C.F.R § 52.21(b)(49)(iv); *see also, PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011) at 12-13. Since the Supreme Court recognized EPA's authority to limit application of BACT to sources that emit GHGs in greater than *de minimis* amounts, EPA believes it may apply the 75,000 tons per year threshold in existing regulations at this time to determine whether BACT applies to GHGs at this facility.

Accordingly, this project continues to require a PSD permit that includes limitations on GHG emissions based on application of BACT. The Supreme Court's decision does not materially limit the FIP authority and responsibility of Region 6 with regard to this particular permitting action. Accordingly, under the circumstances of this project, the TCEQ will issue the non-GHG portion of the permit and EPA will issue the GHG portion.[1]

EPA Region 6 proposes to follow the policies and practices reflected in EPA's PSD and Title V Permitting Guidance for Greenhouse Gases (March 2011). For the reasons described in that guidance, we have not required the applicant to model or conduct ambient monitoring for GHGs,

[1] *See* EPA, Question and Answer Document: Issuing Permits for Sources with Dual PSD Permitting Authorities, April 19, 2011, http://www.epa.gov/nsr/ghgdocs/ghgissuedualpermitting.pdf

nor have we required any assessment of impacts of GHGs in the context of the additional impacts analysis or Class I area provisions. Instead, EPA believes that compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs. We note again, however, that the project has regulated NSR pollutants that are non-GHG pollutants, which are addressed by the PSD permit to be issued by TCEQ

VI. Project Description

The proposed GHG PSD permit, if finalized, will allow CCI to construct a new 100,000 bbl/day condensate splitter plant and bulk petroleum facility at the above location in Nueces County, Texas. The company has proposed a two phased approach, separating construction of the condensate splitter plant from the bulk-petroleum-terminal operations. While the company represents the two phases as separate, they propose to construct each phase concurrently with some equipment shared between the two phases. The splitter plant consists of crude condensate storage tanks, a feed preheat section, charge heaters, fractionation columns, product storage tanks, an emergency flare, and other associated equipment. The process will take hydrocarbon condensate material and process it to obtain products suitable for commercial use, which include Y-grade liquids, naphtha, gas/oil, jet fuel, and diesel products for sale to customers. The bulk-terminal construction phase will include barge/marine loading operations and storage tanks, and will be capable of loading 500,000 bbl/day of crude condensate for export from the facility.

Phased Construction

<u>Phase I</u>
The first phase will focus on the condensate splitter plant and its associated equipment. The splitter plant will consist of two identical 50,000 bbl/day process trains. Each will include heat exchangers to pre-heat the feedstock, a pre-flash drum to remove light hydrocarbons, a charge heater, a fractionation column, and a natural gas-fired boiler to provide process steam requirements. The splitter plant will have four dedicated storage tanks for the raw crude condensate and thirteen tanks for storage of the final products. A flare, an emergency generator, firewater pumps, a cooling water tower, a tank truck loading rack, piping, a barge unloading dock, and associated equipment will also be part of the Phase I construction.

The splitter plant will receive hydrocarbon condensate material by pipeline and barge, store it in the four dedicated tanks, and process it to obtain products suitable for commercial use. The products include Y-grade liquids, naphtha, jet fuel, diesel, and heavy gas oil bottoms. Jet fuel will meet Jet A-1 and JP-45 specifications. The diesel will meet marine grade specifications.

The splitter trains will draw crude condensate directly from the storage tanks. CCI will feed the condensate liquid through a series of heat exchangers to "pre-heat" the feedstock and through a pre-flash drum where the lightest fraction of the condensate is separated from the feed stream and sent directly to the fractionation tower. The remaining feedstock enters the charge heater (either H-1 or H-2) where it is heated to a sufficient temperature to allow for separation into the various products once it enters the bottom of the fractionation tower. The charge heater will use a combination of 5% process gas, taken from the fractionation tower, and 95% natural gas supplied from offsite as fuel. The auxiliary boilers (BL-1 or BL-2) will be provide additional steam heat to the process.

The Y-Grade liquid product will be stored in two pressurized vessels. The pressure vessels should not be a source of GHG pollutants. CCI will move this product off site through pipeline or truck. The naphtha, jet fuel, diesel, and heavy gas oil bottoms are to be stored in fixed roof tanks and later sent for sale off site via ship, barge, pipeline or truck. CCI represents that the truck loading operations will load product under 0.5 psia and be vapor balanced or use pressurized vessels without the potential to emit VOCs at a level requiring control under TCEQ regulations for the Corpus Christi area. VOC emissions from the barge and ship loading operations will be combusted by the marine vapor combustion unit located on the dock area of the facility.

Phase II

The second phase of construction will involve the construction of the bulk petroleum terminal proposed by CCI. It will consist of a pipeline and barge unloading operations to receive crude condensate, six storage tanks to hold the material, a marine ship loading facility, piping and ancillary equipment, which include the marine vapor combustion unit mentioned above to control VOC emissions from the loading operations. The company has requested authorization from the TCEQ to load 500,000 bbl/day of condensate crude through two marine ship-loading docks.

Equipment and Supporting Operations

Cooling Water Tower (EPN: CTW)

A cooling water tower will provide cooling for the operation. CCI proposes a design that will circulate 600,000 gallons of water per hour. CCI represents that this equipment will not be a potential source of GHG (in this case methane) emissions.

Flare (EPN: FL-1)

CCI proposes to construct an elevated flare. The flare will control routine emissions from gas venting, safety relief and pressure control valves, and equipment-clearing emissions anticipated during maintenance, startup, and shutdown activities. It will also function in emergencies as a control device during process upsets. This flare utilizes a continuous natural gas pilot and continuous pilot flame monitor to ensure that unexpected release events result in safe disposal.

Wastewater Management

CCI anticipates that the process will generate wastewater from the various pieces of equipment included in the Phase I project. The individual process wastewater streams flow to an enclosed process sewer and then to an enclosed wastewater treatment plant before discharge to the Tule Lake Turning Basin. The applicant represents that all appropriate waste and storm water discharge permitting will be in place before operation of the system commences. We do not anticipate significant GHG emissions will result from the wastewater treatment system.

Emergency Generator and Firewater Pumps

Diesel-fired engines will provide emergency services at the plant site. Three diesel engines, firing No. 2 distillate fuel, will power an emergency electrical generator and two firewater pumps. This equipment is needed to safely operate the plant and will reduce loading to the flare in the event of a plant emergency.

Product Transfer and Loading

The proposed barge docks, marine ship loading, tank truck rack, and pipelines will transfer crude condensate into the plant site and finished products offsite. Y-Grade product will be transferred offsite via pipeline and tank truck. Naphtha will be transferred offsite via ship and barge. CCI plans to export the jet fuel, diesel, and heavy gas oil and bottoms offsite by barge, ship, and truck. The tank truck loading racks will be vapor balanced and should not be a source of GHG emissions. The pipeline transfer operations will have only fugitive emissions and will not be a significant source of GHG emissions. VOCs from the barge and ship loading operations will vent to a marine vapor combustor located on the proposed docks for destruction. See Section IX.D below for a discussion of the marine vapor combustor and its expected GHG emissions.

The Phase II petroleum-bulk-terminal operations will take in crude condensate from pipeline and barge-unloading operations, accumulate it in six dedicated storage tanks, and transfer the material to marine vessels for outbound shipping. Fugitive emissions and combustion products from operation of the marine vapor combustor are the only expected source of GHG emissions from this phase of the project.

Fugitives

Fugitive emissions of GHG pollutants, including CO_2 and methane, may result from piping equipment leaks. The piping components that may leak include valves, flanges, pump seals, etc. CCI will implement the TCEQ 28VHP Leak Detection and Repair (LDAR) program to control these potential emissions.

VII. General Format of the BACT Analysis

The BACT analyses for this draft permit were conducted by following the "top-down" BACT approach recommended in EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011) and earlier EPA guidance. The five steps in the "top-down" BACT process are listed below.

(1) Identify all potentially available control options;
(2) Eliminate technically infeasible control options;
(3) Rank remaining control technologies;
(4) Evaluate the most effective controls (taking into account the energy, environmental, and economic impacts) and document the results; and,
(5) Select BACT.

VIII. Applicable Emission Units and BACT Discussion

The majority of GHG emissions (> 99%) associated with the project are from six combustion sources: two charge heaters, two auxiliary boilers, the marine vapor combustion unit, and the flare. The rest of the GHG emissions derive from maintenance and operation of emergency equipment at the site and minor fugitive emissions. Fugitive emissions originating from piping components are estimated to be less than one percent of the total project CO_2e emissions (398 TPY CO_2e of the 207,771 TPY CO_2e total). The stationary combustion sources primarily emit CO_2, and small amounts of N_2O and CH_4. The following devices are subject to this GHG PSD permit:

- Charge Heaters (H-1and H-2)
- Auxiliary Boilers (BL-1 and BL-2)
- Marine Vapor Combustion Unit (MVCU)
- Flare (FL-1)
- Emergency Generator (EMGEN) and Firewater Pump (FW-1 and FW-2) Engines
- Process Fugitives (FUGS)
- Cooling Water Tower (CWT)
- Temporary Control Device (TK-MSS)
- Wastewater Treatment Plant (WWTP)

IX. BACT Analyses

A. Post-Combustion Controls

Five of the proposed sources, the two Charge Heaters (H-1 and H-2), the two Auxiliary Boilers (BL-1 and BL-2), the Flare (FL-1) and the Marine Vapor Combustion Unit (MVCU), account for 98% of the total CO_2 emissions from the project and are capable of considering add-on, post combustion control technology to recover CO_2 emissions. Rather than consider add-on, post combustion CO_2 controls as part of the BACT analysis for each of these individual sources, we will examine it here as a technique applicable to all of these emission units.

Step 1 – Identification of Potential Control Technologies for GHGs

Carbon Capture and Storage (CCS)

CCS is an add-on, pollution control technology that involves the separation and capture of CO_2 from flue gas, pressurizing of the captured CO_2 into a pipeline for transport, and injection/storage within a geologic formation. CCS can be used by "facilities emitting CO_2 in large concentrations, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing)."[2]

CCS systems involve the use of adsorption or absorption processes to remove CO_2 from flue gas, with subsequent desorption to produce a concentrated CO_2 stream. The three main capture technologies for CCS are pre-combustion capture, post-combustion capture, and oxy-fuel combustion (IPCC, 2005). Of these approaches, pre-combustion capture is applicable primarily to gasification plants. In this process a solid fuel, such as coal, is made into gas by applying heat under pressure in the presence of steam and oxygen (U.S. Department of Energy, 2011). As of this time, oxy-fuel combustion had not yet reached a commercial stage of deployment for this type of operation. Oxy-fuel combustion requires the development of specific combustors and components with higher temperature tolerances than are currently available (IPCC, 2005). Accordingly, we do not consider pre-combustion capture and oxy-fuel combustion to be available control options for this proposed plant. Post-combustion capture could be applicable to the exhaust streams from the two charge heaters (H-1 and H-2), the two boilers (BL-1 and BL-2), the Flare (FL-1) and the marine vapor combustion unit vents when in operation. Under this scenario, once CO_2 is captured from the flue gas, it would be compressed to 100 atmospheres (atm), or higher, and then transported to an appropriate location for underground injection. The CO_2 injection would be into a suitable geological storage reservoir, such as a deep saline aquifer

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[2]U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, *PSD and Title V Permitting Guidance for Greenhouse Gases*, March 2011, p. 32 (http:/www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf)

or depleted coal seam. It could also be injected into a depleted oil reservoir as part of enhanced oil recovery project or other feasible alternative.

Step 2 – Elimination of Technically Infeasible Alternatives

EPA generally considers a technology technically feasible if it: (1) has been demonstrated and operated successfully on the same type of source under review, or (2) is available and applicable to the source type under review. *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011), pg. 33. CO_2 capture technologies, including post-combustion capture, have not been demonstrated in practice on charge heaters, auxiliary boilers, flares, or marine vapor combustion units. Moreover, while CO_2 capture technologies may be commercially available generally, we believe that there is insufficient information at this time to conclude that CO_2 capture is applicable to the proposed charge heaters, auxiliary boilers, or marine vapor combustion unit at CCI, due to the low volume and low concentration of their respective CO_2 streams. The company represents that the expected CO_2 concentration of the flue gases will be no more than 9% by volume.[3]

With a maximum concentration of 9% CO_2, the purification, compression, and energy consumption necessary will likely negate the benefits of CCS for this source. In addition, there is no nearby pipeline capable of receiving, holding, and transporting the captured CO_2, so one would have to be constructed in order to transfer the CO_2 from the proposed CCI site to a suitable geologic storage location.

EPA is evaluating whether there is sufficient information to conclude that CCS is technically feasible for the charge heaters, auxiliary boilers, or the marine vapor combustion unit at the CCI plant and will consider public comments on this issue. However, because the applicant provided a basis to eliminate CCS on other grounds, we have assumed for purposes of this specific permitting action that the potential technical or logistical barriers do not make CCS technically infeasible for this project, and we are therefore evaluating the economic, energy, and other environmental impacts of CCS in Step 4 of the BACT analysis.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

No ranking is necessary because we are evaluating only one add-on control technology here. Based on a 90% capture efficiency, we estimate that CCS would reduce GHG emissions (CO_2) from the charge heaters, auxiliary boilers, the flare and marine vapor combustion unit by 185,429 TPY.

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[3] CCI provided information on the CO_2 concentration of the exhaust gas stream in the April 28, 2014 resubmittal. In this document, CCI represented the maximum concentration of CO_2 to be 9%. http://www.epa.gov/region6/6pd/air/pd-r/ghg/cci-condensate-response042814.pdf Page 4-3.

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

CCI developed a site-specific cost analysis demonstrating that CCS can be eliminated as BACT for this project in Step 4 based on the excessive costs associated with use of CCS, as well as negative environmental and energy impacts. EPA Region 6 reviewed CCI's CCS cost estimate and believes it adequately approximates the annual cost of CCS control for this project.

The projected capital cost of CCS at the CCI plant is $500 million. Information supplied by CCI indicates that the annualized cost of the facility, assuming a 7% annual interest rate and 20-year equipment life, will be approximately $47.2 million. The cost of installing and operating a post-combustion carbon capture system, using the August 2010 Report of the Interagency Task Force on Carbon Capture and assuming 90% capture and control efficiency, is approximately $21.3 million per year.[4] Therefore, a carbon capture system for this source would cost approximately 45% of the projected total cost of the entire facility without CCS. This cost does not include the construction of the dedicated pipeline necessary to transport the captured and purified CO_2 to a suitable geologic sequestration location, nor does it include the cost of control for the additional GHGs generated by the CCS equipment or the added burden of criteria pollutants generated by operation of this equipment. Implementation of CCS would increase emissions of NO_x, CO, VOC, PM_{10}, SO_2, and ammonia by as much as 13-17%.[5]

While we take no position on the energy and environmental impacts of CCS, many of which likely could be mitigated, we agree with the applicant that CCS is not economically feasible for this specific application because it would increase the total project cost by a minimum of 45%.

Step 5 – Selection of BACT

See the BACT analyses for the remaining technologies considered for the individual combustion sources, below.

B. Charge Heaters (EPNs: H-1and H-2)

GHG emissions, primarily CO_2, result from the combustion of a natural gas and process gas mixture in the proposed charge heaters. The splitter plant will utilize two charge heaters (H-1 and

[4] See May 21, 2014 response to information request, http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/cci-condensate-response052114.pdf.

[5] IPCC, 2005: IPCC Special Report on Carbon Dioxide Capture and Storage. Prepared by Working Group III of the Intergovernmental Panel on Climate Change. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA. Figure 3.7. Available at http://www.ipcc-wg3.de/special-reports/.files-images/SRCCS-Chapter3.pdf

H-2), each with a maximum stated firing rate of 153 MMBtu/hr. As part of the GHG PSD permit application, CCI provided a top-down BACT analysis, as described in Section VII above, for the two heaters. EPA has reviewed CCI's BACT analysis for the heaters, which we have incorporated into this Statement of Basis, and performed our own analysis in setting forth BACT for this proposed permit. The BACT analysis is summarized below.

Step 1 – Identification of Potential Control Technologies for GHGs

- Efficient Burner Design –The heaters will be equipped with efficient burners designed to operate with improved fuel-mixing capabilities.
- Increased heat transfer – The heaters will have state-of-the-art refractory and insulation materials to minimized heat loss and increase thermal efficiency.
- Air Preheat System – Combustion air will be preheated using excess heat from the system prior to entering the combustion section of the heater. This will reduce the heat load for on the heaters, thereby increasing overall thermal efficiency and reducing the amount of natural and process gas combusted. This will reduce GHG emissions from the charge heaters.
- Heat Recovery System – Because this is new construction, CCI will design a heat exchange system into the heaters to make use of hot flue gases and hot product streams to preheat incoming combustion air and feedstock. This will reduce the overall demand for fuel and reduce production of GHGs.
- Fuel Selection – Use of low carbon fuels results in lower GHG emissions. In the case of the CCI heaters, the company will use a mix of 95% commercially available natural gas and 5% process gas from the fractionators. These simpler chained hydrocarbons will produce less GHGs than using longer chained hydrocarbons as fuel.
- Good Combustion Practices – CCI will use oxygen and air intake flow monitors to minimize excess air and optimize the air/fuel mixture. This practice increases combustion efficiency and reduces the GHG emissions.
- Periodic Maintenance – Implementation of a program with scheduled inspections and maintenance activities will result in increased thermal efficiencies, energy savings, and reduced GHG emissions.

Step 2 – Elimination of Technically Infeasible Alternatives

All of the options identified in Step 1 are technically feasible for this project.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Control Technology Description	Typical Overall Control Efficiency (%)	Source
Fuel Selection	11-40%	40 CFR Part 98, Subpart C, Table C-1, "Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel"
Air Preheat System	10-15	GHG BACT for Refineries (Heat Recovery – Air Preheater)
Increased Heat Transfer	5-10	Energy Efficiency Improvement (Section 8)
Heat Recovery System	2-4	GHG BACT for Refineries (Recover Heat from Process Fuel Gas)
Periodic Maintenance	1-10	GHG BACT for Refineries (Improved Maintenance)
Good Combustion Practices	1-3	GHG BACT for Refineries (Combustion Air Controls Limitations on Excess Air)
Efficient Burner Design	N/A	GHG BACT for Refineries (Heat Recovery – Air Preheater)

The majority of GHG emissions from fuel combustion result from the conversion of the carbon in the fuel into CO_2. Thus, use of a completely carbon-free fuel, such as 100% hydrogen, has the potential of reducing CO_2 emissions by 100%. Hydrogen is not a product of the processes at the CCI facility, however, and will not be available as a fuel for the heaters. Nor is it commercially available to the site. Natural gas is the lowest carbon fuel available to CCI at this location.

Good heater design, including heat transfer, combustion air preheating, good combustion practices such as air/fuel ratio control, and periodic tune-ups are all considered effective and provide a range of efficiency improvements, which can be estimated but not directly quantified in this case. Therefore, the above efficiency rankings for the heaters is approximate only.

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

The control technologies proposed in Step 1 are not mutually exclusive and CCI will implement them concurrently. CCI will utilize all of the above options. Therefore, an evaluation of the impacts of the control technologies is not necessary for this review.

Step 5 – Selection of BACT

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

Company / Location	Process Description	BACT Control(s)	BACT Emission Limit / Requirements	Year Issued	Reference
Energy Transfer Company (ETC), Jackson County Gas Plant Ganado, TX	Four Natural Gas Processing Plants 4 Hot Oil Heaters (48.5 MMBtu/hr each) 4 Trim Heaters (17.4 MMBtu/hr each) 4 Molecular Sieve Heaters (9.7 MMBtu/each) 4 Regenerator Heaters (3 MMBtu/hr each)	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT limit for process heaters per plant (one of each heater per plant) of 1,102.5 lbs CO_2/MMSCF 365-day average, rolling daily for each plant	2012	PSD-TX-1264-GHG
Enterprise Products Operating LLC, Eagleford Fractionation Mont Belvieu, TX	NGL Fractionation 2 Hot Oil Heaters (140 MMBtu/hr each) 2 Regenerant Heaters (28.5 MMBtu/hr each	Energy Efficiency/ Good Design & Combustion Practices	Hot Oil Heaters have a minimum thermal efficiency of 85% on a 12-month rolling basis. Regenerant heaters only have good combustion practices.	2012	PSD-TX-154-GHG
Energy Transfer Partners, LP, Lone Star NGL Mont Belvieu, TX	2 Hot Oil Heaters (270 MMBtu/hr each) 2 Regenerant Heaters (46 MMBtu/hr each)	Energy Efficiency/ Good Design & Combustion Practices	Hot Oil Heaters - 2,759 lb CO_2/bbl of NGL processed. Regenerator Heaters - 470 lbs CO_2/bbl of NGL processed. 365-day average, rolling daily	2012	PSD-TX-93813-GHG

Company / Location	Process Description	BACT Control(s)	BACT Emission Limit / Requirements	Year Issued	Reference
Copano Processing L.P., Houston Central Gas Plant Sheridan, TX	2 Supplemental Heaters (25 MMBtu/hr each)	Energy Efficiency/ Good Design & Combustion Practices, and Limited Operation	Each heater will be limited to 600 hours of operation on a 12-month rolling basis.	2013	PSD-TX-104949-GHG
KM Liquids Terminals, Galena Park Terminal Galena Park, TX	2 Hot Oil Heaters (247 MMBtu/hr each)	Energy Efficiency/ Good Design & Combustion Practices	Each heater meets a minimum thermal efficiency of 85% on a 12-month rolling average basis.	2013	PSD-TX-101199-GHG
PL Propylene Houston, TX	2 Charge Gas Heaters (373 MMBtu/hr each)	Energy Efficiency/ Good Design & Combustion Practices	BACT limit of 117 lb CO_2/MMBtu heat input on a 365-day rolling average. CO_2 CEMS installed on each heater.	2013	PSD-TX-18999-GHG

The Enterprise Eagleford Fractionation plant and Energy Transfer Partners Lone Star NGL plant are both natural gas liquids (NGL) fractionation facilities employing hot oil heaters to provide heat for fractionating the incoming feed stream. CCI's charge heaters are direct fired, while the other two facilities use a heat transfer medium. CCI will monitor thermal efficiency of the charge heaters and maintain an 85% thermal efficiency. The two smaller, direct-fired heaters will meet an efficiency standard of 8.57 lb CO_2 /bbl of condensate processed. This BACT requirement is consistent with the recent determinations for KM Liquids and Enterprise Eagleford Fractionators. We have analyzed the proposed BACT and find that a thermal efficiency of 85%, as determined using accepted API efficiency standards, is consistent with other BACT determinations for similar units.

The following specific BACT practices will apply to the charge heaters:

- *Fuel Selection - Use of Low Carbon (Natural Gas) Fuel* – Pipeline quality natural gas will make up the majority of the fuel used at the site. A maximum of 5% plant gas derived from the splitter's fractionators will fire in the proposed heaters.
- *Air Preheat System* – The heaters will be constructed with an air preheat system to reduce overall heat load, increase thermal efficiency, and reduce GHG emissions.
- *Increased Heat Transfer* - The heaters will be constructed with state-of-the-art refractory and insulation materials to minimize heat loss and increase overall thermal efficiency.

- *Heat Recovery System* - The heaters will be designed to route flue gas and hot product streams through a heat exchange section to provide energy to preheat incoming air and fuel, which will reduce the required heat load, increase the thermal efficiency of the heaters, and reduce GHG emissions
- *Efficient Burner Design* – The heaters' design will maximize heat transfer efficiency and reduce heat loss.
- *Good Combustion Practices* – CCI will install, utilize, and maintain an automated air/fuel control system to maximize combustion efficiency in the heaters. The excess air will be limited to 3% oxygen (maximum). The heaters will maintain a minimum thermal efficiency of 85%.
- *Periodic Maintenance* – CCI will maintain analyzers and clean burner tips and convection tubes as needed, but no less frequently than once every 12 months.

<u>BACT Limits and Compliance:</u>

CCI shall demonstrate compliance with an 85% thermal efficiency on the heaters, demonstrated on a 12-month rolling average basis. CCI will continuously monitor the heaters for exhaust temperature, fuel temperature, ambient temperature, and stack O_2 concentration. Thermal efficiency will be calculated for each operating hour from these continuously monitored parameters using equation G-1 from American Petroleum Institute (API) methods 560 (4^{th} ed.) Annex G. To ensure compliance with the proposed emission limit, CCI shall not exceed an annual average firing rate of 137.4 MMBtu/hr for each of the charge heaters. The two heaters will comply with an annual emission limit of 70,889 TPY of CO_2e each.

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

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

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

$$CO_2 = \frac{44}{12} * Fuel * CC * \frac{MW}{MVC} * 0.001 * 1.102311$$

Where:

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

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

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

The emission limits associated with the greenhouse gases CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Table C-2 and the actual heat input (HHV). Comparatively, the emissions from CO_2 contribute the most (greater than 99%) to the overall GHG emissions from the heaters and, therefore, additional analysis is not required for CH_4 and N_2O. To calculate the CO_2e emissions, the draft permit requires calculation of the emissions based on the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1, as amended on November 29, 2013 (78 FR 71904). Records of the calculations are will be kept to demonstrate compliance with the emission limits on a 12-month rolling basis.

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

C. Auxiliary Boilers (EPNs: BL-1and BL-2)

GHG emissions, primarily CO_2, result from the combustion of a natural gas and process gas mixture in the auxiliary boilers. The auxiliary boilers (BL-1 and BL-2) will provide steam to the process with a maximum stated firing rate of 36.3 MMBtu/hr. As part of the GHG PSD permit application, CCI provided a top-down BACT analysis for the boilers, as described in Section VII above, for the two heaters. EPA has reviewed CCI's BACT analysis for the boilers, which has been incorporated into this Statement of Basis. We also provide our own analysis in setting forth BACT for this proposed permit, as summarized below.

Step 1 – Identification of Potential Control Technologies for GHGs

- Air Preheat System – CCI proposes to preheat incoming combustion air using heat exchangers to make the best use of heat generated by the process and reduce the required steam load on the plant.
- Efficient Burner Design –The boilers will be equipped with efficient burners designed to operate with improved fuel mixing capabilities.
- Boiler Insulation – The heaters will have state-of-the-art refractory and insulation materials to minimize heat loss and increase thermal efficiency.
- Economizer – CCI will use an economizer to recover heat from the boiler-stack flue gas and use it to preheat the boiler feed water, reducing the required heat load and decreasing the potential for GHG emissions from the boilers.
- Condensate Return System – Hot condensate will recirculate to the boiler system as boiler feed water, reducing the heat load on the boiler and reducing potential GHG emissions from the boilers.
- Refractory Material Selection – CCI will use refractory materials to provide the highest insulating capacity available to reduce heat loss and increase the energy efficiency of the boilers.
- Fuel Selection – Use of low carbon fuels results in lower GHG emissions. CCI will use a mix of 95% commercially available natural gas and 5% process gas from the fractionators to fire the boilers. These simpler chained hydrocarbons will produce less GHGs than using longer chained hydrocarbons as fuel.
- Good Combustion Practices – Using oxygen and air-intake flow monitors will minimize excess air and optimize the air/fuel mixture. This practice increases combustion efficiency and reduces GHG emissions.
- Periodic Maintenance – Implementation of a program with scheduled inspections and maintenance activities will result in increased thermal efficiencies, energy savings, and reduced GHG emissions.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are technically feasible for this project.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Control Technology Description	Typical Overall Control Efficiency (%)	Source
Fuel Selection	11-40%	40 CFR Part 98, Subpart C, Table C-1, “Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel”
Air Preheat System	10-15	GHG BACT for Refineries (Heat Recovery – Air Preheater)
Boiler Insulation	6-26	Energy Efficiency Design (Section 7.1)
Economizer	2-4	GHG BACT for Refineries (Recovery Heat from Process Flue Gas)
Condensate Return System	1-10	GHG BACT for Refineries (Install Steam condensate Return Lines)
Periodic Maintenance	1-10	GHG BACT for Refineries (Improved Maintenance)
Good Combustion Practices	1-3	GHG BACT for Refineries (Combustion Air Controls – Limitations on Excess Air)
Refractory Material Selection	N/A	GHG BACT for ICI Boilers (Refractory Material Selection)
Efficient Burner Design	N/A	GHG BACT for Refineries (Replace and Upgrade Burners)

The majority of the GHG emissions from fuel combustion result from the conversion of the carbon in the fuel into CO_2. Thus, use of a completely carbon-free fuel, such as 100% hydrogen, has the potential of reducing CO_2 emissions by 100%. As described in Section IX.A above, hydrogen will not be produced in large quantities from the processes at the CCI facility, and will not be available as a fuel for the heaters. Natural gas is the lowest carbon fuel available to CCI at this location. CCI is proposing to use 95% commercially obtained natural gas and 5% process gas in the fuel-gas system. Use of this fuel will result in a significant potential reduction in GHGs from the process.

Good boiler design, including condensate return, use of good refractory materials and effective insulation, use of an economizer, and good combustion practices, such as air/fuel ratio control and periodic maintenance, are all considered effective and provide a range of efficiency improvements for GHG emissions from these boilers.

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

The control technologies proposed in Step 1 are not mutually exclusive and CCI will implement them concurrently. CCI will utilize all of the above options. Therefore, an evaluation of the impacts of the control technologies is not necessary for this review.

Step 5 – Selection of BACT

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

Company / Location	Equipment	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
Air Liquide Houston, TX	Boiler	Energy Generation	Energy Efficiency/ Good Design & Combustion Practices	117 lb/MMBtu heat input 12-month rolling average	2013	PSD-TX-612-GHG
ExxonMobil Mont Belvieu Plastics Plant	Boiler	Polyethylene Production	Energy Efficiency/ Good Design & Combustion Practices	Minimum thermal efficiency of 77%	2013	PSD-TX-103048-GHG
Invista	Boiler	Powerhouse Modifications	Good combustion Practices	235 lb CO_2/Mlbs of 550 psig steam/ fuel limitations	2013	PSD-TX-812-GHG
La Paloma Energy Center	Auxiliary Boiler	Energy Generation	Good combustion Practices	Firing limited to 876 hours per year/fuel limited to natural gas	2013	PSD-TX-1288-GHG
Enterprise Products – PDH Mont Belvieu, Texas	Auxiliary Boilers	Propylene Production	Energy Efficient Design, Good Combustion Practices, Limited Operation	Firing limited to 310 hrs per year at full load. Firing rate limited to 248,500 MMBtu/yr	2014	PSD-TX-1336-GHG

The Enterprise Products PDH plant is a propylene production unit that keeps its similarly sized auxiliary boilers in hot standby mode to assist restart of the plant after unexpected shutdowns. The ExxonMobil Plastics plant incorporated an existing, larger sized boiler into its GHG permit. La Paloma, Invista, and Air Liquide are all larger boilers sized for energy generation. CCI's boilers are direct-fired steam generation units used to provide auxiliary heat to the process. CCI will monitor thermal efficiency of the boilers and maintain an 85% thermal efficiency. We analyzed the proposed BACT limit and find that it is consistent with other BACT determinations for similar units.

CCI proposes all of the options listed in Step 1 as BACT. The following specific BACT practices apply to the auxiliary boilers:

- *Fuel Selection* - Use of low carbon fuels results in lower GHG emissions. CCI will use a mix of 95% commercially available natural gas and 5% process gas from the fractionators to fire the boilers. These simpler chained hydrocarbons will produce less GHGs than using longer chained hydrocarbons as fuel.
- *Air Preheat System* – Incoming combustion air will be heated using heat exchangers to make the best use of heat generated by the process and reduce the required steam load on the plant.
- *Burner Design* – The boilers will be equipped with efficient burners designed to operate with improved fuel mixing capabilities.
- *Boiler Insulation* – The boilers will have state-of-the-art refractory and insulation materials to minimize heat loss and increase overall thermal efficiency of the boilers.
- *Economizer* – CCI will use an economizer to recover heat from the boiler-stack flue gas and use it to preheat the boiler feed water, which will reduce the required heat load for the boiler and decrease GHG emissions.
- *Condensate Return System* – The hot condensate from the boilers will be returned to the boiler system to be used as boiler feed water, which will reduce the required heat load for the boiler and decrease GHG emissions.
- *Refractory material selection* – CCI will use refractory materials to provide the highest insulating capacity available to reduce heat loss and increase the energy efficiency of the boiler.
- *Good Combustion Practices* – CCI will install, utilize, and maintain an automated air/fuel control system to maximize combustion efficiency in the boilers. The excess air will be limited to 3% oxygen (maximum). The boilers will maintain a minimum thermal efficiency of 85%.
- *Periodic Maintenance* – CCI will implement a program with scheduled inspection and maintenance activities. The program will maintain the oxygen analyzers, and other essential equipment as well as clean the boiler's burner tips and convection tubes as needed, but no less than frequently than every 12 months

BACT Limits and Compliance:

CCI shall demonstrate compliance with an 85% thermal efficiency on the auxiliary boilers demonstrated on a 12-month rolling average basis. CCI will continuously monitor the boiler's exhaust temperature, fuel temperature, ambient temperature, and stack O_2 concentration. Thermal efficiency will be calculated for each operating hour from these continuously monitored parameters using equation G-1 from American Petroleum Institute (API) methods 560 (4^{th} ed.)

Annex G. The two auxiliary boilers will to comply with an annual emission limit of 165,640 TPY of CO_2e for each unit.

Both boilers will incorporate efficiency features, including insulation and refractory materials to minimize heat loss, heat transfer components to maximize heat recovery and transfer, efficient burners to reduce fuel usage. CCI will implement a preventive maintenance program to maintain the equipment in good working order and continually employ good combustion practices in operation of the boilers.

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

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

$$CO_2 = \frac{44}{12} * Fuel * CC * \frac{MW}{MVC} * 0.001 * 1.102311$$

Where:

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

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

The emission limits associated with the greenhouse gases CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Table C-2 and the actual heat input (HHV). Comparatively, the emissions from CO_2 contribute the most (greater than 99%) to the overall GHG emissions from the boilers and, therefore, additional analysis is not required for CH_4 and N_2O. To calculate the CO_2e emissions, the draft permit requires calculation of the emissions based on the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1, as amended on November 29, 2013 (78 FR 71904). Records of the calculations will to demonstrate compliance with the emission limits on a 12-month rolling basis.

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

D. Marine Vapor Combustion Unit (MVCU)

The new condensate splitter plant and bulk terminal will utilize a new tank truck loading rack and marine loading facilities to transfer product and unprocessed condensate offsite. The marine loading facilities will be equipped with a marine vapor combustion unit that will be located on the plant's dock. The marine vapor combustion unit will be capable of having a destruction and removal efficiency (DRE) of 99% for VOC vapors. The TCEQ requires a 99% DRE for the VOC vapors generated from marine loading emissions. CCI will add natural gas to the vapor stream to assure that the marine vapor combustion unit maintains the required minimum combustion chamber temperature to achieve adequate destruction.

Step 1 – Identification of Potential Control Technologies

The available control technologies for marine vessel loading emissions are:

- *Vapor Combustion Unit with Appropriate Operational Controls* – Use of a vapor combustor to control VOC emissions associated with marine loading of the finished products from the condensate splitter plant and the bulk terminal operations is an established and effective means of control. Vapor combustion units are capable of 99% DRE for VOC loading emissions. Use of flow and composition monitors to determine the optimum amount of natural gas required to maintain adequate VOC destruction will minimize natural gas combustion and the resulting CO_2 emissions.
- *Use of a Flare* – An alternative to the use of a vapor combustion unit is flaring. Typically, flares are capable of 98% DRE for VOCs.

- *Use of a Vapor Recovery Unit* – An alternative control technology consideration is vapor recovery and recycling of condensed vapors to storage or the process.
- *Minimization* – Minimize the duration and quantity of combustion to the greatest extent possible through good engineering design of the loading process and good operating practices. In this case, submerged loading of barges and marine vessels can reduce the amount of vapors generated during loading operations.

Step 2 – Elimination of Technically Infeasible Alternatives

The vapor combustion unit is designed to meet the TCEQ's requirement to achieve 99% control of VOC emissions from the loading operations. Using a flare in place of a vapor combustion unit would result in only 98% control of VOC emissions from loading operations. Therefore, while technically feasible, we are eliminating the flare from further consideration because it cannot serve as BACT for VOC emissions. We also note that a flare is not likely to have a significantly lower GHG emission rate when compared to a vapor combustion unit.

Vapor recovery units are not technically feasible for this project because they would not be capable of handling the periodic large volumes of vapor associated with marine loading activities.

Minimization and proper operation of the vapor combustion unit are both technically feasible control options.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

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

Virtually all GHG emissions from fuel combustion result from the conversion of the carbon in the fuel and/or waste gas to CO_2. The marine loading facilities will minimize the volume of the waste gas sent to the marine vapor combustion unit. Specifically, CCI will utilize submerged loading technology to reduce up to 80% of VOCs generated during ship loading activities. Proper operation of the marine vapor combustion unit will result in efficiency improvements that are not be directly quantified, but are compatible with submerged loading of barges and marine vessels. Use of an analyzer to determine the combustion chamber temperature will allow for the continuous determination of the correct amount of natural gas needed to maintain the desired DRE of VOCs and ensure that excess natural gas is not unnecessarily combusted.

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

The control technologies remaining in Step 3 are not mutually exclusive and CCI will implement them concurrently. CCI will utilize all remaining options. Therefore, an evaluation of the impacts of the remaining control technologies is not necessary for this review.

Step 5 – Selection of BACT

The following specific BACT practices apply for marine vessel loading:

- *Minimization* – Minimize the duration and quantity of combustion to the extent possible through good engineering design of the process and good operating practice.
- *Proper Operation of a Vapor Combustion Unit* – CCI will reduce the formation of GHGs by proper operation of the marine vapor combustion unit and use of good combustion practices. Poor combustion efficiencies lead to higher methane emissions and higher overall GHG emissions. CCI will monitor the combustion chamber temperature to ensure the adequate destruction of VOCs and to minimize natural-gas combustion and resulting CO_2 emissions.

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

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

$$CO_2 = \frac{44}{12} * Fuel * CC * \frac{MW}{MVC} * 0.001 * 1.102311$$

Where:

CO_2 = Annual CO_2 mass emissions from combustion of natural gas (short tons)
Fuel = Annual volume of the gaseous fuel combusted (scf). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to § 98.3(i).
CC = Annual average carbon content of the gaseous fuel (kg C per kg of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV at § 98.33(a)(2)(ii).

MW = Annual average molecular weight of the gaseous fuel (kg/kg-mole). The annual average molecular weight shall be determined using the same procedure as specified for HHV at § 98.33(a)(2)(ii).
MVC = Molar volume conversion factor at standard conditions, as defined in § 98.6.
44/12 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion of kg to metric tons.
1.102311 = Conversion of metric tons to short tons.

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

E. Flare (FL-1)

A process flare (FL-1) will be part of the condensate splitter plant. The flare will provide a means to control venting during planned maintenance, startup, and shutdown (MSS), and upset situations. The flare is necessary for the plant to operate in a safe manner. The proposed condensate splitter plant will be designed to minimize the volume of waste gas sent to the flare. During routine operation, gas flow to the flare will be limited to pilot and purge gas only. To the greatest extent possible, flaring will be limited to purge/pilot gas, emission events, and MSS activities.

Virtually all GHG emissions from the flare result from the conversion of the carbon in the supplemental fuel (in this case natural gas) and the controlled waste gas into CO_2. The flow rate to the natural gas pilot will be 451scfh. The flare will have a VOC destruction and removal efficiency (DRE) of 98%. This BACT analysis only applies to the firing of natural gas in the pilots and control of MMS related activities.

Step 1 – Identification of Potential Control Technologies

- *Flare Gas Recovery (FGR)* – Installation and operation of a FGR system will reduce GHG combustion emissions by routing combustible gases back to the fuel gas system.
- *Use of a Thermal Oxidizer or Vapor Combustion Unit in Lieu of a Flare* – A vapor combustion device like a thermal oxidizer or vapor combustion unit could provide a high level of DRE for produced vapors from the process and loading operations.
- *Use of a Vapor Recovery Unit in Lieu of a Flare* – A vapor recovery unit could condense VOCs developed as part of the condensate splitter and loading operations and return them to the process or fuel-gas system.
- *Flaring Minimization* – Minimize the duration and quantity of flaring to the extent possible through good engineering design of the process and good operating practices.

- *Proper Operation of the Flare* – Use of flow and composition monitors to determine the optimum amount of natural gas required to maintain adequate VOC destruction in order to minimize natural-gas combustion and the resulting CO_2 emissions.
- *Fuel Selection* – CCI has identified the use of commercially available natural gas as a potential control method to reduce GHG emissions when compared to the use of other available fuels.

Step 2 – Elimination of Technically Infeasible Alternatives

A primary reason why a flare is considered for control of VOCs in the process vent stream is that it can also be used for emergency releases. Thermal oxidizers, vapor combustion units, and vapor recovery units are not capable of handling the sudden large volumes of vapor that could occur during an upset release in the condensate splitter process. Therefore, we are eliminating these control options as technically infeasible.

Similarly, CCI represents a flare-gas recovery system would be technically infeasible because there will be no continuous waste gas flow to the flare that can be compressed a stored for use and that the waste gas from MSS and plant upset events will vary in composition, volume and pressure making the waste gas incompatible with the technical requirements for use in the fuel gas system.

Flare minimization, proper operation of the flare, and fuel selection are technically feasible control options.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- *Flaring Minimization* - Up to 100% reduction of GHG emissions resulting from combusted VOCs due to MSS activities and process upsets.
- *Fuel Selection* - Use of natural gas to fire the flare's pilots and provide added heat content to ensure complete combustion of controlled VOCs. CCI claims 40% efficiency for this practice, when compared to using other fuels that could conceivably be used to increase the heat value of the combusted stream.
- *Proper Operation of the Flare* - Not directly quantifiable.

Proper operation of the flare, use of natural gas as fuel for the flare operations, and flare minimization efforts will result in efficiency improvements that cannot be quantified directly. Therefore, the above ranking is approximate only. Proper operation of the flare will include using an analyzer to determine the heating value of the flared waste gas, which will allow continuous determination of the amount of natural gas needed to maintain a minimum heating value of 300 Btu/scf. This will allow for the proper destruction of VOCs and ensure that natural gas is not unnecessarily added to the flared stream.

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

The control technologies remaining in Step 3 are not mutually exclusive and CCI will implement them concurrently. CCI will utilize all remaining options. Therefore, an evaluation of the impacts of the remaining control technologies is not necessary for this review.

Step 5 – Selection of BACT

The following specific BACT practices are proposed for the flare:

- *Flaring Minimization*– Minimize the duration and quantity of flaring to the extent possible through good engineering design of the process and good operating practice.
- *Proper Operation of the Flare* – Flow and composition monitors will determine the optimum amount of supplemental natural gas required maintain adequate VOC control. A maintenance program to maintain the efficiency of the flare will also be employed.
- *Fuel Selection* – Commercially available natural gas will maintain the pilot flame and add to the Btu value of the combusted stream when needed.

Using good combustion practices, along with a DRE of 98% for VOCs and 99% DRE for combustion of methane, will result in an emission limit for the flare of 2,316 TPY CO_2e during normal operations and 370 TPY CO_2e during MMS conditions. The CO_2e emissions from the combustion of natural gas in the pilots of the flare and normal off-gassing from the process account for approximately 1.2% of the project's total CO_2e emissions. CCI will demonstrate compliance with the CO_2 emission limit using the emission factors for natural gas from 40 CFR Part 98, Subpart C, Table C-1, and the site-specific fuel analysis for process fuel gas (see Table D-4 of the GHG permit application). The equation for estimating CO_2 emissions as specified in 40 CFR 98.253(b)(1)(ii)(A) is as follows:

$$CO_2 = 0.98 \times 0.001 \times \left(\sum_{p=1}^{n} \left[\frac{44}{12} \times (Flare)_p \times \frac{(MW)_p}{MVC} \times (CC)_p \right] \right) * 1.102311$$

Where:

CO_2 = Annual CO_2 emissions for a specific fuel type (short tons/year).
0.98 = Assumed combustion efficiency of the flare.
0.001 = Unit conversion factor (metric tons per kilogram, mt/kg).

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

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

F. Process Fugitives (FUG)

Hydrocarbon emissions from leaking piping components (process fugitives) associated with the proposed project include methane, a GHG. CCI conservatively estimates the additional methane emissions from process fugitives to be 398 TPY as CO_2e. Fugitive emissions of methane are thus negligible, accounting for less than 0.2% of the project's total CO_2e emissions.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Installation of Leakless Technology* – The use of leakless components, i.e. welded connections and fittings, would eliminate the potential for GHG emissions from process and fuel-gas fugitives.
- *Implementation of Leak Detection and Repair Program (LDAR)* – The use of a portable organic vapor detector meeting the specifications and performance criteria specified in 40 CFR Par 60, Appendix A, Test Method 21 to monitor piping components for leaks and repair them when found would result in decreased potential for GHG emissions from the project. The LDAR program would conform to the TCEQ 28 VHP program.

- *Alternative Monitoring Using Infrared Technology* – This control technology is similar in nature to an LDAR program, except an infrared camera is used to detect tipping components in place of a portable organic detector.
- *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.

Step 2 – Elimination of Technically Infeasible Alternatives

All of the options listed in Step 1 are technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- *Installation of Leakless Technology* –100% control of GHG fugitive emissions.
- *Implementation of Leak Detection and Repair (LDAR) Program* – LDAR will reduce VOC emissions, including methane, by approximately 30%.
- *Alternative Monitoring Using Infrared Technology* –We anticipate control efficiencies similar to those estimated for the LDAR program.
- *Compressor Selection* – Considered an effective means of control, but no specific data is available to establish a control level in this case.

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

While all of the options listed in Step 1 are technically feasible and effective, the minimal level of overall GHG emissions from fugitive emission points does not justify imposition of controls on this source.

However, an LDAR program to control the VOC emissions from the source will be required by the TCEQ and that program will result in reduced GHG emissions that occur as process fugitives. The TCEQ 28VHP incorporates use of welded and flanged piping and component connections where practical and prohibits the use of screwed connections on any component 2 inches or greater in nominal diameter. Safety relief and pressure control valves will be vented to the flare system to ensure leaks are not vented to the atmosphere. In this situation, the TCEQ 28 VHP program can be implemented at the site without additional cost or effort on the part of the company or implementing agencies.

Step 5 – Selection of BACT

Because the TCEQ 28 VHP LDAR program is being implemented for VOC control purposes, and it will also result in effective control of the small amount of GHG emissions from the same piping components and fittings, it is determined that TCEQ's 28 VHP LDAR program represents BACT for fugitive emissions control for this source.

G. Emergency Generator and Firewater Pump Engines (EMGEN, FW-1 and FW-2)

The emergency generator and firewater pump engines will have normal operations of 100 hours per year to maintain operational readiness.

Step 1 – Identification of Potential Control Technologies

- *Low Carbon Fuels* – Use of fuels containing lower concentrations of carbon generate less CO_2, than other higher-carbon fuels. Typically, natural gas or high-hydrogen plant tail gas contain less carbon, and thus lower CO_2 emission potential, than liquid or solid fuels such as diesel or coal.
- *Vendor Certified Tier 4 and Clean Burn Engine* – Use of non-road diesel engines complying with 40 CFR Part 60, Subpart IIII will result in more efficient fuel use and reduced GHG emissions when compared to alternatives.
- *Good Combustion Practices and Maintenance* – Good combustion practices include appropriate maintenance of equipment and operating within the recommended air-to-fuel ratio recommended by the manufacturer.
- *Operational Restrictions* – Dedication to emergency service will limit the total hours of operation as well as the GHG emissions from these engines.

Step 2 – Elimination of Technically Infeasible Alternatives

Lower carbon fuels like natural gas and hydrogen-laden plant gas will not be available during certain emergency events. Therefore, reliance on these fuels is not technically feasible for the emergency engines. The other options listed in Step 1 are technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

With the exception of the use of low carbon fuel, all options listed in Step 1 are capable of use and are compatible. Therefore, ranking of these technologies is not necessary.

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

With the exception of using low carbon fuels, all of the control options listed in Step 1 are economically feasible and they will not result in an adverse environmental impact.

Step 5 – Selection of BACT

The following specific BACT practices are proposed for the emergency generator and firewater pump engines:

- *Vendor Certified Tier 4 and Clean Burn Engine* – Tier 4 and Clean Burn Engines complying with 40 CFR Part 60, Subpart IIII will be employed for the emergency generator and firewater pump engines.
- *Good Combustion Practices and Maintenance* – Good combustion practices for compression ignition engines include appropriate maintenance of equipment, periodic testing conducted weekly, and operating within the recommended air-to-fuel ratio, as specified by its design.
- *Operational Restrictions* – Limiting the hours of use for testing and maintenance to 100 hours per year.

Using the BACT practices identified above results in an emission limit of 205 TPY CO_2e. The CO_2e emissions from the emergency use engines accounts for less than 0.1% of the total project CO_2e emissions. CCI will demonstrate compliance with the CO_2 emission limit using the emission factors for Distillate Fuel Oil No. 2 fuel from 40 CFR Part 98 Subpart C, Table C-1. The equation for estimating CO_2 emissions as specified in 40 CFR 98.33(a)(1)(i) is as follows:

$$CO_2 = 0.001 * Fuel * HHV * EF$$

Where:

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

CCI will calculate CH_4 or N_2O emissions using the emission factors for petroleum fuel from 40 CFR Part 98 Subpart C, Table C-2. The equation for estimating CH_4 or N_2O emissions as specified in 40 CFR 98.33(c)(1) is as follows:

$$CH4 \text{ or } N2O = 0.001 * Fuel * HHV * EF$$

Where:

CH_4 or N_2O = Annual CH_4 or N_2O mass emissions from combustion of diesel fuel (metric tons)

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

HHV= Default high heat value of the fuel.

0.001 = Conversion of kg to metric tons.

EF = Fuel specific default CH_4 or N_2O emission factor (kg CO_2/MMBtu).

H. Cooling Water Tower (CWT)

CCI will use a cooling water tower to assist in controlling excess temperatures developed in the condensate-splitter process.

Step 1 – Identification of Potential Control Technologies

- *Use of an Air Cooling System*– Designing and installing an air cooling system would avoid the potential contact of VOCs with water and their eventual release through the cooling water tower.
- *Cooling Water Tower Monitoring and Repair Program* – Implementing a leak detection program would allow the discovery of VOC leaks into the cooling water system and allow the company to locate and repair the leaks once detected.

Step 2 – Elimination of Technically Infeasible Alternatives

Dry bulb temperatures in the Corpus Christi area are typically too high for an air-cooled system to operate effectively for this plant. In addition, VOC leaks would vent directly into the atmosphere without an opportunity to detect and correct the problem. Therefore, an air-cooled system is not technically feasible for this site.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

With the elimination of the air-cooled option, the only remaining control option is a cooling water tower monitoring and repair program. Further ranking of options is not necessary.

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

There are no negative economic, energy or environmental impacts associated with implementation of a cooling water tower monitoring and repair program.

Step 5 – Selection of BACT

BACT for this source will be implementation of a structured cooling water tower monitoring and repair program based on the monitoring and repair requirements of 40 CFR Part 63, Subpart F, with total organic compounds monitored in lieu of hazardous air pollutants.

I. Wastewater Treatment Plant (WWTP)

Storm water and process sewer water becomes entrained with VOCs. CCI's proposed condensate splitter operations will have a wastewater treatment plant designed to reduce these VOCs before the water is discharged to the Tule Lake Turning Basin. CCI conservatively estimates that the VOCs treated will be all methane. Based on these assumptions, the potential CO_2e emissions exiting through the aerobic biological treatment will amount to less than 0.1% (226 TPY) of the plant's total GHG emissions.

CCI will comply with design requirements consistent with 40 CFR Part 63, Subpart G wastewater treatment standards. CCI will use enclosed process sewers with sealed drains and access points. All junction boxes, lift stations, and manholes will be equipped with sealed covers. The oil-water separator will be enclosed and vented to an activated carbon system to remove VOCs.

Given that CCI is committing to controlling VOC emissions from wastewater sources in the described manner and considering the de minimis nature of the GHG emissions, a formal BACT analysis for the unit is not warranted. The proposed design and work practice standards constitute BACT for this situation.

X. Threatened and Endangered Species

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

To meet the requirements of Section 7, EPA is relying on a Biological Assessment (BA) submitted on June 19, 2014, prepared by the applicant, CCI Corpus Christi, LLC ("CCI"), and its consultant, Weston Solutions, Inc. ("Weston"), reviewed and adopted by EPA. CCI is proposing to construct a new condensate splitter facility at proposed plant located in Corpus Christi, Nueces County, Texas. For the purpose of Section 7 of the Endangered Species Act, EPA is relying on a Biological Assessment that includes the emissions from the entire project and their impacts to endangered species. The biological assessment performed for CCI included in its field survey the physical land area where the new facilities will be built.

A draft BA has identified twenty-one (21) species listed as federally endangered or threatened in Nueces County, Texas:

Federally Listed Species for Nueces County by the U.S. Fish and Wildlife Service (USFWS) and the Texas Parks and Wildlife Department (TPWD)	**Scientific Name**
Reptiles	
Green sea turtle	*Chelonia mydas*
Hawksbill sea turtle	*Eretmochelys imbricata*
Kemp's ridley sea turtle	*Lepidochelys kempii*
Leatherback sea turtle	*Dermochelys coriaea*
Loggerhead sea turtle	*Caretta caretta*
Birds	
Piping plover	*Charadrius melodus*
Northern Aplomado falcon	*Falco femoralis septentrionalis*
Whooping crane	*Grus americanus*
Eskimo curlew	*Numenius borealis*
Fish	
Smalltooth sawfish	*Pristis pectinata*
Mammals	
Gulf coast jagaurundi	*Puma yagouaroundi cacomitli*
Ocelot	*Leopardus pardalis*
West Indian manatee	*Trichechus manatus*
Red wolf	*Canis rufus*
Plants	
Slender rush-pea	*Hoggmannseggia tenella*
South Texas ambrosia	*Ambrosia cheiranthifolia*
Whales	
Blue whale	*Balaenoptera musculus*
Fin whale	*Balaenoptera physalus*
Humpback whale	*Megaptera novaeangliae*
Sei whale	*Balaenoptera borealis*
Sperm whale	*Physeter macrocephalus*

EPA has determined that issuance of the proposed permits to CCI for the new condensate splitter process facility will have no effect on fourteen (14) of these listed species, specifically the red wolf (*Canis rufus*), ocelot (*Leopardus pardalis*), Gulf coast jaguarundi (*Puma yagouaroundi cacomitli*), piping plover (*Charadrius melodus*), Northern Aplomado falcon (*Falco femoralis septentrionalis*), eskimo curlew (*Numenius borealis*), smalltooth sawfish (*Pristis pectinata*), blue whale (*Balaenoptera musculus*), fin whale (*Balaenoptera physalus*), humpback whale (*Megaptera novaeangliae*), sei whale (*Balaenoptera borealis*), sperm whale (*Physeter macrocephalus*), South Texas ambrosia (*Ambrosia cheiranthifolia*), and slender rush-pea (*Hoggmannseggia tenella*). These species are either thought to be extirpated from the county or Texas or not present in the action area.

Two (2) terrestrial species, whooping crane (*Grus americana*) and West Indian manatee (*Trichechus manatus*), and five (5) marine species, leatherback sea turtle (*Dermochelys coriacea*), green sea turtle (*Chelonia mydas*), Kemp's ridley sea turtle (*Lepidochelys kempii*), loggerhead sea turtle (*Caretta caretta*) and Atlantic hawksbill sea turtle (*Eretmochelys imbricate*), identified are species that may be present in the Action Area. As a result of this potential occurrence and based on the information provided in the draft BA, the issuance of the permit may affect, but is not likely to adversely affect the whooping crane, West Indian manatee, leatherback sea turtle, green sea turtle, Kemp's ridley sea turtle, loggerhead sea turtle, and Atlantic hawksbill sea turtle.

EPA submitted the final draft BA to the Southwest Region, Corpus Christi, Texas Ecological Services Field Office of the USFWS on June 23, 2014, and to NOAA Southeast Regional Office, Protected Resources Division of NMFS on May 30, 2014 and requested concurrence from each Agency that issuance of the permit may affect, but is not likely to adversely affect these seven federally-listed species.

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

I. Magnuson-Stevens Act

The 1996 Essential Fish Habitat (EFH) amendments to the Magnuson-Stevens Fishery Conservation and Management Act (Magnuson-Stevens Act) set forth a mandate for the National Oceanic Atmospheric Administration's National Marine Fisheries Service (NMFS), regional fishery management councils, and other federal agencies to identify and protect important marine and anadromous fish habitat.

To meet the requirements of the Magnuson-Stevens Act, EPA is relying on an EFH assessment prepared by Weston on CCI, submitted on March 7, 2014, and reviewed and adopted by EPA.

The facility is affects tidally influenced portions of the Tuel Lake Channel, which empties into Nueces Bay and feeds into Corpus Christi Bay leading to the Gulf of Mexico. These tidally influenced portions have been identified as potential habitats of postlarval, juvenile, subadult or adult stages of red drum (*Sciaenops ocellatus*), shrimp (4 species), reef fish (43 species), blacktip shark (*Carcharhinus limbatus*), bull shark (*Carcharhinus leucas*), Atlantic sharpnose shark (*Rhizoprionodon terraenovae*), bonnethead shark (*Sphyrna tiburo*), and finetooth shark (*Carcharhinus isodon*); the juvenile form of blue marlin; and neonate and juvenile forms of the scalloped hammerhead shark (*Sphyrna lewini*), lemon shark (*Negaprion brevirostris*), and spinner shark (*Carcharhinus brevipinna*). The EFH information was obtained from the NMFS's website (http://www.habitat.noaa.gov/protection/efh/efhmapper/index.html).

Based on the information provided in the EFH Assessment, EPA concludes that the proposed PSD permits allowing for CCI's construction of the condensate splitter process facility will have no adverse impacts on listed marine and fish habitats. The assessment's analysis, which is consistent with the analysis used in the BA discussed above, shows the projects' construction and operation will have no adverse effect on EFH.

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

II. National Historic Preservation Act (NHPA)

Section 106 of the NHPA requires EPA to consider the effects of this permit action on properties eligible for inclusion in the National Register of Historic Places. To make this determination, EPA relied on and adopted a cultural resource report prepared by Weston for the CCI project, submitted in July 2014.

For purposes of the NHPA review, the Area of Potential Effect (APE) was determined to be location of the new condensate splitter facility, construction laydown area, supporting structures (totaling about 84.5 acres), and an approximately 8-mile long pipeline (about 48.5 acres) for a total area of 131 acres . Weston conducted a field survey, including shovel testing, of the APE and a desktop review within a 2.0-mile radius of the APE. The desktop review included an archaeological background and historical records review using the Texas Historical Commission's online Texas Archaeological Site Atlas (TASA) and the National Park Service's National Register of Historic Places (NRHP).

Based on the desktop review, three archaeological sites potentially eligible for listing on the National Register were identified within 2.0-mile of the APE; however all the sites were located outside the APE. The new pipeline will be located entirely within the existing Joe Fulton International Trade Corridor which was previously surveyed in 2002. No cultural materials were identified along the Corridor.

EPA Region 6 determines that since there are no historic properties or archaeological resources located within the APE, issuance of the permits to CCI will not affect properties potentially eligible for listing on the National Register.

On April 28, 2014, EPA sent letters to Indian tribes identified by the Texas Historical Commission as having historical interests in Texas to inquire if any of the tribes have historical interest in the particular location of the project and to inquire whether any of the tribes wished to consult with EPA in the Section 106 process. EPA received no requests from any tribe to consult on this proposed permit. EPA will provide a copy of the report to the State Historic Preservation Officer for consultation and concurrence with its determination. Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on historic properties. A copy of the report may be found at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

III. Environmental Justice (EJ)

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

IV. Conclusion and Proposed Action

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

APPENDIX

Annual Facility Emission Limits

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

Table 1. Facility Emission Limits[1]

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
H-1	340-H1	Charge Preheater 1	CO_2	70,803	70,889	Minimum thermal efficiency of 85%. See permit condition III.B.1.o.
			CH_4	1.47		
			N_2O	0.17		
H-2	350-H1	Charge Preheater 2	CO_2	70,803	70,889	Minimum thermal efficiency of 85%. See permit condition III.B.1.o.
			CH_4	1.47		
			N_2O	0.17		
BL-1	240-B1	Boiler 1	CO_2	16,619	16,640	Minimum thermal efficiency of 85%. See permit condition III.B.2.f.
			CH_4	0.34		
			N_2O	0.04		
BL-2	240-B2	Boiler 2	CO_2	16,619	16,640	Minimum thermal efficiency of 85%. See permit condition III.B.2.f.
			CH_4	0.34		
			N_2O	0.04		
FL-1	330-FL-1	Flare	CO_2	2,165	2,316	Good combustion practices. See permit condition III.B.4.
			CH_4	5.99		
			N_2O	No Numerical Limit Established[4]		
FL-MSS	330-FL-1	Flare-MSS	CO_2	368	369	Good combustion practices. See permit condition III.B.4.
			CH_4	0.04		
			N_2O	No Numerical Limit Established[4]		
MVCU	150-FL2	Marine Vapor Combustion Unit	CO_2	29,023	29,116	Good combustion practices. See permit condition III.B.3.
			CH_4	1.12		
			N_2O	0.22		
EMGEN	EMGEN	Emergency Generator	CO_2	122	123	Limit hours of operation and good combustion practices. See permit condition III.B.6.
			CH_4	No Numerical Limit Established[4]		
			N_2O	No Numerical Limit Established[4]		
TK-MSS	Multiple FINS	Tank MSS (RTO emissions from tank degassing)	CO_2	37	37	Good combustion practices. See permit condition III.B.7.
			CH_4	No Numerical Limit Established[4]		
			N_2O	No Numerical Limit Established[4]		
FW-1	FW-1	Firewater Pump 1	CO_2	41	41	Limit hours of operation and good combustion practices. See permit condition III.B.6.
			CH_4	No Numerical Limit Established[4]		
			N_2O	No Numerical Limit Established[4]		

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
FW-2	FW-2	Firewater Pump 2	CO_2	41	41	Limit hours of operation and good combustion practices. See permit condition III.B.6.
			CH_4	No Numerical Limit Established[4]		
			N_2O	No Numerical Limit Established[4]		
FUGS	FUGS	Fugitives	CH_4	No Numerical Limit Established[5]	No Numerical Limit Established[5]	Implementation of LDAR Program. See permit condition III.B.3.
CWT	CWT	Cooling Tower	CH_4	No Numerical Limit Established[5]	No Numerical Limit Established[5]	Implementation of LDAR Program. See permit condition III.B.8.
WWTP	WWTP	Wastewater Treatment Plant	CH_4	No Numerical Limit Established[5]	No Numerical Limit Established[5]	Minimize VOC emissions. See permit condition III.B.9.
Totals[6]			**CO_2**	**206,641**	**CO_2e 207,771**	
			CH_4	**38**		
			N_2O	**0.64**		

1. Compliance with the annual emission limits (tons per year) is based on a 365-day total, rolled daily.
2. The TPY emission limits specified in this table are not to be exceeded for this facility and include emissions from the facility during all operations and include MSS activities.
3. Global Warming Potentials (GWP): CH_4 = 25 N_2O = 298
4. All values indicated as “No Numerical Limit Established” are less than 0.01 TPY with appropriate rounding. The emission limit will be a design/work practice standard as specified in the permit.
5. Fugitive process emissions from EPN FUGS are estimated to be 15.9 TPY of CH_4, and 398 TPY CO_2e. Cooling Tower emissions from EPN CWT are estimated to be 1.84 TPY of CH_4 and 46 TPY CO_2e. Wastewater Treatment Plant emissions from EPN WWTP are estimated to be 9.04 TPY of CH_4 and 226TPY CO_2e.
6. The total emissions for CH_4 and CO_2e include the PTE for process fugitive emissions of CH_4. These totals are given for informational purposes only and do not constitute emission limits.