Statement of Basis
For the
Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit

C3 Petrochemicals LLC

Permit Number: PSD-TX-1342-GHG

April 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 February 12, 2013, C3 Petrochemicals LLC (C3P) submitted to the Environmental Protection Agency (EPA) Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions to authorize the construction of a new propane dehydrogenation (PDH) plant to be located at an existing facility in Alvin, Brazoria County, Texas. On August 12, 2013, C3P submitted a revised application. On November 8, 2013, C3P submitted an addendum to its application. In connection with the same proposed project, C3P submitted a PSD and non-attainment new source review permit (NNSR) amendment application for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on January 25, 2013.

As part of the plant, C3P proposes to construct two boilers, two charge heaters, six interheaters, eight reactors, heat exchangers, a feed pretreatment unit, a coldbox, a fractionation unit, a pressure swing adsorption unit (PSA), catalyst regeneration towers, a cooling tower and a ground flare, along with associated piping, compression, treatment, and storage. After reviewing the application, the EPA Region 6 has prepared the following SOB and draft air permit that would authorize construction of air emission sources at the C3P plant.

This SOB provides the information and analysis used to support the EPA's decisions in drafting the air permit. It includes a description of the proposed plant, the air permit requirements based on best available control technology (BACT) analyses conducted on the proposed new units, and the compliance terms of the permit.

The EPA Region 6 concludes that C3P's application is complete and provides the necessary information to demonstrate that the proposed project meets the applicable air permit regulations. The EPA's conclusions rely upon information provided in the permit application, supplemental information requested by the EPA and provided by C3P, and the EPA's own technical analysis. The EPA is making all this information available as part of the public record.

II. Applicant

C3 Petrochemicals LLC
600 Travis, Suite 300
Houston, TX 77002-2931

Physical Address:

Located on FM 2917, approximately 8 miles south of the intersection of Texas Hwy. 35 and FM 2917, Alvin, Brazoria County, Texas

Contact:

Dale Borths
VP – Environmental, Safety, Security and Health
C3 Petrochemicals LLC
(256) 552-2204

III. Permitting Authority

On May 3, 2011, the EPA published a federal implementation plan (FIP) that makes the EPA Region 6 the PSD permitting authority for the pollutant the GHGs. See 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:

Bonnie Braganza
Air Permitting Section (6PD-R)
(214) 665-7340

IV. Facility Location

The facility is located in Brazoria County, Texas. Brazoria County is currently designated severe nonattainment for ozone, and is currently designated attainment for all other pollutants. The nearest Class I area, at a distance of more than 500 kilometers, is Breton National Wildlife Refuge. The geographic coordinates for this facility are as follows:

Latitude: 29°15’24” North Longitude: - 95º 15’52” West

Figure 1. C3 Petrochemicals Location

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

The EPA Region 6 concludes C3P's application is subject to PSD review for the pollutant GHGs because the project modifies an existing stationary source that emits or has the potential to emit 100,000 tpy CO_2e and would exceed the applicability threshold of 75,000 tons per year (tpy) carbon dioxide CO_2e as described at 40 CFR § 52.21(b)(49)(v)(b) and an emissions increase greater than zero tpy on a mass basis as described at 40 CFR § 52.21(b)(23)(ii) (C3P calculates CO_2e emissions of 796,288 tpy)[1]. As noted in Section III, the EPA implements a GHG PSD FIP for Texas under the provisions of 40 CFR § 52.21 (except paragraph (a)(1)). See 40 CFR § 52.2305.

As the permitting authority for regulated NSR pollutants that trigger the PSD (other than GHGs), the TCEQ has determined that the proposed project is subject to the PSD and non-attainment new source review (NNSR) for non-GHG pollutants, CO, $PM/PM_{10}/PM_{2.5}$ and NOx. The TCEQ has issued the PSD and the NNSR permit for the non-GHG pollutants. Accordingly, under the circumstances of this project, the EPA will issue the GHG portion.[2]

The EPA Region 6 applies the policies and practices reflected in the EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011). Consistent with that guidance, we have not required the applicant to model or conduct ambient monitoring for the GHGs, nor have we required any assessment of impacts of the GHGs in the context of the additional impacts analysis or Class I area provisions of 40 CFR § 52.21 (o) and (p), respectively. Instead, the EPA has determined that compliance with the BACT is the best technique that can be employed at present to satisfy additional impacts analysis and Class I area requirements of the rules as they relate to the GHGs. We note again, however, that the proposed project has regulated the NSR pollutants that are non-GHG pollutants, which will be addressed by the PSD permit to be issued by the TCEQ.

The following table indicates the emission units with the facility identification number (FIN) and the emission point numbers (EPN) that have been considered for this permit.

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[1] An existing unit at the barge loading dock is estimated to see an increase in the GHG emissions of 349 tpy CO_2e as a result of this modification, but is not being physically modified itself. As explained in the GHG Permitting Guidance, for the purposes of determining whether a PSD permits is required, the EPA requires a permitting authority to look beyond the emissions unit that is modified (across the entire source) to determine the extent of emission increases that result from the modification. However, the BACT applies only to the emission unit(s) that have been modified or added to the existing facility. See PSD and Title V permitting Guidance for Greenhouse Gases at 23. As a result, the additional GHG emissions from the barge loading dock have been included in calculating the total tpy CO_2e to determine the PSD applicability. We will not, however, conduct a BACT analysis for the barge loading dock as part of this permit.

[2] *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

FIN	EPN	Description
PDH-H101 PDH-H201	PDH-H101 PDH-H201	PDH Charge Heaters, H101 and H201. Each heater has a maximum design heat input rate of 126 MMBtu/hr, and will be equipped with a Selective Catalytic Reduction (SCR) system and low NOx burners.
PDH-H102 PDH-H202	PDH-H102 PDH-H202	PDH Inter-Heaters 1, H102 and H202. Each heater has a maximum design heat input rate of 135 MMBtu/hr, and will be equipped with a Selective Catalytic Reduction (SCR) system and low NOx burners.
PDH-H103 PDH-H203	PDH-H103 PDH-H203	PDH Inter-Heaters 2, H103 and H203. Each heater has a maximum design heat input rate of 96 MMBtu/hr, and will be equipped with a Selective Catalytic Reduction (SCR) system and ultra-low NOx burners.
PDH-H104 PDH-H204	PDH-H104 PDH-H204	PDH Inter-Heaters 3, H104 and H204. Each heater has a maximum design heat input rate of 78 MMBtu/hr, and will be equipped with a Selective Catalytic Reduction (SCR) system and ultra-low NOx burners.
PDH BOILER 1 PDH BOILER 2	PDH-BOILERS	Two boilers vented to a common stack, PDH Boiler 1 and PDH Boiler 2. Each boiler has a maximum design heat input rate of 615 MMBtu/hr, and will be equipped with a Selective Catalytic Reduction (SCR) system and ultra-low NOx burners.
CCR-1	CCR-1	Continuous Catalyst Regeneration Vent, Reactor Train 1
CCR-2	CCR-2	Continuous Catalyst Regeneration Vent, Reactor Train 2
PDH-FUG	PDH-FUG	Process Fugitives
PDH-FLARE	PDH-FLARE	PDH Flare (Combustion Unit), Routine Emissions
PDH-MSS	PDH-MSS	MSS Emissions
PDH-CT	PDH-CT	Cooling Tower

VI. Project Description

C3P seeks authority to construct a new PDH plant for the production of propylene. The plant will use propane as its primary raw material. As part of the plant, C3P proposes to construct two parallel trains, each consisting of a charge heater, three interheaters, four reactors, feed exchangers, and a catalyst regeneration tower. The project will also require construction of feed driers, pretreatment units, separation units, a pressure swing adsorption unit, a cooling tower, and a ground flare, along with piping, compression, treatment and storage.

Major sections of the PDH process for the proposed facility is shown in the block flow diagram and is summarized in this section. Further details on the process and drawings are available in the applications and other permitting documents.

Process Description: The dehydrogenation of propane occurs in the following stages:

Feed Pre-Treatment

Propane feedstock for the PDH plant will come from outside the battery limits (OSBL) of the Chocolate Bayou complex and will be stored in bullets. Before propane enters the PDH Reaction section of the unit, impurities and moisture are removed. Metals and sulfur compounds are removed via the use of guard beds. Moisture is removed from the propane feed via the use of feed driers. A small volume of waste water will be generated from the regeneration of the feed driers. This waste water will be hard-piped and transferred to the existing Ascend Chocolate Bayou waste water treatment plant.

Heavies Removal

After feed pre-treatment, propane feed is exchanged with hot reactor effluent to pre-heat the feed. The propane feed is then routed to a depropanizer column. Heavier components (primarily butane and heavier) are drawn off as bottom fraction (C4+ fraction). Butanes will be sold as product. Other residual from the bottom of the depropanizer column (C5+) will be stored as liquids. The storage tank for these liquids (FIN 320T-102) is vented to the flare (EPN PDH-FLARE). These liquids will be loaded into tank trucks and transported off-site for disposal. The overhead product (propane) from the depropanizer column is then cooled and routed to the separation section (Coldbox) of the process, where it is combined with recycle hydrogen and is exchanged against cold reactor effluent prior to use in the PDH reaction section.

PDH Reaction

The cooled propane feed from the separation section (Coldbox) is routed to the PDH reaction section. It is heated via the feed exchanger and then routed to the reactors. The dehydrogenation of propane to propylene takes place in two parallel reaction trains. Each reaction train consists of four reactors in series which utilize a proprietary catalyst. Each of these reactors will have an associated gas-fired heater. The heaters are identified as the Charge Heater (EPNs PDH-H101 and PDH-H201) prior to the first reactor, Inter-Heater 1 (EPNs PDH-H102 and PDH-H202) prior to the second reactor, Inter-Heater 2 (EPNs PDH-H103 and PDH-H203) prior to the third reactor, and Inter-Heater 3 (EPNs PDH-H104 and PDH-H204) prior to the fourth reactor.
In addition to the desired propylene product, other hydrocarbons such as ethane, ethylene, and methane are also produced. Effluent from each reaction train is routed to the reactor effluent compression and treating section of the plant. Emissions of NO_X produced in the charge heater

and three inter-heaters on each reactor train will be controlled via the use of ultra-low NO_X burners and selective catalytic reduction (SCR).

Continuous Catalyst Regeneration

The continuous catalyst regeneration (CCR) section of the PDH process is designed to replenish the catalyst's activity in a continuous operation. There is a CCR for each reactor train. In the regeneration towers, three of the four basic steps of the catalyst regeneration process take place. These are (1) burning of the coke, (2) removal of excess moisture, and (3) oxidation and dispersion of metal promoters. The coke burn step is a complete burn, leaving no VOCs or CO to be emitted to the atmosphere, and is the only step that has CO_2 emissions.

Coke (i.e. pure carbon) is formed in the reactors as an undesired byproduct of the reaction and is deposited on the catalyst over time. In the CCR, the coke is pure carbon fuel waiting to burn in the presence of heated air. Electric heated air is introduced into the CCR for spontaneous combustion and the CO_2 is released via the CCR stacks.

After leaving the regeneration tower, catalyst flows by gravity into a hopper. In the hopper, nitrogen and oxygen atmosphere from the regeneration tower is purged from the catalyst and the atmosphere is changed to a hydrogen atmosphere. The catalyst then flows by gravity to a lift engager, where high purity hydrogen is used to pneumatically lift the catalyst back to the top of Reactor No. 1.

At the top of Reactor No. 1, the catalyst enters the upper portion of the reactor. As it enters the upper portion of the reactor, the platinum on the catalyst is changed from its oxidized state (resulting from the carbon burning in the Regeneration Tower) to its reduced state by reaction with high temperature hydrogen, thus completing the fourth step of the catalyst regeneration process.

Reactor Effluent Compression and Treating

The hot reactor effluent from the fourth reactor is cooled with the reactor feed exchanger and compressed. It is then sent through a reactor effluent drier before entering the separation section. The dried, compressed reactor effluent is then sent to a cryogenic separation system to separate hydrogen and methane from heavier hydrocarbons. A heavy aromatic solvent (FIN 320T-101) is occasionally injected into this section of the process to minimize reactor effluent and reactor effluent compressor cooler fouling. Spent solvent generated as a result of this solvent injection is stored (FIN 320T-103) and subsequently loaded into tank trucks for off-site disposal. The heavy aromatic solvent tank and spent solvent tank both vent to the unit flare (EPN PDH-FLARE).

Gas Separation (Coldbox)

In the dehydrogenation process, hydrogen (H_2) is formed as a result of the main reaction of propane. The purpose of the gas separation section is to remove this hydrogen as well as methane from the heavier hydrocarbons by cryogenic gas separation (Coldbox).

The coldbox is utilized to separate uncondensable process gas components like hydrogen and methane from the propane and propylene hydrocarbon phase by partial condensation. The hydrocarbon phase is condensed. The hydrogen and methane remain in the gas phase. Hydrocarbons condensed in the gas separation step are sent to the fractionation section of the PDH unit. The gas phase from this step is sent to the hydrogen PSA unit. The only GHG emissions from the cold box are from the piping fugitives.

Fractionation

Lower hydrocarbons such as ethane and ethylene are also formed as by-products of the PDH process and condensed in the coldbox. The purpose of the fractionation section of the PDH unit is to remove these by-products from the desired propylene product by distillation. This section of the PDH unit consists of a selective hydrogenation process (SHP) reactor (for C3 diene removal), deethanizer, demethanizer, and propylene/propane splitter.

The purpose of the SHP reactor is to remove C3 dienes from the hydrocarbon liquid phase from the coldbox. This removal is accomplished by adding hydrogen from the PSA unit to selectively convert these C3 dienes to propylene. In the deethanizer, ethane, ethylene, and other light components are removed from the hydrocarbon liquid phase from the SHP reactor. The overhead vapors from the deethanizer go to the demethanizer. The bottom product from the deethanizer, consisting of a mixture of propylene and propane goes to the propylene/propane splitter. In the demethanizer, lighter components (primarily CH_4) are removed in the overhead stream and blended into the fuel gas system of the PDH unit. Heavier components (primarily ethane and ethylene) from the bottom of the demethanizer column are transported via pipeline to customers. In the propane/propylene splitter, propane is separated from the desired propylene product. Propylene is obtained as overhead product of the C3 splitter. Propane and traces of higher boiling components are removed as the bottom product of this splitter. This bottom product is recycled to the depropanizer column in the feed pre-treatment section of the PDH unit.

Hydrogen Pressure Swing Adsorption (PSA)

The hydrogen pressure swing adsorption unit takes feed from the gas separation section of the plant and, using a selective absorbent to produce saleable H_2 gas. This high-purity H_2 gas is also utilized in the CCR section of the plant as described previously and in the SHP section of the plant. The remaining tail gas from the PSA unit is blended into the fuel gas system of the PDH unit.

Raw Material and Product Storage

Primary feeds to the PDH process include propane, ammonia for the SCR units, solvent injection for the compression section of the plant, and caustic. Propane feed is stored in storage bullets prior to introduction into the PDH process. There will be no routine venting from these bullets. Each will be equipped with pressure safety valves (PSVs) that will vent to the flare. Anhydrous ammonia will be received via pipeline and stored in a pressurized storage vessel, with PSV venting to the flare. Organic liquids used in the process will be stored in vertical fixed roof tanks that vent to the PDH flare. Fresh caustic will be stored in vertical fixed roof tanks. Other chemicals on-site are those used for boiler feed water treatment and cooling water treatment. These are either stored in atmospheric tanks or isotainers.

Propylene product will be stored in a sphere and sold to customers. C_2 and H_2 products will also be transferred off-site via pipeline. C4 products will be stored in spheres and loaded into barges under a contract with Ascend. Barge loading and the flare associated with this barge loading is authorized by the TCEQ PBR Registration Number 77064 issued to Ascend. C5+ heavies from the process will be stored in a horizontal tank that vents to the PDH flare.

Raw Material and Product Loading/Unloading

VOCs unloaded at the PDH plant will be received via tank truck. Dry couplings or the equivalent will be used and unloading emissions controlled by the PDH flare. With the exception of C4, all products will be transferred from the PDH plant via pipeline. C4 will be loaded into barges as discussed in the previous section. There may be an increase in the GHG emissions as a result of barge loading operations but there will be no modification to the control device at the barge loading dock.

Fuel Gas System

The Fuel Gas System is utilized to provide fuel for combustion in the two PDH Reaction trains and steam generators. Fuels include natural gas and process fuel gases. The overhead from the demethanizer tower, and the tail gas from the PSA vent to the process fuel gas system. Additionally, any process vessel during maintenance could vent gases to the fuel gas system prior to flaring.

Steam Generation

Two boilers (FINs PDH BOILER 1 and PDH BOILER 2) will be used for steam generation at the PDH unit to produce high pressure (HP) steam for various heating purposes in the unit. They will utilize a combination of fuel gas generated by the process and natural gas. Emissions of oxides of nitrogen (NO_X) from these boilers will be controlled via the use of ultra-low NO_X burners and selective catalytic reduction (SCR). Both boilers will vent to a single SCR unit (EPN PDH BOILERS).

Cooling Water System

The PDH unit will utilize a single cooling tower (EPN PDH-CT). Several of the heat exchangers on the loop in VOC service will be operated with a water-side pressure that is less than the process-side pressure. Therefore, the cooling water system is considered to be a potential source of VOC, GHG and PM emissions.

Flare

The PDH plant will utilize one multi-stage ground flare (EPN PDH-FLARE) for the control of intermittent process and analyzer vent streams, emergency venting of pressure safety valves

(PSVs) in the PDH unit, and vents from the storage tanks. The flare also controls the VOC emissions from periodic maintenance, startup, and shutdown (MSS) events that require degassing of process equipment and piping. In addition to normal operation and MSS events, the flare is designed to control emissions from emergency releases. It is estimated that the emissions from the flare will be 620 TPY CO_2e for the EPN PDH-FLARE and PDH-MSS

Multi-stage flares are designed with several small burners that break the waste gas into many small flames. The first (low-pressure) stage is designed to be on line at all times. As pressure in the flare header increases and decreases, a PLC opens and closes additional staging valves. This keeps the waste gas exiting the burners at the proper velocity for smokeless operation. There is a continuous natural gas purge to the flare to maintain header velocity. In addition, the burners are designed to crosslight, thus minimizing the number of pilots necessary. Flare pilots are fueled by low-carbon pipeline natural gas and are in operation 8,760 hours per year. The flare will be subject to the TCEQ Highly Reactive Volatile Organic Compound (HRVOC, 30 TAC Chapter 115, subchapter H) and Federal 40 CFR §60.18 requirements. It will be designed to achieve a minimum destruction and removal efficiency of 98% for CH_4 and VOC.

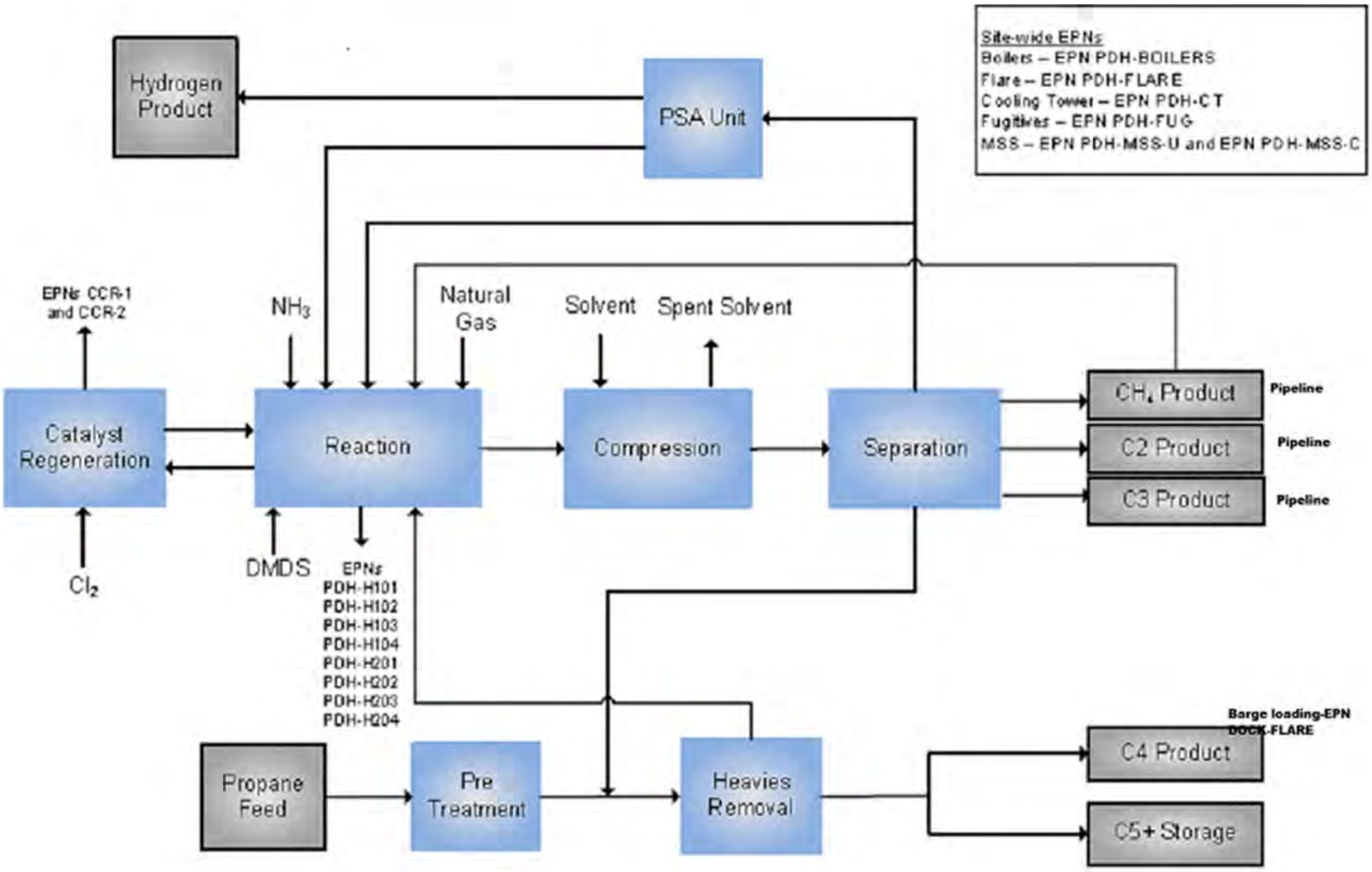
This multi-stage ground flare will comply with 40 CFR §60.18 requirements during normal, routine operations. For upset and high pressure conditions when the flare cannot comply with the provisions of 40 CFR §60.18, C3P will establish specific heating value and tip velocity standards and obtain the EPA Region 6 approval prior to operation of this flare for these purposes.

Wastewater Storage and Treatment

The PDH unit will generate three waste water streams. These are from regeneration of the propane feed dryer, regeneration of the reactor effluent dryer, and spent caustic from the CCR vent gas scrubber. As discussed previously, the waste water from all streams will be hard-piped to their ultimate disposition. Waste water from the regeneration of the reactor effluent dryer will be disposed in the existing deepwell disposal at the Ascend Chocolate Bayou plant. The other two waste water streams will be treated in the existing Chocolate Bayou waste water treatment plant.

Routine Maintenance, Startup, and Shutdown Activities

Planned and predictable MSS activities at the PDH unit will be conducted in a way that will minimize emissions to the atmosphere. This will generally be accomplished by clearing equipment before line openings or vessel opening. Where feasible, this equipment will be cleared back to the process or routed to the process flare. These MSS emissions are identified as the EPN PDH-MSS**.**


Site-wide EPNs
Boilers – EPN PDH-BOILERS
Flare – EPN PDH-FLARE
Cooling Tower – EPN PDH-CT
Fugitives – EPN PDH-FUG
MSS – EPN PDH-MSS-U and EPN PDH-MSS-C
Hydrogen Product
PSA Unit
EPNs CCR-1 and CCR-2
NH3
Natural Gas
Solvent
Spent Solvent
Catalyst Regeneration
Reaction
Compression
Separation
CH4 Product
Pipeline
C2 Product
Pipeline
C3 Product
Pipeline
Cl2
DMDS
EPNs
PDH-H101
PDH-H102
PDH-H103
PDH-H104
PDH-H201
PDH-H202
PDH-H203
PDH-H204
Barge loading-EPN DOCK-FLARE
Propane Feed
Pre Treatment
Heavies Removal
C4 Product
C5+ Storage

VII. General Format of the BACT Analysis

The BACT analyses for this draft permit were conducted in accordance with the EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011), which outlines the steps for conducting a "top-down" BACT analysis. Those steps are listed below.

(1) Identify all potentially available control options;
(2) Eliminate technically infeasible control options;
(3) Rank remaining control technologies;
(4) Evaluate the economic, energy, and environmental impacts; and
(5) Select BACT.

VIII. Applicable Emission Units

Most of the GHG associated with the proposed project are from combustion sources (i.e., heaters and boilers). The site also has fugitive emissions from piping components, CCR vents, a flare, and a cooling tower which contribute small amount of GHG emissions. The combustion units (i.e. heaters, boilers, and flare) primarily emit carbon dioxide (CO_2), and small amounts of nitrous oxide (N_2O) and methane (CH_4). The CCR vents emit CO_2 and the process fugitives and cooling tower emit CH_4. The following devices are subject to this GHG PSD permit:

- Charge Heaters (EPNs: PDH-H101 and PDH-H201)
- Inter-Heaters (EPNs: PDH-H102, PDH-H202, PDH-H103, PDH-H203, PDH-H104, and PDH-H204)
- Boilers (EPN: PDH-BOILERS)
- Continuous Catalyst Regeneration Vents (EPNs: CCR-1 and CCR-2)
- Flare (EPN: PDH-FLARE)
- Process Fugitives (EPN: PDH-FUG)
- MSS Emissions (EPN: PDDH-MSS)
- Cooling Tower (PDH-CT)

It should be noted that all the pumps and compressors to process and move products in the PDH plant are electric driven, unlike other PDH plants (See Enterprise Products proposed PSD-TX-1336-GHG, and issued PL Propylene LLC, PSD- TX -18999-GHG).

IX. BACT Analyses

As part of the PSD review, C3P provided in the GHG permit application a 5-step top-down BACT analysis for the emission units covered by the proposed GHG PSD Permit. The EPA has reviewed this BACT analysis for the applicable emission units, and also provides its own analysis in setting forth BACT for this proposed permit, as summarized below.

A. Post Combustion BACT Analysis Carbon Capture System for Process Heaters and Boilers (EPNs: PDH-H101, PDH-201, PDH-H102, PDH-H103, PDH-H104, PDH-H202, PDH-203, PDH-204, PDH BOILER 1, and PDH BOILER 2)

In lieu of considering the CCS as an add-on control technology for CO_2 emissions as part of the BACT analysis for each of the combustion related emission unit sources, we are considering it here as an add-on pollution control technology for all combustion emission unit types for the proposed project because, if the CCS were applied, the project would route all recovered CO_2 into a common compression and transport network. Control technologies such as design and work practice standards will be discussed later in this section.

Step 1 – Identification of Potential Post Combustion Control Technologies for the GHG.

Carbon Capture and Sequestration (CCS)

The CCS is classified as an add-on pollution control technology, which 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. The CCS is generally applied to "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)."[3]

The 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 the CCS are pre-combustion capture, post-combustion capture, and oxyfuel combustion (IPCC, 2005). Of these approaches, pre-combustion capture is applicable primarily to gasification plants, where solid fuel such as coal is converted into gaseous components by applying heat under pressure in the presence of steam and oxygen (U.S. Department of Energy, 2011). At this time, oxyfuel combustion has not yet reached a commercial stage of deployment for gas turbine applications and still requires the development of oxy-fuel combustors and other components with higher temperature tolerances (IPCC, 2005). Accordingly, pre-combustion capture and oxyfuel combustion have no practical application for this proposed PDH facility. The third approach, post-combustion capture, is applicable to the proposed process heaters and boilers.

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

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

monoethanolamine (MEA) is currently the preferred option because it is the most mature and well-documented technology (Kvamsdal et al., 2011), and because it offers high capture efficiency, high selectivity, and the lowest energy use compared to the other existing processes (IPCC, 2005). Post-combustion capture using MEA is also the only process known to have been previously demonstrated in practice on gas turbines (Reddy, Scherffius, Freguia, & Roberts, 2003). As such, post-combustion capture using MEA is the sole carbon capture technology considered in this BACT analysis.

A number of specific methods may potentially be used for separating (capturing) the CO_2 from the exhaust gas stream post combustion, including adsorption, physical absorption, chemical absorption, cryogenic separation, and membrane separation.[4] Many of these methods are either still in development or are not suitable for treating process heater and boiler exhaust gases due to the characteristics of the exhaust stream[5] (also, Wang et al., 2011). Of the emerging CO_2 post combustion capture technologies, MEA (amine) absorption is the most commercially developed for state-of-the-art large scale CO_2 separation processes.

In a typical MEA absorption process, the flue gas is cooled before it is contacted counter-currently with the lean solvent in a reactor vessel. The scrubbed flue gas is cleaned of solvent and vented to the atmosphere, while the rich solvent is sent to a separate stripper where it is regenerated at elevated temperatures and then returned to the absorber for re-use. Fluor's Econamine FG Plus process operates in this manner, and it uses an MEA-based solvent that has been specially designed to recover CO_2 from oxygen-containing streams with low CO_2 concentrations typical of gas turbine exhaust (Fluor, 2009). This process has been used successfully to capture 365 tons per day of CO_2 from the exhaust of a natural gas combined-cycle plant owned by Florida Power and Light in Bellingham, Massachusetts. The CO_2 capture plant was maintained in continuous operation from 1991 to 2005 (Reddy, Scherffius, Freguia, & Roberts, 2003).

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

Step 2 – Elimination of Technically Infeasible Alternatives

The EPA generally considers a technology to be 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.

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[4] *CO_2 Capture by Solid Adsorbents and Their Applications: Current Status and New Trends*, Qiang Wang, et.al, Energy & Environmental Science, April 2011.

[5] International Panel on Climate Change (IPCC), *Carbon Dioxide Capture and Storage*, Cambridge University Press September 2005.

While post combustion CO_2 capture technology has been demonstrated in practice on steam methane reformers at a refinery,[6] it has not been demonstrated in practice on reactor heaters and boilers in chemical plants.

The EPA is evaluating whether there is sufficient information to conclude that the CCS is technically feasible for this reactor heaters and boilers at the C3P PDH plant and will consider public comments on this issue. However, because the applicant has provided a basis to eliminate the CCS on other grounds, we have assumed, for purposes of this specific permitting action, that the potential technical or logistical barriers do not make the CCS technically infeasible for this project and we are therefore evaluating the economic, energy, and other environmental impacts of the 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. C3P estimates that the CCS would reduce GHG emissions (CO_2) from the heaters and boilers by 715,084 tpy,[7] based on a 90% capture efficiency.

Step 4 – Evaluation of Economic, Energy, and Environmental Impacts

C3P developed a site-specific cost analysis for post-combustion the CCS that provided the basis for eliminating the technology in step 4 of the BACT analysis. The *Report of the Interagency Task Force on Carbon Capture and Storage (August 2010)* was used as the basis for determining these site-specific costs. The EPA Region 6 reviewed C3P's CCS cost estimate and believes it adequately approximates the annual cost of a CCS control for this project.

The projected capital cost of CCS at C3P PDH plant is $858 million. See Appendix B for the cost estimates that were based on a 2010 Report of the Interagency Task Force on Carbon Capture and an assumed 90% capture of CO_2 emissions. On an annualized basis, the cost of installing and operating the CCS is $81 million. The majority of this annual cost is attributed to the capture and compression facilities that would be required for the facility (approximately $74 million). The estimated average annual cost for CO_2 transport and storage, based on the calculation methodology selected, are $0.3 million and $6.7 million respectively. The estimated cost of the CCS will increase the capital cost of the PDH project by $858 million, or approximately 71%. The EPA agrees that this increase in project cost is substantial and that the CCS should be rejected as the BACT on economic grounds.

Economic infeasibility notwithstanding, C3P also asserts that the CCS can be eliminated as the BACT based on the environmental impacts from a collateral increase of National Ambient Air Quality Standards (NAAQS) pollutants. Implementation of the CCS would increase emissions of

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[6] A fact sheet on the project, with additional links to project information can be found at https://sequestration.mit.edu/tools/projects/port_arthur.html.

[7] This reduction does not take into account the additional 178,700 tons CO_2 that would be emitted by the new boiler which would result in an additional 17,870 tons of CO_2 (the 10% that is not captured by CCS) being released.

NO_X, CO, VOC, PM_{10}, SO_2, and ammonia by as much as 13-17%.[8] The proposed plant is located in the Houston, Galveston, and Brazoria (HGB) area of ozone non-attainment and the generation of additional NO_X and VOC could exacerbate ozone formation in the area. Since the project is located in an ozone non-attainment area, energy efficient technologies are preferred over add-on controls such as the CCS that would cause an increase in emissions of NO_X and VOCs to the HGB non-attainment area airshed. The EPA has reviewed C3P's analysis and agrees that these other environmental factors resulting from the installation and operation of a CCS system further support the rejection of the CCS as the BACT for this proposed project.

Step 5 – Selection of BACT

See Section B for the additional BACT analysis for the Heaters (FINs/EPNs: PDH-H101, PDH-H102, PDH-H103, PDH-H104, PDH-H201, PDH-H202, PDH-H203, PDH-H204) and Section C for the additional BACT analysis for the Boilers (EPN: PDH BOILERS).

B. Process Heaters (FINs/EPNs: PDH-H101, PDH-H102, PDH-H103, PDH-H104, PDH-H201, PDH-H202, PDH-H203, PDH-H204)

The plant's process heaters supply heat for the two trains of reactors used in the dehydrogenation process. The first heaters in each train (PDH-H101 and PDH-H202) are charge heaters supporting the first reactor, and the remaining heaters (PDH-H102, PDH-H103, PDH-H104, PDH-H202, PDH-H203, and PDH-H204) are interheaters placed between the subsequent reactors. These heaters will utilize a combination of natural gas and process gas. The process gas generated by the PDH process includes PSA tail gas, deethanizer overheads, and demethanizer overheads. Consistent with representations made by the technology vendor, these heaters will be designed and operated to achieve a maximum thermal efficiency of 87%, given the planned use of the SCR.

Step 1 – Identification of Potential Control Technologies for the GHGs

- *Use of Low Carbon Fuels* – Combustion of any carbon-containing fuel will produce GHG emissions. Of the fuels typically used by industrial processes (coal, fuel oil, natural gas, and process fuel gas), natural gas is the lowest carbon fuel that can be burned. Fuels used by the proposed PDH unit include natural gas and process gas. The alternative means for disposing of this process gas is in a flare, which would result in the same amount of GHG emissions. If the process gas is flared, more natural gas would be required for the heaters to replace the fuel value of this gas. Therefore, using the process gas as fuel is an effective means of reducing overall plant GHG emissions.
- *Heater Design* – New heaters can be designed with a number of features to improve efficiency by minimizing heat loss and increasing overall thermal efficiency. Design features that improve overall thermal efficiency include efficient burners and refractory and insulation materials on surfaces to minimize heat loss, as well as recovery of hot

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[8] 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

condensate, minimization of steam vents, and use of an economizer to preheat boiler feed water streams.

- *Heater Air/Fuel Control* – Complete combustion can be achieved with the use of 2-3% oxygen. Controlling the air to fuel ratio to maintain this oxygen level in a heater is effective in reducing emissions from overuse of excess air. This level can be maintained with the use of exhaust gas oxygen analyzers, which provide real-time readings of oxygen levels in the exhaust gas.
- *Periodic Tuning* – Equipment will be maintained appropriately in order to maintain maximum efficiency. As part of the maintenance activity, the combustors are tuned to restore highly efficient low-emission operation. These periodic tune-ups of the heaters include:

    - Preventive maintenance check of the fuel gas flow meters annually;
    - Preventive maintenance check of excess oxygen analyzers quarterly;
    - Cleaning of burner tips as needed; and
    - Cleaning of convection section as needed.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible for controlling the GHG emissions from the process heaters.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- *Use of Low Carbon Fuels* – up to 100% for fuels containing no carbon;
- *Heater Design*- 10%;
- *Heater Air/Fuel Control – 5-25%; and*
- *Periodic Tuning* – 2-10%.

The combination of all the above controls are being proposed by the applicant.

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

The EPA has not identified any negative economic, energy, or environmental impacts associated with these control options.

Step 5 – Selection of BACT

C3P will utilize all of the technologies listed in Step 1. The heater design and heater air/fuel ratio control are described in the section below.

BACT Limits and Compliance:

The GHG BACT limits for similar facilities utilizing heaters with the reaction system are summarized in the table below.

Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
PL Propylene LLC Houston, TX	Propane Dehydrogenation Plant	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT for Regeneration Air Heater – Maintain firebox temperature of >1,000 °F	2013	PSD-TX-18999-GHG
DCP Midstream NGL Fractionation Plant Beaumont, TX	Hot Oil Heaters, 179 MMBtu/hr and Regeneration Heaters, 36 MMBtu/hr	Low Carbon Fuels; Efficient Process Controls, Good Combustion Practices, and Scheduled Maintenance	Minimum thermal efficiency of 85% for hot oil heaters. Minimum thermal efficiency of 80% for regeneration heaters; also limited to 6,000 hrs/yr	2013	PSD-TX-110557-GHG
KM Liquid Terminals Galena Park, TX	Hot Oil Heaters	Low Carbon Fuels; Good Combustion and Operating Practices; Energy Efficient Design	Minimum thermal efficiency of 85%	2013	PSD-TX-101199-GHG
Enterprise Products Operating LLC, Eagleford Fractionation and DIB Units Mont Belvieu, TX	NGL Fractionation	Energy Efficiency/ Good Design & Combustion Practices	Hot Oil Heaters (140 MMBtu/hr) BACT 85% thermal efficiency. Regenerant heaters (28.5 MMBtu/hr) BACT is good operating and maintenance practices.	2012	PSD-TX-1286-GHG

C3P selected an energy efficient design to optimize heat, fuel, and overall energy efficiency. As a result, less energy is consumed per pound of product produced and less CO_2 is generated. The process heaters for each reactor train will be operated as a unit. Therefore, an aggregate BACT limit is appropriate. The BACT for this train consists of the following practices, and a proposed BACT limit of 87% thermal efficiency, which is more efficient than some heaters previously permitted by the EPA Region 6. Each process heater reactor train will be permitted with an emission limit of 230,308 TPY CO_2e based on a 12-month rolling average.

BACT Compliance:

- Heater/thermal efficiency will be calculated for the 4 heaters in each reactor train as a group because the heaters function as a unit with common steam and burner management systems. Efficiency will be calculated by totalizing the fuel to the four heaters in each reactor train to determine heat input and the heat added to the process in each heater combined with the steam production to determine heat recovery. Heater monitoring will include CEMS for NO_X, CO, and excess oxygen; and monitoring of the firebox temperature for each heater, monitoring of the fuel flow rate to the heaters, the process flow rate, and process temperatures to and from each heater.
- The exhaust gas will be continuously monitored with an O_2 analyzer that meets the EPA specifications in 40 CFR 60, Appendix B, Spec. 3 to be within the range of 2-3% oxygen
- Thermal efficiency will be calculated using the parameters described above and equation G-1 from the American Petroleum Institute (API) methods 560 (4th ed.) Annex G and will be 87% on a 12 month rolling average.
- C3P will maintain records of heater tune-ups, burner tip maintenance, and O_2 analyzer calibrations and maintenance for all heaters. In addition, records of fuel usage and stack exhaust temperature will be maintained.
- C3P will demonstrate compliance with the CO_2 limit for the heaters based on metered fuel consumption, the emission factor for natural gas from 40 CFR Part 98 Subpart C, Table C-1, and equation C-5, converted to short tons.
- C3P will also calculate the CH_4 and N_2O emissions based on the default emission factors contained in 40 CFR Part 98 Subpart C, Table C-2 and equation C-8b, converted to short tons.
- The CO_2e emissions will be based on procedures and Global Warming Potentials (GWP) contained in 40 CFR Part 98, Subpart A, Table A-1 (78 FR 71904) for each pollutant. The relevant GWP values include: $CH_4 = 25$; $N_2O = 298$. The CO_2e mass emissions will be calculated on a monthly basis and divided by the tons of propylene produced during the month. The resulting quotient is added to the 12-month rolling average and compared to the BACT requirement to determine compliance with the BACT limit.
- As an alternative, C3P may install, calibrate, and operate a CO_2 CEMS and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording the CO_2 emissions. If this alternative is selected, the calculations shall be in accordance with the methodologies provided in 40 CFR § 98.33(a) (4).

C. Boilers (FIN/EPN: PDH BOILER 1/PDH BOILERS, PDH BOILER 2/PDH BOILERS)

C3P has determined that steam production will be needed for the project. Two new high pressure gas-fired boilers are proposed to be constructed as part of the project. The one-hour maximum firing rate for each boiler is 644 MMBtu/hr.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Use of Low Carbon Fuels* – Combustion of any carbon-containing fuel will produce GHG emissions. Of the fuels typically used by industrial processes (coal, fuel oil, natural gas, and process fuel gas), natural gas is the lowest carbon-containing fuel that can be burned. Fuels used by the proposed PDH unit include natural gas and process gas. The process gas generated by the PDH process includes PSA tail gas, Deethanizer overheads, and Demethanizer overheads. The alternative means for disposing of this process gas is destruction in a flare, which would result in the same amount of GHG emissions. If the process gases are flared, more natural gas would be required for the boilers to replace the fuel value of these gases. Therefore, using them as fuel is an effective means of reducing overall plant GHG emissions.
- *Energy Efficient Boiler Design* – New boilers can be designed with a number of features to improve efficiency by minimizing heat loss and increasing overall thermal efficiency. Operating a boiler at near steady state conditions allows it to achieve maximum efficiency. Design features that improve overall efficiency include efficient burners, and refractory and insulation materials on surfaces to minimize heat loss.
- *Operation and Maintenance Procedures* - Energy efficiency measures in boilers is provided in the document titled: Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy and Plant Managers (Environmental Energy Technologies Division, University of California, sponsored by USEPA, June 2008).[9] The periodic tune-ups of the boilers include:

    - Calibration of the fuel gas flow meters;
    - Preventive maintenance check of the excess oxygen analyzers;
    - Cleaning of the burner tips as needed;
    - Cleaning of the convection section as needed;
    - Fuel/air control with the assistance of oxygen trim controls; and
    - Blowdown steam recovery and minimization of steam vents.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible for controlling GHG emissions from the boilers.

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[9] Neelis, Maartin. (2008). Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry – An ENERGY STAR(R) Guide for Energy and Plant Managers. Lawrence Berkeley National Laboratory: Lawrence Berkeley National Laboratory. Retrieved from: http://escholarship.ucop.edu/uc/item/8dg961x6

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- *Use of Low Carbon Fuels*- Up to 100% for fuels containing no carbon;
- *Energy Efficient Boiler Design* – 6-26%; and
- *Operating and Maintenance Practices* - up to 10% and it should be noted that the fuel/air control results in 1% less GHG emissions for every 15% reduction in excess air.

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

The EPA has not identified any negative economic, energy or environmental impacts associated with the control options in Step 1.

Step 5 – Selection of BACT

C3P will utilize all of the technologies listed in Step 1. The boiler design and operating and maintenance procedures are listed below.

Steam is used throughout industrial sources and is typically generated by boilers and waste heat recovery units. Use of low carbon fuels, efficient boiler design with good operating, and maintenance procedures are all considered effective and have a range of efficiency improvements for steam boiler units that cannot be directly quantified.

Energy efficiency measures in boilers is provided in the document titled: Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy and Plant Managers (Environmental Energy Technologies Division, University of California, sponsored by USEPA, June 2008).[10] The table 2 below is from this report and addresses improvement measures and the estimated associated efficiency improvements that can be realized.

The GHG BACT limit for permits issued and for known technologies on industrial boilers for recent issued permits are summarized in the table below. The EPA has also conducted a search of available energy efficiency measures and limits and has determined the BACT for the boilers. It should be noted that the only comparable boiler for pressures of 1200 psig or greater is the Chevron Permit in which the BACT is determined to be to be 77% thermal efficiency. C3P BACT thermal efficiency is set at a higher standard of 82%.

Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
ExxonMobil Chemical Company	Boilers, 98 MMBtu/hr	Low Carbon Fuels; Good Combustion	Minimum Thermal	2013	PSD-TX-103048-GHG

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[10] Neelis, Maartin. (2008). Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry – An ENERGY STAR(R) Guide for Energy and Plant Managers. Lawrence Berkeley National Laboratory: Lawrence Berkeley National Laboratory. Retrieved from: http://escholarship.ucop.edu/uc/item/8dg961x6

Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
Mont Belvieu, TX		and Operating Practices; Energy Efficient Design	Efficiency of 77%		
PL Propylene LLC Houston, TX	Waste Heat Boiler	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT for Waste Heat Boiler –117 lb CO_2/MMBtu heat input	2013	PSD-TX-18999-GHG
BASF Fina Petrochemicals	425.4 MMBtu/hr Steam Package Boilers located at an existing ethylene cracking process	Energy Efficiency/ Good Design and Combustion Practices	421,399 TPY CO_2e/ Minimum Thermal Efficiency of 77%	2012	PSD-TX-903-GHG
Iowa Fertilizer Company	472.4 MMBtu/hr Auxiliary Boiler	Energy Efficiency; Good Design and Combustion Practices	51,748 TPY CO_2e, 117 lb CO_2/MMBtu on a 30-day rolling average	2012	56-10-001
Chevron Phillips Chemical Company Baytown, TX	Very High Pressure Boiler (1200psig and (500 MMBtu/hr)	Low Carbon Fuels; Good Combustion and Operating Practices; Energy Efficient Design	Minimum Thermal Efficiency of 77%.	2013	PSD-TX-748-GHG
Rohm and Haas, Texas, Inc. Deer Park, TX	2 new 515 MMBtu/hr boilers	Energy Efficiency/ Good Design & Combustion Practices	117.12 lb CO_2/MMBtu (HHV) on a 12-month rolling basis for each boiler	2013	PSD-TX-1320-GHG

The C3P has selected an energy efficient design and features for the boilers as indicated in the GHG PSD Permit Application (revised July 2013) at 41. The design and good operating and maintenance procedures will meet the thermal efficiency of 82% based on a 12 month rolling average and a 12 month rolling average CO_2e of 330,053 tpy.

BACT Compliance:

- Boiler thermal efficiency will be calculated by determining the natural gas and/or fuel gas fed to the boilers and the steam produced using boiler feed water meters less blowdown.
- Boiler monitoring will include CEMS for NO_X, CO, and excess oxygen; and monitoring of the firebox temperature for each boiler, monitoring of the fuel flow rate to the boilers, and the process flow rate, monitoring the exhaust temperature, fuel temperature, and ambient temperature.
- Thermal efficiency will be calculated using the parameters described above and equation G-1 from American Petroleum Institute (API) methods 560 (4th ed.) Annex G. Thermal efficiency will be based on a 12 month rolling average to be greater than 82%.
- For the boilers, the C3P will maintain records of heater tune-ups, burner tip maintenance, O_2 analyzer calibrations, and maintenance for the new steam boiler. In addition, records of fuel usage, and stack exhaust temperature will be maintained.
- C3P will demonstrate compliance with the CO_2 limit for the boilers based on metered fuel consumption, the emission factor for natural gas from 40 CFR Part 98 Subpart C, Table C-1, and equation C-5, converted to short tons.
- C3P will also calculate the CH_4 and N_2O emissions based on the default emission factors contained in 40 CFR Part 98, Table C-2 and equation C-8b, converted to short tons.
- The CO_2e emissions will be based on procedures and Global Warming Potentials (GWP) contained in the 40 CFR Part 98, Subpart A, Table A-1, (78 FR 71904) for each pollutant. The relevant GWP values include: CO_2 =1; CH_4 = 25; N_2O = 298.
- The CO_2e mass emissions will be calculated on a monthly basis and divided by the lbs of steam produced during the month. The resulting quotient is added to the 12-month rolling average and compared to the BACT requirement to determine compliance with the BACT limit. Records of the calculations will be required to be kept on-site and made readily available for inspection to demonstrate compliance with the BACT emission limits on a 12-month rolling average for the CO_2e limit.
- As an alternative, C3P may install, calibrate, and operate a CO_2 CEMS and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording CO_2 emissions. If this alternative is selected, the calculations shall be in accordance with the methodologies provided in 40 CFR § 98.33(a) (4).
- An initial stack test demonstration will be required for CO_2 emissions from the new steam boilers. 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 boilers and are considered a de minimis level in comparison to the CO_2 emissions.

D. Ground Flare (EPN: PDH-FLARE)

The GHG emissions from the flare (EPN PDH-FLARE) consist primarily of CO_2. Routine emissions are generated from the combustion of the natural gas pilots used to maintain the required minimum heating value to achieve adequate VOC destruction as in 40 CFR 60.18. Other routine vents to the flare are from the PDH units, analyzers and from the storage tanks.

The multi-state flare is also designed to accept a major emergency episode (upset) and for periodic MSS activities.

Step 1 – Identification of Potential Control Technologies for GHGs

- Install a flare gas recovery device (FGR);
- Flare design;
- Flare Minimization- Minimize the quantity and duration of VOC material vented; and
- Good Combustion practices.

Step 2 – Eliminate Technically Infeasible Options

The FGR can be sized to recover the continuous expected vent streams to the flare not currently recovered and recycled internally, such as analyzer vents, leakages from pressure relief valves, and storage tank vents. However, there are inherent safety reasons for not using the FGR for this plant. If there is a major relief episode, it would disrupt the compositions and flow to the FGR, resulting in a plant process upset that would subsequently result in increased flaring to manage the event. A relief episode has unpredictable flow and composition. Therefore the flare recovery device has been eliminated in this step.

Flare minimization, Flare design, and Good combustion practices are all considered to be technically feasible options.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

C3P will utilize the technically feasible technologies described above. Therefore it is not necessary to rank them.

Step 4 – Economic, Energy, and Environmental Impacts

The EPA has not identified any negative economic, energy, or environmental impacts associated with the control options in Step 1.

Step 5 – Selection of BACT

- The EPA has reviewed the C3P's analysis and concurs with C3P that flare design, flare minimization that consists of minimizing the quantity and duration of the VOC material vented, and good combustion practices are BACT.

The flare design and operating practices are described in further detail here.

Flare Design – C3P proposes the following elements of good flare design to optimize combustion efficiency and minimize emissions.

- Multi-stage ground flare with 11 stages, with 2 pilots. Burners in this flare are designed to crosslight, thus minimizing the number of pilots necessary.

- The flare will incorporate the latest burner design and combustion temperature control to minimize NO_X formation while, at the same time, maximizing the VOC control efficiency.

Flare Minimization – C3P will implement the following measures:

- Utilize process off-gases as fuel for boilers and heaters;
- Utilize PDH process controls to minimize upset conditions; and
- Clear equipment to storage as possible to minimize the quantity of the VOC materials vented to the flare during the MSS activities.

Good Combustion Practices – C3P will implement the following measures:

- Use of flow meters and gas composition monitors on the flare gas lines to improve flare gas combustion and optimize flare combustion efficiency.
- The flow meter and analyzers used for flare compliance will be operational at least 95% of the time when waste gas is being sent to the flare, averaged over a calendar year. The flow meter will be calibrated biannually.
- Continuous monitoring of the flare pilot.

The BACT limit for the flare will be 620 tpy CO_2e emissions from the PDH vents, relief valves and during the MSS activities.

E. Continuous Catalyst Regeneration (CCR) Vents (EPNs: CCR-1 and CCR-2)

The CCR section of the PDH process is designed to replenish the catalyst's activity in a continuous operation by burning off the coke deposits. The CCR vents (one for each reaction section) contribute approximately 0.58% of the total quantities of CO_2 from the PDH plant.

Step 1– Identification of Potential Control Technologies for GHGs

The CCR is an essential process unit in the PDH plant operations. The only GHG control option is:

- Good process design technology. The proprietary design and catalyst technology used by the C3P PDH plant minimizes the coke formation on the catalyst, providing for maximum heat transfer in the catalyst and minimizing associated emissions. Also the use of a nitrogen purge instead of steam minimizes the energy and results in lower GHG emissions.

Step 2 – Eliminate Technically Infeasible Options

Good process design technology is considered technically feasible for controlling GHG emissions from the CCR vents.

Step 3 – Rank Remaining Control Technologies

The applicant has proposed to use good process design technology for the CCR vent.

Step 4 – Economic, Energy and Environmental Impacts

The EPA has not identified any negative economic, energy, or environmental impacts associated with the good process control options in Step 1.

Step 5 – Selection of BACT

The EPA has reviewed C3P's analysis and concurs with C3P that the use of good process design technology is considered BACT for the CCR vents.

BACT compliance for the CCR Vents

- Use of N_2 purge in the CCR; and
- 4,636 tpy CO_2e emissions limit based on a 12 month rolling average.

F. Cooling Tower (EPN-CT)

The construction of the PDH plant will include one cooling tower for process cooling water service. The majority of cooling service provided by the cooling tower will be for processes containing VOC. Three cooling water services with small quantities ($\leq$ 5%) of methane (CH_4) in the process stream have also been identified. The cooling water services that contain CH_4 also contain VOC in the process gas. In most cases, the VOC in these process streams include propylene, a highly reactive VOC (HRVOC). C3P will implement a monitoring program for the cooling tower in accordance with the TCEQ HRVOC rules and will maintain records of this monitoring in compliance with these rules.

Step 1 – Identify All Available Control Technologies

The control options for VOC/GHG emissions from cooling towers include

- Non-contact design with the use of heat exchangers;
- Use of heat exchangers for which the water-side pressure is greater than the process side pressure; and
- Implementation of a leak detection and repair program.

Step 2 – Eliminate Technically Infeasible Options

All of the options in Step 1 are considered technically feasible for controlling the VOC/GHG emissions from the cooling tower.

Step 3 – Rank Remaining Control Technologies

The applicant will use all the above control technologies and therefore ranking is not necessary.

Step 4 – Evaluate Economic, Energy, and Environmental Impacts

The EPA has not identified any negative economic, energy, or environmental impacts associated with the control options in Step 1.

Step 5 – Select BACT

- Non-contact design with the use of heat exchangers.

The cooling water loop will include a number of heat exchangers that are non- contact design with the cooling water.

- Use of heat exchangers for which the water-side pressure is greater than the process side pressure.

Wherever possible in the operation of the plant, the cooling water service will operate with the water-side pressure greater than the process side pressure and as such, any leak in the exchanger would result in the leak of cooling water into the process and would not result in VOC/GHG emissions.

- Implementation of a leak detection and repair program

For heat exchangers that operate with the process-side pressure greater than the water-side pressure may leak the process gas to the cooling tower. To control the VOC/GHG emissions from the cooling tower, C3P will monitor the cooling tower return water on a monthly basis, using the TCEQ sampling methodology for cooling tower, (specified in the permit) assuming all the VOC is stripped out in the cooling tower. Any leaks identified will be repaired as soon as possible.

<u>BACT compliance for the cooling tower.</u>

- The C3P heat exchange system will also be subject to the continuous HRVOC monitoring requirements of 30 TAC §115.764(a). These requirements will include the installation/operation of continuous flow monitors on each cooling tower inlet and of continuous strippable VOC concentration monitors on each cooling tower inlet.
- A plant shutdown will be triggered by a cooling water VOC concentration of 0.08 ppmw VOC or greater.

G. Fugitives from Equipment

The proposed PDH plant will have some piping fugitives that estimated to consist of approximately 0.15 TPY CH_4 emissions and less than 0.001 CO_2 (3.77 CO_2e). This is less than 0.0004% of the total GHG emissions from the PDH plant.

Step 1 – Identify Available Control Technologies

Piping fugitives may be controlled by various techniques, including:

- Leakless technology to eliminate fugitive emissions sources is an expensive design option usually reserved for toxic and hazardous gases;
- Audio Visual and Olfactory (AVO) program for monitoring (primarily) natural gas pipelines that have the mercaptan odor for detecting leaks. This program can be performed at a lower cost and more frequently and therefore leaks can be detected and repaired immediately;
- Instrument leak detection and repair (LDAR) programs in accordance with applicable federal and state regulations and permit conditions. This program usually requires quarterly monitoring and therefore leaks can remain for almost a quarter before being detected and repaired; and
- Remote sensing technology such as infrared cameras detects leaks immediately and make it possible to repair the leak quickly thereby reducing fugitive emissions.

Step 2 – Eliminate Technically Infeasible Options.

All the above controls are considered technically feasible.

Step 3 – Rank According to Effectiveness

Leakless technology is nearly 100% effective in eliminating fugitive emissions. This technology is primarily used for toxic gases. This is the most effective control.

An AVO program can be performed frequently and is effective for gases that have an odor.

Instrument LDAR programs and remote sensing have been determined by the EPA to be equivalent methods of piping fugitive controls.[11] These programs have been estimated to have a leak control effectiveness between 70-90% for most fugitive equipment.

Step 4 – Evaluate the Most Effective Controls

Use of leakless technology can have adverse environmental impacts. In addition, the sealing mechanism, such as a bellows, is not repairable online and may leak in the event of a failure until the next unit shutdown. Following a failure of one of these parts, the component is most often not repairable online and may leak until the next unit shutdown, resulting in the emissions from the leak itself as well as the emissions of GHGs and other criteria pollutants that result from the need to shut down and re-start the facility. Regular maintenance activities in the PDH process unit would potentially require a process unit shut down since isolation of the equipment would not be available. Emissions of GHG and conventional pollutants from maintenance activities would be increased due to having to degas larger sections of piping and perform unit shutdowns. Flanges and connectors inherently cannot be leakless, and the facility cannot be properly and effectively

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[11] 73 Fed. Reg. 78199-78219, December 22, 2008

constructed, operated, or maintained without the use of flanges and connectors. C3P cannot eliminate the use of flanges and connectors, but will use welded piping (leakless) where practicable in the PDH plant.

AVO program can be implemented for the natural gas pipelines that has the "mercaptan" odor and is a lower cost program.

LDAR programs have historically been used to detect leaks in chemical plants and are the regulatory requirement for fugitive emissions.

Remote Sensing using infrared imaging is an alternative method to the LDAR program using EPA Method 21 for detection of VOC. This usually requires less manpower, but the equipment is more expensive than that required by the LDAR program and is considered equally effective to the LDAR program.

Due to the negligible amount of GHG emissions from process fugitives, the most effective control technology is the implementation of an LDAR as BACT for the PDH plant.

Step 5 – Select BACT

C3P will incorporate the control of GHG emissions (methane) control through the use of the TCEQ 28 VHP LDAR and CNTQ (quarterly monitoring of connectors) programs as work practices that will assure the minimization of GHG from these sources. This program and relevant compliance requirements are in the draft permit.

BACT compliance for Fugitive emissions

- Implementation of the 28 VHP LDAR program
- Implementation of the CNTQ program for flanges and connectors.

H. Endangered Species Act

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, the EPA is required to insure that any action authorized, funded, or carried out by the 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, the EPA is relying on a Biological Assessment (BA) prepared by the applicant, C3 Petrochemicals, LLC ("C3P") and its consultant, TRC Environmental Corporation ("TRC"), thoroughly reviewed and adopted by the EPA.

A draft BA has identified fifteen (15) species listed as federally endangered, threatened, or proposed endangered/threatened in Brazoria County, Texas:

Federally Listed Species for Brazoria County by the U.S. Fish and Wildlife Service (USFWS), National Marine Fisheries Service (NMFS) and the Texas Parks and Wildlife Department (TPWD)	**Scientific Name**
Reptiles	
Hawksbill sea turtle	*Eretmochelys imbriacata*
Green sea turtle	*Chelonia mydas*
Kemp's ridley sea turtle	*Lepidochelys kempii*
Leatherback sea turtle	*Dermochelys coriaea*
Loggerhead sea turtle	*Caretta caretta*
Birds	
Piper plover	*Charadrius melodus*
Eskimo curlew	*Numenius borealis*
Whooping crane	*Grus americana*
Fish	
Sharpnose shiner	*Notropis oxyrhynchus*
Smalltooth sawfish	*Pristis pectinata*
Mammals	
Jaguarundi	*Herpailurus yaguarondi*
Louisiana black bear	*Ursus americanus luteolus*
Ocelot	*Leopardus pardalis*
Red wolf	*Canis rufus*
West Indian manatee	*Trichechus manatus*

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

Because of the EPA's "no effect" determination, no further consultation with the USFWS and NMFS is needed.

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 the 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 NOAA's National Marine Fisheries Service (NMFS), regional fishery management councils (FMC), and other federal agencies to identify and protect important marine and anadromous fish habitat.

To meet the requirements of the Magnuson-Stevens Act, the EPA is relying on an EFH Assessment prepared by the TRC on behalf of C3P, thoroughly reviewed, and adopted by the EPA.

The facility property is located adjacent to tidally influenced portions of the Chocolate Bayou which empties into the Chocolate Bay, which is part of the Galveston Bay system. These tidally influenced portions have been identified as potential habitats of postlarval, juvenile, subadult or adult stages of red drum (*Sciaenops ocellatus*), white shrimp (*Penaeus setiferus*), brown shrimp (*Farfantepenaeus aztecus*) and reef fish (43 species). 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, the EPA concludes that the proposed PSD permit allowing C3P construction of a new PDH manufacturing plant within an existing Chocolate Bayou 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 project's construction and operation will have no adverse effect on the 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.

J. National Historic Preservation Act (NHPA)

Section 106 of the NHPA requires the 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, the EPA relied on, thoroughly reviewed and adopted two (2) cultural resources reports prepared by the TRC on behalf of C3P. The first cultural resources report, submitted on March 4, 2014, surveyed the construction footprint of the project, and a second cultural resources report, submitted on May 1, 2014, surveyed the linear facilities associated with the project which included several pipelines and a transmission line.

For purposes of the NHPA review, the Area of Potential Effect (APE) was determined to be the location of the proposed construction of the PDH plant and construction laydown area covering approximately 12 acres and linear facilities including pipelines covering approximately 873 acres, for a total APE covering 885 acres for this project. Of note, approximately 10.8 miles of a new 36-mile propane pipeline, identified as Propane #1, will be installed in a new pipeline corridor. Other parts of the propane pipeline and other pipelines will be constructed within existing rights-of-way or within the project construction footprint.

The TRC conducted a field survey of the property, including shovel tests, and a desktop review of the archaeological background and historic records within a 1.0-mile radius of the APE. Based on the results of the field survey, no archaeological resources or historic structures were found within the APE. Based on the desktop review, two archeological sites were identified within a 1.2 mile radius of the APE. These sites are considered potentially eligible for listing on the

National Register (NR); however, they are outside of the APE and should not be effected by project construction and operation.

Although C3P has conducted a cultural resource survey on a majority of the Propane #1 pipeline, there remain approximately 10.8 miles of proposed propane pipeline corridor to which C3P has been unable to secure access for purposes of conducting survey work. The EPA, C3P and the SHPO have agreed in principle to a Programmatic Agreement (PA) requiring a pre-construction survey of this corridor to be signed by the SHPO and C3P. Once this survey has been completed in accordance with the PA, C3P will provide the results to the EPA and the SHPO, and will work in consultation with the EPA and the SHPO to take any additional actions to ensure that all conditions under the PA are met to satisfy all obligations under Section 106 of the NHPA.

Based on information provided in the cultural resources report, the EPA Region 6 determines that the potential for intact archaeological resources is low within the construction footprint of the project itself and for the existing pipeline corridors. The EPA has therefore determined that, for these portions of the APE, issuance of the permit to C3P will not affect properties on or potentially eligible for listing on the NR. However, construction of C3P's project may only proceed in accordance with the PA for the remaining 10.8 miles of the proposed propane pipeline corridor and any post-review discoveries.

On March 18, 2014, the EPA sent letters to the 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 the EPA in the Section 106 process. The EPA received no requests from any tribe to consult on this proposed permit.

The 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.

K. 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 the 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 the EPA has historically issued PSD permits, there is no National Ambient Air Quality Standard (NAAQS) for GHGs. The global climate-change inducing effects of GHG emissions, according to the "Endangerment and Cause or Contribute Finding", are far-reaching and multi-dimensional

(75 FR 66497). Climate change modeling and evaluations of risks and impacts are typically conducted for changes in emissions that are orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible [PSD and Title V Permitting Guidance for GHGS at 48]. Thus, we conclude it would not be meaningful to evaluate impacts of GHG emissions on a local community in the context of a single permit. Accordingly, we have determined an environmental justice analysis is not necessary for the permitting record.

L. Conclusion and Proposed Action

Based on the information supplied by C3P, the GHG PSD Permit Application, and our independent evaluation of the information contained in our Administrative Record, it is our determination that the proposed conditions, as described above, represent the BACT for GHGs. Therefore, the EPA is proposing to issue C3P a PSD permit for GHGs for the facility, subject to the PSD permit conditions specified herein. This draft permit is subject to review and comments. A final decision on issuance of the permit will be made by the EPA after considering comments received during the public comment period.

Appendix A

Annual Facility Emission Limits

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY		
PDH-H101 PDH-H102 PDH-H103 PDH-H104	PDH-H101 PDH-H102 PDH-H103 PDH-H104	Process Heaters, Reactor Train 1	CO_2	230,078	230,308	Excess oxygen from heaters is limited to 3% or less. 87% thermal efficiency in Reactor Train 1. See Special Condition III.A.2.
			CH_4	4.2		
			N_2O	0.42		
PDH-H201 PDH-H202 PDH-H203 PDH-H204	PDH-H201 PDH-H202 PDH-H203 PDH-H204	Process Heaters, Reactor Train 2	CO_2	230,078	230,308	Excess oxygen from heaters is limited to 3% or less. 87% thermal efficiency in Reactor Train 2. See Special Condition III.A.2.
			CH_4	4.2		
			N_2O	0.42		
PDH BOILER 1 PDH BOILER 2	PDH-BOILERS	Boilers	CO_2	329,748	330,055	Thermal efficiency of 82%. See Special Condition III.A.3.
			CH_4	5.6		
			N_2O	0.56		
CCR-1	CCR-1	Train 1 CCR Vent	CO_2	2,318	2,318	Process design of the plant. Catalyst regeneration will use Nitrogen as purge gas. See Special Condition III.A.4.
CCR-2	CCR-2	Train 2 CCR Vent	CO_2	2,318	2,318	Process design of the plant. Catalyst regeneration will use Nitrogen as purge gas. See Special Condition III.A.4.
PDH-FUG	PDH-FUG	Process Fugitives	CH_4	No Numerical Limit Established[4]	No Numerical Limit Established[4]	Implementation of LDAR 28VHP Program. See Special Condition III.A.5.
PDH-FLARE	PDH-FLARE	Ground Flare	CO_2	165	178	Flare will meet the requirements of 40 CFR 60.18. with an efficiency > 98%. See Special Condition III.A.6.
			CH_4	0.5		
			N_2O	<0.01[5]		
PDH-MSS	PDH-MSS	Ground Flare MSS	CO_2	412	443	Good Operational Practices. See Special Condition III.A.7.
			CH_4	1.2		
			N_2O	<0.01[5]		

FIN	**EPN**	**Descrip-tion**	**GHG Mass Basis**		**TPY CO_2e[2,3]**	**BACT Requirements**
				TPY		
PDH-CT	PDH-CT	Cooling Tower	CH_4	0.4	11	Continuous monitoring of cooling water for HRVOCs/ See Special Condition III.A.8.
Totals[6]			**CO_2**	**795,115**	**CO_2e 795,940**	
			CH_4	**16.3**		
			N_2O	**1.4**		

1. Compliance with the annual emission limits (tons per year) is based on a 12-month rolling total.
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): CO_2 =1, CH_4 = 25, N_2O = 298.
4. Fugitive process emissions from EPN PDH-FUG are estimated to be <0.001 TPY CO_2, 0.1 TPY of CH_4 and 4 TPY CO_2e.
5. These values are less than 0.01 TPY with appropriate rounding.
6. Totals are given for informational purposes only and do not constitute emission limits.

C3 Petrochemicals - PDH Plant
Estimated Cost for Construction and Operation of a Post-Combustion CCS System

	Cost ($/ton of CO_2 Controlled)[1]	Cost ($/ton of CO_2 transported per 100 km)[1]	Tons of CO_2 Controlled/yr[2]	Pipeline Length for CO_2 Transport System (km CO_2 transported)[3]	Total Annualized Cost of CCS	Capital Recovery Factor[4]	Capital Cost of CCS
	$103.42		715,084		$73,954,008	0.0944	$783,469,814
Minimum		$0.91	715,084	225	$146,090	0.0944	$1,547,680
Maximum		$2.72	715,084	225	$436,665	0.0944	$4,626,032
Average		$1.82	715,084	225	$291,377	0.0944	$3,086,856
Minimum	$0.51		715,084		$364,693	0.0944	$3,863,562
Maximum	$18.14		715,084		$12,971,627	0.0944	$137,421,605
Average	$9.33		715,084		$6,668,160	0.0944	$70,642,584

Total Capital Cost for CO_2 Capture, Transport, and Storage Systems			
Minimum	$74,464,791	0.0944	$788,881,056
Maximum	$87,362,300	0.0944	$925,517,451
Average	$80,913,546	0.0944	$857,199,254
Total Capital Cost of PDH Unit without CCS			
			$1,200,000,000
Percentage of CCS Capital Cost Compared to Total Plant Capital Cost Without CCS			
Minimum			66%
Maximum			77%
Average			71%

ge *Interagency Task Force on Carbon Capture* (August, 2010). Reported costs in $/tonne were converted to $/ton.

s 90% capture of the CO_2 emissions from the boilers, heaters, and CCR vents.

e into the Denbury System was provided by Pipeline Technology LLC.

on 7% interest rate and 20 year equipment life

torage of CO_2] are limited to capital and operational costs, and do not include potential costs associated with long-term liability." (from the *Report of the Interagency Task Force on*