Draft Statement of Basis

Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit
for the Occidental Chemical Corporation, Ingleside Chemical Plant

Permit Number: PSD-TX-1338-GHG

March 2014

This document serves as the statement of basis 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 December 28, 2012, Occidental Chemical Corporation (OxyChem) Ingleside Chemical Plant submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions for a proposed construction project at an existing major stationary source of criteria pollutants. In connection with the same proposed project, OxyChem submitted a PSD permit application for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on December 27, 2012. The project at the Ingleside Chemical Plant proposes to construct a new ethylene production unit consisting of five ethane cracking furnaces and recovery equipment to produce ethylene. 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 OxyChem Ingleside Chemical Plant.

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 OxyChem's application is complete and provides the necessary information to demonstrate that the proposed project meets the applicable air permit regulations. EPA's conclusions rely upon information provided in the permit application, supplemental information provided by OxyChem 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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III. Permitting Authority

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

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

EPA, Region 6
1445 Ross Avenue
Dallas, TX 75202

The EPA, Region 6 Permit Writer is:

Aimee Wilson
Air Permitting Section (6PD-R)
(214) 665-7596

IV. Facility Location

The OxyChem, Ingleside Chemical Plant is located in San Patricio County, Texas. The geographic coordinates for this facility are as follows:

Latitude:	27° 52' 51" North
Longitude:	-97° 14' 39" West

San Patricio County is currently designated attainment for all pollutants. The nearest Class I area is the Big Bend National Park, but it is located more than 350 miles (600 kilometers) from the proposed facilities. Therefore, the emissions from this project are not expected to have an impact on this Class I area.

Figure 1. Occidental Chemical Corporation, Ingleside Chemical Plant Location

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

EPA concludes that OxyChem's application is subject to PSD review for the pollutant GHGs because the project would lead to an emissions increase of 75,000 TPY CO_2e as described at 40 CFR § 52.21(b)(49)(iv)(b) and an emissions increase greater than zero TPY on a mass basis as described at 40 CFR § 52.21(b)(23)(ii) (OxyChem calculates CO_2e emissions of 474,976 TPY). EPA Region 6 implements a GHG PSD FIP for Texas under the provisions of 40 CFR § 52.21 (except paragraph (a)(1)). See 40 CFR § 52.2305.

As the permitting authority for regulated NSR pollutants that trigger PSD (other than GHGs), TCEQ has determined that the proposed project is subject to PSD review for non-GHG pollutants. TCEQ has determined that the proposed project is subject to PSD for VOC, NO_2, CO, and PM/PM_{10}/$PM_{2.5}$. At this time, TCEQ has not issued a PSD permit for the non-GHG pollutants. Accordingly, under the circumstances of this project, the TCEQ will issue the non-GHG portion of the PSD permit and EPA will issue the GHG portion.[1]

EPA Region 6 applies the policies and practices reflected in 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 GHGs, nor have we required any assessment of impacts of GHGs in the context of the additional impacts analysis or Class I area provisions of 40 CFR §§ 52.21(o) and (p), respectively. Instead, EPA has determined that compliance with 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 GHGs. We note again, however, that the proposed project has regulated NSR pollutants that are non-GHG pollutants, which will be addressed by the PSD permit to be issued by TCEQ.

VI. Project Description

OxyChem is proposing to construct and operate a new 1.5 billion pound-per-year Ethylene Plant at its existing site near Ingleside, Texas on land immediately adjacent to the existing Vinyl Chloride Monomer (VCM) Plant. The new Ethylene Plant will receive ethane feed from an OxyChem planned Natural Gas Liquids (NGL) Fractionation Plant to be constructed on adjacent property or by pipeline. The Ethylene Plant will produce market grade ethylene which will be transported by pipeline as feed material to the existing VCM Plant or to other markets.

The ethane feed to the Ethylene Plant is combined with recycled ethane from the ethylene fractionator and superheated with water before being sent to the cracking furnaces. The cracking furnaces will be equipped with selective catalytic reduction (SCR) technology for NO_x control.

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[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

Pre-heated ethane using recovered heat is fed to five cracking furnaces to be further heated to cracking temperature. The ethane cracking furnace design includes energy efficiencies, such as the use of heat exchangers on the process and flue gas outlet of the cracking furnaces to recover waste heat. Hydrogen rich vent gas is used for furnace fuel which is beneficial in reducing CO_2 emissions.

To minimize coke formation in the cracking furnace tubes and extend the duration between decokes, a sulfide material is added continuously to the ethane feed stream at low part-per-million (ppm) levels. Two chemicals may be used for this purpose: dimethyl disulfide (DMDS) or dimethyl sulfide (DMS). The sulfide chemical is stored in a pressurized tank and truck off-loading of the material is accomplished using vapor balancing with the delivery truck.

The effluent from the cracking furnaces is used to recover heat by producing high pressure steam and preheating ethane in transfer line exchangers (TLEs) before being quenched in the quench tower. The cracked gas from the TLEs is cooled and partially condensed by direct countercurrent contact with recirculating water in the quench tower. The condensed gasoline and dilution steam, along with quench water, are separated in the bottom section of the quench tower, and the non-condensable gas exits the top of the quench tower.

The quench tower overhead vapors (non-condensable gas) are sent to the first stage of the steam-driven charge gas compressor where the vapors are compressed in a three-stage centrifugal compressor. Acid gases are removed from the charge gas in the third-stage compressor discharge. The acid-gas removal consists of a three-stage caustic wash tower. Charge gas from the caustic wash tower overhead is chilled in the dryer feed chiller system. Charge gas from the dryer feed chiller system overhead is dried in a molecular sieve drying system.

The vapor from the charge gas dryer is chilled before entering the front-end de-ethanizer. The de-ethanizer tower produces a vapor overhead product with primarily ethane, ethylene, and lighter content and a bottoms product that is stripped of ethane and lighter components. Acetylene is removed from the de-ethanizer overhead by selective hydrogenation to ethylene and ethane. The de-ethanizer overhead product is then chilled and sent to the de-methanizer.

The overhead of the de-methanizer consists of methane and hydrogen. This hydrogen-rich vapor from the de-methanizer is processed to separate hydrogen for use in the hydrogenation reactors and the balance is used as fuel gas, thus reducing natural gas usage. During brief periods when more fuel gas is produced than is required by the furnaces, hydrogen is vented through a hydrogen vent to remove fuel gas from the system. De-methanizer bottoms are fed to the ethylene fractionator. The ethylene fractionator overhead vapor is condensed as ethylene product that is sent out by pipeline or to the adjacent VCM plant. The ethylene fractionator bottoms are predominantly ethane and this stream is returned to the cracking furnace feed.

The de-ethanizer bottoms product is sent to the de-butanizer to separate the C3s and C4s from the C5+ gasoline. The debutanizer bottoms product is sent to C5 gasoline storage. The de-butanizer overhead product is hydrotreated in the hydrogenation reactor to convert diolefins and olefins into normal propane and butane. The propane/butane mix stream from the hydrogenation reactor is returned to the NGL Fractionation Plant as feed or shipped off site as product.

One of the byproducts of the Ethylene Plant is a stream called pyrolysis gasoline. This material is sold to petroleum refineries as a gasoline blend stock. The pyrolysis gasoline will be loaded into trucks for transportation to the refinery customers. The vents from loading these trucks are routed to the cracker thermal oxidizers for VOC control.

A propylene refrigeration system, which utilizes a steam turbine-driven centrifugal compressor, provides refrigeration at four levels of temperature. A binary refrigerant system uses methane and ethylene to provide the coldest level of refrigeration in the plant for cooling and condensing process streams at three additional levels.

Spent caustic from the caustic tower is treated in a wet air oxidizer system to oxidize sulfides and other chemical oxidation demand before being discharged to the wastewater treatment plant.

A five-cell cooling tower will be used to remove the heat from the process by thermal exchange.

A unique aspect of this project is the use of two thermal oxidizers equipped with waste heat boilers to combust low pressure discharges of vent gases from process equipment and storage vessels. The heat content of these process streams will be used as fuel to generate steam that will be utilized within the ethylene unit. This will reduce the steam and fuel demands in the site's steam cogeneration units. Combusting these vents in a flare would result in lower VOC emissions control and does not provide heat recovery. The two thermal oxidizers are designed to destroy and remove organic materials from the collected vent gases with an efficiency of at least 99.9%. They are supplied with natural gas to ensure complete combustion with minimum production of carbon monoxide.

In addition to the thermal oxidizers, which provide the primary emissions control for process vents, a high pressure flare system provides a means to collect and combust hydrocarbon process streams that have relieved or been drained to the flare headers at a rate or pressure greater than the thermal oxidizers can control. This will only occur during start-up, shut-down, or upset conditions. The emergency relief collection and transfer systems discharge to a multi-point, low-profile, high-pressure ground flare with a staged burner control system. A heat radiation shielding fence will minimize the radiation to the acceptable level outside the fence and avoid production of a visible flame. Numerous pilots, supplied with natural gas, are provided to ensure that any emergency relief of process streams will be combusted.

Process wastewaters, contaminated storm water, surface wash down, and other wastewaters are collected in process area sumps which pump to wastewater storage tanks. The wastewater storage tank is vented to the thermal oxidizers. Wastewater from the wastewater storage tank is sent to the wastewater steam stripper to remove volatile organic compounds prior to treatment in an activated sludge treatment system within the existing VCM Plant.

A summary of storage tanks is provided as follows:

1) Pressure tanks: 90,000-gal propylene tank; two 650,000-gal C3/C4 tanks; 10,000-gal anhydrous ammonia tank; 10,000-gal DMS/DMDS tank.
2) Low pressure tanks venting to the oxidizers: three 1,100,000-gal contaminated water tanks; two 135,000-gal pyrolysis gasoline tanks; 45,000-gal heavy oil tank; 105,000-gal collected oil tank; 18,000-gal wash oil tank; two 82,620-gal spent caustic tanks.
3) Atmospheric tanks: 10,000-gal methanol tank (PBR 106.473); 10,000-gal sulfuric acid tank (PBR 106.472).

Also, the new facilities include a diesel-fired emergency generator. In addition, the site has two existing cogeneration units. The existing cogeneration units are not being modified. They are permitted by TCEQ under permit Nos. 35335 and PSD-TX-880.

The cogeneration units will provide steam and power to the new Ethylene Plant. Currently, the excess power produced by the cogeneration plants is sent to the grid. The cogeneration units will not have an increase in their currently permitted firing rates.

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.

As part of the PSD review, OxyChem provided in the GHG permit application a 5-step top-down BACT analysis for the emission units covered by the proposed GHG PSD Permit. EPA has reviewed OxyChem’s BACT analysis for the applicable emission units, which has been incorporated into this Statement of Basis, and also provides its own analysis in setting forth BACT for this proposed permit, as summarized below.

VIII. Applicable Emission Units and BACT Discussion

The majority of the GHGs associated with the project are from combustion sources (i.e., cracking furnaces, furnace decoking, thermal oxidizers, high-pressure ground flare, and emergency engine testing). The project has some fugitive emissions from piping components which contribute an insignificant amount of GHGs. These stationary combustion sources primarily emit carbon dioxide (CO_2) and small amounts of nitrous oxide (N_2O) and methane (CH_4). In addition, GHGs are emitted from the cooling tower, a hydrogenation regeneration vent, and a hydrogen vent. The following devices are subject to this GHG PSD permit:[2]

- Ethane Cracking Furnaces (EPNs: CR-1 through CR-5)
- Ethane Cracking Furnaces MSS Activities (EPNs: CR-1-MSS through CR-5-MSS)
- Thermal Oxidizers (EPNs: CR-6 and CR-7)
- High Pressure Flare (EPN: CR-8)
- High Pressure Flare - MSS Activities (EPN: CR-8-MSS)
- Emergency Generator Diesel Engine (EPN: CR-9)
- Cooling Tower (EPN: CR-11)
- C_3/C_4 Hydrogenation Regeneration Vent - MSS Activities (EPN: CR-12)
- Ethylene Plant Fugitive Emissions (EPNs: CR-13, CR-14, CR-15, and CR-16)
- Hydrogen Vent (EPN: CR-19)

IX. Ethane Cracking Furnaces Nos. 1 through 5 (EPNs: CR-1 through CR-5)

The ethane cracking furnaces for the proposed facilities include five identical combustion units expected to fire natural gas and hydrogen-rich fuel gas at a maximum heat rate of 275 MMBtu/hr each. Typically, four of these units will be operating while the fifth unit is being serviced or held on stand-by. However, at times, all five units may be running at full capacity.

Normal operation involves natural gas and/or process-related fuel gas (high hydrogen gas) firing in the furnaces and the control of NO_x emissions using SCR. Three additional operating

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[2] Two Cogeneration Units (EPNs CG-1 and CG-2) are existing units that will not be modified, so a BACT analysis is not required. In addition, we note that the non-GHG emissions from the cogeneration units are addressed in the TCEQ permit and any additional emissions of hydrocarbons and CO to the cogeneration units are covered by the applicable requirements of the state permit.

scenarios are described in Section X that pertain to furnace maintenance, start-up, and shutdown (MSS) activities.

During normal operations, furnaces will be operated using process-generated fuel gas, which is a combination of hydrogen, methane, ethane, and heavier hydrocarbons. During this operation, the heat input to the firebox is maintained to achieve the desired cracking rate. Ethane and steam are fed to the furnace tube inlets, and the furnace outlet is routed to the quench tower where the process gases are cooled.

It should be noted that normal operations can include firing only natural gas without the process fuel gas, and so, this scenario is included in the emission calculations. Firing with natural gas represents worst-case emissions for most criteria pollutants because fuel gas with hydrogen is a much cleaner fuel and results in less CO_2. OxyChem will use hydrogen-rich fuel gas as a preferred fuel for the furnaces and will minimize CO_2 emissions in this way. The only exception to burning this fuel gas is that some of the produced hydrogen will be used in the facilities' hydrogenation processes.

Step 1 - Identify All Available Control Options

- Low carbon fuels – Use of low carbon fuels to reduce the amount of carbon dioxide generated in the combustion process.
- Furnace excess air control – Monitoring of oxygen in the flue gas for optimal efficiency.
- Good operating and maintenance practices – Visual monitoring of flame patterns and periodic cleaning of burner and feed nozzles to assure complete combustion and efficiency. Also includes periodic refractory repair and cleaning of process heating and waste heat recovery systems when required to maximize thermal efficiency.
- Energy efficient design – Use of waste heat recovery from the furnace flue gas and the furnace process effluent gases, thereby offsetting GHG emissions from other process heating sources. Waste heat recovery would require the installation of heat recovery exchangers on the process outlet gas and the flue gas from the cracking furnaces.
- Carbon capture and sequestration (CCS) – Capture, compression, transport, and geological storage of carbon dioxide from the cracking furnace flue gas exhaust.

Step 2 - Elimination of Technically Infeasible Alternatives

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. *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 an olefins cracking furnace. 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 sources that have low concentration CO_2 streams, such as cracking furnaces.[3] As a result, EPA believes that CCS is technically infeasible for the ethane cracking units and can be eliminated as BACT. Nevertheless, because OxyChem has provided a cost analysis of CCS with its permit application, we have decided to evaluate CCS through Step 4 of the BACT analysis. In regards to the remaining control options, EPA finds that all are technically feasible.

Step 3 - Ranking of Remaining Technologies Based on Effectiveness

- Energy Efficient Design - Waste heat recovery can reduce GHG emissions from the furnace by reducing the furnace firing rate and steam demand for the Ethylene Plant. Possible GHG emissions from the furnaces and cogeneration facility can be reduced by approximately 543,270 tons per year due to reduced steam and firing rate demands with the installation of waste heat recovery on the furnaces. Therefore, this is considered the second most effective control technology for the ethylene furnaces.
- Low Carbon Fuels - The use of the hydrogen rich vent gas from the ethylene recovery section in lieu of natural gas for fuel in the cracking furnaces reduces the amount of CO_2 generated in the cracking furnaces. It is estimated that the CO_2 emissions from the cracking furnaces are reduced by about 41%, or 412,294 tons per year, using this alternative low carbon fuel source. This is considered the third most effective control technology for this application.
- CCS – If CCS were technically feasible for this source category or process, it is assumed that CCS would reduce GHG emissions from the cracking furnaces by up to 262,612 tons per year (utilizing a hydrogen rich fuel), based on a 90% capture efficiency, and would be the most effective control method for the ethane cracking furnaces.
- Furnace Excess Air Control - Excess air control using stack gas oxygen monitors and good operating and maintenance practices are considered good engineering practice and have been included with the proposed furnace design. Implementing these design elements and operational parameter monitoring is effective at minimizing formation of CO_2 in the ethane cracking furnaces, but the effects are not directly quantifiable.

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[3] OxyChem provided a response to EPA's comments on the completeness of the application on July 22, 2013. In this submittal on page 16 (Response #10) OxyChem states "The CO_2 concentration in the flue gas of the furnaces is only about 4.6% volume". http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/occidental_ethylene_response2epa-completeness.pdf

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

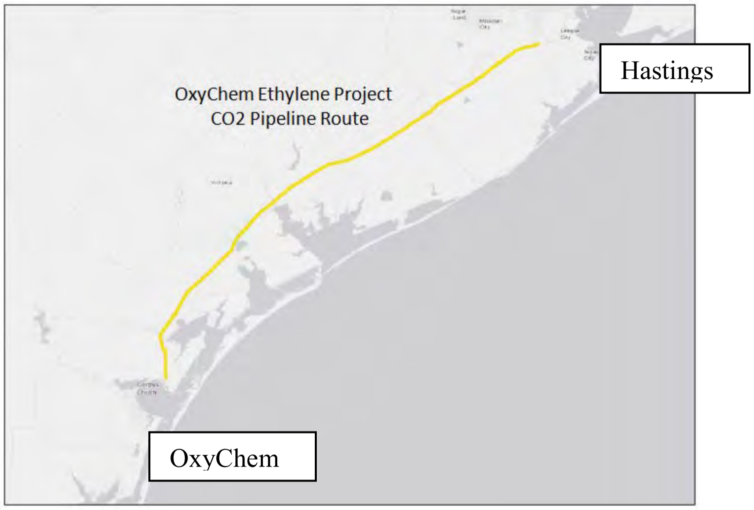
<u>Carbon Capture and Storage</u>

Even though CCS was determined to be technically infeasible at Step 2, the applicant provided additional evidence that supports the rejection of CCS as BACT in Step 4. CO_2 emissions from the cracking furnaces could theoretically be absorbed in a conventional amine solvent. The CO_2 could then be concentrated in an amine regenerator vent stream, dried, compressed and routed to oil production facilities using CO_2 for enhanced oil recovery (EOR) or stored in geologic formations. OxyChem evaluated a number of opportunities for CO_2 storage or use in EOR. A search of the National Carbon Sequestration Database and Geographic Information System (NATCARB) identified five sites that were evaluated for potential storage or transportation of CO_2:

1) NRG (Thompsons, TX),
2) University of Texas (~10 miles off-shore, Gulf of Mexico),
3) Hunton (Freeport, TX),
4) Conoco Phillips project (Sweeny, TX), and
5) Denbury Hastings CO_2 pipeline near Pearland, TX.

The first four sites are impracticable because they are currently in the planning or development stages, or have been cancelled. Therefore, the nearest currently viable option for transporting the captured CO_2 is the Denbury Hastings CO_2 pipeline. Transporting the CO_2 from the Ingleside site to the Hastings field would require a 180 mile pipeline shown on the graphic below.

Mapped Pipeline Route from the proposed OxyChem
Ethylene Plant (Ingleside, TX) to Hastings (Pearland, TX)



Assuming capture, compression, and sequestration of the CO_2 in the cracking furnace flue gas could reduce the CO_2emissions from the cracking furnaces by up to 262,612 tons per year, based on 90% capture efficiency, but would require an additional 446 MMBtu/hr of thermal energy to strip the $CO_2$from the capture solvent. The current steam production of the OxyChem facility, including the additional steam produced from waste heat boilers, cannot meet this increased demand without curtailing existing production units as demonstrated in the table below.

Table 1. Ingleside Steam Balance

Steam Generation (Existing Cogeneration)	
Heat Recovery Steam Generator No. 1	1,000 Mlb/hr
Heat Recovery Steam Generator No. 2	1,000 Mlb/hr
Total Production	**2,000 Mlb/hr**
Steam Consumers (Net Consumption)	
Existing Steam Turbine Generator	1,000 Mlb/hr
Existing Process Consumers	750 Mlb/hr
Ethylene Unit (Net Consumption)	120 Mlb/hr
Potential Amine Regenerator for CCS	400 Mlb/hr
Total Consumption including CCS	**2,270 Mlb/hr**
Site Steam Totals	
Site Steam Deficiency	**-270 Mlb/hr**

Therefore, implementation of CCS would require the installation of a new natural gas-fired steam boiler that would be a source of additional CO_2 emissions. It is estimated that the increased CO_2 emissions from the new boiler would be 228,158 ton/yr. A summary of the basis for avoided CO_2 emissions is provided in the following tables.

Table 2: Emissions Assuming Natural Gas Fired Boiler for New Amine Regenerator

Assume maximum firing for maximum CO_2 capture		
Max CO_2 emissions from Furnaces (100% load)	13,324	lb/hr per furnace
Number of Furnaces	5	Furnaces
CO_2 Capture (assuming 90% recovery)	262,612	ton/year
Total CO_2 capture	59,957	lb/hr
Use gas processing data on amine absorber-strippers from Campbell Gas Processing Books From J.M. Campbell & Co Gas Processing Handbook (Table 4.10))		
Energy Required per lb of CO_2 for Regeneration	72,000	Btu/hr per gpm of DEA
Solvent Specific Gravity	1.1	
Factor per lb Solvent	130.8	Btu/lb of solvent
Solvent Concentration (Aqueous DEA)	25%	
Factor per lb of DEA	523	Btu/lb of DEA
Moles CO_2/Mole DEA	0.2	
Energy Required per lb of CO_2 absorbed	6242.9	Btu/lb CO_2
Additional Steam Energy Required for Amine Regenerator	374.3	MMBtu/hr
Boiler Efficiency	84%	
Fuel Required	445.6	MMBtu/hr
CO_2 Factor	116.9	lb/MMBtu/hr
CO_2 Produced	52,091	lb/hr
CO_2 Produced from boilers for regenerator	228,158	ton/year

Consequently, the net overall reduction in CO_2 emissions from the ethane furnaces from CCS would be 34,454 tons/year (262,612 – 228,158 tons/year). If this additional amount of CO_2 generated was considered in the cost analysis, the total cost would be $1,013/ton. However, the cost-effectiveness analysis for a CCS system designed to control the ethane cracking furnaces (shown below) conservatively did not include the increase in GHG emissions from the new boiler.

The estimated annualized capital and operating and maintenance (O&M) costs for the recovery and compression equipment for the OxyChem ethane cracking furnaces was originally estimated to be $28,536,835 per year (utilizing a capital recovery factor of 6.14% and equipment life of 30 years). However, after a review of similar recently submitted ethylene plant CCS system designs and associated costs that were approved by the EPA Region VI, OxyChem conservatively adjusted the annualized cost to be $26,530,710 per year. A summary of the costs are included in Table 3.

Table 3 - Economic Analysis for Carbon Capture and Compression

Cost Type	Units	OxyChem's Original Estimate ($ Millions)	Updated Cost Estimate ($ millions)
Carbon Capture Plants - Capital and Operating Expense Estimation			
CO_2 Compressor and Intercoolers	$ (millions)	220.5	27.5
Amine Absorber Systems, CO_2 Purification System, Blower, Piping, Boiler, and Ducting	$ (millions)		213.6
Total Capture and Compression Costs	**$ (millions)**	**220.5**	**241.1**
Utility Plant - Capital and Operating Expense Estimation			
Fuel, Utilities, Amine	$ (millions) / yr	15	11.7
Total Expense Estimation - 90% Capture [1]			
Operating Expense	$ / Ton CO_2 Avoided	57	45
Capital Expense [2]	$ / Ton CO_2 Avoided	52	56

[1] Calculations –
Operating Expenses / Total CO_2 Captured;
Total Capital Expenses * Capital Recovery Factor / Total CO_2 Captured
[2] Based on a capital recovery factor of 6.14% with an expected equipment life of 30 years and an interest rate of 4.5%.

The estimated annualized capital and operating and maintenance (O&M) costs for CO_2 transport was originally estimated to be $29,289,359 per year (utilizing a capital recovery factor of 6.14% and equipment life of 30 years). This included eight pumping stations that would be required for the 180 mile pipeline. However, utilizing the 2013 National Energy Technology Laboratory, Estimating Carbon Dioxide Transport and Storage Costs 2013 documentation that has been utilized in recently submitted ethylene plant CCS system designs and associated costs that were approved by the EPA Region VI, OxyChem conservatively adjusted the annualized cost to be about $8,385,233 per year.

A summary of the costs are included in Table 4 and a summary of the carbon compression and pipeline analysis is included in Table 5.

Table 4 - Economic Analysis for CO_2 Transport

Cost Type	OxyChem's Original Estimate [4]	DOE/NETL Calculation[1]		
	Cost ($ millions)	Units	Cost Equation	Cost ($millions)
Pipeline Materials	229.5	$, Diameter (inches), Length (miles)	$\$70{,}350 + \$2.01 \times L \times (330.5 \times D^2 + 686.7 \times D + 26{,}960)$	15.6
Pipeline Labor		$, Diameter (inches), Length (miles)	$\$371{,}850 + \$2.01 \times L \times (343.2 \times D^2 + 2{,}074 \times D + 170{,}013)$	70.9
Pipeline Miscellaneous [2]		$, Diameter (inches), Length (miles)	$\$147{,}250 + \$1.55 \times L \times (8{,}417 \times D + 7{,}234)$	16.3
Pipeline Right of Way		$, Diameter (inches), Length (miles)	$\$51{,}200 + \$1.28 \times L \times (577 \times D + 29{,}788)$	7.7
Pipeline Control System		$	$111,907	0.1
CO_2 Surge Tank		$	$1,244,724	1.2
Total Materials and Labor Estimation	**229.5**	**$**	**--**	**111.8**
O&M Expense Estimation (Total for life of equipment)	353.1	$ / mile / year	$8,454	45.7
Total Expense Estimation	582.6	$	-	157.5
Amortized Cost[5]	25.9	$/yr	-	8.4
Total Cost ($/ Ton CO_2)	**98.5**	**31.9**		

[1] National Energy Technology Laboratory, Estimating Carbon Dioxide Transport and Storage Costs, United States Department of Energy, Page 12, DOE/NETL-2013/1614.

[2] Per NETL doc: Miscellaneous costs are inclusive of surveying, engineering, supervision, contingencies, allowances for funds used during construction, administration and overheads, and regulatory filing fees

[3] Calculations –

Operating Expenses / Total CO_2 Captured or avoided;

Total Capital Expenses * Capital Recovery Factor / Total CO_2 Captured

[4] OxyChem Original Estimate based on 8 pumping stations for 180 miles of 6 inch diameter pipeline, $0.03/kW for annual pipeline pump electrical requirements and 75% efficiency, and pipeline annual operating expenses of 4% of installed costs.

[5] A capital charge rate of 6.14% was assumed with an expected equipment life of 30 years and an interest rate of 4.5% (per NETL).

Table 5 - Economic Analysis for CCS

Cost Type	Units	Estimated Cost ($ millions)
Carbon Capture Plants - Capital and Operating Expense Estimation		
CO_2 Compressor and Intercoolers	$ (millions)	27.5
Amine Absorber Systems, CO_2 Purification System, Blower, Piping, Boiler, and Ducting	$ (millions)	213.6
Pipeline Material and Costs	$ (millions)	111.8
Utility Plant - Capital and Operating Expense Estimation		
Fuel, Utilities, Amine	$ (millions) / yr	11.7
Piping Annual O&M	$ (millions) / yr	1.52
Total CO_2 CCS Cost Estimation at 90% Capture [1]		
Total	$ / Ton CO_2 Avoided	132.96

[1] A capital charge rate of 6.14% was assumed with an expected equipment life of 30 years and an interest rate of 4.5% (per NETL).

Estimated annual revenue from CCS would be $5,250,000 based on $20 per ton for use in enhanced oil recovery. Based on the amount of CO_2 that could be captured, OxyChem would not qualify for the additional tax credit. OxyChem estimated the average cost-effectiveness for CCS to be $113/ton of CO_2 emission reduction based on annualized cost estimates, as shown in Table 6 below.

Table 6 - CCS Cost Effectiveness including Offsets (Sale of CO_2)

CCS Technology for CO_2 Emissions	Tons of CO_2 Avoided per Year[1]	Cost - 90% Capture ($/ton of CO_2 Avoided)	Total Annual Cost[2] (Million $ per year)
Capture and Compression	262,612	101	26.53
Transport	262,612	31.93	8.39
Total CCS Cost (without offsets)	**262,612**	**132.96**	**34.92**
Sale to EOR	262,612	(20.00)	(5.25)
Total CCS Cost (with offsets)	**262,612**	**112.96**	**29.66**

[1] This represents 90% capture of the total CO_2 emissions from the ethane cracking furnaces.
[2] Total Annual Cost represents an amortized cost for the capital expenditure and operating and maintenance costs. A capital recovery rate of 6% was assumed with an expected equipment life of 30 years and interest rate of 4.5%.

The addition of CCS for the furnaces would increase the total project costs by more than 35%. This figure is based on a $1 billion project cost, $241.1 million for CCS, and $111.8 million for a pipeline. If the cost for capturing CO_2 from the thermal oxidizers was included, the total project costs would increase by over 44%. This is based on an additional cost of $89.1 million for CCS on the thermal oxidizers. The combined furnace and thermal oxidizer CO_2 capture costs do not include the increased costs necessary for the larger pipeline that would be needed to accommodate both CO_2 streams; and therefore the cost increase would actually be higher.

These estimated CCS costs are comparable to those for similar facilities permitted recently where EPA rejected CCS as cost-prohibitive. Therefore, this option is rejected as a control technology for GHG emissions for both economic and technical infeasibility reasons.

Energy Efficient Design

The ethane cracking furnace design includes energy efficiencies, such as the use of heat exchangers on the process and flue gas outlet of the cracking furnaces to recover waste heat. The waste heat recovery will recover 119.87 MMBtu/hr per furnace that can be utilized by the Ethylene Plant. This will reduce the amount of steam required by the cogeneration unit and thereby avoid 350,343 tons per year CO_2 emissions from the combustion of natural gas to generate steam (assuming 84% boiler efficiency and 116.91 lbs CO_2/MMBtu). In addition, the waste heat recovery will be used to preheat the ethane feed mix at an average of 64.44 MMBtu/hr per furnace. This will also reduce the amount of steam required by the cogeneration unit and thereby avoid an additional 192,927 tons per year of CO_2 emissions from the burning of natural gas to generate steam (assuming 84% boiler efficiency and 116.91 lbs CO_2/MMBtu). Therefore, the total CO_2 avoided due to the waste heat recovery is estimated at 543,270 tons per year CO_2 or 0.72 lbs CO_2/lb of ethylene. There are no economic, energy, or environmental impacts associated with this control option that would justify its elimination as BACT.

Low Carbon Fuels

The use of the hydrogen rich vent gas for furnace fuel is considered part of the furnace operation for reducing CO_2 formation. There are no economic, energy, or environmental impacts associated with this control option that would justify its elimination.

Furnace Excess Air Control

Excess air control using stack gas oxygen monitors and good operating and maintenance practices are considered good engineering practice and have been included with the proposed furnace design. Implementing these design elements and operational parameter monitoring is effective at minimizing formation of CO_2 in the ethane cracking furnaces, but the effects are not directly quantifiable. There are no economic, energy, or environmental impacts associated with this control option that would justify its elimination.

Step 5 - Selection of BACT

To date, other facilities with an ethane cracking furnace and a GHG BACT limit are summarized in the table below:

Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
BASF FINA Petrochemicals LP, NAFTA Region Olefins Complex Port Arthur, TX	Ethylene Production	Energy Efficiency/ Good Design & Combustion Practices	Limit flue gas exhaust temperature ≤ 309 °F on a 365-day average, rolling daily.	2012	PSD-TX-903-GHG
Williams Olefins LLC, Geismar Ethylene Plant Geismar, LA	Ethylene Production	Energy Efficiency/ Low-emitting Feedstocks/ Lower-Carbon Fuels	Cracking heaters to meet a thermal efficiency of 92.5% Ethane/Propane to be used as feedstock Fuel gas containing 25% volume hydrogen on an annual basis	2012	PSD-LA-759
INEOS Olefins & Polymers U.S.A., Chocolate Bayou Plant Alvin, TX	Ethylene Production	Energy Efficiency/ Good Design & Combustion Practices	Limit flue gas exhaust temperature ≤ 340 °F. Fuel will have ≤ 0.71 lbs carbon per lb of fuel (CC); 0.85 lbs GHG/lbs of ethylene. 365-day total, rolled daily.	2012	PSD-TX-97769-GHG
Equistar Chemicals, La Porte Complex La Porte, TX	Ethylene Production	Energy Efficiency/ Good Design & Combustion Practices	Cracking furnaces to meet a thermal efficiency of 91% and flue gas exhaust temperature ≤ 302 °F	2013	PSD-TX-752-GHG
Equistar Chemicals, Channelview North Plant Channelview, TX	Ethylene Production	Energy Efficiency/ Good Design & Combustion Practices	Cracking furnaces to meet a thermal efficiency of 89.5% and flue gas exhaust temperature ≤ 408 °F	2013	PSD-TX-748-GHG

Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
Chevron Phillips Chemical Company, Cedar Bayou Plant Baytown, TX	Ethylene Production	Energy Efficiency/ Good Design & Combustion Practices	Limit flue gas exhaust temperature ≤ 350 °F on a12-month rolling average basis.	2013	PSD-TX-748-GHG
ExxonMobil Chemical Company, Baytown Olefins Plant Baytown, TX	Ethylene Production	Energy Efficiency/ Good Design & Combustion Practices	Limit flue gas exhaust temperature ≤ 340 °F on a 365-day rolling average. Maximum firing rate of 515 MMBtu/hr.	2013*	PSD-TX-102982-GHG

*Permit currently under review by the EPA Environmental Appeals Board.

OxyChem will only utilize ethane as a feedstock to produce ethylene, making the facility similar to INEOS, Williams Olefins, and ExxonMobil in the table above. OxyChem is proposing that BACT be based on a furnace flue gas exhaust temperature of ≤340 °F on a 12 month rolling average. This temperature is comparable to the other Olefins Plants in the table above that will only use ethane as a feed. The OxyChem facility will have a specific energy consumption (SEC) value of 16.1 MMBtu/ton ethylene, which is less than ExxonMobil's SEC of 17.2 MMBtu/ton ethylene. In addition OxyChem will meet an output based limit of 0.39 tons CO_2e/ton ethylene produced at all times, including during MSS.

BACT for this application will include the following:

- Low carbon fuels – Use of low carbon fuels such as the proposed hydrogen rich vent gas from the ethylene recovery section instead of only natural gas for fuel in the cracking furnaces will reduce the amount of carbon dioxide generated in the combustion process.
- Energy efficient design – Use of waste heat recovery from the furnace flue gas in the form of heat exchangers on the furnace process outlets; and boiler feed water economizers in the furnace stacks, offsets GHG emissions from other process heating sources. The stack gas temperatures will be maintained at less than 340°F during normal operation, which is consistent with other recently issued permits for similar processes.
- Furnace excess air control – Monitoring of oxygen in the stack gas and controlling excess air based on a limit of 10% oxygen is for optimal efficiency.
- Good operating and maintenance practices – Visual monitoring of flame patterns and periodic cleaning of burner and feed nozzles to assure complete combustion and efficiency. Also includes periodic refractory repair and cleaning of process heating and waste heat recovery systems when required to maximize thermal efficiency.

The following table lists the proposed compliance monitoring methodology selected as BACT for the ethane cracking furnaces:

Table 7: Furnace Operating and Maintenance Practices

Furnace Operating and Maintenance Practices					
Operating/ Maintenance Practice	**Frequency**	**Method of Ensuring Compliance**	**Recordkeeping Method**	**Indicators**	**Corrective Actions**
Stack oxygen concentration monitoring	Continuous	Maintain records, planned maintenance and calibrations	Electronic	Oxygen concentration >10%	Operating parameter adjustment
Stack temperature monitoring	Continuous	Maintain records, planned maintenance, and calibrations	Electronic	Stack temperature > 340 ºF	Operating parameter adjustment
Visual inspection of burners during operation	Weekly	Established operator work requirement	Electronic and paper	Abnormal flame pattern	Online cleaning or repair
Visual inspection of burners during furnace shutdown	2 to 3 times per year	Planned maintenance schedule	Maintenance records	Damaged burner or refractory	Repair or replace equipment
TLE Performance	Continuous	Maintain records	Electronic	High process fluid exit temperature (>850ºF)	TLE cleaning

BACT Limits and Compliance:

Implementation of the operational and maintenance practices above results in an annual emission limit of 59,035 TPY of CO_2e for each furnace. OxyChem will meet an output-based BACT limit of 0.39 ton CO_2e/ton of ethylene produced on a 12 month rolling average including periods of furnace MSS. The proposed emission limit is based on a 12 month rolling total basis as monitored by a Continuous Emissions Monitoring System (CEMS) for CO_2. The CO_2 CEMS will be operated as in 40 CFR 60 Appendix B, Specification 3 and meet the quality assurance procedures of 40 CFR 60, Appendix F. A data acquisition handling system (DAHS) will be used to measure and record the CO_2 to demonstrate compliance with the annual emission limit and the BACT limit. In addition to meeting the quantified emission limit, EPA is proposing that OxyChem will demonstrate compliance with energy efficient operations by continuously monitoring the exhaust stack temperature of each furnace. The maximum stack exit temperature of 340^{o}F on a 12 month, rolling average basis will be calculated daily for each furnace.

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 blended fuel gas, and the actual heat input (HHV). However, the emission limit is for all GHG emissions from the furnace, and is met by aggregating total emissions. To calculate the CO_2e emissions, the draft permit requires calculation of the emissions based on the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1, as published on November 29, 2013 (78 FR 71904). Records of the calculations would be required to be kept to demonstrate compliance with the CO_2e emission limit on a 12-month average, rolling monthly.

An initial stack test demonstration will be required for CO_2 emissions from one of the five emission units to verify that the CO_2e limit will be met. The stack test will also monitor the exhaust stack temperature to ensure compliance with the BACT limit of 340°F on a 12 month rolling average. An initial stack test demonstration for CH_4 and N_2O emissions are not required because the CH_4 and N_2O emission are less than 0.01% of the total CO_2e emissions from the furnaces and are considered a *de minimis* level in comparison to the CO_2 emissions.

X. Ethane Cracking Furnaces Nos. 1 through 5 - MSS Activities (EPNs: CR-1-MSS through CR-5-MSS)

The ethane cracking furnaces mentioned above have three additional scenarios that can be described as follows:

- Furnace Cold Start-up - When the furnaces are starting up after a complete plant shutdown, there is no process generated fuel gas available and pipeline supplied natural gas is fired in the furnaces.
- Hot Steam Standby - Hot steam standby mode of operation is established immediately after a furnace has completed a steam decoke. During hot steam standby, the furnace has steam flowing through the tubes, minimum firing rate on the firebox, and the furnace discharge is routed to the quench tower. This operation mode is maintained until the furnace is placed back in the normal operation mode.
- Steam Decoking - Due to the high furnace tube temperatures during normal operations, coke deposits build up on the furnace tube walls. To maintain efficient furnace operation, this coke must be removed periodically using a steam decoking process.

Carbon deposits or coke gradually build up on the tube walls of the furnaces during normal operations. This coke build up interferes with heat transfer through the tubes, which increases furnace temperatures and reduces thermal efficiency. The furnace deposits must periodically be removed or decoked. This decoking is accomplished with the introduction of steam and air at high temperatures to convert the deposits to gaseous carbon dioxide. The exhaust gas is discharged through the furnace with the flue gas. The carbon dioxide emissions from this decoking maintenance activity are included in the emissions from the cracking furnaces.

The steam decoking process is started by cutting the ethane feed to an operating furnace while leaving steam flowing through the furnace tubes, and maintaining firebox heat input at a reduced rate. The furnace discharge continues to feed forward to the quench tower until the ethane is purged from the furnace tubes.

Once the furnace tubes are cleared of ethane, the furnace discharge is diverted from the quench tower to the furnace firebox. Air is added to the furnace tubes along with steam, to begin burning coke in the furnace tubes.

The air flow is gradually increased until all of the coke is burned off. Once decoking has been completed, the air flow to the tubes is cut off, steam flow is maintained on the furnace tubes, minimum firing is maintained on the firebox, and the furnace outlet is re-routed to the quench column.

The emissions from these activities were reviewed and the only possible increase in GHG emissions involves the steam decoking scenario. However, as shown in the emission calculations, steam decoking GHG emissions are not greater than emissions estimated for normal operations.

Step 1 - Identification of Potential Control Technologies

Potential GHG emission control technologies for decoking the cracking furnaces were identified as follows:

- Mechanical cleaning – Use shot blast or hydro-lancing to mechanically remove coke from the tubes. The coke would then be disposed of in a solid waste landfill.
- Reduced air – Limit the air feed to reduce carbon dioxide formation.
- Low coking design and operation – Proper furnace coil design and using anti-coking agents during normal operation will tend to reduce coke formation and minimize carbon dioxide formation.
- Good operating practices – Periodic visual inspections of the furnace and monitoring of the furnace stack temperature to determine when decoking is needed.

Step 2 - Elimination of Technically Infeasible Alternatives

Reduced Air

The reduction in air is not technically feasible. Limiting air could result in an incomplete decoke, which would lead to an increase in the frequency of decoke events. Because coke buildup acts as an insulator, its presence decreases the efficiency of the furnace, resulting in an increase in CO_2. Therefore, reduced air feed is eliminated as a control technology.

Mechanical Cleaning

The cracking furnaces have vertical tube coils of varying diameters. Mechanical cleaning of the coils would require the cutting and physical removal of the furnace coils and bends during each decoke. The coils would then have to be re-welded after cleaning. The practical and potential safety issues with the re-welding of materials are excessive for the minimal reduction in GHG emissions. The operation would also generate additional PM emissions from the decoking, which is a highly regulated pollutant. Therefore, mechanical cleaning is eliminated as a control technology.

All other options are considered technically feasible.

Step 3 - Ranking of Remaining Technologies Based on Effectiveness

- Low Coking Design and Operation - GHG reductions from coil design and use of anti-coking agents is difficult to quantify. However, it is estimated that these activities will extend the furnace run life by 25% and increase furnace run time between decoking activities, resulting in a reduction in carbon dioxide emissions equivalent to about 160 tons per year. This is considered the second most effective control technology for this application.
- Good Operating Practices - Visual inspections and furnace stack temperature monitoring have been included with the proposed furnace design. Implementing these elements is effective in avoiding unnecessary CO_2 in the ethane cracking furnaces, but the effects are not directly quantifiable.

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

Low coking design and operation

Minimizing coke formation through the proper furnace coil design for the feedstock and the use of anti-coking agents will increase furnace run time between decoking and improve furnace efficiency, thereby reducing operating costs. These design features are included in the proposed furnace design.

Good operating practices

Visual inspections and furnace stack temperature monitoring have been included with the proposed furnace design.

Step 5 - Selection of BACT

The use of a proper coil design for the ethane cracking furnaces and using anti-coking agents as needed in the furnace feed to maximize the furnace run time between decokes is considered BACT for minimizing coke formation. The amount of anti-coking agent will be highly dependent on the furnace condition and operation. Therefore, a frequency or amount of anti-coking agent addition cannot be quantified.

Good operating practices are also selected as BACT for minimizing coke formation, including periodic visual inspections of the furnace firebox and cleaning the convection section when the furnace stack temperatures exceed the 340ºF permit limit. The total number of furnace decokes is expected to be 36 per year. This frequency was the basis for estimating GHG emissions, however, the actual number of decoke events required per year can vary and the need for decoking will be based on temperature monitoring, as described above.

XI. Thermal Oxidizers Nos. 1 and 2 (EPNs: CR-6 and CR-7)

The thermal oxidizer system for the proposed facilities includes two identical combustion units with waste heat boilers expected to fire pipeline natural gas and waste gas at a maximum rate of 85 MM Btu/hr. Typically, these units will both be operating and will share the load of waste gases generated by the new facilities.

Waste gases include both continuous and intermittent streams from the process and storage vessels. All non-pressurized storage tanks at the site handling VOC materials with vapor pressures greater than 0.5 psia are vented to the thermal oxidizers for control.

Also, emissions from pyrolysis gasoline truck loading will be handled through the oxidizers. The pressure ratings of trucks are sufficient to maintain 100% collection of displaced vapors.

Because each thermal oxidizer is capable of handling all of the waste gas from the proposed facilities, each unit will be permitted at maximum rates so that operational flexibility is maximized. Also, the thermal oxidizers will be equipped with heat recovery boilers to recover waste heat for increased energy efficiency. Steam generation from these units is intended to reduce the demand for steam from the existing cogeneration units.

Non-condensable vent streams from the ethane cracking process, storage and loading area are generally combusted to destroy VOC before the inert gases are released to the atmosphere. This control can be accomplished in elevated flares, enclosed flares, and vapor combustors (thermal oxidizers). The destruction efficiency and the potential GHG control technologies vary depending on the type of VOC control device selected.

Thermal oxidizers were selected as the primary control technology because they can achieve a higher destruction efficiency of VOCs than flares, and provide for heat recovery. Waste heat recovery on the two thermal oxidizers, included in the proposed design, is an energy efficiency improvement by using waste heat to generate steam; and thereby lessening fuel firing in other steam generating sources.

Step 1 - Identification of Potential Control Technologies

The following BACT analysis was used to identify the best method for controlling GHG emissions from the selected thermal oxidizers, available control technologies are identified as follows.

- Thermal efficient combustor design – Design achieves good fuel and air mixing with sufficient temperatures to ensure complete combustion and to maximize thermal efficiency.
- Low carbon fuels – Use of low carbon fuels to reduce the amount of carbon dioxide generated by burner or supplemental fuel combustion process.
- Oxidizer air/fuel control – Monitoring of oxygen in the flue gas and firebox temperature for optimal efficiency.
- Flame monitoring and periodic tune-up – Visual monitoring of flame patterns and cleaning of burner and feed nozzles to assure complete combustion and efficiency. Also, includes periodic refractory repair and cleaning of waste heat recovery systems when required to maximize thermal efficiency.
- Waste heat recovery – Use of thermal oxidizers with high firebox temperatures and waste heat recovery from the oxidizer exhaust to preheat the combustion air or produce steam for use at the site, thereby offsetting GHG emissions from other fuel combustion sources.
- Carbon capture and storage – Capture, compression, transport and geological storage or use of CO_2 in the thermal oxidizer flue gas exhaust. CO_2 emissions from the thermal oxidizer flue gas could be absorbed in a conventional amine solvent. The CO_2 could then be concentrated in an amine regenerator vent stream, compressed and routed to oil production facilities using CO_2 for EOR or stored in geologic formations. OxyChem

previously noted that the measured route to EOR (180 miles) is closer than other potential geologic storage sites. The nearest location for EOR would be the Hastings CO_2 flood near Pearland, Texas.

Step 2 - Elimination of Technically Infeasible Alternatives

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. *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 a similar VOC control device. 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 sources that have low volume CO_2 streams, such as the thermal oxidizers for this project. As a result, EPA believes that CCS is technically infeasible for the thermal oxidizers and can be eliminated as BACT. Nevertheless, because OxyChem has provided a cost analysis of CCS with its permit application, we have decided to evaluate CCS through Step 4 of the BACT analysis. In regards to the remaining control options, EPA finds that all are technically feasible.

Step 3 - Ranking of Remaining Technologies Based on Effectiveness

- Carbon Capture and Storage - If CCS were technically feasible for this source category or process, it is assumed that CCS would reduce GHG emissions from the thermal oxidizers by 97,090 tons/yr based on 90% capture of CO_2 and would be the most effective control method for the thermal oxidizers.
- Waste Heat Recovery - Waste heat recovery can reduce GHG emissions from the cogeneration units by reducing steam demand for the proposed Ethylene Plant. It is estimated that GHG emissions from the cogeneration facilities will be reduced by about 18,200 tons/yr as a result of installing waste heat recovery on thermal oxidizers. This reduction is based on the more efficient cogeneration operation of raising gas turbine loads to maintain power output. This approach is considered the next most effective control technology.
- Thermal Efficient Combustor Design, Fuel Selection, Oxidizer Air/Fuel Control, and Flame Monitoring (Good Engineering Practices) - Combustor design, oxidizer air/fuel with temperature control, stack gas oxygen monitors, use of pipeline natural gas for burner and supplemental fuel, and flame monitoring are considered good engineering practice and have been included with the proposed design. Evaluating their effectiveness and a subsequent evaluation of each technology is difficult to quantify, but they are all considered effective for minimizing GHG emissions from the thermal oxidizers.

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

Carbon Capture and Storage

Even though CCS was determined to be technically infeasible at Step 2, the applicant provided additional evidence that supports the rejection of CCS as BACT in Step 4. The capture, compression, and sequestration of the CO_2 in the flue gas from the thermal oxidizers would reduce the GHG emissions from the thermal oxidizers by 97,090 tons/yr based on 90% capture efficiency, but would require an additional 165 MMBtu/hr of fuel to strip the CO_2 from the solvent. A new natural gas-fired boiler would be needed to supply this additional steam demand and was included in the cost analysis for CCS. This approach would also create additional GHG emissions. It is estimated that the increased GHG emissions from the new boiler for CCS would be 84,353 tons/yr.

Table 8 - Emissions Assuming Natural Gas Fired Boiler for new Amine Regenerator

Assume maximum firing for maximum CO_2 capture		
Max CO_2 emissions from Thermal Oxidizers (100% load)	12,315	lb/hr per thermal oxidizer
CO_2 Capture (assuming 90% recovery) - 2 Thermal Oxidizers	97,090	ton/year
Total CO_2 capture	22,167	lb/hr
Use gas processing data on amine absorber-strippers from Campbell Gas Processing Books		
From J.M. Campbell & Co Gas Processing Handbook (Table 4.10))		
Energy Required per lb of CO_2 for Regeneration	72000	Btu/hr per gpm of DEA
Solvent Specific Gravity	1.1	
Factor per lb Solvent	130.8	Btu/lb of solvent
Solvent Concentration (Aqueous DEA)	25%	
Factor per lb of DEA	523	Btu/lb of DEA
Moles CO_2/Mole DEA	0.2	
Energy Required per lb of CO_2 absorbed	6242.9	Btu/lb CO_2
Additional Steam Energy Required for Amine Regenerator	138.4	MMBtu/hr
Boiler Efficiency	84%	
Fuel Required	164.7	MMBtu/hr
CO_2 Factor	116.9	lb/MMBtu/hr
CO_2 Produced	19,259	lb/hr
CO_2 Produced from boilers for regenerator	84,353	ton/year

Consequently, the net overall reduction in CO_2 emissions from the thermal oxidizers from CCS would be 12,737 tons/year (97,090 – 84,353 tons/year). If this additional amount of CO_2 generated was considered in the cost analysis, the total cost would be $1,428/ton. However, the cost-effectiveness analysis for a CCS system designed to control the thermal oxidizers (shown below) conservatively does not include the increase in GHG emissions from the new boiler.

The estimated annualized capital and operating and maintenance (O&M) costs for the recovery and compression equipment for the OxyChem thermal oxidizers was originally estimated to be $12,397,681 per year (utilizing a capital recovery factor of 6.14% and equipment life of 30 years). However, after a review of similar recently submitted ethylene plant CCS system designs and associated costs that were approved by the EPA Region VI, OxyChem conservatively adjusted the annualized cost to be about $9,808,791 per year. A summary of the estimated costs are included in Table 9.

Table 9 - Economic Analysis for Carbon Capture and Compression

Cost Type	Units	OxyChem's Original Estimate ($ Millions)	Updated Cost Estimate ($ millions)
Carbon Capture Plants - Capital and Operating Expense Estimation			
CO_2 Compressor and Intercoolers	$ (millions)	120.5	10.2
Amine Absorber Systems, CO_2 Purification System, Blower, Piping, Boiler, and Ducting	$ (millions)		79.0
Total Capture and Compression Costs	**$ (millions)**	**120.5**	**89.1**
Utility Plant - Capital and Operating Expense Estimation			
Fuel, Utilities, Amine	$ (millions) / yr	15	4.3
Total Expense Estimation - 90% Capture [1]			
Operating Expense	$ / Ton CO_2 Avoided	51	45
Capital Expense [2]	$ / Ton CO_2 Avoided	76	56

[1] Calculations –
Operating Expenses / Total CO_2 Captured;
Total Capital Expenses * Capital Recovery Factor / Total CO2 Captured
[2] Based on a capital recovery factor of 6.14% with an expected equipment life of 30 years and an interest rate of 4.5%.

The estimated annualized capital and operating and maintenance (O&M) costs for CO_2 transport was originally estimated to be $29,289,359 per year (utilizing a capital recovery factor of 6.14% and equipment life of 30 years). This included eight pumping stations that would be required for the 180 mile pipeline. However, utilizing the 2013 National Energy Technology Laboratory, Estimating Carbon Dioxide Transport and Storage Costs 2013 documentation that has been utilized in recently submitted ethylene plant CCS system designs and associated costs that were approved by the EPA Region VI, OxyChem is conservatively adjusting the annualized cost to be about $8,385,233 per year. Additionally, significant potential corrosion issues and material selection requirements would be created by the sulfur dioxide in the flue gas.

A summary of the costs are included in Table 4 in a previous section and a summary of the carbon compression and pipeline analysis is included in Table 10.

Table 10 - Economic Analysis for CCS

Cost Type	Units	Estimated Cost ($ millions)
Carbon Capture Plants - Capital and Operating Expense Estimation		
CO_2 Compressor and Intercoolers	$ (millions)	10.2
Amine Absorber Systems, CO_2 Purification System, Blower, Piping, Boiler, and Ducting	$ (millions)	79.0
Pipeline Material and Costs	$ (millions)	111.8
Utility Plant - Capital and Operating Expense Estimation		
Fuel, Utilities, Amine	$ (millions) / yr	4.3
Piping Annual O&M	$ (millions) / yr	1.52
Total CO_2 CCS Cost Estimation at 90% Capture [1]		
Total	$ / Ton CO_2 Avoided	187.39

[1] A capital charge rate of 6.14% was assumed with an expected equipment life of 30 years and an interest rate of 4.5% (per NETL).

Estimated annual revenue from the sale of CO_2 would be $1,940,000 based on $20 per ton for use in EOR. Based on the amount of CO_2 that could be captured, OxyChem would not qualify for the additional tax credit. The average cost-effectiveness for CCS is estimated to be $167/ton of CO_2 emission reduction based on annualized cost estimates, as shown in Table 11 below.

Table 11 - CCS Cost Effectiveness including Offsets (Sale of CO_2)

CCS Technology for CO_2 Emissions	Tons of CO2 Avoided per Year[1]	Cost - 90% Capture ($/ton of CO_2 Avoided)	Total Annual Cost[2] (Million $ per year)
Capture and Compression	97,091	101	9.81
Transport	97,091	86.36	8.39
Total CCS Cost (without offsets)	**97,091**	**187.39**	**18.19**
Sale to EOR	97,091	(20.00)	(1.94)
Total CCS Cost (with offsets)	**97,091**	**167.39**	**16.25**

[1] This represents 90% Capture of the total CO_2 emissions from the thermal oxidizers.

[2] Total Annual Cost represents an amortized cost for the capital expenditure and operating and maintenance costs. A capital charge rate of 6.14% was assumed with an expected equipment life of 30 years and interest rate of 4.5%.

The addition of CCS for the thermal oxidizers would increase the total project cost by over 20%. The cost to add CCS to the thermal oxidizers is relatively low compared to the cost to add CCS to the furnaces due to the relatively small amount of CO_2 being recovered. Because use of the thermal oxidizers with waste heat recovery for control of low pressure vents is considered BACT relative to the use of a flare, and the added cost of CCS for the thermal oxidizers would raise the cost of installing the thermal oxidizers by more than 30 fold. These costs compared to similar facilities which have been permitted recently are considered to be cost prohibitive by EPA. Therefore, this option is rejected as a control option for GHG emissions.

Waste Heat Recovery and Good Engineering Practices

Combustor design, oxidizer air/fuel with temperature control, stack gas oxygen monitors and flame monitoring are considered good engineering practice and have been included with the proposed design. Evaluating their effectiveness and a subsequent evaluation of each technology was not considered necessary for this BACT determination.

Step 5 - Selection of BACT

Implementing the following design and operating practices is considered BACT for minimizing GHG emissions from the proposed thermal oxidizers in this project:

- Waste heat recovery – The thermal oxidizers will operate with high firebox temperatures and waste heat recovery from the oxidizer exhaust to preheat the combustion air and produce steam for use at the site. Heat recovery will be ensured by monitoring waste heat with a target stack temperature of approximately 500 ºF. As a result, GHG emissions will be minimized from other fuel combustion sources.
- Thermal Efficient Combustor design – Thermal efficient design achieves good fuel and air mixing with sufficient temperatures to ensure complete combustion and to maximize thermal efficiency. The firebox will be lined with refractory to minimize heat losses to the atmosphere. The firebox temperature will be monitored and maintained at a temperature of 1,300 °F or more to assure complete combustion and improve energy recovery.
- Use of pipeline natural gas for burner and supplemental fuel will minimize GHG emissions and therefore is considered part of good operation practices.
- Oxidizer air/fuel control – Monitoring of oxygen in the flue gas and firebox temperature for optimal efficiency will minimize GHG emissions from the thermal oxidizers. An oxygen analyzer in each stack will be provided to assure the proper amount of air is used in the combustion process. Vent gas feed, supplemental natural gas fuel and combustion air flow will be metered into each thermal oxidizer.

- Flame monitoring and periodic tune-up – Visual monitoring of flame patterns and cleaning of burner and feed nozzles when needed to assure complete combustion and efficiency. Periodic refractory repair and cleaning of waste heat recovery systems when required will maximize thermal efficiency.

Table 12: Thermal Oxidizer Operating and Maintenance Practices

Furnace Operating and Maintenance Practices					
Operating/ Maintenance Practice	**Frequency**	**Method of Ensuring Compliance**	**Recordkeeping Method**	**Indicators**	**Corrective Actions**
Stack oxygen concentration monitoring	Continuous	Maintain records, planned maintenance and calibrations	Electronic	Oxygen concentration >10% averaged daily	Operating parameter adjustment
Thermal Oxidizer firebox temperature monitoring	Continuous	Maintain records, planned maintenance, and calibrations	Electronic	Firebox temperature > 1300 °F on an hourly basis	Operating parameter adjustment
Waste Heat Recovery exhaust temperature monitoring	Continuous	Maintain records, planned maintenance, and calibrations	Electronic	Stack temperature < 500 °F on an hourly basis	Operating parameter adjustment
Thermal Oxidizer Feed Flow monitoring on natural gas, waste gas, and combustion air flows.	Continuous	Maintain records, planned maintenance, and calibrations	Electronic	-	-

Implementation of the operational and maintenance practices above results in an annual emission limit of 54,131 TPY of CO_2e for each thermal oxidizer. In addition to meeting the quantified emission limit, EPA is proposing that OxyChem will demonstrate compliance with energy efficient operations by continuously monitoring the firebox temperature of each thermal oxidizer. When combusting process vents, the minimum temperature of 1,300°F on a 12-month, rolling average basis will be calculated daily for each thermal oxidizer. The proposed emission limit is based on a 12-month rolling total basis as monitored by a Continuous Emissions Monitoring System (CEMS) for CO_2. The CO_2 CEMS will be operated as in 40 CFR 60 Appendix B, Specification 3 and meet the quality assurance procedures of 40 CFR 60, Appendix F. A data acquisition handling system (DAHS) will be used to measure and record the CO_2 to demonstrate compliance with the annual emission limit and the BACT limit.

XII. High Pressure Flare (EPNs: CR-8 and CR-8-MSS)

The high pressure flare is used to safely combust large volumes of non-condensable flammable hydrocarbon vapor streams during start-up and shutdown, emergency conditions, and decommissioning of large volumes of hydrocarbons for maintenance. Under normal operation, the only GHG emissions associated with the flare are from the natural gas pilot burners. This BACT analysis considers potential control technologies for combusting natural gas in the flare pilots.

Step 1 - Identification of Potential Control Technologies

Potential GHG emission control technologies for the emergency flare are identified as follows:

- Staged flare design – the installation of a staged flare design with good combustion practices to minimize assist gas during low load operation will reduce GHG emissions from the flare when in operation.
- Waste heat recovery – Use of waste heat recovery from the planned MSS flare exhaust to produce steam for use at the site, thereby offsetting GHG emissions from other fuel combustion sources.
- Carbon capture and storage (CCS) – Capture, compression, transport and geological storage or use of CO_2 in the planned MSS flare exhaust.
- Low carbon fuels – Use of low carbon fuels to reduce the amount of carbon dioxide generated in the pilot fuel combustion process. The use of a low carbon fuel for assist gas will reduce GHG emissions from the flare when assist gas is required at low planned MSS loads.
- Pilot reliability and sizing – The use of energy efficient (low BTU) pilots to minimize natural gas consumption.
- Pilot flame monitoring – Monitoring of the pilots with temperature monitors.

Step 2 - Elimination of Technically Infeasible Alternatives

Waste heat recovery and CCS would require an enclosed combustion system. This is not technically feasible for safety reasons because the flare also controls instantaneous high flows from the emergency relief system. The remaining control options are technically feasible.

Step 3 - Ranking of Remaining Technologies Based on Effectiveness

- Staged Flare Design - A staged flare design minimizes the use of supplemental assist gas required for complete combustion over a large operating range of planned MSS for the flare. This is considered the most effective control technology.

- Pilot Reliability and Sizing - Modern high efficiency pilots can reduce natural gas consumption by about 30% over larger traditional pilots. This approach will reduce GHG emissions by about 253 tons/yr.
- Low Carbon Fuels - Use of pipeline natural gas for pilot fuel and assist gas will assure reliable flare operation while minimizing GHG emission compared to other carbon rich fuels. The use of a low carbon assist gas such as natural gas will further reduce the GHG emissions when assist gas is required at very low planned MSS loads. This approach is considered the next most effective technology for GHG emission control for this application.
- Pilot Flame Monitoring - Pilot flame monitoring is considered good operational practices which have been included with the proposed design.

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

Staged Flare Design

Staged flaring is economically and environmentally practical for the proposed project.

Pilot Reliability and Sizing

High efficiency pilots reduce natural gas consumption as well as GHG emissions and do not cost more than larger traditional pilots. Therefore, they are included in the proposed design.

Low Carbon Fuels and Pilot Flame Monitoring

Use of pipeline natural gas for pilot fuel and assist gases, pilot flame monitoring, and burner preventative maintenance are considered good operational practices for safety as well as environmental compliance and have been included with the proposed design.

Step 5 - Selection of BACT

The following specific BACT practices are proposed for the high pressure flare:

The use of a staged flare with good combustion practices provides the most reliable and effective control of VOC emissions with the least amount of supplemental assist fuel, which also minimizes cost and GHG emissions. The use of high efficiency pilots with good operational practices, including use of pipeline natural gas for pilot fuel and pilot flame monitoring will be included for safety and performance. Natural gas is also considered the most reliable and economical assist gas. Total pilot duty for all stages will be minimized, and therefore GHG emissions will be minimized. Each pilot will be monitored with a thermocouple. Both electronic and flame front generator systems will be provided for lighting the pilots.

OxyChem proposes to monitor and record the following parameters to demonstrate continuous compliance with the high pressure flare operating specifications:

- Continuously monitor and record the pressure of the flare system header,
- Continuously monitor and record the flow to the flare through a flow monitoring system,
- Continuously monitor the composition of the waste gas contained in the flare system header through an online analyzer located on the common flare header, and record the heating value of the flare system header,
- Maintain a minimum heating value and maximum exit velocity that meets 40 CFR § 60.18 requirements for the routine streams routed to the flare including the assist gas flow or the requirements of an approved equivalency determination, and
- Monitor and maintain a minimum heating value of 800 Btu/scf of the waste gas (adjusted for hydrogen) routed to the flare system to ensure the intermittent stream is combustible.

Using these operating practices above will result in an emission limit for the flare of 70,684 TPY CO_2e. OxyChem will demonstrate compliance with the CO_2e 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 ethane and waste gas (see Tables 3-3C and 3-3D 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:

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

Where:

CO_2 = Annual CO_2 emissions for a specific fuel type (short tons/year).
DRE = 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 GHG mass emission limits in TPY associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Subpart C, Table C-2 using the GWPs as published on November 29, 2013 (78 FR 71904), site specific analysis of waste gas, and the actual heat input (HHV).

XIII. Emergency Generator Diesel Engine (EPN: CR-9)

The diesel-fired emergency generator engine is included in this application for the Ethylene Plant because the engine generates GHG emissions during its scheduled testing. Use of this engine for emergency conditions will not be authorized by this permit because these emergency events are not subject to permitting requirements.

Step 1 - Identification of Potential Control Technologies

A natural gas-fired or electrically driven engine could be considered as alternatives to a diesel engine; however, availability of natural gas and/or electricity during emergency events is not as certain as a diesel-fuel, and so, these alternatives are not considered as practical technologies for this service.

Potential GHG emission control technologies considered in the BACT analysis for this engine are identified as follows:

- EPA Tier 2 (40 CFR § 89.112 Table 1) level of emission limitations for combustion products.
- Change oil and filter every 500 hours of operation or annually, whichever comes first.
- Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first.
- Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.

Step 2 - Elimination of Technically Infeasible Alternatives

All options identified above are considered technically feasible.

Step 3 - Ranking of Remaining Technologies Based on Effectiveness

The ranking of the identified control technologies for emergency diesel engines mentioned in Step 1 are difficult to determine relative to effectiveness of emissions control, but all are expected to be relevant for maintaining clean operations. These are based on the 40 CFR Part 63, Subpart ZZZZ (RICE MACT) requirements, and therefore are meant to minimize emissions.

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

All of the available control technologies identified are considered cost-effective and have minimal negative energy and environmental impacts.

Step 5 - Selection of BACT

All of the identified control technologies in Step 1 are considered as appropriate measures of BACT and will be utilized for minimizing GHG emissions from the diesel emergency generator engine.

The following specific BACT practices are proposed for the engines:

- *Good Operation and Maintenance Practices* – Good operation and maintenance 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.

Using the operating and maintenance practices identified above results in an emission limit of 61 TPY CO_2e for the engine. OxyChem will demonstrate compliance with the CO_2 emission limit using the emission factors for diesel 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)(3)(ii) is as follows:

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

Where:

CO_2 = Annual CO_2 mass emissions from combustion of diesel fuel (short tons)

Fuel = Annual volume of the liquid fuel combusted (gallons). 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 liquid 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).
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.

XIV. Cooling Tower (EPN: CR-11)

The cooling requirements for the proposed Ethylene Plant will be provided by evaporative cooling systems. To prevent scale formation, acid is injected into the circulation water system to reduce the alkalinity and pH.

In the process, bicarbonate ion is converted into CO_2, which de-gasses in the cooling tower. CO_2 is discharged to the atmosphere through the mechanical draft cooling tower fan stacks.

The CO_2 emissions are conservatively estimated using the maximum expected bicarbonate concentration and cooling tower make-up water flow rate assuming all the bicarbonate ion is converted to CO_2. In actual practice, some bicarbonate remains in the circulating water and is removed with the blowdown water from the cooling tower.

Step 1 - Identification of Potential Control Technologies

Potential GHG emission control technologies for the cooling tower are identified as follows:

- Low cycles of concentration – The tower could be operated at sufficiently low cycles of concentration so as to not require any acid addition.
- Acid and blowdown control – Monitoring of circulating water pH and conductivity to control the acid addition and blowdown to control water chemistry.
- Pretreatment of make-up water – Use a reverse osmosis system to remove bicarbonates in the make-up water.
- Once-through seawater cooling – Use of once through seawater for process cooling rather than an evaporative cooling system.
- Air cooling – Use of air coolers rather than an evaporative cooling water system for process cooling.

Step 2 - Elimination of Technically Infeasible Alternatives

All options identified above are considered technically feasible.

Step 3 - Ranking of Remaining Technologies Based on Effectiveness

Once Through Seawater Cooling

The use of once through seawater cooling tower would eliminate 100% of CO_2 emission from the cooling tower with minimal increase in power or thermal combustion related GHG emissions. This approach is considered the most effective control for GHG emissions.

Air Cooling

The use of air cooling would also eliminate 100% of the CO_2 emissions from the cooling tower; however, it would significantly increase the power and thermal energy requirements for the Ethylene plant due to higher operating temperatures and pressures in the refrigeration and distillation column condensers. This approach is considered the second highest effective control technology for cooling towers. However, this technology would result in increased GHG emissions from the cogeneration facilities.

Pretreatment of Make-up Water

Pretreatment of the make-up water in a reverse osmosis system could remove most of the bicarbonates from the cooling tower make-up and potentially eliminate the CO_2 emissions from the cooling tower. This approach is considered the third most effective control technology for the cooling towers. However, this pretreatment would result in increased GHG emissions from the cogeneration facilities for the additional power requirements for the reverse osmosis systems, which require high water pressure to operate effectively.

Low Cycles of Concentration

Operation of the cooling tower with an increased wastewater blowdown rate to eliminate the needed acid addition and thereby bicarbonate concentration (aka low cycles of concentration), could reduce the CO_2 emissions by 80-90%. There is still some dissolved CO_2 in the make-up water that would be stripped out even if no acid were added. This approach is considered the next most effective control technology.

Acid and Blowdown Control

The effect on GHG emissions of using pH and specific conductivity monitoring to control the acid injection and blowdown is difficult to assess, but it is considered potentially effective means of reducing GHG emissions.

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

Once Through Seawater Cooling

The use of once through seawater cooling might be considered detrimental to fish and wildlife. The use of sea water can also lead to increased fouling of heat exchangers. Therefore, due to minimal reduction in GHG emissions, this technology is not selected as a control option for GHG emission on the basis of these negative consequences.

Air Cooling

The use of air cooling would eliminate the cooling tower GHG emissions, but would increase the emissions from the cogeneration facilities. It is difficult to assess quantities, but air cooling for these facilities would generally be expected to increase energy consumption by 5 - 10 %. This approach would generate 8,000 to 16,000 tons per year of increased GHG emissions from the cogeneration facilities. The increased emission would certainly be significantly more than the 668 tons per year that would be eliminated from the cooling tower. Therefore, air cooling is rejected on the basis of overall energy consumption and the resulting increase in GHG emissions.

Pretreatment of water makeup

Pretreatment of the make-up water in a reverse osmosis system would require increasing the water pressure by several hundred psig. The additional power requirements would add about 4 MMBtu/hr of natural gas firing at the cogeneration facilities, increasing the GHG emissions by 2,048 tons per year. These GHG emissions more than off-sets the elimination of the 668 tons per year of GHG emissions from the cooling tower. Therefore, pretreatment of the make-up water by reverse osmosis is rejected due to the overall potential increase in GHG emissions.

Low Cycles of Concentration

The blowdown rate from the cooling tower would need to be increased from 300 gallons per minute to at least 800 - 1200 gallons per minute to prevent scaling in the cooling water system without any acid addition. There is no other use for this water and it would have to be discharged as wastewater. This approach is considered extremely wasteful of fresh water, especially considering the minimal reduction in GHG emissions that would be realized, and therefore, this approach is rejected as a reasonable control option.

Acid and Blowdown Control

The use of pH and specific conductance monitoring of the cooling tower water have been used in industry to control scaling and/or corrosion in the cooling tower system. Implementation of the pH and conductivity monitors can also provided some control of GHG emissions by maintaining consistent alkalinity in the cooling tower water. These monitors are considered cost-effective with minimal energy and environmental impacts.

Step 5 - Selection of BACT

The following specific work practices were determined to be BACT for the cooling tower:

Due to the negative energy and environmental impacts of most of the control options, the only control option selected as BACT is acid and blowdown control. OxyChem will install pH and conductivity analyzers on the cooling water supply to control acid addition and blowdown. Laboratory instruments will be used to periodically check the accuracy of these devices and provide information when the on-line analyzers are out of service for an extended period of time due to maintenance. This approach will minimize the GHG emissions associated with the cooling tower and satisfy GHG BACT requirements.

Using the operating practices above will result in an emission limit for the cooling tower of 668 TPY CO_2e. Compliance will be based on the monthly calculation of GHG emissions. OxyChem shall, on a monthly basis, test the cooling tower make-up water for alkalinity following Method 2320B from the *Standard Methods for the Examination of Water and Wastewater*. The bicarbonate value from this analysis will be used to calculate CO_2 emissions from the cooling tower using the following equations.

$$HCO_3\ loading\left(\frac{lb}{hr}\right) = Makeup\ Water\left(\frac{lb}{hr}\right) \times bicarbonate\ (ppm)$$

$$CO_2\left(\frac{lb}{hr}\right) = HCO_3\left(\frac{lb}{hr}\right) \times 44 \times \left(\frac{1}{61}\right)$$

Where:
44 = Molecular Weight of CO_2
61 = Molecular Weight of HCO_3

$$CO_2\,TPM\ = CO_2\left(\frac{lb}{hr}\right)\times 2{,}000\frac{lb}{ton}\times xx\ hr/month$$

XV. C_3/C_4 Hydrogenation Reactor Regeneration Vent – MSS Activities (EPN: CR-12-MSS)

The unsaturated C3s and C4s are hydrogenated to propane and butane over a fixed bed catalyst in the C3/C4 Hydrogenation Reactor. Over time, carbon will deposit over the catalyst surface. Periodically the carbon deposits must be removed to maintain catalyst activity and reactor conversion. This is accomplished with the introduction of high temperature steam and air to convert the carbon deposits to gaseous CO_2. The exhaust gas is discharged to the atmosphere during this operation. Eventually, the catalyst can no longer be successfully regenerated and must be replaced.

Step 1 - Identification of Potential Control Technologies

Potential GHG emission control technologies for the C3/C4 Hydrogenation Reactor Regeneration Vent were identified as the follows:

- Catalyst disposal – Dispose of catalyst and replace with new catalyst instead of regenerating the catalyst.
- Reduced air – Limit the air feed to reduce carbon dioxide formation.
- Low coking design and operation – Proper reactor design and operation will tend to reduce coke formation and minimize carbon dioxide formation.

Step 2 - Elimination of Technically Infeasible Alternatives.

All of the identified alternatives are technically feasible.

Step 3 - Ranking of Remaining Technologies Based on Effectiveness

- Catalyst Disposal - Disposing of the catalyst by landfill would eliminate 100% of the GHG emissions (13 tons per year) from this source. This is the most effective control technology for GHG emissions from this source.
- Reduced Air - Reducing the air would result in some of the carbon being converted to carbon monoxide instead of carbon dioxide. It is estimated that potentially as much as 50% of the carbon could be converted to carbon monoxide instead of carbon dioxide which would reduce carbon dioxide emissions by 6.5 tons per year. This is considered the second most effective control technology.

- Low Coking Design and Operation - Low coking design and operation is difficult to quantify, but is considered an effective means of minimizing GHG emissions. Assuming run life is extended by 25%, the reduction in carbon dioxide emissions is equivalent to about 3 tons per year.

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

Catalyst Disposal

Disposing of the catalyst instead of regeneration would generate additional solid waste and represent a significant cost burden for replacement catalyst. The replacement cost for the C3/C4 hydrogenation catalyst is $1,500,000 for catalyst and $400,000 for labor and is typically replaced every 5 years, if regenerated on a regular basis. It is anticipated there will be up to 2 to 3 regeneration events per year. Therefore, the total cost for replacing the catalyst rather than regenerating would be $3,800,000 per year. This equates to $294,000 per ton of GHG avoided. This does not include the disposal costs associated with removing the catalyst. Therefore, this control technology is not considered cost-effective and is eliminated a possible control technology.

Reduced Air

Limiting the air feed would increase CO while reducing CO_2. CO is a criteria pollutant with higher toxicity than CO_2. As mentioned earlier in the furnace decoking BACT section, limiting air could also result in incomplete catalyst regeneration. Carbon deposits reduce catalyst activity and reactor conversion which would lead to an increase in the frequency of regeneration events. This alternative is rejected as a control option for GHG emissions because this could result in an increase in GHG emissions.

Low coking design and operation

Minimizing coke formation through the proper reactor design and operation to increase reactor run time between regeneration is considered cost-effective and will have minimal energy and environmental effects.

Step 5 - Selection of BACT

A proper reactor design with good operating practices will minimize coke formation and is considered BACT for C3/C4 Hydrogenation Reactor Regeneration Vent – MSS Activities. The reactor will be fed a C3/C4 distillate and a purified hydrogen stream to minimize contaminants and catalyst fouling. The reactor will be loaded with hydrogenation catalyst per catalyst supplier recommendations. Reactor temperatures, pressures, and hydrogen concentrations will be maintained within recommended levels. The annual emissions are estimated to be 13 TPY of CO_2. These emissions are based on regenerating the hydrogenation reactors twice a year.

XVI. Ethylene Plant Fugitive Emissions (EPNs: CR-13, CR-14, CR-15, and CR-16)

Fugitive emissions were estimated for the state PSD application for six areas of the proposed facilities: the CR Furnace Area Fugitives (EPN CR-13), the CR Charge Gas Area Fugitives (EPN CR-14), the CR Recovery Area Fugitives (EPN CR-15), the CR C_3+ Area Fugitives (EPN CR-16), the CR Waste Treatment and C_5 Area Fugitives (EPN CR-17) and the CR LPG Storage Area Fugitives (EPN CR-18). However, because the last two areas do not contain GHG pollutants, they are not included in this GHG application. Calculations utilize the TCEQ's SOCMI factors with ethylene, without ethylene and average factors, all based on the ethylene content of the streams.

Summary calculations are provided for only four of the six fugitive areas within the Ethylene Plant since these areas are the only ones that include GHG emissions. These areas include the following: the CR Furnace Area Fugitives (EPN CR-13), the CR Charge Gas Area Fugitives, (EPN CR-14), the CR Recovery Area Fugitives (EPN CR-15) and the CR C_3+ Area Fugitives (EPN CR-16).

Fugitive leakage from process equipment piping components associated with the proposed project includes methane and CO_2. The controlled emissions associated with the fugitive components have been estimated to be 3 tons/yr of methane and 0.1 ton/yr of CO_2.

Step 1 - Identification of Potential Control Technologies

Potential GHG emission control technologies for the fugitive emissions are identified as follows:

- Leakless Technology
- Administration of a monitored leak detection and repair (LDAR) program for fugitive emissions.
- Remote Sensing
- Audio/Visual/Olfactory (AVO) Monitoring

Step 2 - Elimination of Technically Infeasible Alternatives

All of the identified alternatives are technically feasible.

Step 3 - Ranking of Remaining Technologies Based on Effectiveness

- The use of leakless technology, such as barrier sealing systems for pumps and compressors, rupture discs for relief devices, and bellows sealed valves, is capable of 100% control for each source and is considered the most effective control technology.
- LDAR programs are typically used to control VOC emissions and can achieve up to 97% control of VOC emissions. Although not specifically designed for GHG emissions, they can be used to control methane emissions. Monitors typically used for Method 21 instrument monitoring cannot detect CO_2 leaks. However, they can be utilized to determine methane leaks. It is assumed that the same control factors can be applied to methane emission sources. Therefore, this is the second most effective control technology.
- Remote sensing using infrared imaging has proven effective for identification of leaks. The process has been the subject of EPA rulemaking for an alternative monitoring method to Method 21. Although effectiveness is likely comparable to that of EPA method 21, it has not been quantified. Therefore, this is the third most effective control technology.
- AVO means of identifying leaks owes its effectiveness to the frequency of observation opportunities. These opportunities arise as technicians make inspection rounds. This method cannot generally identify leaks at a low leak rate as instrumented readings can identify. However, low leak rates have lower potential impacts than larger leaks.

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

Leakless Technology

Leakless components, such as bellows valves, are commonly only available in smaller sizes, are significantly more expensive, and are typically used in highly toxic or hazardous material service. Consequently, their overall effectiveness is limited. The marginal additional level of control that is achieved over an LDAR program from the use of leakless technology is minimal and not considered cost-effective for VOC or GHG control.

LDAR instrument monitoring program

The TCEQ's most aggressive fugitive monitoring and maintenance program, 28MID with quarterly monitoring of flanges, is currently considered BACT for controlling fugitive VOC emissions at the existing site. It is more aggressive than the 28LAER program due to the quarterly flange monitoring. As part of this 28MID approach, all pumps and compressor seals in light liquid service are vented to control or are designed with non-leaker technology. This LDAR program will be implemented via instrumented Method 21 for piping components (valves, pumps, connectors, and compressors) that are in greater than 10% methane service.

Remote Sensing

Remote sensing using an infrared imaging has proven effective for identification of leaks. Instrument LDAR programs and the alternative work practice of remote sensing using an infrared camera have been determined by EPA to be equivalent methods of piping fugitive controls.[4]

AVO

AVO methods are generally somewhat less effective than instrument LDAR and remote sensing because they are not conducted at specific intervals. This method cannot generally identify leaks at as low a leak rate as instrumented reading can identify. This method, due to frequency of observation, is effective for identification of larger leaks.

Step 5 - Selection of BACT

The implementation of an instrumented monitoring system for components in methane service is considered BACT. In addition, OxyChem will install barrier seal systems on pumps and compressors in VOC services (which will have a significant amount of methane), and where technically feasible, install rupture discs beneath relief valves in VOC service (which will have a significant amount of methane) that discharge to the atmosphere. Implementing these design practices in addition to the proposed LDAR program is considered beyond BACT for fugitive emission sources for the proposed new Ethylene Plant.

The CO_2e emissions estimated from equipment leaks in new and modified piping and equipment amount to 79 TPY, or less than 0.02% of the total CO_2e emissions from the project. Tracking emissions against a numeric limit is considered infeasible due to the insignificant quantity of emissions expected and the unpredictability of component leaks. EPA is proposing to follow the monitoring, recordkeeping, and repair practices of the TCEQ 28MID LDAR program fugitive monitoring program with quarterly connector monitoring to ensure the minimization of GHG emissions from LDAR components for components containing greater than 10% CH_4.

XVII. Hydrogen Vent (EPN: CR-19)

Hydrogen is a major constituent of the fuel gas which is generated by the cracking process. This fuel gas is used as the primary fuel source for the cracking furnaces. During periods in which the

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[4] 73 FR 78199-78219, December 22, 2008.

amount of fuel gas produced is greater than the fuel demand of the furnaces, excess fuel must be diverted from the fuel gas system. This is considered an intermittent stream and is estimated to emit up to 1.44 ton per year of methane or 36 tons per year CO_2e.

Step 1 - Identification of Potential Control Technologies

Potential GHG emission control technologies for the hydrogen vent were identified as the follows:

- Vent hydrogen to the atmosphere – Hydrogen can be vented to the atmosphere at a safe location to remove excess fuel from the fuel gas system.
- Hydrogen venting to the Thermal Oxidizers – The hydrogen vent can be routed to the thermal oxidizers to combust the stream and generate steam from the heat of combustion.
- Reduce heater firing efficiency – Furnace firing efficiency can be reduced by adding excess air to the furnaces which causes an increase in fuel consumption per unit of production.
- Hydrogen venting to the flares – The hydrogen vent can be routed to the flare systems to combust the stream.

Step 2 - Elimination of Technically Infeasible Alternatives

Reducing heater firing efficiency is not technically feasible and has been eliminated as an alternative. Reducing the firing efficiency of the heaters would require changes to the heater design. These design changes would affect the firing efficiency of the heater for 100% of the operating time, while the need to burn additional fuel is only needed for an estimated 60 days per year. The remaining alternatives are considered technically feasible.

Step 3 - Ranking of Remaining Technologies Based on Effectiveness

- Hydrogen venting to the Thermal Oxidizers – Venting hydrogen to the thermal oxidizers accomplishes the objective of removing fuel from the fuel gas system and generates steam from the heat of combustion. Venting hydrogen to the thermal oxidizers will increase emissions of CO_2 by 4.53 tons/yr and NO_x by 4.33 tons/yr while reducing methane emissions by at least 99.9%. This option would be the most effective technology of reducing GHG emissions, as it would make use of the heat energy.
- Hydrogen venting to the flares – Hydrogen venting to the high pressure flare system would reduce methane emissions by 99% through combustion, but would increase CO_2 emissions by 4.53 tons/yr and NO_x emissions by 9.95 tons/yr. Additionally, there would be no heat recovery associated with this control option. This option would be the second most effective technology of reducing GHG emissions.

- Vent hydrogen to the atmosphere – Venting the hydrogen to the atmosphere accomplishes the objective of removing fuel from the fuel gas system with low impact to the operating equipment and environment. Venting hydrogen to the atmosphere will emit 1.44 tons per year of methane and zero tons of NOx. This option has the lowest impact to the environment relative to criteria pollutants with minimal increase in GHG emissions relative to the project total emissions.

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

Venting hydrogen to the thermal oxidizers

Venting hydrogen to the thermal oxidizers will increase emissions of CO_2 by 4.53 tons/yr and NOx by 4.33 tons/yr and will reduce methane emissions to less than 0.01 tons per year or 0.3 tons of CO_2e. This option does allow for energy recovery in the form of steam production, which would provide some economic return. However, the currently designed thermal oxidizers associated with the Ethylene Plant do not have the current capacity to accept this stream and be able to control the normal Ethylene Plant vent streams. Therefore, two additional thermal oxidizers would be required to control the capacity of the hydrogen vent stream. Each thermal oxidizer is estimated to cost $5,000,000 in capital costs, based on recent vendor estimates to control 1.44 tons of methane emissions. This equates to nearly $7,000,000 per ton of methane removed, not including operating or piping costs to the thermal oxidizers. Therefore, this control technology is not considered cost-effective and is eliminated as a potential control technology.

Venting fuel gas to the flare system

Venting fuel gas to the flare system would increase CO_2 emissions by 4.53 tons/yr and NO_x emissions by 9.95 tons/yr while reducing methane emissions to 0.01 tons per year or 0.3 tons of CO_2e. There is no economic or energy advantage to this option. NO_x is a heavily regulated criteria pollutant. Therefore, this option would create more pollution than it would eliminate (i.e. 9.95 tons of NO_x and 4.53 tons per year CO_2, while reducing 1.44 tons per year of methane). Therefore, this option will have highly negative environmental impact and is eliminated as a potential control technology.

Venting hydrogen to the atmosphere

Venting hydrogen to the atmosphere will emit 1.44 tons per year of methane and zero tons per year NOx. This option will have the lowest environmental impact.

Step 5 - Selection of BACT

Venting hydrogen to the atmosphere is considered BACT. The amount of fuel gas generated by the process is based on engineering evaluation of the proposed plant design, and the calculated fuel gas balance for this unit is very close to being in balance with no excess fuel gas. With the potential that there will be excess fuel gas generation, the design must anticipate this possibility and provide a means of handing the excess.

XVIII. 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, EPA is required to insure that any action authorized, funded, or carried out by EPA is not likely to jeopardize the continued existence of any federally-listed endangered or threatened species or result in the destruction or adverse modification of such species' designated critical habitat.

To meet the requirements of Section 7, EPA is relying on a Biological Assessment (BA) prepared by the applicant, Occidental Chemical Corporation ("OxyChem"), and its consultant, Tetra Tech, and adopted by EPA.

A draft BA has identified eighteen (18) species listed as federally endangered or threatened in San Patricio, Aransas, Calhoun, Jackson, Matagorda, Refugio and Victoria Counties, Texas:

Federally Listed Species for San Patricio, Aransas, Calhoun, Jackson, Matagorda, Refugio and Victoria Counties 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	
Green sea turtle	*Chelonia mydas*
Hawksbill sea turtle	*Eretmochelys imbriacata*
Kemp's ridley sea turtle	*Lepidochelys kempii*
Leatherback sea turtle	*Dermochelys coriaea*
Loggerhead sea turtle	*Caretta caretta*
Mammals	
Gulf coast jaguarundi	*Herpailurus yagouaroundi cacomitli*
Ocelot	*Leopardus pardalis*
West Indian manatee	*Trichechus manatus*
Red Wolf	*Canis lupus rufus*

Federally Listed Species for San Patricio, Aransas, Calhoun, Jackson, Matagorda, Refugio and Victoria Counties by the U.S. Fish and Wildlife Service (USFWS), National Marine Fisheries Service (NMFS) and the Texas Parks and Wildlife Department (TPWD)	**Scientific Name**
Birds	
Attwater's prarie chicken	*Tympanuchus cupido attwateri*
Interior least tern	*Sternula antillarum athalosossos*
Northern aplomado falcon	*Falco femoralis septentrionalis*
Eskimo curlew	*Numenius borealis*
Piper Plover	*Charadrius melodus*
Whooping crane	*Grus americana*
Plants	
Black lace cactus	*Echinocereus reichenbachii var. albertii*
South Texas ambrosia	*Ambroia cheiranthifolia*
Slender rush-pea	*Hoffmannseggia tenella*

EPA has identified eighteen (18) species listed as federally endangered or threatened in San Patricio, Refugio, Calhoun, Aransas, Victoria, Jackson and Matagorda Counties by the U.S. Fish and Wildlife Service (USFWS), National Marine Fisheries Service (NMFS) and the Texas Parks and Wildlife Department (TPWD).

EPA has determined that issuance of the proposed permit to OxyChem for the new ethylene plant will have no effect on seven (7) of these listed species, specifically the the red wolf (*Canis rufus*), slender rush-pea (*Hoffmannseggia tenella*), interior least tern (*Sternula antillarum athalassos*), eskimo curlew (*Numenius borealis*), South Texas ambrosia (*Ambrosia cheiranthifolia*), Black lace cactus (*Echinocereus reichenbachii var. albertii*), and West Indian manatee (*Trichechus manatus*). These species are either thought to be extirpated from the county or Texas or not present in the action area.

The remaining eleven (11) species 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 following species:

- Attwater's prairie chicken (*Tympanuchus cupido attwateri*)
- Gulf Coast jaguarundi (*Herpailurus yagouaroundi cacomitli*)
- Ocelot (*Leopardus pardalis*)
- Northern Aplomado falcon (*Falco femoralis septentrionalis*)
- Piping plover (*Charadrius melodus*)
- Whooping crane (*Grus americana*)

- Leatherback sea turtle (Dermochelys coriacea)
- Green sea turtle (*Chelonia mydas*)
- Kemp's ridley sea turtle (*Lepidochelys kempii*)
- Loggerhead sea turtle (*Caretta caretta*)
- Hawksbill sea turtle (*Eretmochelys imbricate*)

EPA will submit the final draft BA to the Southwest Region, Corpus Christi, Texas Ecological Services Field Office of the USFWS for its concurrence that issuance of the permit may affect, but is not likely to adversely affect those eleven federally-listed species.

EPA will also submit the final draft BA to the NOAA Southeast Regional Office, Protected Resources Division of NMFS for its concurrence that issuance of the permit may affect, but is not likely to adversely affect the following species:

- leatherback sea turtle (*Dermochelys coriacea*)
- green sea turtle (*Chelonia mydas*)
- Kemp's ridley sea turtle (*Lepidochelys kempii*)
- loggerhead sea turtle (*Caretta caretta*)
- Hawksbill sea turtle (*Eretmochelys imbricate*)

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 BA can be found at EPA's Region 6 Air Permits website at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XIX. Magnuson-Stevens Fishery Conservation and Management 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 Administrations'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 the Tetra Tech on behalf of OxyChem and reviewed and adopted by EPA.

The facility is adjacent to tidally influenced portions of the La Quinta Channel that adjoins to the Corpus Christi Ship Channel 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), 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).

Furthermore, these tidally influenced areas have also been identified by NMFS to contain EFH for neonate of the finetooth shark (*Carcharhinus isodon*); juvenile of the blue marlin (*Makaira nigricans*); neonate and juvenile of the scalloped hammerhead shark (*Sphyrna lewini*), lemon shark (*Negaprion brevirostris*), and spinner shark (*Carcharhinus brevipinna*); and neonate, juvenile, and adult of the blacktip shark (*Carcharhinus limbatus*), bull shark (*Carcharhinus leucas*), sharpnose shark (*Rhizoprionodon terraenovae*), and bonnet head shark (*Sphyrna tiburo*).

Based on the information provided in the EFH Assessment, EPA concludes that the proposed PSD permit allowing OxyChem construction of a new ethylene plant within the existing Ingleside 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 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.

XX. 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 cultural resource reports prepared by HRA Gray & Pape, LLC ("HRA") on behalf of Tetra Tech submitted on January 13, 2014 for the site facility and February 24, 2014 for the pipeline.

For purposes of the NHPA review, the Area of Potential Effect (APE) was determined to be approximately 3,719 acres comprised of the project site and the pipeline corridor. The project site covers 260 acres and contains the construction footprint of the project. The pipeline corridor is approximately 114-miles long with a 200 foot-wide right-of-way and covers about 3,459 acres of land. HRA prepared separate cultural resource reports for each portion of the APE. A field survey, including shovel testing, and a desktop review on the archaeological background and historical records within a 1.0-mile radius of the facility's APE and a 0.5-mile radius of the pipeline's APE, which included a review of the Texas Historical Commission's online Texas Archaeological Site Atlas (TASA) and the National Park Service's National Register of Historic Places (NRHP), were performed for each report.

Based on the desktop review for the site facility, four (4) previous cultural surveys have been completed within a 1-mile radius of the APE. Nineteen (19) historic or archaeological sites were identified from those reports, all of which are outside of the APE. Based on the results of the facility site field survey, no archaeological resources or historic structures were found.

Based on the desktop review for the 114-mile pipeline corridor, at least nineteen (19) previous cultural surveys have been completed within a 0.5-mile radius of the APE. The desktop review and field survey of the pipeline corridor identified a total of thirty-three (33) cultural resources within the APE. Thirty (30) of these sites do not meet the eligibility criteria for listing on the National Register (NR). Three (3) sites are considered potentially eligible for listing on the NR and will be avoided by use of horizontal directional drilling.

Although OxyChem has been able to conduct cultural resource survey on a majority of the pipeline, there remain three (3) tracts of land, approximately 1.86 miles total in length, which OxyChem has been unable to secure access for purposes of conducting survey work. There exists one previously recorded archaeological site, identified in the desktop review, located within this unsurveyed portion of the pipeline corridor. EPA, Texas's State Historic Preservation Officer ("SHPO") and OxyChem will sign a Programmatic Agreement (PA) requiring a pre-construction survey of these three remaining parcels. Once this survey has been completed, OxyChem will provide the results to 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.

EPA Region 6 determines that for the site facility, while there are cultural materials of historic or prehistoric age identified within the 1-mile radius of the APE, the potential for intact archaeological resources is low within the construction footprint of the project itself. For the surveyed portion of the pipeline corridor, there are cultural materials of historic or prehistoric age identified within the 0.5-mile radius of the APE and there are archaeological resources located within the pipeline's APE that will be avoided. EPA has therefore determined that, for these portions of the APE, issuance of the permit to OxyChem will not affect properties on or potentially eligible for listing on the NR. EPA and the SHPO agree that construction of OxyChem's project may only proceed in accordance with the PA for the remaining 1.86 miles of the pipeline and any post-review discoveries.

On February 27, 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. 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 these reports may be found at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XXI. Environmental Justice (EJ)

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

XXII. Conclusion and Proposed Action

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

APPENDIX

Annual Facility Emission Limits

Annual emissions, in tons per year (TPY) on a 12 month total, rolling 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]		
CR-1 CR-2 CR-3 CR-4 CR-5	CR-1, CR-1-MSS CR-2, CR-2-MSS CR-3, CR-3-MSS CR-4, CR-4-MSS CR-5, CR-5-MSS	Ethane Cracking Furnace Nos. 1-5	CO_2	291,791[4]	295,175[4]	0.39 tons CO_2e/ton ethylene produced and furnace gas exhaust temperature ≤ 340 °F on a 12-month rolling average. See permit conditions III.A.1.j. and o.
			CH_4	40[4]		
			N_2O	8[4]		
CR-6 CR-7	CR-6 CR-7	CR Thermal Oxidizer Nos. 1 and 2	CO_2	107,878[5]	108,261[5]	Minimum firebox temperature of 1,300 °F with Flue gas exhaust < 500°F on a 12 month rolling average basis. See permit condition III.A.2.f. and g.
			CH_4	4.6[5]		
			N_2O	0.9[5]		
CR-8 CR-8-MSS	CR-8 CR-8-MSS	CR High Pressure Flare (including MSS)	CO_2	70,383	70,684	Flare will meet the requirements of 40 CFR 60.18. See permit conditions III.A.3.h.
			CH_4	3.7		
			N_2O	0.7		
CR-9	CR-9	CR Emergency Generator Diesel Engine	CO_2	61	61	Use of good operating and maintenance practices. See permit condition III.A.4.
			CH_4	No Emission Limit Established[6]		
			N_2O	No Emission Limit Established[6]		
CR-11	CR-11	CR Cooling Tower	CO_2	668	668	Monitor the feed water and make-up water. See permit condition III.A.5.
CR-12-MSS	CR-12-MSS	C_3/C_4 Hydrogenation Regeneration Vent	CO_2	No Emission Limit Established[7]	No Emission Limit Established[7]	Proper reactor design and good operating practices. See permit condition III.A.6.
			CH_4	No Emission Limit Established[6,7]		
CR-13 CR-14 CR-15 CR-16	CR-13 CR-14 CR-15 CR-16	Fugitives	CO_2	No Emission Limit Established[8]	No Emission Limit Established[8]	Implementation of effective LDAR program. See permit condition III.A.7.
			CH_4	No Emission Limit Established[8]		

FIN	EPN	Description	GHG Mass Basis		TPY CO$_2$e[2,3]	BACT Requirements
				TPY[2]		
CR-19	CR-19	Hydrogen Vent	CH$_4$	No Emission Limit Established[9]	No Emission Limit Established[9]	Venting hydrogen to the atmosphere creates the lowest environmental impact. See permit condition III.A.8.
Totals[10]			**CO$_2$**	**470,794**	**474,976**	
			CH$_4$	**52.9**		
			N$_2$O	**9.6**		

1. Compliance with the annual emission limits (tons per year) is based on a 12-month rolling total, to be updated the last day of the following month.
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$_2$O = 298
4. The GHG Mass Basis TPY limit and the CO$_2$e TPY limit for the cracking furnaces apply to all five furnaces combined and include MSS activities noted as CR-1-MSS through CR-5-MSS. Emissions for each furnace are 58,358 TPY CO$_2$, 8 TPY CH$_4$, 1.6 TPY N$_2$O, and 59,035 TPY CO$_2$e.
5. The GHG Mass Basis TPY limit and the CO$_2$e TPY limit for the thermal oxidizers apply to both thermal oxidizers combined. Emissions from each thermal oxidizer are 53,939 TPY CO$_2$, 2.3 TPY CH$_4$, 0.45 TPY N$_2$O, and 54,131 TPY CO$_2$e.
6. These values indicated as “No Emission 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.
7. Emissions from the C$_3$/C$_4$ Hydrogenation Reactor Regeneration Vent are estimated at 13 TPY of CO$_2$ and 13 TPY CO$_2$e. The emission limit will be a design/work practice standard as specified in the permit.
8. Fugitive process emissions are estimated to be 0.01 TPY CO$_2$, 3.15 TPY CH$_4$, and 79 TPY CO$_2$e. The emission limit will be a design/work practice standard as specified in the permit.
9. Emissions from the venting of the hydrogen vent to the atmosphere are estimated at 1.3 TPY CH$_4$ and 35 TPY of CO$_2$e. The emission limit will be a design/work practice standard as specified in the permit.
10. Total emissions include the PTE for fugitive emissions, and other small volume streams that vent to the atmosphere. Totals are given for informational purposes only and do not constitute emission limits.