Statement of Basis

Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit
for the Equistar Chemicals LP, Channelview Plant

Permit Number: PSD-TX-1280-GHG

December 2012

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 in 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 October 27, 2011, Equistar Chemicals, LP (Equistar) Channelview North Plant submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions. A revised application was submitted on July 6, 2012 (hereinafter, referred to as “the application”). In connection with the same proposed project, Equistar submitted a PSD and Nonattainment New Source Review (NNSR) permit applications for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on October 25, 2011. The project at the Channelview Complex proposes to restart the methanol unit at the existing Channelview North Plant. After reviewing the application, EPA Region 6 has prepared the following Statement of Basis (SOB) and draft air permit to authorize construction of new equipment and modification of existing air emission sources at the Equistar, Channelview North 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 Equistar’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 EPA requested and provided by Equistar, 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). Texas still retains approval of its plan and PSD program for pollutants that were subject to regulation before January 2, 2011, i.e., regulated NSR pollutants other than GHGs.

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

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

Air Permits Division (MC-163)
TCEQ
P.O. Box 13087
Austin, TX 78711-3087

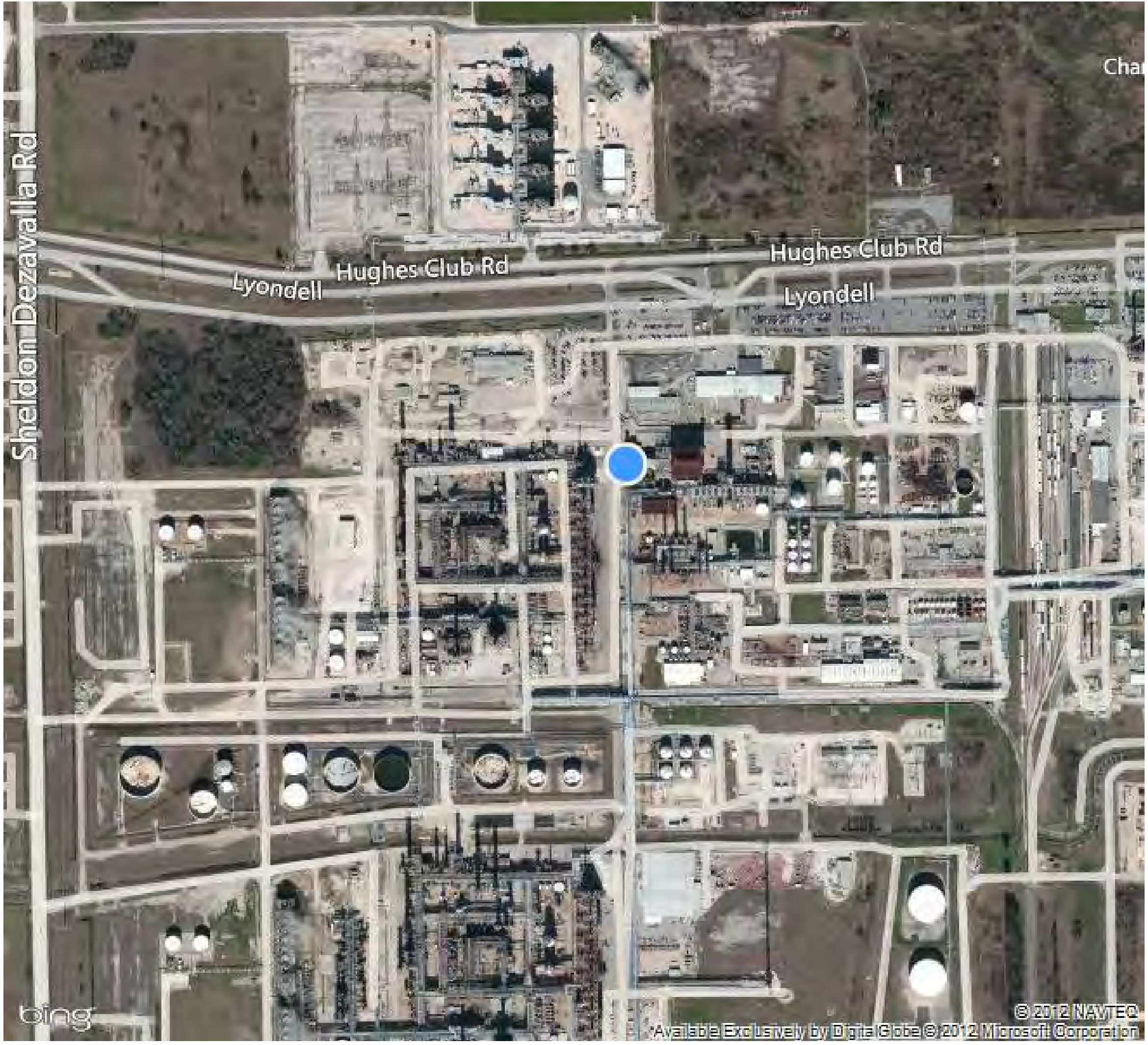
IV. Facility Location

The Equistar, Channelview North Plant is located in Harris County, Texas, and this area is currently designated “nonattainment” for Ozone. The nearest Class 1 area is the Breton National Wildlife Refuge, which is located over 100 miles from the site. The geographic coordinates for this facility are as follows:

Latitude:	29º 50’ 0.7” North
Longitude:	- 95º 07’12.66” West

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

Figure 1. Equistar Chemicals, Channelview Plant Location



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

EPA concludes Equistar's application is subject to PSD review for the pollutant GHGs, because the project would lead to an emissions increase of GHGs for a facility as described at 40 CFR § 52.21(b)(23) and (49)(iv). Under the project, GHG emissions increases will have a mass basis over zero tpy and are calculated to exceed the applicability threshold of 75,000 tpy CO_2e (Equistar calculates an increase of 831,653 tpy CO_2e). 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 other than GHGs, TCEQ has determined the modification is subject to PSD review for CO, PM_{10}, and $PM_{2.5;}$ and NO_x and VOC for NNSR. At this time, TCEQ issued the PSD permit (PSDTX1280) and the NNSR permit (N144) for the non-GHG pollutants on October 23, 2012.

Accordingly, under the circumstances of this project, the State issued the non-GHG portion of the permit and EPA will issue the GHG portion.[1]

EPA Region 6 applies the policies and practices reflected in the EPA document entitled "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, and we have not required any assessment of impacts of GHGs in the context of the additional impacts analysis or Class I area provisions. Instead, EPA has determined that compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs. We note again, however, that the project has triggered review for regulated NSR pollutants that are non-GHG pollutants under the PSD and NNSR permit amendments sought from TCEQ, so air quality modeling or ambient monitoring may be required in order for TCEQ to issue the permit amendments for the non-GHG pollutants.

VI. Project Description

With this permit application, Equistar is proposing to restart the methanol unit (MeOH Restart Project) at the Channelview North Plant. As part of the MeOH Restart Project, Equistar is proposing to transfer the existing equipment from Highly Purified Isobutylene (HPIB) production back to MeOH production.

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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

The rated capacity of the Channelview MeOH process unit is approximately 273 million gallons of high purity methanol per year using light hydrocarbon (typically natural gas) as a feedstock. The unit also has the capacity of injecting carbon dioxide as a supplemental feed.

The feedstock is compressed, preheated, and pretreated to remove sulfur and chlorine compounds. The treated feed is then mixed with steam before being sent to the reformer.

The reformer consists of a large number of catalyst-filled tubes suspended in the radiant section of a process heater. The process stream containing light hydrocarbons and steam flows into the tubes where it is heated to reaction temperature to produce the synthesis gas.

Steam required to operate the unit is produced from waste heat in the reformer. The synthesis gas is cooled, compressed, reheated, and sent to the conversion reactor. The converter effluent is cooled with the crude methanol, separated as a liquid phase, and sent to product purification. The off-gas is recycled to the methanol converter. The purge gas is used as fuel in the reformer fuel gas.

Light ends are removed in the topping column from the crude methanol and used as fuel in the reformer. The topped product is sent to a refining column, where the high purity methanol is removed as the overhead stream, cooled and sent to storage tanks and the bottom stream consisting of water with a trace of hydrocarbons is sent to on-site wastewater treatment. A refining column side stream containing water and mixed alcohol is returned to the process.

VII. General Format of the BACT Analysis

The BACT analyses was conducted in accordance with the *“Top-Down” Best Available Control Technology Guidance Document* outlined in the 1990 draft U.S. EPA *New Source Review Workshop Manual*, which outlines the steps for conducting a top-down BACT analysis. Those steps are listed below.

(1) Identify all potentially available control options;

(2) Eliminate technically infeasible control options;

(3) Rank remaining control technologies;

(4) Evaluate the most effective controls and document the results; and

(5) Select BACT.

Also in accordance with the *"Top-Down" Best Available Control Technology Guidance Document* outlined in the 1990 draft U.S. EPA *New Source Review Workshop Manual*, BACT analyses take into account the energy, environmental, and economic impacts of the control options. Emission reductions may be determined through the application of available control techniques, process design, and/or operational limitations. Such reductions are necessary to demonstrate that the emissions remaining after application of BACT will not cause adverse environmental effects to public health and the environment.

Each emission unit submitted in the PSD GHG application was evaluated separately in the top-down 5-step BACT analysis.

VIII. Applicable Emission Units and BACT Discussion

The majority of the contribution of GHGs associated with the project is from combustion sources (i.e., reformer furnace, and flares). The site has some fugitive emissions from piping components which contribute a relatively small 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). The following devices are subject to this GHG PSD permit:[2]

- Reformer Furnace (EHTF7001)
- Flares (EEMERFLARE, EMEOHFLARE, and 17E01)
- Fugitive Emissions (EFUGMEOH)

IX. Reformer Furnace (EHTF7001)

The MeOH process unit consists of a reformer furnace (EHTF7001). The furnace is equipped with low NO_x burners and selective catalytic reduction (SCR) systems to control NO_x emissions. Furnace fuel is natural gas and it may also combust high hydrogen fuel gas as a secondary fuel when practicable and available.

As part of the PSD review, Equistar provided in the GHG permit application a 5-step top-down BACT analysis for the reformer furnace. In setting forth BACT for this proposed permit, EPA has reviewed Equistar's BACT analysis for the furnace, portions of which has been incorporated into this SOB, and also conducted its own analysis, as summarized below.

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[2] Flare 17E01, an existing unit, will have a collateral increase of 39 TPY GHG emissions after this project but is an unmodified emission unit for which a BACT analysis is not required. In addition, we note that the non-GHG emissions from the flare are addressed in the TCEQ permit and any additional emissions of hydrocarbons and CO to the flare is covered by the applicable requirements of the state permit.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Use Hydrogen as the Primary Fuel* – Hydrogen when burned has no potential for generation of CO_2 emissions.
- *Carbon Capture and Storage* – CCS is an available add-on control technology that is applicable for all of the site's affected combustion units.
- *Fuels Selection* – Use of fuels containing lower concentrations of carbon generate less CO_2 than other higher-carbon fuels. Typically, gaseous fuels such as natural gas or a hydrogen rich gas stream contain less carbon, and thus lower CO_2 potential, than liquid or solid fuels such as diesel or coal. Equistar proposes to use a hydrogen rich gas stream as the secondary fuel for the furnace.
- *Energy Efficient Design* – Equistar selected a furnace design that will maximize efficiency by incorporating the latest improvements in heat transfer and fluid flow to maximize the energy efficiency and energy recovery.
- *Best Operation Practices* – Best operation practices include periodic tune-ups and oxygen trim controls. The tune-ups will include instrument calibrations and cleaning of dirty or fouled mechanical parts. Oxygen trim control allows the excess oxygen to be controlled to optimum levels, thus allowing the furnace to operate at continuous high levels of efficiency.
- *N_2O Catalysts* – N_2O catalysts have been used in the nitric/adipic acid plants to minimize N_2O emissions.
- *Post-Combustion Catalytic Oxidation* – Post-combustion catalytic oxidation provides rapid conversion of a hydrocarbon into CO_2 and water vapor in the presence of available oxygen.

Carbon Capture and Sequestration (CCS)

Carbon capture and storage is an available GHG control technology for "facilities emitting CO_2 in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing)."[3] For purposes of a BACT analysis, CCS is classified as an add-on pollution control technology. CCS involves the separation and capture of CO_2 from the combustion process flue gas, and the captured CO_2 is then pressurized and transported by pipeline or other means of transportation, if necessary, where it is injected into a long-term geological location. Several types of CCS technologies are in various stages of development and are being considered for CO_2 separation and capture.

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

As it stands currently, CCS Technology and its components can be summarized in the table[4] below adopted from IPCC's *Carbon Dioxide Capture and Storage* report:

CCS Component	CCS Technology
Capture	Post-combustion
	Pre-combustion
	Oxyfuel combustion
	Industrial separation (natural gas processing, ammonia production)
Transportation	Pipeline
	Shipping
Geological Storage	Enhanced Oil Recovery (EOR)
	Gas or oil fields
	Saline formations
	Enhanced Coal Bed Methane Recovery (ECBM)
Ocean Storage	Direct injection (dissolution type)
	Direct injection (lake type)
Mineral carbonation	Natural silicate minerals
	Waste minerals
CO_2 Utilization/Application	Industrial Uses of CO_2 (e.g. carbonated products)

For large, point sources, there are three types of CO_2 capture configurations – pre-combustion capture, post-combustion capture, and oxy-combustion capture:

1) Pre-combustion capture is the capture of CO_2 prior to combustion. It is a technological option available to integrated gasification combined cycle (IGCC) plants. In these plants, coal is gasified to form synthesis gas (syngas with key components of carbon monoxide and hydrogen). Carbon monoxide (CO) is reacted with steam to form CO_2 which is then removed and the hydrogen is then diluted with nitrogen and fed into the gas turbine combined cycle.

2) Post-combustion capture involves extracting CO_2 in a purified form from the flue gas following combustion of the fuel. This capture technology is primarily for coal-fired power plants and electric generating units (EGU), although it may be of use for other

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[4] Intergovernmental Panel on Climate Change (IPCC) Special Report, Bert Metz, Ogunlade Davidson, Heleen de Coninck, Manuela Loos and Leo Meyer (Eds.), *Carbon Dioxide Capture and Storage* (New York: Cambridge University Press, 2005), Table SPM.2, 8. <http://www.ipcc.ch/pdf/special-reports/srccs/srccs_wholereport.pdf>

source types. Currently, all commercial post-combustion capture is via chemical absorption process using monoethanolamine (MEA)-based solvents.[5]

3) Oxy-combustion technology is primarily applied to coal-burning power plants where the capture of CO_2 is obtained from a pulverized coal oxy-fuel combustion in which fossil fuels are burned in a mixture of recirculated flue gas and oxygen, rather than in air. The remainder of the flue gas, that is not recirculated, is rich in CO_2 and water vapor, which is treated by condensation of the water vapor to capture the CO_2.[6] Nitrogen is a major component of flue gas in the boiler units that burn coal in air, post-combustion capture of CO_2 is essentially a nitrogen-CO_2 separation which can be done but at a high cost. However, if there were no nitrogen present as in the case of oxy-combustion, then CO_2 capture from flue gas would be greatly simplified[7]. It is expected that an optimized oxy-combustion power plant will have ultra-low CO_2 emissions.

Once CO_2 is captured from the flue gas, CO_2 is compressed to 100 atmospheres (atm) or higher for ease of transport (usually by pipeline) into a storage area that, in most cases, is a geological storage area. Also, CO_2 can be stored and transported for a non-storage use (e.g., carbonation for beverages).

Geological storage of CO_2 involves the injection of compressed CO_2 into deep geologic formations (injection zones) overlain by competent sealing formations and geologic traps that will prevent the CO_2 from escaping. There are five types of geologic formations that are considered: clastic formations; carbonate formations; deep, unmineable coal seams; organic-rich shales; and basalt interflow zones. There is a large body of ongoing research and field studies focused on developing better understanding of the science and technologies for CO_2 storage.[8]

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible, except for N_2O catalysts and post-combustion catalytic oxidation.

N_2O catalysts have not been used to control N_2O emissions from reformer furnace applications. In addition, the low N_2O concentrations present in the exhaust stream would make installation of

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[5] Wes Hermann et al. *An Assessment of Carbon Capture Technology and Research Opportunities - GCEP Energy Assessment Analysis, Spring 2005*. <http://gcep.stanford.edu/pdfs/assessments/carbon_capture_assessment.pdf>
[6] U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory, "Oxy-Fuel Combustion", August 2008. < http://www.netl.doe.gov/publications/factsheets/rd/R&D127.pdf>
[7] Herzog et al., page 4-5
[8] U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory *Carbon Sequestration Program: Technology Program Plan*, <http://www.netl.doe.gov/technologies/carbon_seq/refshelf/2011_Sequestration_Program_Plan.pdf>, February 2011

N_2O catalysts technically infeasible. N_2O catalysts are therefore eliminated as a technically feasible option for the proposed project.

The reformer furnace flue gas design temperature is in the range of 270 ^oF to 305 ^oF. It is expected to contain about 1 ppmv CH_4. The temperature is below the lowest operating temperature for catalytic oxidation. In addition, the flue gas CH_4 concentration is about two orders of magnitude below the lower end of VOC concentration streams which would typically be fitted with catalytic oxidation for control. Addition of post-combustion catalytic oxidation on the reformer furnace for control of CH_4 is technically infeasible for the proposed project. Accordingly, post-combustion catalytic oxidation is eliminated as a technically feasible option for the proposed project.

EPA considers CCS to be an available control option for high-purity CO_2 streams that merit initial consideration as part of the BACT review process, especially for new facilities. As noted in EPA's GHG Permitting Guidance, a control technology is "available" if it has a potential for practical application to the emissions unit and the regulated pollutant under evaluation. Thus, even technologies that are in the initial stages of full development and deployment for an industry, such as CCS, can be considered "available" as that term is used for the specific purposes of a BACT analysis under the PSD program. In 2010, the Interagency Task Force on Carbon Capture and Storage was established to develop a comprehensive and coordinated federal strategy to speed the commercial development and deployment of clean coal technology. As part of its work, the Task Force prepared a report that summarized the state of CCS and identified technical and non-technical challenges to implementation.[9] EPA, which participated in the Interagency Task Force, supported the Task Force's conclusion that although current technologies could be used to capture CO_2 from new and existing plants, they were not ready for widespread implementation at all facility types. This conclusion was based primarily on the fact that the technologies had not been demonstrated at the scale necessary to establish confidence in their operations. EPA Region 6 has completed a research and literature review and has found that nothing has changed dramatically in the industry since the August 2010 report and there is no specific evidence of the feasibility and cost-effectiveness of a full scale carbon capture system for the project and equipment proposed by Equistar.

Based on the information reviewed for this BACT analysis, while there are some CO_2 capture technologies that are currently technically infeasible for the affected emission units, EPA has determined that, as a whole, Carbon Capture and Storage (CCS) is technologically feasible for this proposed project. Listed below is a summary of those CCS components and technologies that are technically feasible and those CCS components that are not technically feasible for the Equistar project.

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[9] See *Report of the Interagency Task Force on Carbon Capture and Storage* available at http://www.epa.gov/climatechange/policy/ccs_task_force.html

Step Two – Summary for CCS for Equistar

CCS Component	CCS Technology	Technical Feasibility
Capture	Post-combustion	Y
	Pre-combustion	N
	Oxyfuel combustion	N
	Industrial separation (natural gas processing, ammonia production)	N
Transportation	Pipeline	Y
	Shipping	Y
Geological Storage	Enhanced Oil Recovery (EOR)	Y
	Gas or oil fields	N*
	Saline formations	N*
	Enhanced Coal Bed Methane Recovery (ECBM)	N*
Ocean Storage	Direct injection (dissolution type)	N*
	Direct injection (lake type)	N*
Mineral carbonation	Natural silicate minerals	N*
	Waste minerals	N*
Large scale CO_2 Utilization/Application		N*

* Both geologic storage and large scale CO_2 utilization technologies are in the research and development phase and currently commercially unavailable.[10]

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- Use of Hydrogen as the Primary Fuel (100%)
- Carbon capture and storage (up to 90%)
- Fuel Selection (>12%)
- Energy Efficient Design
- Best Operation Practices

Hydrogen has no capacity to produce CO_2 when combusted. Hydrogen as a primary fuel would provide 100% effectiveness in control of CO_2 emissions from the reformer furnace and thus considered to be the most effective control. CO_2 capture and storage is capable of achieving up to 90% reduction of produced CO_2 emissions. Selection of a fuel with a low carbon content can reduce emissions of CO_2. If methane was used as the primary fuel, as opposed to another fossil fuel, it could have a minimum of 12% control effectiveness. Natural gas is the lowest carbon fuel

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[10] U.S. Department of Energy, *Carbon Sequestration Program: Technology Program Plan*, page 20-23

that could be relied upon for continuous fueling of the proposed operation. Energy efficient design, use of low-carbon fuel, and best operation practices are all considered effective and have a range of efficiency improvements which cannot be directly quantified; therefore, the above ranking is approximate only. The estimated efficiencies were obtained from Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy and Plant Managers (Environmental Energy Technologies Division, University of California, sponsored by USEPA, June 2008). This report addressed improvements to existing energy systems as well as new equipment.

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

Use of Hydrogen as the Primary Fuel

Hydrogen could be used as the only fuel for the reformer furnaces, providing 100% elimination of CO_2 from the flue gas, provided hydrogen is available, and the necessary firebox heat release and temperatures could be produced. The National Renewable Energy Laboratory (NREL) has determined that the net effect of using hydrogen as a fuel when produced by the most common means, steam methane reforming, is an overall increase in GHG emissions.[11] Accordingly, use of hydrogen as the primary fuel is eliminated based on the negative environmental impact of these collateral increases in CO_2.

Carbon Capture and Sequestration

Equistar developed an analysis for CCS that provided the basis for eliminating the technology in step 4 of the BACT process as a viable control option based on economic costs and environmental impact. The recovery and purification of CO_2 from the stack gases would necessitate significant additional processing, including environmental/air quality penalties, to achieve the necessary CO_2 concentration for effective sequestration.

The majority of the cost for CCS was attributed to the capture and compression facilities that would be required. The capital cost for capture alone is estimated to be more than $130,000,000. The capital cost of transportation is estimated at $21,000,000. The pipeline needed for transport would be 30 miles away from the facility, thereby necessitating the construction of a new pipeline to connect. The estimated annual operation and maintenance costs for the pipeline are $259,000. The estimated CCS capital needed only for capture and a new pipeline for the current project results in an increase of more than 50% in the capital costs for Equistar's project. While it is difficult to quantify the revenue from selling CO_2, EPA expects the revenue from selling the

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[11] NETL publication, *Life Cycle Assessment of Hydrogen Production via Natural Gas Steam Reforming,* page 23, Conclusions. http://www.nrel.gov/docs/fy01osti/27637.pdf

CO_2 would not result in a significant decrease in CCS cost. EPA Region 6 reviewed Equistar's CCS cost estimate and believes it adequately approximates the cost of a CCS control for this project and demonstrates those costs are prohibitive in relation to the overall cost of the proposed project, and thus CCS has been eliminated as BACT for this project as economically infeasible.[12]

Economic infeasibility notwithstanding, Equistar asserts that CCS can have a collateral increase of National Ambient Air Quality Standards (NAAQS) pollutants. Implementation of CCS would increase emissions of GHGs, NOx, CO, VOC, PM_{10}, and SO_2 because of the increased energy needed to operate the CCS controls. The proposed plant is located in an area of ozone non-attainment (Houston, Galveston, and Brazoria (HGB)), and the generation of additional NOx and VOC could exacerbate ozone formation in the area. As a result, CCS could also be eliminated based on its environmental impacts, since its use would cause an increase in emissions of NOx and VOCs to the HGB non-attainment area airshed.

Fuel Selection

The use of low-carbon fuel is economically and environmentally practicable for the proposed project. Natural gas is the lowest emitting carbon fuel that could be relied upon for the proposed operation. The plant also produces fuel gas, containing a high percentage of hydrogen, which may be utilized as a secondary fuel for the furnace when it is available. Further, combustion of natural gas and fuel gas in lieu of higher carbon-based fuels such as diesel and coal not only reduces GHG emissions, but also reduces emissions of other combustion products such as NO_x, CO, VOC, PM_{10}, and SO_2, providing environmental benefits as well.

Energy Efficient Design

The use of an energy efficient furnace and unit design is economically and environmentally practicable for the proposed project. By optimizing energy efficiency, the project requires less fuel than comparable less-efficient operations, resulting in cost savings. Further, reduction in fuel consumption corresponding to energy efficient design provides additional environmental benefits of reducing emissions of other combustion products such as NO_x, CO, VOC, PM_{10}, and SO_2. As furnaces of this type age, refractory and insulation degrade in performance, and convection section tubes become fouled, efficiency can degrade slightly. Equistar anticipates that thermal efficiency will decrease to no lower than 90% as an annual average in the late stages of the furnace life.

Best Operation Practices

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[12] Equistar also examined utilization of the salt dome caverns they currently own and operate for CCS, and estimated that it would cost $1.8 billion for development and injection well installation, which is also economically infeasible.

Best operation practices effectively support the energy efficient design. Thus, the economic and environmental benefits of energy efficient design techniques also apply to the use of best operation practices.

Step 5 – Selection of BACT

To date, other facilities with a 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	GHG BACT for furnace limit flue gas exhaust temperature ≤ 309 °F. 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. Alvin, TX	Ethylene Production	Energy Efficiency Low Carbon Fuels	Cracking heater to meet thermal efficiency of 92.6% and flue gas exhaust temperature ≤ 340 °F 0.85 lbs GHG/lbs of ethylene 35% hydrogen in fuel to maintain a 0.71 carbon percentage in fuel	2012	PSD-TX-97769-GHG

Chevron Phillips, Olefins Unit Cedar Bayou, TX	Ethylene Production	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT for furnace limit flue gas exhaust temperature $\leq$ 350 °F. 365-day average, rolling daily	2012	PSD-TX-748-GHG*

*Permit was not issued as of December 21, 2012. The comment period for the proposed permit ended on December 17, 2012.

BASF and Williams have differing processes for producing ethylene. BASF is a steam driven operation using multiple feedstocks, whereas Williams is utilizing electrical driven compressors and only ethane/propane as a feedstock which will require less energy consumption. The Chevron Phillips facility will be constructed similar to the BASF facility in that it too will be steam driven and will utilize ethane as the primary feedstock. The Chevron Phillips facility also utilizes a configuration that combines the steam production of eight cracking furnaces with a very high pressure boiler. Chevron Phillips exhaust temperature will be higher than BASF due to the design differences of the two facilities. The furnaces listed in the table above are all for ethylene production. Equistar is producing methanol which has different furnace requirements. The reformer furnace utilized by Equistar cannot be directly compared to the ethylene furnaces listed above.

The following specific BACT practices are proposed for the furnace:

- *Fuel Selection* – Using natural gas as the primary fuel, and plant produced high hydrogen fuel gas as a supplemental fuel provides a reduction in combustion CO_2 when compared to diesel or coal.
- *Energy Efficient Design* - Continuously monitor the reformer furnaces' exhaust stack temperature and control to a maximum stack exit temperature of 320 °F on a 365-day total, rolling average basis. A thermal efficiency of 90% will be maintained.
- *Best Operation Practices* – The use of best operation practices includes periodic combustion tune-ups and maintaining the recommended combustion air and fuel ranges of the equipment as specified by its design, with the assistance of oxygen trim control.

BACT Compliance:

Equistar elects to demonstrate compliance with energy efficient operations by continuously monitoring the exhaust stack temperature of the reformer furnace. The maximum stack exit temperature of 320 °F on a 365-day total, rolling average basis will be calculated daily for the furnace. Thermal efficiency will be calculated monthly from these parameters using equation G-1 from American Petroleum Institute (API) methods 560 (4th ed.) Annex G. Equistar conducted calculations to gauge the efficiency of the furnaces under degraded conditions. Equistar determined that when accounting for degradation they could not ensure a thermal efficiency greater than 90% over the life of the equipment. Efficient furnace design, use of low carbon fuels, and good combustion practices of the furnaces corresponds to a permit limit of 827,411 tpy CO_2e.

Equistar will design the reformer furnace to be energy efficient by implementing the latest improvements and technologies in heat transfer and fluid flow to maximize the energy efficiency and energy recovery. Equistar will implement the following to ensure efficient operation of the reformer furnaces:

- Radiant section thermal efficiency - Vertical process tubes combined with floor mounted burners. Highly luminous radiant section, maximizing radiant heat transfer. Process tube placement to assure uniform heating, and to minimize shadowing;
- Sealed system - Minimize air infiltration with proper sealing of firebox penetrations;
- Reduce heat loss - Brick and ceramic fiber insulation to reduce heat loss;
- Process tube design - Preheating of process fluids in the convection section with a triangular tube arrangement to maximize transfer of heat into the process fluids. Careful installation of catalyst in radiant tubes to assure even flow and corresponding heat transfer to process fluid;
- Burner design - Long, thin flames parallel to tubes with highly luminous flame envelopes. Minimum excess air design to enhance efficiency. Low-NOx burners; and
- Careful control of feedstock/steam ratios, temperatures, pressures, and residence times to maximize production rate at normal firing rates.

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. Records of the calculations would be required to be kept to demonstrate compliance with the emission limits on a 365-day average, rolling daily.

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

Where:

CO_2 = Annual CO_2 mass emissions from combustion of natural gas and/or plant produced high hydrogen gas (short tons)

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

As an alternative, Equistar may install, calibrate, and operate a CO_2 continuous emissions monitor (CEMS) and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording CO_2 emissions.

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Table C-2, site specific analysis of process fuel gas, and the actual high heat value (HHV). Comparatively, the emissions from CO_2 contribute the most (greater than 99%) to the overall emissions from the furnaces and; therefore, additional site specific emission factors are not required for CH_4 and N_2O.
An initial stack test demonstration will be required for CO_2 emissions from each emission unit. An initial stack test demonstration for CH_4 and N_2O emissions is not required because the CH_4 and N_2O emission are less than 0.01% of the total CO_2e emissions from the heaters and are considered a *de minimis* level in comparison to the CO_2 emissions, making initial stack testing impractical and unnecessary.

X. Flares (EEMERFLARE, and EMEOHFLARE)

The Methanol Unit will be equipped with two new flares (EEMERFLARE and EMEOHFLARE). The Methanol Unit also has an existing flare (17E01) which will not be evaluated for BACT. CO_2 emissions from flaring process gas are produced from the combustion of carbon containing compounds (e.g., CO, VOCs, CH_4) present in the process gas streams and the pilot fuel. CO_2 emissions from the flare are based on the estimated flow rates of CO_2 and flared carbon-containing gases derived from heat and material balance data. The flares are examples of control devices in which the control of certain pollutants causes the formation of collateral GHG emissions. Specifically, the control of CH_4 in the process gas at the flare results in the creation of additional CO_2 emissions via the combustion reaction mechanism. However, given the relative GWPs of CO_2 and CH_4, it is appropriate to apply flare combustion controls to reduce CH_4 emissions since the impact of that GHG reduction will be greater than the GHG impact of the additional CO_2 emissions resulting from combustion, and there will also be concurrent destruction of VOCs and HAPs.

Step 1 – Identification of Potential Control Technologies

- *Flare Gas Recovery* – Flaring can be reduced by installation of commercially available recovery systems, including recovery compressors and collection and storage tanks.
- *Waste Gas Minimization* – Minimizing the gas streams sent to the flare by returning them to the process and reduce GHG emissions.
- *Use of Natural Gas for Pilots* - Natural gas is a readily available low carbon fuel that can be used to fire the pilots.
- *Good Flare Design* – Good flare design can be employed to destroy large fractions of the flare gas. Good flare design includes pilot flame monitoring, flow measurement, and monitoring/control of waste gas heating valve..

Step 2 – Elimination of Technically Infeasible Alternatives

Only one option identified in Step 1 is considered technically infeasible, flare gas recovery.

Installing a flare gas recovery system to recover flare gas to the fuel gas system is considered feasible control technology for industrial flares generally; however the specific flares in this project are intermittent flares combusting MSS emissions. The MSS streams sent to the flares are a waste stream that cannot be routed to the fuel gas system or to a process unit due to its composition and variability. For this project, flare gas recovery is eliminated as technically infeasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Natural gas-fired pilots, waste gas minimization, and good flare design will be applied as GHG BACT for the flares in order to minimize emissions from the flares.

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

No significant adverse energy or environmental impacts associated using natural gas-fired pilots, waste gas minimization, or good flare design are expected.

Step 5 – Selection of BACT

Natural gas-fired pilots, waste gas minimization, and good flare design will be applied as GHG BACT for the flares in order to minimize emissions from the flares. The flare will meet the requirements of 40 CFR §60.18, and will be properly instrumented and controlled. These BACT practices result in a BACT limit of 181 tpy CO_2e for EPN EEMERFLARE and 3,755 tpy CO_2e for EPN EMEOHFLARE.

Equistar will demonstrate compliance with the CO_2 emission limits using the emission factors for natural gas from 40 CFR Part 98 Subpart C, Table C-1, and the site specific fuel analysis for process fuel gas. The equation for estimating CO_2 emissions as specified in 40 CFR 98.253(b)(1)(ii)(A) is as follows:

Where:

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

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

XI. Fugitive Emissions (EFUGMEOH)

GHGs emissions from leaking pipe components (fugitive emissions) in the proposed project contain CO_2 and CH_4. The majority of the fugitive emissions are CH_4.

Step 1 – Identification of Potential Control Technologies

- *Installation of leakless technology components to eliminate fugitive emission sources.*
- *Instrumented Leak Detection and Repair (LDAR) program (Method 21).*
- *Leak Detections and Repair with remote sensing technology*
- *Auditory, Visual, and Olfactory (AVO) monitoring program.*
- *Design and construct facilities with high quality components, with materials of construction compatible with the process.*

Step 2 – Elimination of Technically Infeasible Alternatives

None of the options identified in Step 1 are considered technically infeasible.

Leakless/Sealless Technology – Leakless technology valves may be incorporated in situations where highly toxic or otherwise hazardous materials are present. Likewise, some technologies, such as bellows valves, cannot be repaired without a unit shutdown.

Instrument LDAR Programs – LDAR programs have traditionally been developed for control of VOC emissions. Instrumented monitoring is considered technically feasible for components in CH_4 service.

Remote Sensing – Remote sensing technologies have been proven effective in leak detection and repair. The use of sensitive infrared camera technology has become widely accepted as a cost effective means for identifying leaks of hydrocarbon.

AVO Monitoring – Leaking components can be identified through AVO methods. AVO programs are common and in place industry and are considered technically feasible.

High quality components - A key element in control of fugitive emissions is the use of high quality equipment that is designed for the specific service in which it is employed. The olefins unit at Equistar's La Porte plant utilizes such components, and materials of construction, including gasketing that is compatible with the service in which they are employed.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- Leakless Technologies (~100%)
- Instrumented LDAR 28LAER (97%)
- LDAR with Remote Sensing (>75%)
- AVO Monitoring Program (30%)
- Design and Construct Using High Quality Components (Not Measurable)

Leakless technologies are nearly 100% effective in eliminating fugitive emissions from the specific interface where installed, however leak interfaces remain even with leakless technology components in place. In addition, the sealing mechanism, such as a bellows, is not repairable online and may leak in the event of a failure until the next unit shutdown. This is the most effective of the controls.

Instrumented monitoring can identify leaking CH_4, making identification of components requiring repair possible. This is the second most effective of the controls.

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.[13]

As-observed AVO methods are generally somewhat less effective than instrument LDAR and remote sensing, since 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.

Use of high quality components is effective in preventing emissions of GHGs, relative to use of lower quality components.

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

Use of leakless technology can have adverse environmental impacts, since following a failure of one of these parts, the component is most often not repairable online and may leak until the next unit shutdown, resulting in the emissions from the leak itself, and the emissions of GHG and

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[13] 73 FR 78199-78219, December 22, 2008.

other criteria pollutants that result from the need to shutdown and restart the facility. Based on these potential adverse environmental impacts, leakless technologies are eliminated as BACT.

LDAR programs for which instrumented detection of leaks is an essential activity have traditionally been developed for control of VOC emissions. The adverse impact of non-VOC fugitive emissions of CH_4 due to global warming potential has not been quantified, and no reasonable cost effectiveness has been assigned. Equistar proposes to use TCEQ method 28LAER for LDAR.

Remote sensing of fugitive components in CH_4 service can provide an effective means to identify leaks. However, this option is rejected as BACT since the higher ranked 28LAER program will be adopted for control of fugitive CH_4 emissions. However, as an alternative, Equistar may conduct remote sensing for detection of leaks for pipes with fugitive emissions components that are in methane service

Adverse impact of environmental impacts of as-observed AVO methods have not been noted, and no reasonable cost effectiveness has been assigned. Equistar proposes to use AVO methods as additional monitoring for leaks.

Design to incorporate high quality components is effective in proving longer term emissions control.

Step 5 – Selection of BACT

Equistar proposes to use TCEQ method 28LAER for LDAR for fugitive emissions of methane for components that are in methane service. In addition to instrumented monitoring required by TCEQ 28LAER, Equistar will also use high quality components and conduct as-observed AVO monitoring. As noted above, as an alternative, Equistar may conduct remote sensing for detection of leaks for pipes with fugitive emissions components that are in methane service.

XII. Threatened and Endangered Species

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

EPA designated Equistar and its consultant, URS Corporation ("URS"), as non-federal representatives for purposes of informal consultation and preparation of a biological assessment for EPA's use in complying with the Act and EPA has reviewed a BA prepared by the applicant.

That BA contains ambiguous recommendations, but includes the best available data and technical analysis.

The BA identifies twelve (12) species listed as federally endangered or threatened in Harris County, Texas by the U.S. Fish and Wildlife Service (USFWS), National Marine Fisheries Service (NMFS) and the Texas Parks and Wildlife Department (TPWD).

Federally Listed Species for Harris County	**Scientific Name**
Plant	
Texas Prairie Dawn Flower	*Hymenoxys texana*
Birds	
Red-cockaded Woodpecker	*Picoides borealis*
Whooping Crane	*Grus americana*
Fish	
Smalltooth Sawfish	*Pristis pectinata*
Mammals	
Louisiana Black Bear	*Ursus americanus luteolus*
Red Wolf	*Canis rufus*
Amphibians	
Houston Toad	*Bufo houstonensis*
Reptiles	
Green Sea Turtle	*Chelonia mydas*
Kemp's Ridley Sea Turtle	*Lepidochelys kempii*
Leatherback Sea Turtle	*Dermochelys coriacea*
Loggerhead Sea Turtle	*Caretta caretta*
Hawksbill Sea Turtle	*Eretmochelys imbricate*

The BA identifies an action area, i.e., the area in which endangered or threatened organisms might be potentially affected by construction and operation of the proposed facility, including its emissions and wastewater discharges. EPA has adopted the data and analysis contained in the BA, and concludes that none of the 12 species listed above or their critical habitats occur in that action area. Accordingly, EPA's permit action will have no effect on listed species or critical habitat.

The BA is available at http://yosemite.epa.gov/r6/Apermit.nsf/AirP. Region 6 welcomes comments on the BA or concerns on the project's potential effect on listed species or their habitat.

XIII. Magnuson-Stevens Act

Pursuant to Section 305(b)(2) of the Magnuson-Stevens Fishery Conservation and Management Act and implementing regulations at 50 CFR 600.05 – 600.930, EPA is required to consult with

NOAA's National Marine Fisheries Service on proposed actions that may adversely affect essential fish habitat (EFH). The project is adjacent to tidally influenced portions of the San Jacinto River which empties into Galveston Bay system. These tidally influenced portions have been identified as potential habitats of postlarval, juvenile, subadult or adult red drum (*Sciaenops ocellatus*), white shrimp (*Penaeus setiferus*), brown shrimp (*Penaeus aztecus*), dog snapper (*Lutjanus jocu*), dwarf sandperch (*Diplectrum bivittatum*), lane snapper (*Lutjanus synagris*), and red snapper (*Lutjanus campechanus*) and NOAA has designated those waters essential fish habitat (EFH).

To assist EPA in evaluating the project's potential effects on those species and EFH, the applicant prepared an EFH assessment, which EPA has reviewed and adopted. 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. The EFH Assessment is available at http://yosemite.epa.gov/r6/Apermit.nsf/AirP. Region 6 welcomes comments on the EFH Assessment or concerns on the project's potential effect on EFH or the commercial species at issue.

XIV. 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 a cultural resources report by URS, Equistar's consultant, submitted on November 16, 2012.

URS conducted a desktop review using the Texas Historical Commission's online Texas Archaeological Site Atlas (TASA) of the archaeological and historical records within a 1-mile radius area of potential effect (APE). After considering the report submitted by the applicant, because no eligible properties are within the APE and the potential for archaeological resources is very low in the previously disturbed construction footprint itself, EPA's issuance of the permit to Equistar will not affect properties potentially eligible for listing on the National Register.

On November 30, 2012, 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. As of December 21, 2012, no Indian tribes have requested to participate in consultation. EPA will provide a copy of the report to the State Historic Preservation Officer for consultation and concurrence with its determination. Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on historic properties. The report is located at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XV. 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.

XVI. Conclusion and Proposed Action

Based on the information supplied by Equistar, our review of the analyses contained the TCEQ PSD 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 Equistar 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, rolling average, shall not exceed the following:

Table 1. Facility Emission Limits

FIN	**EPN**	**Description**	**GHG Mass Basis**		**TPY CO_2e[1,2]**
				TPY[1]	
HTF7001	EHTF7001	Reformer Furnace	CO_2	826,600	827,556
			CH_4	16	
			N_2O	2	
MEOHFLARE EMERFLARE	EMEOHFLARE EEMERFLARE	Methanol Flare and Methanol Emergency Flare [3]	CO_2	3,936	3,936
			CH_4	Negligible	
			N_2O	Negligible	
FUGMEOH	EFUGMEOH	Fugitive Process Emissions	CO_2	Not Applicable	Not Applicable
			CH_4	Not Applicable	
Totals[4]			**CO_2**	**830,614**	**CO_2e 831,675**
			CH_4	**21**	
			N_2O	**2**	

1. The TPY emission limits specified in this table are not to be exceeded for these EPNs and include emissions from the facility during all operations and include MSS activities.
2. Global Warming Potentials (GWP): $CH_4 = 21$, $N_2O = 310$
3. The methanol unit waste gas flow may be routed to either flare, or to both flares.
4. Total emissions include the PTE of 5 TPY CH_4 and 39 TPY CO_2 for fugitive emissions, and 39 TPY CO_2 from the existing East Plant Flare (17E01) for a total of 183 TPY CO_2e. Totals are given for informational purposes only and do not constitute emission limits.

BACT Limits

BACT requirements for all new and modified units are identified in the table below.

Table 2. BACT Limits

FIN	EPN	Description	BACT Requirements
HTF7001	EHTF7001	Reformer Furnace	Furnace Gas Exhaust Temperature $\leq$ 320 ^{o}F. Maintain Thermal Efficiency of 90%. See permit condition IV.A.1.o.through q.
MEOHFLARE	EMEOHFLARE	Methanol Flare	Good Combustion Practices. See permit condition IV.A.2.
EMERFLARE	EEMERFLARE	Methanol Emergency Flare	Good Combustion Practices. See permit condition IV.A.2.
FUGMEOH	EFUGMEOH	Fugitive Process Emissions	Implementation of LDAR program. See permit condition IV.A.3.