Statement of Basis

Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit
For OCI Beaumont LLC

Permit Number: PSD-TX-1334-GHG

June 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 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 December 21, 2012, EPA Region 6 received an application from OCI Beaumont LLC (OCI) for a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions resulting from a modifications relating to a debottlenecking project to increase capacity for methanol and ammonia processing units at an existing facility. A revised application was submitted on December 17, 2013 (hereinafter, referred to as “the application”). In connection with the same proposed project, OCI submitted a PSD permit application for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on December 19, 2012. OCI proposes to modify the methanol reforming units at its existing plant located in Nederland, Jefferson County, Texas. 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 OCI Beaumont Plant.

As part of the modifications for this project, OCI proposes to construct a new pre-reformer heater, pre-reformer, saturator column, flare and a selective catalytic reduction (SCR) control unit to reduce NOx emissions; and modify the existing reformers. The existing facility was built in 1968, and this permit allows modification to the existing equipment as well as the addition of new equipment. Additionally, process energy improvements will be incorporated in the 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 project, the applicable air permit requirements, and an analysis showing how the applicant complied with the requirements.

EPA Region 6 concludes that OCI’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 OCI, 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:

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

IV. Facility Location

The facility is located in Nederland, Jefferson County, Texas and is attainment for ozone and all other criteria pollutants. 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:	30^0 0’55.84” North
Longitude:	- 94º 02’05.79” West

Figure 1 illustrates the facility location for this draft permit.

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

EPA concludes OCI'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)(v)(b). Under the project, PSD applies because the modification is otherwise subject to PSD and the 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 (OCI calculates an increase of 1,205,711 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 $PM_{2.5}$, NO_x, and VOC. At this time, TCEQ has not yet issued the PSD permit (PSD-TX-1334) for the non-GHG pollutants. Accordingly, under the circumstances of this project, the State will issue 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 permit 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 and Process Description

OCI currently operates a methanol and ammonia plant in Beaumont. The draft permit will allow OCI to modify the existing methanol plant for increased production at the facility. OCI is requesting a PSD GHG permit from EPA in order to modify the methanol plant with the construction of a flare, pre-reformer heater, pre-reformer, SCR control unit, saturator column, and modification of the reformers with several process energy improvements. The SCR control unit will reduce NOx emissions from all the reformers and pre-reformer heater. The two existing reformers will be modified to optimize heat transfer, as well as use CO_2 as supplement feed to increase methanol production. With the proposed construction and optimizations, the methanol capacity of the plant will be 1,098,000 metric tons per year.

Methanol is produced in the OCI plant by the steam reforming process. The steam reforming process blends methane from the natural gas feed stream with steam to produce synthesis gas that is further converted and purified to produce the commercial grade methanol. Details on the process and flow diagrams can be obtained from the permit application.

The feed to the methanol plant is natural gas which is treated to remove sulfur that could poison the catalyst in the reformer section. Supplemental feed to the plant includes recycled hydrocarbons from the plant, including the new saturator column. The desulfurized natural gas is saturated with steam in the saturator column and preheated in the new pre-reformer heater and is passed over the pre-reformer prior to entering the primary reformer furnaces (reformers). The pre-reformer is an adiabatic fixed bed reactor and will increase flexibility in the feed to the steam reformers and decrease the heat load required by the existing reformers to improve overall plant capacity. The pre-reformer begins the formation of process gas and converts any hydrocarbons heavier than methane present in the feedstock into methane. The partially converted process gas is then sent through the catalyst in the tubes of the radiant section of the primary reformers to complete the conversion of the methane feedstock to process gas. The resultant process gas mixture is known as synthesis gas (syngas). Syngas is a gaseous mixture consisting of various

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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

concentrations of hydrogen, carbon monoxide, carbon dioxide, and methane. The convection section of the reformers is utilized to recover the heat of the combustion gases of the reformers units to produce the steam used in the plant. The tubes in the existing reformers will be replaced with larger and thinner tubes to improve heat transfer for syngas formation. Heat transfer improvement will allow more syngas produced per pound of fuel combusted.

Fuel for the fired heaters of the pre-reformer and reformers is a mixture of natural gas and plant process gas. In the OCI methanol plant the emissions from the combustion units of the reformers exit via one stack (STK 41) which also has a duct burner for an SCR unit to reduce NOx emissions.

The addition of a saturator column assists in processing the organic liquid streams (dehydrator tails and stripper tails) in the plant, so that steam/condensate is recovered instead of being combusted in the convection section of the reformers. Combustion of the liquid stream increases all combustion emissions including CO_2. Recovering the condensate from the liquid stream allows the natural gas that passes through the saturator column to be saturated and therefore less steam is required for the reforming gas synthesis reaction. Additionally the saturator column also processes an atmospheric vent stream resulting in a reduction of 626 TPY CO_2 and approximately 6.8 TPY methane. This vent stream in the saturator column combines with the natural gas feed stream to the synthesis section of the plant.

Syngas from the reformers is cooled, compressed to 1500 psig, and sent to the methanol synthesis section. Syngas can also be combined with pure CO_2 at this stage to increase the production of methanol in the synthesis section. The syngas from the reformers is combined with the methanol reactors circulation loop and enters the methanol reactors via a recirculating compressor. In each pass, around 35% of the gases react to form methanol. The gases exit the reactors and are cooled in a gas-to-gas coolers before entering the air cooler and water cooler section. Here the crude methanol condenses out and the remaining gases are recycled back to the reactor. The crude methanol is stored and sent to a distillation train for product purification. The recycle process has a buildup of inert gases in the system (methane, nitrogen). The inert gases are purged from the recycle process and sent to the ammonia plant's pressure swing absorption unit (PSA) or reformer fuel system.

The condensates produced in the cooling processes are collected and heated in the saturator water heat exchangers prior to entering the saturator column to be recovered as steam. The saturator column uses natural gas to strip unwanted process hydrocarbons from heated water streams. The saturated natural gas is used as feedstock for the reformers while the saturator column recovers water as steam. This decreases the demand for reformer generated steam to meet the steam-to-carbon ratio requirements for the reformer syngas production.

Crude methanol is purified in a four column refining process to remove water and other impurities. Light ends are condensed, and the non-condensable gases are removed with a natural gas educator and routed to the reformer fuel gas system. Undesired mixed alcohol streams from the distillation process are collected and recycled as feedstock through the saturator column. The topped product is sent to a refining column, where the high purity methanol is removed from the column bottoms, cooled and sent to storage tanks. The methanol product storage tanks vent to a water scrubber system that can be recycled to the crude methanol tank.

To control the buildup of excess hydrogen and undesirable gases (methane and nitrogen) in the synthesis loop, a portion of the unreacted high-pressure gas is continually purged from the system. When the ammonia plant is not operating, the purge gas is routed to the reformer fuel gas system and burned as fuel gas. When the ammonia plant is operating, the stream goes directly to the PSA system where hydrogen is recovered and is used for the synthesis of ammonia. The non-condensable gases from the PSA system are purged to the fuel gas system.

Since the project will not include modifications at the ammonia plant, the permit will not address GHG from any equipment of the ammonia plant, and the operations of the ammonia plant are not considered relevant. Additionally, the ammonia plant does not have any source of GHG emissions with the exception of a flare since the operations involve direct synthesis of ammonia with nitrogen and hydrogen over a catalyst bed.

The following table indicates the emission units that have been considered for this permit.

EPN	Description
STK41	Two reformers will be modified for better heat transfer and product conversion. These existing reformers will have a maximum combined fuel rate of 2,200 MMBtu/hr
	Pre-Reformer Heater with maximum firing rate of 197 MMBtu/HR
	SCR duct burner – design capacity of 169 MMBtu/hr
FL42	Reformer MSS flare with 4 pilots with an average natural gas sweep use of 3.83MMscf/yr. Used for MSS emissions and continuous stripper tail vents of approximately 48 LB/hr. Meets all requirements of 40 CFR 60.18
	Methanol plant fugitives

The following emissions units will see an increase in process flow and possible increase in GHG emissions, but the emission units are not being physically modified[2]. Therefore, the GHG emissions from the existing units are not subject to the BACT requirements for a PSD permit.

EPN	Description
MET-STK44	Carbon Dioxide Stripper Vent
326	Marine Vapor Control System Flare
FL321	Ammonia plant Flare

VII. General Format of the BACT Analysis

The BACT analyses was conducted by following the "top-down" BACT approach outlined in EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011). 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 Greenhouse Gas Permitting Guidance, BACT analyses must take into account the energy, environmental, and economic impacts of the control options. Emission reductions may be achieved 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.

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[2] As explained in the GHG Permitting Guidance for the purposes of determining whether a PSD permit is required, the EPA requires a permitting authority to look beyond the emissions unit that is modified (across the entire source) to determine the extent of emission increases that result from the modification. However, the BACT applies only to the emission unit(s) that have been modified or added to the existing facility. See PSD and Title V permitting Guidance for Greenhouse Gases at 23.

VIII. Applicable Emission Units and BACT Discussion.

While the majority of GHGs associated with the project are from combustion sources (i.e., reformer furnaces and flares), there are 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:

- Pre-Reformer Heater, Reformer Furnaces (Reformers), and SCR Duct Burner (EPN STK 41)
- MSS Reformer Flare (EPN – FL 42)
- Fugitive Emissions (MET-FUG 247)

A. Pre- Reformer Heater, Reformers, and SCR Duct Burner (EPN STK 41)

The methanol plant consists of a new pre-reformer heater, pre-reformer and modification of two existing reformers. Additionally, a SCR control unit (duct burner) will be used to reduce NOx as required by TCEQ, since OCI is located in the Beaumont Port Arthur (BPA) area.

As part of the PSD review, OCI 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 OCI's BACT analysis for the furnace, portions of which has been incorporated into this SOB, and also conducted its own analysis, as summarized below.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Carbon Capture and Storage* – CCS is an available add-on control technology that is applicable for all of the site's affected combustion units. The CCS is classified as an add-on pollution control technology, which involves the separation and capture of CO_2 from flue gas, pressurizing of the captured CO_2 into a pipeline for transport, and injection/storage within a geologic formation. The CCS is generally applied to "facilities emitting CO_2 in large concentrations, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing)."[3]

  The CCS systems involve the use of adsorption or absorption processes to remove CO_2 from flue gas, with subsequent desorption to produce a concentrated CO_2 stream. The three main capture technologies for the CCS are pre-combustion capture, post-combustion capture, and oxyfuel combustion (IPCC, 2005). Of these approaches, pre-combustion capture is applicable primarily to gasification plants, where solid fuel such as coal is converted into gaseous components by applying heat under pressure in the presence of

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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

steam and oxygen (U.S. Department of Energy, 2011). At this time, oxyfuel combustion has not yet reached a commercial stage of deployment for gas turbine applications and still requires the development of oxy-fuel combustors and other components with higher temperature tolerances (IPCC, 2005). Accordingly, pre-combustion capture and oxyfuel combustion have no practical application for this proposed PDH facility. The third approach, post-combustion capture, is applicable to the proposed process heaters and boilers.

With respect to post-combustion capture, a number of methods may potentially be used for separating the CO_2 from the exhaust gas stream, including adsorption, physical absorption, chemical absorption, cryogenic separation, and membrane separation (Wang et al., 2011). Many of these methods are either still in development or are not suitable for treating power plant flue gas due to the characteristics of the exhaust stream (Wang, 2011; IPCC, 2005). Of the potentially applicable technologies, post-combustion capture with an amine solvent such as monoethanolamine (MEA) is currently the preferred option because it is the most mature and well-documented technology (Kvamsdal et al., 2011), and because it offers high capture efficiency, high selectivity, and the lowest energy use compared to the other existing processes (IPCC, 2005). Post-combustion capture using MEA is also the only process known to have been previously demonstrated in practice on gas turbines (Reddy, Scherffius, Freguia, & Roberts, 2003). As such, post-combustion capture using MEA is the sole carbon capture technology considered in this BACT analysis.

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

In a typical MEA absorption process, the flue gas is cooled before it is contacted counter-currently with the lean solvent in a reactor vessel. The scrubbed flue gas is cleaned of solvent and vented to the atmosphere while the rich solvent is sent to a separate stripper where it is regenerated at elevated temperatures and then returned to the absorber for re-use. Fluor's Econamine FG Plus process operates in this manner, and it uses an MEA-based solvent that has been specially designed to recover CO_2 from oxygen-containing streams with low CO_2 concentrations typical of gas turbine exhaust (Fluor, 2009).

Once CO_2 is captured from the flue gas, the captured CO_2 is compressed to 100 atmospheres (atm) or higher for ease of transport (usually by pipeline). The CO_2 would then be transported to an appropriate location for underground injection into a suitable

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

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

geological storage reservoir, such as a deep saline aquifer or depleted coal seam, or used in crude oil production for enhanced oil recovery (EOR). There is a large body of ongoing research and field studies focused on developing better understanding of the science and technologies for CO_2 storage.

- *Fuel 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. Increased use of hydrogen in the fuel gas to the combustion units will provide the lowest carbon fuel and reduce GHG emissions. However, the operations of the methanol and ammonia plants requires the hydrogen byproduct of the methanol reactions to be used as feed for the ammonia plant. The process fuel gas will contain the hydrogen byproduct from the methanol plant when the ammonia plant is down. Another consideration is the use of the recycle process gas as supplemental fuel gas for the heaters instead of being vented to the flare. This option reduces the net GHG emissions from the plant. Also 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* – By optimizing energy efficiency, the project requires less fuel than comparable less-efficient operations, resulting in fewer GHG emissions. 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. Reformer/heater and plant design will maximize heat transfer efficiency by incorporating the latest process improvements in heat transfer, fluid flow and energy recovery. A saturator column will increase energy efficiency in the plant by recycling water waste streams and utilizing it to saturate the natural gas feed stream to the reformers, which otherwise would require the use of steam. Additionally reducing the stack flue gas temperatures by heat exchangers wherever possible will also reduce the fuel consumption per pound methanol produced.

- *Best Operational Practices* – Best operation practices include periodic tune-ups, oxygen trim control, and installation of modern instrumentation and controls. Periodic tune-ups 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. Installation of modern instrumentation and controls optimizes methanol production and reduces emissions.

Step 2 – Elimination of Technically Infeasible Alternatives

The EPA generally considers a technology to be technically feasible if it: (1) has been demonstrated and operated successfully on the same type of source under review, or (2) is available and applicable to the source type under review.

CCS has not been demonstrated and operated successfully for combustion sources on a large capacity MeOH plant that has high stack flue gas rates and low CO_2 concentration. OCI estimates that the combined large stack flow rates have an average CO2 concentration of less than 10.0%. EPA is evaluating whether CCS is technically feasible for the OCI project and will consider public comments on this issue. Because there is a basis to eliminate CCS on other grounds in Step 4 of the BACT analyses after considering the energy, environmental and economic impacts, we will assume, for purposes of this specific permitting action, that the potential technical or logistical barriers do not make CCS technically infeasible.

All other options identified in Step 1 are considered technically feasible and have been proposed by the applicant.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

OCI estimates that the CCS would reduce GHG emissions (CO_2) from the pre-reformer heater and reformers by 1,000,936 tpy,[6] based on a 90% capture efficiency. This is the most efficient technology for reduction of GHGs.

Fuel selection for low carbon fuels. The greater the concentration of H_2 in the fuel the lower the GHG emissions.

Energy Efficient Design – 15%.

Best Operational Practices have various degrees of effectiveness and are approximately 11-22% effective in reduction of GHG.

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

OCI developed a site-specific cost analysis for post-combustion the CCS that provided the basis for eliminating the technology in step 4 of the BACT analysis, which is attached as Appendix B. The OCI cost analysis is based on a CCS cost study document by the Celanese, Ltd Clear Lake methanol plant project (PSD-TX1296-GHG), which in turn relied on the *Report of the Interagency Task Force on Carbon Capture and Storage (dated August 2010)* which was used as the basis for determining these site-specific costs. EPA Region 6 reviewed OCI's CCS cost estimate and believes it adequately approximates the annual cost of a CCS control for this project.

The projected capital cost of CCS at OCI plant is $180.8 million. On an annualized basis, OCI estimates the net annualized cost of installing and operating the CCS is $74.5 million. The estimated cost of the CCS will increase the estimated capital cost of the OCI project from $83 million to $263.8 million, which represents an increase of approximately 317%. EPA agrees that this increase in project cost is substantial and that the CCS should be rejected as BACT on economic grounds.

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[6] This reduction does not take into account the additional 495,500 tons CO_2 that would be emitted by the new boiler. which would result in an additional 49,550 tons of CO_2 (the 10% that is not captured by CCS) being released.

Further, we note that CCS can be eliminated as BACT based on the environmental impacts from a collateral increase of National Ambient Air Quality Standards (NAAQS) pollutants. Implementation of the CCS would increase emissions of NO_X, CO, VOC, PM_{10}, SO_2, and ammonia by as much as 13-17%.[7] In particular, the existing facility is located in an area that was recently redesignated from non- attainment to attainment for the 8 hour ozone levels[8]. Accordingly, new NOx sources in this area are required to have controls to reduce NOx emissions. Therefore, the proposed OCI energy efficient technologies are preferred over add-on controls such as the CCS that would cause an increase in emissions of NO_X and VOC into the current airshed. Therefore, the adverse environmental impacts resulting from the installation and operation of a CCS system further support the rejection of the CCS as BACT for this proposed project.

Fuel Selection, Energy Efficient Design, and Best Operational Practices remain viable alternatives.

Step 5 – Selection of BACT

Fuel Selection, Energy Efficient Design, and Best Operational Practices will be utilized for all the combustion units at OCI.

1. **Reformers & Pre-Reformer Heater (EPN STK 41)**

Reformers supply the heat and steam demand for the methanol plant. The reformers and pre-reformer heater use a combination of natural gas and process fuel gas.

The steam reforming process in a methanol plant differs from the design of other catalytic reformers used in olefin plants. The table below provides information on other operating methanol plants or ones that have recently received a PSD permit for GHG emissions.

Company Location and Quantity (in metric tons per day)	Process Description	Control Options	Control[1] Limits/Requirements	Year permit Issued-Operation
Equistar Chemicals, Channelview, TX, 273 million gallons/year (3008MTPD)		Energy Efficiency, Good Combustion Practices	Reformer furnace thermal efficiency of 90%. Flue gas exhaust temperature limited to ≤ 320 ºF	2013 PSD-TX-1280-GHG

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

[8] See Chapter 4 of the Texas submittal at:
http://www.tceq.texas.gov/assets/public/implementation/air/sip/bpa/08006sip_ado_complete.pdf
EPA's approval at: http://www.gpo.gov/fdsys/pkg/FR-2010-10-20/pdf/2010-26261.pdf

Company Location and Quantity (in metric tons per day)	Process Description	Control Options	Control[1] Limits/Requirements	Year permit Issued-Operation
Celanese Chemicals Clear Lake, TX 3923MTPD	Two step reforming	Efficient energy design	Furnace Exhaust temperature ≤ 350 °F. 30MMBTU(HHV)/ton methanol produced	2013
Chile 1 2268MTPD	One step reformer with a steam stripper for recycling hydrocarbons.	Efficient energy and water recovery systems	33.15 (LHV) MMTBU/MT	1988
Chile III 3000MTPD	One step reforming with the introduction of a natural gas (NG) saturator to recover organic compounds.	Energy efficient design to reduce organic waste in air and water	31.88 (LHV) MMBTU/MT	1999
IRAN 5000MTPD	Two step reforming including autothermal reformer with pre-reformer and NG saturator	Energy efficiency and organic compounds recycling	29.86 (LHV) MMBTU/MT	2004
EGYPT 3600MTPD	Two step combined reformer including auto thermal reformer with a two-step NG saturator	Energy efficiency, minimize water waste	30.56(LHV) MMTBU/MT	
Beaumont Methanol – now OCI	One step reforming with two terrace reformers	Good design	42.02(LHV) MMBTU/MT	1968
Proposed OCI 3000MTPD	One step reforming with two terrace reformers, a pre-reformer, and NG saturator.	Thermal efficiency of the reformer unit to be 88%. Heat recovery of heater flue gas. Recovery of vent streams to the saturator column normally vented to the atmosphere.[2]	33.0 (LHV) MMBTU/MT Flue gas stack temperature after the SCR duct burner is limited to 422°F.	

1. For PSD permits in the USA, we consider the controls as BACT
2. See information regarding the saturator column in Section VI of the SOB

While the limits of the other methanol plants may be lower, a BACT limit of 33 (LHV) MMBTU/MT of methanol produced is appropriate for the OCI project in light of the age of the existing OCI methanol plant (1968) and the fact that not all equipment and processes will be modified as part of this project. We note that the modifications that will be made, including the energy efficient modifications proposed, represent a 21 % reduction in energy demand from the operations of the existing plant. Also the higher stack temperature limit for the OCI plant is expected because of the duct burner for the SCR that will be installed to reduce NOx emissions. The energy modifications proposed are primarily to process more Syngas in the reformer section of the plant, whereas the methanol reactors and downstream processing systems will not be modified. In order to obtain the lower BACT limits of 31 MMBTU (LHV) /MT and below contained in other permits, the complete plant would need to be reconstructed, which is not required for modifications at an existing plant, nor is it compatible with the OCI's business plans for the Beaumont plant[9]. Unlike the two other recently permitted new methanol plants in Texas (that have SCR downstream of each burners), the existing OCI design configuration features reformers that vent to a common stack. Therefore to reduce NOx, the SCR unit is in the stack and requires heat from a duct burner for efficient NOx control. OCI will maximize heat recovery from the flue gas of the SCR (625^0F to 422^0F) to ensure energy-efficient operation with the use of heat exchangers. With the existing configuration and design of the OCI plant, OCI has determined that further reduction of stack temperature is technically infeasible[10].

Fuel Selection: Natural gas and process fuel gas will be utilized for combustion in the reformers. As a byproduct of the methanol synthesis reaction, hydrogen gas is produced that is consumed in the downstream ammonia plant. When the ammonia plant is down the hydrogen stream will be vented to the process fuel gas.

Energy Efficient Design: The modification to the reformer section of the plant includes the replacement of the current reformer tubes with ones that are more heat and energy efficient. In addition, the saturator column allows for the processing of the recycle liquid streams as steam that saturates the natural gas feed, reducing the need for steam. The saturator column also processes and eliminates an atmospheric 626 TPY CO_2 vent stream that has approximately 6.8 TPY methane. The vent gas from the saturator column is used as process fuel gas. Reducing the stack flue gas temperatures by heat exchangers wherever possible will also reduce the fuel consumption per pound methanol produced. As furnaces of this type age, refractory and insulation degrade in performance, and convection section tubes become fouled, efficiency can degrade slightly. The thermal efficiency for the reformers is 88% based on a 12-month rolling average.

Best Operational Practices: Best operational practices effectively support the energy efficient design. Efficient combustion control with the addition of modern instrumentation and controls will keep the excess air for combustion to a minimum by keeping the O_2 levels below 3% in the stack flue gas. Additionally periodic tuning of the heater/reformer reduces the CO and unburned carbon thereby reducing GHG combustion emissions. OCI also will maintain proper insulation to decrease heat losses from the reformers as well as minimize air infiltration into the reformer sections. Heat recovery of the flue gas to preheat reformer feed will be optimized by monitoring the combined stack temperature to be less than or equal to 422^0F

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

a. OCI shall demonstrate compliance with energy efficient operations by continuously monitoring the exhaust stack temperature of the reformers and heater. The maximum stack exit temperature of 422°F on a 365-day total, rolling average basis will be calculated daily for the EPN STK41.

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[9] OCI's response to EPA Information requests dated March 6, 2014 (Attachment C)

[10] See OCI response dated March 6, 2014 to EPA information request.

b. OCI will also maintain compliance with the CO_2 emission levels on a 12 month rolling total basis.

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 12 month rolling total basis.

OCI will demonstrate compliance with the CO_2 emission limit for the heaters using the 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), Eq. C-5 is :

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

Where:

CO_2 = Annual CO_2 mass emissions from combustion of natural gas 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.

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 high heat value (HHV). Comparatively, the emissions from CO_2 contribute the most (greater than 99%) to the overall emissions from the furnaces; 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 EPN STK 41. 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 for these components impractical and unnecessary.

c. An initial performance test as specified in the draft permit will be required to demonstrate the 88% thermal efficiency and the BACT limit.

d. The BACT limit of 33 LHV MMBtu/MT (12-month rolling average) shall be calculated based on methanol produced and fuel consumed at the reformers excluding the fuel used in the SCR duct burner.

2. SCR Duct Burner (EPN STK 41)

The primary purpose of the SCR duct burner is to reduce the NOx from the stack flue gas generated by the reformers and heater, and will be required to control NOx emissions in the TCEQ permit for non-GHGs.

Fuel Selection: The duct burner will burn only natural gas or plant process gas.

Energy Efficient Design: Recover heat from the flue gas using a heat exchanger system and good burner design.

Best Operational Practices: Burner maintenance, periodic tuning and good combustion control of excess air by monitoring O_2 in the stack to be less than 3%.

BACT and Emission Limits Compliance:

BACT compliance for the SCR duct burner is identical to that of the reformers (in the previous section VIII.B.1).

B. **MSS Reformer Flare (EPN FL 42**)

The new flare will be installed primarily to control maintenance, startup and shutdown (MSS) emissions from the reformers and from the vent gas for the stripper tails tank and pressure control valves. Currently, in its existing operation, emissions from both the MSS and stripper tail tank vent to the atmosphere. The CO_2e emissions from the flare are approximately 1.9% of the total emission increase from the project. 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. Flares are examples of control devices in which the control of certain pollutants causes the formation of collateral GHG emissions. Specifically, combusting CH_4 creates additional CO_2 emissions. However, given the relative GWP of CO_2 and CH_4, it is appropriate to reduce CH_4 emissions and there will also be an environmental benefit of the concurrent destruction of VOCs and HAPs. The flare will meet the requirements of 40 CFR §60.18, and will be properly instrumented and controlled.

Step 1 – Identification of Potential Control Technologies

- *Flare Gas Recovery (FGR)* – Flaring can be reduced by installing commercially available recovery systems. FGR utilizes a water seal drum to prevent recoverable gas flow from going to the flare while allowing the flare to function in the event of an emergency. A compressor located on the downstream end of the main flare header is used to increase the pressure of a constant volumetric flow of flare gas, allowing it to reach a unit that can beneficially use the flare gas as fuel.
- *Waste Gas Minimization* – Minimizing the gas streams sent to the flare by returning them to the process during MSS activities.
- *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 technically infeasible, flare gas recovery.

A flare gas recovery system is feasible control technology for industrial flares that have continuous waste gas flows; however the specific flare in this project has an intermittent flow of MSS emissions. The MSS streams sent to the flare are a waste stream that cannot be routed to the fuel gas system or to a process unit due to its variability. For this project, flare gas recovery is eliminated as technically infeasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Waste gas minimization, use of natural gas for pilots, and good flare design are all effective controls and will be applied as BACT for the flare.

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

There are no significant adverse energy or environmental impacts associated with the above remaining control options.

Step 5 – Selection of BACT

OCI will implement waste gas minimization, use of natural gas for pilots, and good flare design.

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

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

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

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

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

b. OCI will reduce the MSS by waste gas minimization using the procedures in the TCEQ PSD-TX 1334 permit.

c. Only natural gas will be used for the pilot.

d. The flare will be designed and operated to have a minimal 99% control for VOC/CH_4 during MSS events and will meet the BACT limit of 23,417 tpy CO_2e on a 12 month rolling average for EPN FL42.

C. Methanol Plant Fugitive Emissions (EPN MET-FUG 247)

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

- *Leakless technology components.* Leakless technology components may be incorporated in situations where highly toxic or otherwise hazardous materials are present. Leakless components like bellow valves, cannot be repaired without a unit shutdown and cannot be used for plants that have maintenance and repair programs online.
- *Instrumented Leak Detection and Repair (LDAR) program (EPA Method 21).* LDAR programs have traditionally been developed for control of VOC emissions. Instrumented monitoring is considered technically feasible for components in CH_4 service. The TCEQ 28VHP program is currently being used at the existing OCI plant.
- *LDAR with remote sensing technology.* The use of sensitive infrared camera technology has become widely accepted as a cost effective means for identifying leaks of hydrocarbon. However, this technology cannot quantify the leak like EPA Method 21. 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 fugitive controls.[11]
- *Auditory, Visual, and Olfactory (AVO) monitoring program.* Leaking components from natural gas can be identified through AVO methods. This program can be performed at a lower cost and more frequently and leaks can be detected and repaired immediately.
- *High quality components.* Design and construct facilities with high quality components, with materials of construction compatible with the process. A key element to control fugitive emissions is the use of high quality equipment that is designed for the specific service in which it is employed.

Step 2 – Elimination of Technically Infeasible Alternatives

Leakless Technology, Instrumented LDAR programs, LDAR with remote sensing, AVO monitoring, and High quality components are all technically feasible for the OCI project.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Leakless Technology (~100%)
Instrumented LDAR (97%)
LDAR with Remote Sensing (75%- 95%)
AVO Monitoring Program (90% for natural gas)
High Quality Components (Not Measurable)

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 other criteria pollutants that result from the need to shutdown and restart the facility. Based on

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

these potential adverse environmental impacts, leakless technologies can be eliminated as BACT.

In addition, while the use of leakless components, instrumented LDAR and/or LDAR with remote sensing may be somewhat more effective than as-observed AVO methods, the incremental GHG emissions controlled by technologies is considered a *de minimis* level in comparison to the total project's proposed CO_2e emissions. Given that GHG fugitives are conservatively estimated to comprise less than 0.02% CO_2e emissions from this project, there is, in any case, a negligible difference in emissions between the considered control alternatives. Accordingly, given the costs of installing leakless technology (which is estimated to be 3 to 10 times higher than comparable high quality valves) or instrumented LDAR or LDAR with remote sensing when not otherwise required, these methods are not economically practicable for GHG control from components in natural gas or fuel gas service and could be excluded as BACT.

In this case, an instrumented LDAR program (TCEQ method 28VHP) is already required for this facility under the non-GHG permits, is proposed by the applicant, and thus will not be eliminated as BACT. However, use of leakless technology and LDAR with remote sensing are eliminated on economic grounds.

An AVO Monitoring Program has an economic advantage to the other programs and there are no known adverse environmental or energy impacts. OCI proposes to use AVO methods as additional monitoring for leaks.

S**tep 5** – Selection of BACT

EPA has reviewed and concurs with OCI's proposal to use Instrumented LDAR (via TCEQ method 28VHP), an AVO monitoring program, and use high quality components as BACT for the methanol plant fugitive emissions.

BACT Compliance

a. TCEQ 28VHP LDAR program as currently being used for the rest of the plant.
b. Daily AVO monitoring of the natural gas pipelines and components.
c. Design of facility using high quality components for the specific service.

IX. Threatened and Endangered Species

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

To meet the requirements of Section 7, EPA has reviewed and adopted a Biological Assessment (BA) dated May 1, 2014, prepared by Wolf Environmental on behalf of OCI and EPA. The draft

BA identified fourteen (14) species listed as federally endangered or threatened in Jefferson County, Texas:

Federally Listed Species for Jefferson County by the U.S. Fish and Wildlife Service (USFWS), National Marine Fisheries Service (NMFS), and the Texas Parks and Wildlife Department (TPWD)	**Scientific Name**
Birds	
Piping plover	*Charadrius melodus*
Fish	
Smalltooth sawfish	*Pristis pectinata*
Mammals	
Louisiana black bear	*Ursus americanus luterolus*
Red wolf	*Canis rufus*
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*
Whales	
Blue Whale	*Balaenoptera musculus*
Finback Whale	*Balaenoptera physalus*
Sei Whale	*Balaenoptera borealis*
Humpback Whale	*Megaptera novaeangliae*
Sperm Whale	*Physeter macrocephalus*

EPA has determined that issuance of the proposed permit to OCI for a project to increase capacity for methanol and ammonia processing units at its existing facility will have no effect on the fourteen (14) listed species, as there are no records of occurrence, no designated critical habitat, nor potential suitable habitat for any of these species within the action area.

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

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

X. National Historic Preservation Act (NHPA)

Section 106 of the NHPA requires EPA to consider the effects of this permit action on properties eligible for inclusion in the National Register of Historic Places. To make this determination, EPA relied on and adopted a cultural resource report prepared by Moore Archeological Consulting (MAC) on behalf of OCI's consultant Wolf Environmental, and submitted on March 5, 2014.

For purposes of the NHPA review, the Area of Potential Effect (APE) was determined to be approximately 28 acres of land that contains the construction footprint of the project. MAC performed a field survey of the property and a desktop review on the archaeological background and historical records within a 1-mile radius of the APE.

Based on the results of the field survey, no archaeological resources or historic structures were found within the APE. Based on the desktop review for the site, no cultural resource sites were identified within a 1-mile radius of the APE.

On February 24, 2014, EPA sent letters to Indian tribes identified by the Texas Historical Commission as having historical interests in Texas to inquire if any of the tribes have historical interest in the particular location of the project and to inquire whether any of the tribes wished to consult with EPA in the Section 106 process. EPA received no requests from any tribe to consult on this proposed permit. EPA will provide a copy of the report to the State Historic Preservation Officer for consultation and concurrence with its determination. Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on historic properties. A copy of the report may be found at http://yosemite.epa.gov/r6/Apermit.nsf/AirP

XI. 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.

XII. Conclusion and Proposed Action

Based on the information supplied by OCI, our review of 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 OCI 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 A

Annual Emission Limits in PSD permit

EPN	Description	GHG Mass Basis		TPY[1,2,3] CO_2e	BACT Limits & Conditions
			TPY[1]		
STK 41	Reformer furnaces, Preheater and SCR duct burner	CO_2	1,173,573	1,178,593	1. Stack temperature to be monitored and not to exceed 422^0 F on an hourly basis, using SCR. Condition IV.2.k 2. Reformer net thermal efficiency 88% based on initial tests. Condition IV.2.l 3. Methanol output BACT limit of 33MMBtu (LHV)/MT on a 12 month rolling average (excluding fuel to the SCR burner)
		CH_4	59.34		
		N_2O	11.87		
FL42	Reformer MSS flare	CO_2	16,721	23,417	1. Use only for startup, shutdown and maintenance activities, and for the stripper tails tank vent. Condition IV.3 2. Meet 40 CFR 60.18 requirements and efficiency of 99%.
		CH_4	265.82		
		N_2O	0.17		
MET-FUG247	Methanol plant fugitives	CO_2	15	80	Work practice standards as noted in Special Condition IV.4
		CH_4	2.6		
	Totals[4]	CO_2	1,190,309	1,202,090	
		CH_4	327.76		
		N_20	12.29		

1. Compliance with the annual emission limits (tons per year) is based on a 12-month rolling total.
2. The TPY emission limits specified in this table are not to be exceeded for this facility and include emissions from the facility during all operations and include MSS activities. This total is rounded off for estimation purposes to two significant figures.
3. Global Warming Potentials (GWP): CO_2 =1, CH_4 = 25, N_2O = 298
4. Totals are given for informational purposes only and do not constitute emission limits.

Appendix B

Cost Estimate for Implementing Carbon Capture and Sequestration {CCS) Technology

Prepared by OCI Beaumont LLC

A. Purpose

1. This is a cost estimate for implementing CCS technology to reduce C02 emissions from the proposed OCI Beaumont LLC Debottleneck Project.
2. This cost estimate is provided to support the Best Available Control Technology (BACT) analysis as required for the pending PSD GHG permit for OCI's proposed Debottleneck Project.

B. Design Cost Basis

1. C02 Streams Selected for CCS: For purposes of this cost estimate analysis,the design scope for CCS implementation is to treat only one waste gas stream: the proposed new Selective Catalytic Reduction (SCR) unit exhaust. The proposed SCR exhaust includes the combined exhaust from the reformer furnace, pre-heat furnace, and SCR duct burner system. Each of these contributing units is a gas-fired external combustion unit, and the exhaust streams from these three units are combined prior to treatment in a single new SCR unit for NOx emissions abatement. The SCR exhaust accounts for over 90% of the total potential GHG emission increases associated with the proposed OCI Debottleneck Project.

2. C02 Streams Not Selected: Other project-related GHG emissions that are excluded from the scope of this BACT cost analysis would be disproportionately expensive for application of CCS technology as compared to the SCR exhaust. This is because the other GHG sources have much lower C02 emission rates and/or are physically impossible to capture (e.g.,fugitive equipment leaks, flares, and a small/low-pressure process vent emitting less than 20 tpy C02). Therefore, the lowest possible relative control cost for CCS implementation (on a cost per ton of C02 reduced basis) is evaluated by excluding these minor GHG sources from the CCS implementation scope and limiting this CCS implementation cost evaluation to the most readily treatable GHG emission stream, which is the SCR exhaust as discussed above.

3. CCS Technology: Monoethanolamine (MEA) absorption and desorption (steam stripping) of C02 is the most widely used CCS technology applied to combustion exhaust streams similar to the SCR exhaust included in the scope of this analysis. Other CCS technologies have been applied to similar combustion exhaust streams, but with mixed results and without the proven "track record" of MEA with respect to commercial-scale technical feasibility demonstrations. Any cost analysis of a less thoroughly demonstrated CCS technology would need to include large cost multipliers to reflect the real-world uncertainties inherent in implementing a technology without a strong demonstrated feasibility "track record." Therefore the lowest possible relative control cost is evaluated by focusing on MEA-based CCS technology.

C. Cost Estimate Strategy

1. Comparison Approach: In order to support this site-specific CCS cost estimate evaluation OCI relied upon another CCS cost study document provided for the Celanese, Ltd Clear Lake (i.e., "Celanese") methanol plant project, which was authorized by PSD GHG permit No. PSD-TX-1296-GHG dated Dec. 12, 2013. The Celanese CCS cost study report was titled "Celanese Project Fairway" and was developed by Worley Parsons and included with a Celanese GHG permit application document dated June 2013. Celanese provided supplemental CCS cost information to the EPA on Nov. 8,2013 that is also reflected in OCI's cost analysis. OCI relied upon this Celanese/Worley Parsons CCS cost study report because this study report was the only relevant study identified by OCI that was supported by detailed documentation, based on current CCS design technology based on a comparable quantity of C02 emissions from a comparable process, and approved by the EPA as part of another Texas GHG PSD permit. Therefore, OCI evaluated the Celanese CCS design cost estimate as the "model" for OCI's CCS cost evaluation as discussed below.

Cost Estimate for Implementing Carbon Capture and Sequestration (CCS) Technology OCI Beaumont LLC - Supporting BACT Analysis for Debottleneck PSD GHG Permit

2. Model CCS Design: The "model" CCS design from the above-noted Celanese/Worley Parsons study report was based on a CCS design using MEA adsorption/stripping to capture 90% of the C02 in a gas-fired steam methane reformer exhaust containing about 8% C02 concentration by volume. The model CCS design capacity was 496,222 TPY of C02 to be captured and either injected underground for sequestration/disposal purposes or added into an existing C02 pipeline for use in Enhanced Oil Recovery {EOR). The model plant had insufficient steam generation to desorb/strip captured C02 from MEA.

3. OCI CCS Design: OCI's CCS cost estimate analysis is based on MEA adsorption/stripping to capture 90% of the C02 in a combined combustion exhaust stream that includes combustion exhaust from OCI's gas-fired steam- methane reformer ,gas-fired pre-heat furnace, and gas-fired SCR duct burner system. The OCI SCR exhaust will contain up to 1,112,150 TPY of C02 at a typical concentration of about 7% C02 by volume. The OCI CCS system would be designed to capture 90% of the potential 1,112,150 TPY of C02 emissions, which translates to 1,000,935 TPY of C02 CCS capture design capacity. The captured C02 would either be injected underground for sequestration/disposal purposes or added into an existing C02 pipeline for use in EOR, and a fraction of the captured C02 may be used as additional C02 feed in the OCI methanol process. Consistent with the Celanese model study, OCI's CCS cost estimate includes construction of a new gas-fired boiler to produce steam for desorbing/stripping captured C02 from MEA.

D. CCS Cost Estimate Calculations (all "TPY" and "tons" values refer to short tons)

1. Model Design Ratio Calculations (based on Celanese model as discussed above)

a) Model Design Capacity= 496,222 TPY C02 captured

b) OCI Design Capacity= 1,000,935 TPY C02 captured (=90% of SCR exhaust emissions)

c) Design Capacity Scaling Factor= 2.02 = OCI Capacity/Model Capacity

d) Capital Cost Scaling Factor= 1.52 = (2.02) "0.6 [see References E.1- E.3 below)

2. OCI CCS Capital Cost Estimate

a) Estimated Model Capital Cost= $118,600,000 Excludes NOx offset costs ,which would not apply to OCI

b) Estimated OCI Capital Cost= $180,800,000 = Model Cost * Capital Cost Scaling Factor

c) Period of CCS Equipment Service= 20 years (assuming a relatively short service life due to corrosive process conditions in MEA-based designs and limited number of commercial-scale implementations)

d) Annual Capital Recovery Rate = 19% Typical actual recovery rate and consistent with rate approved by EPA Region 6 for ExxonMobil [see Reference E.4 below)

e) Annualized Capital Cost= $35,440,000 per year

Cost Estimate for Implementing Carbon Capture and Sequestration {CCS) Technology
OCI Beaumont LLC- Supporting BACT Analysis for Debottleneck PSD GHG Permit

3. OCI CCS Operating & Maintenance (O&M) Cost Estimate

a) OCI Maintenance, Property Tax & Insurance Cost=	$7,232,000 per year= 4% of Estimated OCI Capital Cost
b) Model Electricity Cost=	$3,939,486 per year. Includes electricity for boiler, amine and compression systems at $50.00/MW-hr.
c) Local Electricity Cost Scaling Factor=	1.20 = 60/50 because Celanese applied $50/kW-hr but local Beaumont rate is estimated at $60/kW-hr
d) Estimated OCI Electricity Cost=	$9,549,000 per year= Model Costs * Design Capacity Scaling Factor * Local Eletricity Cost Scaling Factor
e) Model Natural Gas Cost =	$16,561,362 per year. Steam boiler fuel at $5.00/MMBtu.
f) Estimated OCI Natural Gas Cost=	$33,454,000 per year= Model Costs * Design Capacity Scaling Factor
g) OCI Additional Labor Costs =	$1,000,000 Estimated same as additional model plant labor for capture & compression, which was based on total labor cost of $90/hour including benefits, materials, overhead charges, and other indirect labor costs.
h) Pipeline & Storage Costs =	- Not Included- May be insignificant compared to other O&M costs
i) Estimated OCI Total O&M Costs=	$51,235,000 per year= Item 3.a + Item 3.d + Item 3.f + Item 3.g

4. OCI Potential Revenue and Averted Cost Estimate

a) Potential C02 Feed Purchase Price=	$20 per ton of C02 from existing C02 pipeline
b) Potential Rate of C02 Process Feed=	17,100 TPY (from process simulations)
c) Potential C02 Feed Cost Averted=	$342,000 per year = Item 4.a * Item 4.b
d) Recovered C02 Available for EOR =	984,000 TPY = CCS design capacity - process feed C02
e) Potential C02 EOR Sale Price=	$12 per ton of C02 into existing C02 pipeline
f) Potential C02 EOR Revenue =	$11,808,000 per year= Item 4.d * Item 4.e
g) Total Potential Revenue & Averted Cost=	$12,150,000 per year= Item 4.c + Item 4.f

5. BACT Control Cost Effectiveness

a) OCI Total Net Annualized CCS Cost=	$74,525,000 per year = Item 2.e +Item 3.i- Item 4.g
b) OCI C02 Reduction from CCS =	1,000,935 TPY same as CCS capture design capacity
c) C02 from Model CCS Steam Boiler =	245,314 TPY (gas-fired steam boiler required by CCS)
d) C02 from OCI CCS Steam Boiler =	495,500 TPY = Model C02 Emissions* Design Capacity Scaling Factor (no incremental efficiency is expected as compared to model)
e) OCI Net C02 Reduction from CCS =	505,400 TPY =Item 5.b- Item 5.d
f) OCI Control Cost Effectiveness for Implementing CCS =	$147.46 per ton of C02 reduced from CCS compared to proposed BACT= Item 5.a / Item 5.e

E. References

1. Gael D. Ulrich and Palligarnai T. Vasudevan, Capital Costs Quickly Calculated, Chemical Engineering, April 2009, pp. 46-52.
2. Max S. Peters, Klaus D. Timmerhaus, and Ronald E. West, Plant Design and Economics for Chemical Engineers. McGraw-Hill, Inc., 5th Edition, 2003, pp. 242- 244
3. Kenneth K. Humphreys and Paul Wellman, Basic Cost Engineering, 3rd Ed., Marcel Dekker, Inc., 1996, pp. 8- 20.
4. Email dated Sep. 20, 2013 from Mr. Benjamin Hurst of ExxonMobil to Mr. Jeffry Robinson et.al. of EPA Region 6; with approval indicated by EPA's issuance of final GHG PSD Permit PSD-TX-102982-GHG for the ExxonMobil Chemical Company Baytown Olefins Plant project on Nov. 25, 2013.