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March 6, 2014

Mrs. Bonnie Braganza P.E.
EPA Region VI
Air Permits Section (6PD-R)
1445 Ross Avenue
Dallas, TX 75202

Subject: Response to EPA Information Requests, 2/10/14 and 2/25/14
Air Permit No. 901 PSD TX 1334
OCI Beaumont LLC

Dear Mrs. Braganza:

OCI Beaumont LLC (OCI) is submitting the following information in response to your e-mail requests for additional information dated 2/10/2014 and 2/25/2014. The information below is formatted with your original question and OCI's response and are grouped for each e-mail.

February 10, 2014 e-mail:

1. Background basis regarding the cost conclusion of \$106.2/tonCO2 removed on pg F of Appendix B. BACT analyses is a site (case by case) evaluation and not fully dependent on historical 2010 reports. Since CO2 is used in your process at the plant, I will need the BACT analyses to evaluate the technical and economic feasibility of utilizing CO2 in the plant.

   OCI Response: You requested the cost basis and calculations for the data we provided you in the air permit application for carbon capture and sequestration (CCS) or the stack parameters of the combustion source exhaust gases. A more detailed BACT cost analysis for CCS has been completed and is included as Attachment A.

2. I realize that with the saturator process the energy consumption per metric ton of methanol produced will be reduced from current operations. However I did not see additional energy alternatives for reducing the fuel consumption to the heaters such as air or fuel gas preheat. This option will reduce the stack flue gas temperatures from the reformers, boilers etc.

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<u>OCI Response:</u> We have committed to pre-heating air and fuel to the reformer furnaces as part of new design. Natural gas fuel for the reformer furnaces will be pre-heated in exchanger 72-E-007-2014, as depicted on Sketch No. SK-04. This sketch was enclosed in the updated NOD response submitted earlier. We will also install air pre-heaters on the air intakes for each reformer furnace. A basic sketch of where the reformer air pre-heaters will be located is included as Attachment B.

The design of the new fired pre-heat furnace is not compatible with any reasonable options for air preheating. The new fired pre-heat furnace is an updraft heater with a burner on the bottom, which means that air-preheating would be difficult and disproportionately expensive to install on this furnace.

3. I will also need to know how often and why the facility may operate under Case C versus Case D since reducing CO2 would require optimizing the use of CO2 in your plant processes as in Case D.

   <u>OCI Response:</u> We will continue to look for an alternate source of CO2 to add to the process and intend to use it all of the time once it is located. Until the alternate source of CO2 is established, the plant will operate in Case C configuration during normal operating hours. Once the alternate source of CO2 is established, the plant will operate in the Case D configuration during normal operating hours.

4. Also since your PFD is pretty busy and hard to read in a 8X11 document is it possible for you to break it into 2-3 PFDs? Alternatively put it in a .jpg or .png format. It will be a great help. Thanks.

   <u>OCI Response:</u> An updated block flow diagram on multiple pages was enclosed in the updated NOD response.

5. The ammonia unit and the PSA has a vent stream that contains hydrogen which enters the fuel system used in the methanol plant. Has an evaluation been done if additional hydrogen can be used in the fuel system to lower the carbon factor? Please let me know if the fuel composition in the application is based on past analyses and if it is typical of normal operations of the plants. You may want to check the Equistar draft permit and SOB.

   <u>OCI Response:</u> The fuel gas composition represents normal operation. We use all of our available H2 in the Ammonia Production. Any remaining unclaimed H2 in the PSA Vent Stream, which is cost pro-hibitive to recover, is then burned in the Methanol Reformers.

February 25, 2014 e-mail:

1. The application/amendment indicated 4 scenarios of operation. The GHG emissions are considerably different for these operating scenarios. The application indicates that the injection of CO2 to the reformers would increase methanol production. A BACT limit for these different scenarios will be proposed based on the carbon factor and fuel to the reformers. The BACT limit will be based on a rolling 365 day average, MMBTU/MTPD for flexibility of operating under the four operating scenarios. Short term compliance monitoring will be specified to meet the BACT limit.

   OCI Response: For the BACT Limits, they were provided in Appendix D of our NOD Response. With regards to the BACT Limits, we would prefer these to be based on a 12-month rolling average vs 365 day avg, as you stated for consistency with the TCEQ monitoring and recordkeeping time periods.

2. EPA has noted based on the recent information provided by OCI that at this time, OCI does not have the ability of obtaining commercially available CO2 for some of your operating scenarios.

   OCI Response: It is correct that we are continuing to pursue a contract to purchase CO2 from an offsite provider but a CO2 purchase contract has not yet been established.

3. EPA notes that there is a considerable difference in the fuel firing rates and GHG emissions from the Updated Permit Amendment Application dated October 30, 2013 and that of December 17, 2013 without any major change to the equipment. Please verify the lower numbers in the December 17, 2013 application.

   OCI Response: The change in fuel firing rates and GHG emissions are related to an important equipment design change. The initial GHG emission estimates did not include a gas-fired SCR duct burner system, and the later GHG emission estimates include the gas-fired SCR duct burner system. In between the dates of these two sets of GHG emission calculations, OCI's engineering team determined that the gas-fired SCR duct burner system would be required in order to comply with BACT requirements that will be included in the TCEQ PSD permit for NOx. The SCR will only perform as required by the TCEQ's PSD permit if the minimum required SCR catalyst temperature is maintained by firing the proposed new SCR duct burner system.

4. The output BACT limit in MMBtu/ton of methanol of 35.66MMbtu/MTPD methanol is higher than recently permitted facilities that have modified the SMR reactors and is also higher than the 1999 Chile Methanol Plant, that has a one step reforming and a saturator similar to the OCI design. There is no explanation as to why this energy optimization project of the OCI plant cannot achieve the BACT of 31.88.

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OCI Response: The new engineering analysis for the BACT limit indicates that the post-project OCI methanol production process will be able to comply with 33.0 MMBtu/metric ton (MMBtu/MT) on a lower heating value (LHV) basis. This engineering analysis is included as Attachment C.

5. Energy efficiency for the heaters in all recently permitted facilities is determined by best utilization of the heat from the flue gas (stack) and the compliance monitoring is the stack temperature. I am proposing a stack temperature of less than 340 deg F. If this is not possible please provide me the reasons.

   OCI Response: In the current design, the exhaust from the reformer furnace and new pre-heat furnace will be combined for NOx abatement in a SCR system for compliance with the amended PSD permit to be issued by the TCEQ for the Debottleneck project. The SCR requires a minimum temperature in order to meet BACT for NOx consistent with the TCEQ's PSD permit requirements. The SCR exhaust passes thru two exchangers to recover heat to assist with the Saturator efficiency and reduce the SCR exhaust from 620 °F to 420 °F prior to exiting the SCR Unit Stack. With this design, trying to recover any additional useful waste heat from the SCR Unit Stack is not technically feasible. Therefore, there is no technically feasible method to further reduce the proposed SCR exhaust temperature by recovering useful heat to achieve less than 420 °F in the SCR Unit Stack.

   It is technically feasible to reduce the SCR exhaust stack temperature to less than 420 °F by routing the additional heat into an exhaust cooling system, but such an exhaust cooling system could not recover any useful heat and would simply be an ineffective use of electrical energy and/or other utilities and would be for no useful purpose.

6. Since there is a CO2 compressor and line, the fugitives should be estimated and monitored from this line. Please indicate the process to access the fugitive emissions and components from this line. You have not included this in your revised application to date.

   OCI Response: OCI has developed a conservative GHG fugitive component emission calculation and has estimated GHG emissions as if all fugitive leaks were 100% methane. As such, the previously provided fugitive emission calculations are a reasonable and conservative estimate of total GHG emissions from fugitive equipment to be affected by the Debottleneck Project.

7. The VHP program proposed in the application will specifically state that the instrument must be capable of detecting Methane emissions and calibrated.

   OCI Response: Our current LDAR Program (28VHP) requires calibration with methane and look forward to receiving the draft GHG permit.

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If there are any questions or if any further information is required, please contact me at (409) 723-1920.

Sincerely,

Clifford R. Wenzel, P.E.
Environmental Engineer

Attachments

C: Kristi Mills-Jurach, P.E.
Team Leader, Chemical Section
TCEQ Office of Air
P. O. Box 13087, MC #163
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File

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Attachment A

CCS Cost Evaluation

Attachment A

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

A. Purpose

1. This is a cost estimate for implementing CCS technology to reduce CO2 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. CO2 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. CO2 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 CO2 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 CO2). Therefore, the lowest possible relative control cost for CCS implementation (on a cost per ton of CO2 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 CO2 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 WorleyParsons 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/WorleyParsons 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 CO2 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.

2. Model CCS Design: The "model" CCS design from the above-noted Celanese/WorleyParsons study report was based on a CCS design using MEA adsorption/stripping to capture 90% of the CO2 in a gas-fired steam methane reformer exhaust containing about 8% CO2 concentration by volume. The model CCS design capacity was 496,222 TPY of CO2 to be captured and either injected underground for sequestration/disposal purposes or added into an existing CO2 pipeline for use in Enhanced Oil Recovery (EOR). The model plant had insufficient steam generation to desorb/strip captured CO2 from MEA.

3. OCI CCS Design: OCI's CCS cost estimate analysis is based on MEA adsorption/stripping to capture 90% of the CO2 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 CO2 at a typical concentration of about 7% CO2 by volume. The OCI CCS system would be designed to capture 90% of the potential 1,112,150 TPY of CO2 emissions, which translates to 1,000,935 TPY of CO2 CCS capture design capacity. The captured CO2 would either be injected underground for sequestration/disposal purposes or added into an existing CO2 pipeline for use in EOR, and a fraction of the captured CO2 may be used as additional CO2 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 CO2 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 CO2 captured
b) OCI Design Capacity =	1,000,935	TPY CO2 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

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 sytems 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 CO2 Feed Purchase Price =	$20	per ton of CO2 from existing CO2 pipeline
b) Potential Rate of CO2 Process Feed =	17,100	TPY (from process simulations)
c) Potential CO2 Feed Cost Averted =	$342,000	per year = Item 4.a * Item 4.b
d) Recovered CO2 Available for EOR =	984,000	TPY = CCS design capacity - process feed CO2
e) Potential CO2 EOR Sale Price =	$12	per ton of CO2 into existing CO2 pipeline
f) Potential CO2 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 CO2 Reduction from CCS =	1,000,935	TPY same as CCS capture design capacity
c) CO2 from Model CCS Steam Boiler =	245,314	TPY (gas-fired steam boiler required by CCS)
d) CO2 from OCI CCS Steam Boiler =	495,500	TPY = Model CO2 Emissions * Design Capacity Scaling Factor (no incremental efficiency is expected as compared to model)
e) OCI Net CO2 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 CO2 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.

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Attachment B

Sketch A – Reformer Air Preheat Location

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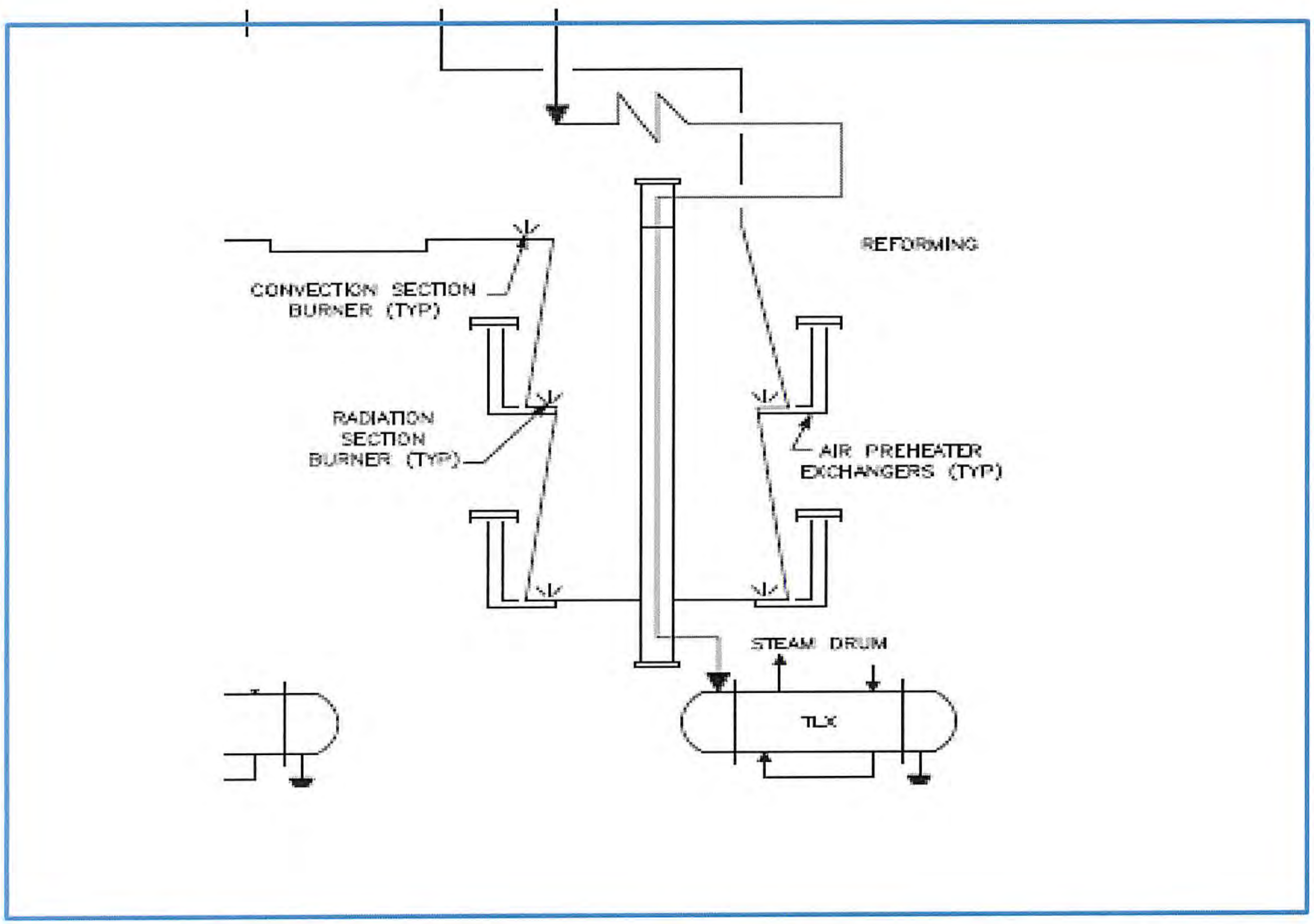
Attachment B



Sketch A: Burner and Combustion air System for side-fired Reformers

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Attachment C

Methanol Production Efficiency Evaluation

Attachment C
Methanol Production Efficiency Evaluation
OCI Beaumont LLC - Supporting BACT Analysis for Debottleneck PSD GHG Permit

A. Purpose: The following analysis is provided in response to request number 4 of 7 as listed in the EPA's email dated February 25, 2014, which is quoted as follows:

The output BACT limit in MMBtu/ton of methanol of 35.66MMbtu/MTPD methanol is higher than recently permitted facilities that have modified the SMR reactors and is also higher than the 1999 Chile Methanol Plant, that has a one step reforming and a saturator similar to the OCI design. There is no explanation as to why this energy optimization project of the OCI plant cannot achieve the BACT of 31.88.

B. Updated Efficiency Assessment: We understand that BACT is a case-by-case evaluation with consideration for sources that have comparable designs and with adjustments for site-specific differences. In response to this comment, OCI has conducted a more detailed assessment of the calculated efficiency value for the OCI methanol production process (as it will operate after implementing the proposed debottleneck project) based on updated process simulations and other engineering analyses. The new assessment indicates that the post-project OCI methanol production process will be able to comply with 33.0 MMBtu/metric ton (MMBtu/MT) on a lower heating value (LHV) basis.

C. Efficiency Calculation Scope: This proposed new 33.0 MMBtu LHV/MT value for the GHG permit is calculated without including any fuel input for the selective catalytic reduction (SCR) duct burner system, which is a NOx abatement technology required by the TCEQ air permit for the debottleneck project, and is not considered part of the manufacturing process. For example, the 31.88 MMBtu LHV/MT efficiency value calculated for the 1999 Chile Methanol Plant does not include fuel heat input for any SCR duct burner system.

D. Site-specific Differences: Following are key site-specific differences between the calculated efficiency of 1999 Chile Methanol Plant as compared to the post-project OCI Beaumont methanol manufacturing process:

1. The 1999 Chile plant efficiency value of 31.88 MMBtu/MT LHV was calculated based on actual average heat input and production data from actual operation of the Chile plant. The Chile plant is not required to comply with this value every year for the operating life of the plant. Even if the exact same 1999 Chile plant design were constructed at the OCI Beaumont facility, OCI would request a permit compliance limit no lower than 32.5 MMBtu/MT LHV (i.e., 2% above the average actual 31.88 value) to ensure that 100% compliance is possible for every rolling 12-month period

of operation. This 2% higher efficiency value is appropriate for permit compliance to account for normal operating variability, potential efficiency impacts from local ambient conditions and feedstock differences, and the likely impact of aging equipment over a typical 30-year plant lifespan. These site-specific factors could easily result in a 2% variance in performance as compared to the actual average 1999 Chile plant efficiency.

2. OCI's proposed post-project design will include a new pre-reformer with an associated gas-fired furnace, which are not included in the 1999 Chile Plant design. The proposed pre-reformer will add more than 1.2 MMBtu/MT LHV heat input to the OCI manufacturing process. The pre-reformer is necessary to accomplish the fundamental purpose of the proposed OCI debottleneck project, which is to debottleneck the production capacity of the existing methanol manufacturing process. As discussed above, the 1999 Chile Plant design would correspond to a permit compliance limit no lower than 32.5 MMBtu/MT LHV. If the 1.2 MMBtu/MT LHV of heat input associated with the proposed OCI pre-reformer is added to the 1999 Chile Plant efficiency, then the comparable permit efficiency limit for the 1999 Chile Plant design would be 32.5 + 1.2 = 33.7 MMBtu/MT LHV.

3. OCI is proposing to modify an existing methanol manufacturing process. The original construction of the OCI Beaumont plant was completed in 1966 whereas the 1999 Chile Methanol Plant was an entirely new plant constructed in 1999. The only way to significantly improve the efficiency of the existing OCI manufacturing process would be to reconstruct large portions of the existing OCI methanol plant. Such extensive reconstruction is not compatible with OCI's business plans for the Beaumont plant.

E. <u>BACT Analysis Conclusion:</u> As discussed in Item D.2 above, the 1999 Chile Plant efficiency is equivalent to 33.7 MMBtu/MT LHV after adjusting for basic site-specific design and compliance requirement differences. As discussed in Item A above, OCI is now proposing 33.0 MMBtu/MT on a LHV basis for the methanol manufacturing process without consideration of the SCR duct burner fuel. Therefore, OCI's proposed efficiency value can be considered equivalent to, or better than, the relevant calculated efficiency for the 1999 Chile Methanol Plant. OCI has no technically feasible options to comply with a lower thermal efficiency that would be compatible with the basic scope of OCI's proposed debottleneck project. Based on this analysis, 33.0 MMBtu/MT LHV is BACT for the post-project OCI Beaumont methanol manufacturing process considering relevant examples from other known methanol plants with adjustments for site-specific differences.