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From:	Robinson, Jeffrey
To:	Wilson, Aimee; Tomasovic, Brian
Subject:	Fw: ExxonMobil Information
Date:	Friday, September 20, 2013 12:50:05 PM
Attachments:	2013.09.20_PSD-TX-102982-GHG Response.pdf

From: Hurst, Benjamin M <benjamin.m.hurst@exxonmobil.com>
Sent: Friday, September 20, 2013 12:07:24 PM
To: Robinson, Jeffrey; Kovacs, Jeffrey K
Cc: Bass, Margaret S; Rebecca Rentz (rrentz@winstead.com)
Subject: RE: ExxonMobil Information

Jeff

Attached is our response to the additional information requested in your e-mail below. In the attachment, we have included your questions/requests verbatim followed by our responses in blue text. If you have any additional questions, please contact me at (281) 834-6110 or benjamin.m.hurst@exxonmobil.com.

Thank you,

Benjamin M. Hurst
Baytown Olefins Plant
Ph: (281) 834-6110
Email: benjamin.m.hurst@exxonmobil.com

From: Robinson, Jeffrey [mailto:Robinson.Jeffrey@epa.gov]
Sent: Tuesday, September 17, 2013 12:13 PM
To: Kovacs, Jeffrey K
Cc: Hurst, Benjamin M
Subject: ExxonMobil Information

Jeff:

Below is our additional information request based on our discussion last week and additional EPA internal discussion after our meeting last week:

Sierra Club Comment C(3)(b)(ii) “The Cost Analysis for Carbon Capture and Sequestration is Invalid – Annualized Capital Costs”

- Please provide additional information on how the annualized capital costs for CCS were calculated. In particular, are there any additional specifics you can provide for the use of a 19% capital charge rate.

Sierra Club Comment D “The Draft Permit Fails to Account for Increased Upstream and Downstream Production (Debottlenecking)”

- Please provide a list of affected but unmodified units that will have an increase of GHG emissions due to this project.
- Provide the GHG emissions of affected but unmodified units
- Please provide an analysis to show that affected units are not modified (as defined at 40 CFR 52.21(b)(2)) as a result of this project.
- In particular, please address how the bottoms product from the new deethanizer being utilized as a feed to the existing base plant depropanizer (as indicated on page 2-1 of the application) will affect emission increases at the base plant.

Sierra Club Comment F "BACT Should Include a Flare Gas Recovery System"

- Need to potential proposed BACT limit assuming EPA proceeds EPA proceeds with FGS as BACT (ex. % recovery) and a proposed method for monitoring from this project
- Need any additional supplemental information for BACT or emission changes to the elevated flare and the ground flare assuming FGS as BACT
- Need updated emissions for the elevated flare
- Please indicate if the emission unit(s) intended to utilize recovered product/process gases as fuel is already permitted to utilize the product/recovered process gases as fuel.
- Changes to existing emissions for any downstream emission points receiving recovered gases.
- ExxonMobil's review for PSD applicability of downstream units assuming FGS as BACT for this project

Please call Aimee or myself if you have questions.

Jeff Robinson, Section Chief
Air Permits Section
EPA Region 6
214-665-6435

RE: *Baytown Olefins Plant Draft Permit PSD-TX-102982-GHG*

Sierra Club Comment C(3)(b)(ii) "The Cost Analysis for Carbon Capture and Sequestration is Invalid – Annualized Capital Costs"

- Please provide additional information on how the annualized capital costs for CCS were calculated. In particular, are there any additional specifics you can provide for the use of a 19% capital charge rate.

Response: The capital charge rate of 19% used to estimate the annualized capital cost for CCS represents capital charges consistent with the New Source Review (NSR) Workshop Manual (1990). Specifically, on page b.8 in Appendix B of the NSR Workshop Manual, EPA states that "fixed annual costs include plant overhead, taxes, insurance, and capital recovery charges." So, the capital charge rate is the sum of the taxes and insurance, capital recovery factor, and plant overhead. ExxonMobil used a rate of 4% (of total capital cost) for taxes and insurance, consistent with the NSR manual. No tax credits were applied since there is uncertainty in receiving credits on an ongoing basis.[1] The capital recovery factor is based on the available interest rate for the project and the assumed equipment life. The interest rate (i.e., cost of money) for a major venture such as the Proposed BOP Project[2] is based on ExxonMobil's long term (20+ year) assessment of treasury rates with appropriate consideration of investment risk. For a project such as the Proposed BOP Project, that value is in the range of 10% to 14%, and a rate of 14% was used for the analysis of CCS for the Proposed BOP Project. This interest rate appropriately reflects the uncertainty in returns on major ventures as compared to commercial (e.g., bond) markets, and would actually be expected to be much higher if the project was required to implement an unproven and undemonstrated CCS technology that would increase the capital cost of the project by at least 27% and maybe as high as 41%. The analysis of CCS for the Proposed BOP Project assumed a 20 year equipment life, but a shorter equipment life of 10 to 16 years is more likely based on the acidic nature of the process. Based on an interest rate of 14%, a 20 year equipment life, and tax/insurance rate of 4%, the capital recovery factor is 15% and the capital charge rate is 19%. Please note that the range of appropriate interest rates (10% to 14%) and assumed equipment life (10 to 20 years) result in a capital recovery factor range of 12% to 19% and a capital charge rate from 16% to 23%. ExxonMobil used a capital charge rate of 19% in the analysis as noted above. Plant overhead for the Proposed BOP Project was excluded from the capital charge rate analysis because it was included in the annual operating cost analysis.

In the example in Appendix B of the NSR Workshop Manual, the capital charges (i.e., capital charge rate) are almost 16% of the total capital cost of the project. Additionally, other applications for industrial expansions/projects submitted to the EPA Region 6 used interested rates varying from 7% to 12% and equipment life values between 10 and 30 years, resulting in capital recovery factors ranging from 9% to 17%. Thus, capital charge rates as high as 21% were used, if the applicants had accounted for taxes and insurance as allowed by the NSR Workshop Manual (1990).

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[1] The existing Section 45Q is authorized to provide tax credits for only 75 million tons of CO_2, *see* 26 U.S.C. section 45Q(e), which is an insignificant amount when compared to the total amount of CO_2 that is produced each year and that could be sequestered. Given that credits are limited and capped on annual basis, operators cannot be certain whether their projects qualify, whether there are still credits available in a given year, and how many of those credits they will be able to claim, if any. Therefore, there is no guarantee that ExxonMobil will receive a full credit, if any, on a consistent year-to-year basis.

[2] The "Proposed BOP Project" refers to the proposed project at BOP that is the subject of the draft permit PSD-TX-102982-GHG.

Sierra Club Comment D "The Draft Permit Fails to Account for Increased Upstream and Downstream Production (Debottlenecking)"

- Please provide a list of affected but unmodified units that will have an increase of GHG emissions due to this project.

Response: The affected but unmodified units that will have an increase of GHG emissions attributable to this project are anticipated to be the following steam and electricity generators: Boilers A, B, C, and D, Trains, 1, 2, 3, and 4.

- Provide the GHG emissions of affected but unmodified units

Response: The GHG emissions from affected but unmodified units are based on a representative incremental steam demand on the boilers and trains noted above totaling 165 klb/hr of 1,500 pound steam on an annual basis. The affected, unmodified sources identified above will each incrementally increase firing to produce incremental steam and/or electricity for the Proposed BOP Project. Based on this incremental steam production, the accumulative increase in actual GHG emissions at these units is approximately 110,000 tpy of CO_2e.

- Please provide an analysis to show that affected units are not modified (as defined at 40 CFR 52.21(b)(2)) as a result of this project.

Response: The affected units are not modified (as defined at 40 CFR 52.21(b)(2)) as a result of this project because we are not making physical change or change in the method of operation. There is only increased utilization of the units. Furthermore, the units are not subject to BACT review pursuant to 40 CFR 52.21(j)(3) which states, "*A major modification shall apply best available control technology for each regulated NSR pollutant for which it would result in a significant net emissions increase at the source. This requirement applies to each proposed emissions unit at which a net emissions increase in the pollutant would occur <u>as a result of a physical change or change in the method of operation in the unit</u>.*" *[Emphasis added]* This is also supported by EPA's GHG permitting guidance which notes that "BACT applies in the context of a modification to only an emission unit that has been modified or added to an existing unit." (PSD and Title V Permitting Guidance for Greenhouse Gases, p. 23, March 2011)

- In particular, please address how the bottoms product from the new deethanizer being utilized as a feed to the existing base plant depropanizer (as indicated on page 2-1 of the application) will affect emission increases at the base plant.

Response: The bottoms product from the new deethanizer being utilized as a feed to the existing base plant depropanizer (as indicated on page 2-1 of the application) will not result in an actual GHG emissions increase from the depropanizer column or at any downstream column/separator. This is because emissions from fugitive components are not dependent upon the unit throughput. However, there may be an increase in the heat duty and/or electrical demand of the depropanizer's (and/or downstream columns') reboilers or condenser pumps. These utilities (i.e. steam and electricity) are provided, at least in part (electricity might be purchased), by the existing boilers and trains noted above. Therefore, an actual increase in GHG emissions attributable to increased utilization of the boilers and/or trains may occur. No other actual emission increases in GHG are expected as a result of the new deethanizer being utilized as a feed to the existing base plant depropanizer.

(pages omitted)