A

Report of the Interagency Task Force on Carbon Capture and Storage

August 2010

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Executive Summary

Introduction

Carbon capture and storage (CCS) refers to a set of technologies that can greatly reduce carbon dioxide (CO_2) emissions from new and existing coal- and gas-fired power plants, industrial processes, and other stationary sources of CO_2. In its application to electricity generation, CCS could play an important role in achieving national and global greenhouse gas (GHG) reduction goals. However, widespread cost-effective deployment of CCS will occur only if the technology is commercially available and a supportive national policy framework is in place.

In keeping with that objective, on February 3, 2010, President Obama established an Interagency Task Force on Carbon Capture and Storage composed of 14 Executive Departments and Federal Agencies. The Task Force, co-chaired by the Department of Energy (DOE) and the Environmental Protection Agency (EPA), was charged with proposing a plan to overcome the barriers to the widespread, cost-effective deployment of CCS within ten years, with a goal of bringing five to ten commercial demonstration projects online by 2016. Composed of more than 100 Federal employees, the Task Force examined challenges facing early CCS projects as well as factors that could inhibit widespread commercial deployment of CCS. In developing the findings and recommendations outlined in this report, the Task Force relied on published literature and individual input from more than 100 experts and stakeholders, as well as public comments submitted to the Task Force. The Task Force also held a large public meeting and several targeted stakeholder briefings.

While CCS can be applied to a variety of stationary sources of CO_2, its application to coal-fired power plant emissions offers the greatest potential for GHG reductions. Coal has served as an important domestic source of reliable, affordable energy for decades, and the coal industry has provided stable and quality high-paying jobs for American workers. At the same time, coal-fired power plants are the largest contributor to U.S. greenhouse gas (GHG) emissions, and coal combustion accounts for 40 percent of global carbon dioxide (CO_2) emissions from the consumption of energy. EPA and Energy Information Administration (EIA) assessments of recent climate and energy legislative proposals show that, if available on a cost-effective basis, CCS can over time play a large role in reducing the overall cost of meeting domestic emissions reduction targets. By playing a leadership role in efforts to develop and deploy CCS technologies to reduce GHG emissions, the United States can preserve the option of using an affordable, abundant, and domestic energy resource, help improve national security, help to maximize production from existing oil fields through enhanced oil recovery (EOR), and assist in the creation of new technologies for export.

While there are no insurmountable technological, legal, institutional, regulatory or other barriers that prevent CCS from playing a role in reducing GHG emissions, early CCS projects

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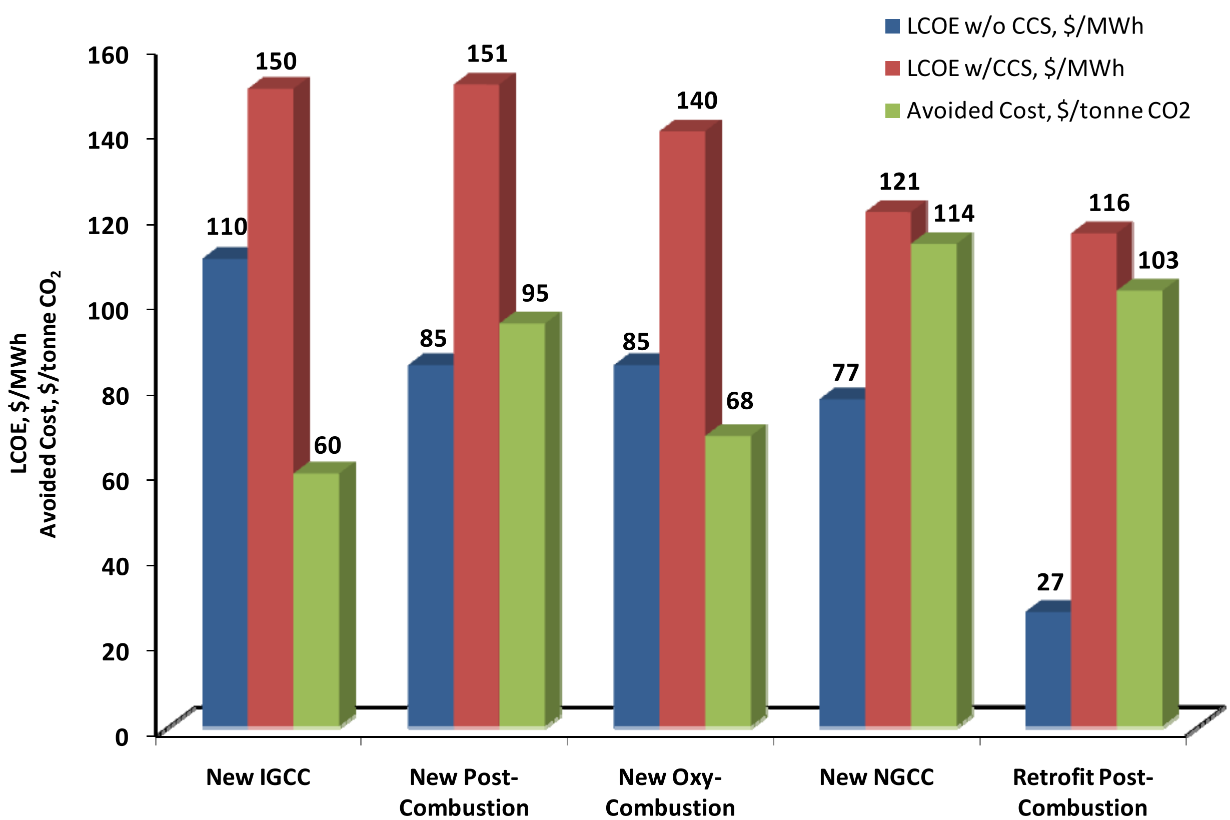
technology increases the capital cost of a new IGCC facility by $400 million and results in an energy penalty of 20 percent. For post-combustion and oxy-combustion capture, the increases in capital costs are $900 million and $700 million respectively, and the energy penalty would be 30 and 25 percent. For a natural gas combined cycle (NGCC) plant, the capital cost would increase by $340 million and an energy penalty of 15 percent would result from the inclusion of CO_2 capture. The costs associated with CO_2 capture in terms of increases in the LCOE or cost per tonne of CO_2 avoided are shown in Figure A-9. The LCOE ranges from $116/MWh to $151/MWh, depending upon the type of facility and whether the application is for a new plant or a retrofit of an existing plant. This compares to an LCOE of $85/MWh for a new supercritical PC plant and a $27/MWh LCOE for the existing fleet of power plants. In terms of costs per tonne of CO_2 avoided, values range from $60/tonne to $114/tonne.

Figure A-9. Comparison of Levelized Cost of Electricity for Different Types and Configurations of Power Plants



Source: (DOE, 2010a; DOE, 2010b)

A.3 Cost Estimating Methodology

A summary of the costing assumptions behind the levelized cost of electricity (LCOE) calculation referred to throughout the Task Force CCS report is contained here. A fully documented methodology can be found in DOE (2010a) and DOE (2010b).

<u>Capital Costs</u>

All capital costs are presented as "overnight costs" expressed in December 2009 dollars. Capital costs are presented at the total plant cost (TPC) level. TPC includes:

- equipment (complete with initial chemical and catalyst loadings),
- materials,
- labor (direct and indirect),
- engineering and construction management, and
- contingencies (process and project).

Owner's Costs

Owner's costs were subsequently calculated and added to the TPC. The result is defined as total overnight cost (TOC) and is the capital expenditure used in the calculation of LCOE. The owner's costs included in the TOC cost estimate are shown in Table A-4.

Table A-4. Owner's Costs Included in TOC

Owner's Cost	Comprised of
Preproduction Costs	• 6 months O&M, and administrative & support labor • 1 month maintenance materials @ 100% Capacity Factor (CF) • 1 month non-fuel consumables @ 100% CF • 1 month of waste disposal costs @ 100% CF • 25% of one month's fuel cost @ 100% CF • 2% of TPC
Inventory Capital	• 60 day supply of fuel and consumables @100% CF • 0.5% of TPC (spare parts)
Land	• $3,000/acre (300 acres for greenfield IGCC and PC, and 100 acres for NGCC)
Financing Costs	• 2.7% of TPC
Other Owner's Costs	• 15% of TPC
Initial Cost for Catalyst and Chemicals	• All initial fills not included in bare erected cost (BEC)
Prepaid Royalties	• Not included in owner's costs (included with BEC)
Allowance for Funds Used During Construction (AFUDC) and Escalation	• Varies based on levelization period and financing scenario • 33-yr IOU high risk: Total As-Spent Capital Cost (TASC) = TOC * 1.078 • 33-yr IOU low risk: TASC = TOC * 1.075 • 35-yr IOU high risk: TASC = TOC * 1.140 • 35-yr IOU low risk: TASC = TOC * 1.134

The category labeled "Other Owner's Costs" includes the following:

- preliminary feasibility studies, including a Front-End Engineering Design (FEED) study;

- economic development (costs for incentivizing local collaboration and support);
- construction and/or improvement of roads and/or railroad spurs outside of site boundary;
- legal fees;
- permitting costs;
- owner's engineering (staff paid by owner to give third-party advice and to help the owner oversee/evaluate the work of the EPC contractor and other contractors); and
- owner's contingency: sometimes called "management reserve", these are funds to cover costs relating to delayed startup, fluctuations in equipment costs, unplanned labor incentives in excess of those for a 5 day, 10 hours per day work schedule.

Cost items excluded from "Other Owner's Costs" include:

- EPC Risk Premiums,
- transmission interconnection,
- taxes on capital costs, and
- unusual site improvements.

Operations and Maintenance

The production costs or operating costs and related maintenance expenses (O&M) pertain to those charges associated with operating and maintaining the power plants over their expected life. These costs include:

- operating labor,
- maintenance – material and labor,
- administrative and support labor,
- consumables,
- fuel,
- waste disposal, and
- co-product or by-product credit (that is, a negative cost for any by-products sold).

Thirty-Year, Current-Dollar LCOE

The revenue requirement method of performing an economic analysis of a prospective power plant has been widely used in the electric utility industry. This method permits the incorporation of the various dissimilar components for a potential new plant into a single value that can be compared to various alternatives. The revenue requirement figure-of-merit is a current-dollar, 30-year LCOE. The effective levelization period is the sum of the operational levelization period (30 years for all plants) and the capital expenditure levelization period (assumed to be 3 years for NGCC plants and 5 years for IGCC and PC plants). The sum results in an effective levelization period of 33 years for the NGCC cases and 35 years for the IGCC and PC cases. The LCOE is expressed in mills/kWh (numerically equivalent to \$/MWh). The current-dollar, 30-year LCOE was calculated using a simplified equation derived from the NETL PSFM (Power Systems Financial Model Version 5.0, 2006).

The equation used to calculate LCOE is as follows:

$$LCOE_P = \frac{(CCF_P)(TOC) + (LF)[(OC_{F1}) + (OC_{F2}) + \ldots] + (CF)(LF)[(OC_{V1}) + (OC_{V2}) + \ldots]}{(CF)(MWh)}$$

where:

$LCOE_P$ = levelized cost of electricity over P years, \$/MWh

P = levelization period (e.g., 10, 20 or 30 years)

CCF_P = capital charge factor for a levelization period of P years

TOC = total overnight cost, \$

LF = levelization factor (a single levelization factor is used in each case because a single escalation rate is used for all costs)

OC_{Fn} = category n fixed operating cost for the initial year of operation (but expressed in “first-year-of-construction” year dollars)

CF = plant capacity factor

OC_{Vn} = category n variable operating cost at 100 percent CF for the initial year of operation (but expressed in “first-year-of-construction” year dollars)

MWh = annual net megawatt-hours of power generated at 100 percent CF

All costs are expressed in December 2009 year dollars, and the resulting LCOE is expressed in mixed year dollars.

Although their useful life is usually well in excess of 30 years, 33-year (NGCC) and 35-year (IGCC and PC) levelization periods (including the variable capital expenditure levelization periods as defined above) are the levelization periods used in this study.

The technologies modeled in this study were divided into one of two categories for calculating LCOE: Investor Owned Utility (IOU) high risk and IOU low risk. All IGCC cases as well as PC and NGCC cases with CO_2 capture are considered high risk. The non-capture PC and NGCC cases are considered low risk. The resulting CCF and LFs are shown in Table A-5.

Table A-5. Economic Parameters for LCOE Calculation

	High Risk 5 year construction	**Low Risk** 5 year construction	**High Risk** 3 year construction	**Low Risk** 3 year construction
Capital Charge Factor	0.1773	0.1691	0.1567	0.1502
Levelization Factor	1.42689	1.45104	1.41094	1.43262

The economic assumptions used to derive the CCFs are shown in Table A-6. The difference between the high risk and low risk categories is manifested in the debt-to-equity ratio and the weighted cost of capital. The values used to generate the CCFs and LFs in this study are shown in Table A-7.

Table A-6. Parameter Assumptions for Capital Charge Factors

Parameter	**Value**
TAXES	
Income Tax Rate	38% (Effective 34% Federal, 6% State)
Capital Depreciation	20 years, 150% declining balance
Investment Tax Credit	0%
Tax Holiday	0 years
FINANCING TERMS	
Repayment Term of Debt	15 years
Grace Period on Debt Repayment	0 years
Debt Reserve Fund	None
TREATMENT OF CAPITAL COSTS	
Capital Cost Escalation During Construction (nominal annual rate)	3.6%[1]
Distribution of Total Overnight Capital over the Capital Expenditure Period (before escalation)	3-Year Period: 10%, 60%, 30% 5-Year Period: 10%, 30%, 25%, 20%, 15%
Working Capital	zero for all parameters
% of Total Overnight Capital that is Depreciated	100% *(this assumption introduces a very small error even if a substantial amount of TOC is actually non-depreciable)*
INFLATION	
LCOE, O&M, Fuel Escalation (nominal annual	3.0%[2] COE, O&M, Fuel

[1] A nominal average annual rate of 3.6% is assumed for escalation of capital costs during construction. This rate is equivalent to the nominal average annual escalation rate for process plant construction costs between 1947 and 2008 according to the *Chemical Engineering* Plant Cost Index.

[2] An average annual inflation rate of 3.0% is assumed. This rate is equivalent to the average annual escalation rate between 1947 and 2008 for the U.S. Department of Labor's Producer Price Index for Finished Goods, the so-called "headline" index of the various Producer Price Indices. (The Producer Price Index for the Electric Power

Parameter	Value
rate) Escalation rates must be the same for LCOE approximation to be valid	

Table A-7. Financial Structure for Investor Owned Utility High and Low Risk Projects

Type of Security	% of Total	Current (Nominal) Dollar Cost	Weighted Current (Nominal) Cost	After Tax Weighted Cost of Capital
Low Risk				
Debt	50	4.5%	2.25%	
Equity	50	12%	6%	
Total			8.25%	7.39%
High Risk				
Debt	45	5.5%	2.475%	
Equity	55	12%	6.6%	
Total			9.075%	8.13%

A.4 Planned Demonstrations of CO_2 Capture Technologies

DOE/NETL is currently engaged in two major CCS demonstration programs.

The Clean Coal Power Initiative (CCPI) is an innovative technology demonstration program that fosters more efficient clean coal technologies for use in new and existing coal-based power plants. The intent of CCPI is to accelerate technology adoption and thus rapidly move promising new concepts to a point where private-sector decisions on deployment can be made.

CCPI is currently pursuing three pre-combustion and three post-combustion CO_2 capture demonstration projects (Table A-8). The pre-combustion projects involve CO_2 capture from IGCC power plants. The generating capacities at the demonstration facilities range from 257 to 582 MW. The capture efficiencies range from 67 percent to 90 percent, and total CO_2 captured ranges from 1.8 to 2.7 million tonnes per year. The demonstrations will be initiated between 2014 and 2016, and the projects will run for 2-3 years. The post-combustion projects will capture CO_2 from pulverized coal (PC) plant slipstreams representing the equivalent of 60 to 235 MW of power production. Each will capture 90 percent of CO_2 emissions with total capture of 0.4 to 1.5 million tonnes per year.

Generation Industry may be more applicable, but that data does not provide a long-term historical perspective since it only dates back to December 2003.)

(pages omitted)

B

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)

C

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 6
1445 ROSS AVENUE, SUITE 1200
DALLAS, TX 75202-2733

JUN 2 9 2012

Mr. Jeffrey K. Kovacs, P.E.
Environmental Section Supervisor
ExxonMobil Corporation
P.O. Box 4004
Baytown, TX 77522-4004

RE: Application Completeness Determination for ExxonMobil Corporation
Greenhouse Gas Prevention of Significant Deterioration Permit
ExxonMobil Chemical Company – Baytown Olefins Plant (BOP)

Dear Mr. Kovacs:

This letter is in response to your application received by this office on May 22, 2012 for a Greenhouse Gas Prevention of Significant Deterioration permit. After our initial review of the application and supporting information, we have determined that this application is incomplete based on the requirements of 40 CFR 124 and additional information is required to begin the processing of the application. Enclosed is a list of the information required (see Enclosure).

Upon receipt of the additional information, the Environmental Protection Agency (EPA) will prepare a completeness determination. The requested information is necessary for EPA to develop a Statement of Basis and Rationale for the terms and conditions for the requisite permit. As we develop our preliminary determination, it may be necessary for EPA to request additional clarifying or supporting information. If the supporting information substantially changes the original scope of the permit application, an amendment or new application may be required.

Although not required as a part of our completeness determination, the EPA may not issue a final permit without determining that there will be no effects on endangered species or until it has completed consultation under Section 7 of the Endangered Species Act(16 USC 1536). In addition, the EPA must undergo consultation pursuant to Section 106 of the National Historic Preservation Act (16 USC 470f). To expedite these consultations, the EPA requests that permit applicants provide a Biological Assessment and a cultural resources report covering the project and action area.

If you have any questions concerning the review of your application, please contact Melanie Magee of my staff at (214) 665-7161.

Sincerely yours,

William K. [signature]

Carl E. Edlund, P.E.
for Director
Multimedia Planning and
Permitting Division

cc: Mr. Mike Wilson, P.E.
Director, Air Permits Division
Texas Commission on Environmental Quality

ENCLOSURE

EPA Completeness Comments
ExxonMobil Corporation
Application for Greenhouse Gas Prevention of Significant Deterioration Permit
ExxonMobil Chemical Company – Baytown Olefins Plant (BOP)

Process Description

1. On page 2-1, the permit application indicates the furnaces will fire imported natural gas or a blended fuel gas that consists of imported natural gas and tail gas. Tail gas is a recycle stream resulting from an initial separation of methane and hydrogen. The application also states that the composition of the blended fuel gas will vary and will depend on current hydrogen production and disposition. The permit application states the use of natural gas as the primary fuel for lowering the GHG emissions. Please provide additional technical information explaining why natural gas would be considered over fuel gas containing hydrogen (H2). Provide all relevant factors including economics and energy impacts. Please provide additional information pertaining to the use of H2 as a secondary fuel gas to the furnace. What circumstances will allow or disallow hydrogen to be used as either a primary in lieu of natural gas or as a secondary fuel?

2. Please supplement the process flow diagram by identifying all emission control points for GHG emissions, include the emission control point identification numbers.

3. On pages 2-3 and 2-4 of the permit application, it states that "no increase in GHG emissions are being requested" for the changes proposed at the Acetylene Converter Regeneration Vent, Cooling Tower, Wastewater Collection and Treatment System and Storage Tanks. Please provide the PSD applicability calculations for these units to support the "no increase" in GHG emissions request.

4. Please provide supplemental technical data that discusses the design and operation of the new staged flare system, i.e., percent combustion efficiency, percent emission reduction, proposed monitoring and recordkeeping strategy, maintenance schedule, etc. Will it be computer controlled? If so, will there be manual overrides? Please provide benchmark comparison data of new flare system to similar or existing sources. Was a flare gas recovery system considered for the proposed project? Please supplement the BACT analysis to support its elimination.

BACT Analysis

5. On page 4-3, the permit application states that "Good operating and maintenance practices for the steam cracking furnaces extend the performance of the combustion equipment, which reduces fuel gas usage and subsequent GHG emissions…Examples of good operating and maintenance practices include good air/fuel mixing in the combustion zone; sufficient residence time to completed combustion; proper fuel gas supply system operation in order to minimize fluctuations in fuel gas quality; good burner maintenance

and operation; and overall excess oxygen levels high enough to safely complete combustion while maximizing thermal efficiency."

A. Please provide comparative benchmark data on the percent efficiency of the burners compared to existing or similar sources. Please provide details concerning the preventive maintenance on burners, frequency and recordkeeping. How often will burners be inspected? How will this be ensured? What recordkeeping requirements are you proposing? What will alert on-site personnel to problems?

B. What will be the operating parameters that will ensure minimum excess air? Please include a discussion on how O_2 analyzers will be utilized to determine optimum excess air to provide proper combustion.

C. Please provide further discussion as to how good combustion efficiency will be ascertained for the furnace's operating parameters pertaining to feedstock/steam ratios, temperatures, pressures, and residence times. What is ExxonMobil's preferred monitoring method, recordkeeping requirements for the cracking furnaces (e.g., continuous or periodic)?

D. Please submit a detailed description of the anticipated procedures that are proposed as part of the maintenance practices and include a proposed schedule for planned maintenance.

6. It is indicated in the "Energy Efficient Design" section that "the proposed project will use a proprietary furnace design to minimize its carbon footprint...To maximize thermal efficiency at BOP; the steam cracking furnaces will be equipped with heat recovery systems to produce steam from waste heat for use throughout the plant."

A. Please provide benchmarking data that compares the technologies outline in this section to other existing or similar sources, i.e., the percent energy efficiency and CO_2 control effectiveness of the economizer, steam generation from process waste heat, feed preheat and minimize hydrocarbon ratio.

B. What operating parameters does ExxonMobil prefer to monitor to determine that the thermal efficiency in the plant is optimized, i.e., stack temperature, pressure, fuel combusted per product produced, etc.?

C. Provide any supporting data to substantiate operating and design improvements to the proposed technologies compared to the past operation and design, e.g., past energy consumed per ton of product and what will be the difference compared to the new construction, comparative benchmark studies to similar operations. Please include any technical data that supports your conclusions, as well as the associated decrease in GHG per pound of product.

7. On page 4-8 of the permit application, the cost estimates provided for the Carbon Capture and Storage (CCS) appear to solely rely on the August 2010 report entitled "Report of the

Interagency Task Force on Carbon Capture and Storage." BACT is a case-by-case determination. Please provide site-specific facility data to evaluate and eliminate CCS from consideration. This material should contain detailed information on the quantity and concentration of CO_2 that is in the waste stream and the equipment for capture, storage and transportation. Please include cost of construction, operation and maintenance, cost per pound of CO_2 removed by the technologies evaluated and include the feasibility and cost analysis for storage or transportation for these options. Please discuss in detail any site specific safety or environmental impacts associated with such a removal system.

8. On page 4-10 of the permit application in the entitled Decoking Activities, the application identifies two potential practices that are technically feasible for CO_2 control for decoking operations which are limiting air/steam during the decoking process and minimizing the amount of coke formed in the furnace through proper design and operation.

    A. Please provide supplemental data that will discuss the design of the proposed furnaces and how it will translate to decreasing coking potential as is asserted in the application?

    B. What percentage of coke reduction in the tubes will occur in lbs coke/lbs of product processed? Please include technical data that supports your conclusions, as well as the associated decrease in GHG per pound of product.

    C. What design or process operation modifications will ensure the uniform distribution of the feed and heating in the tubes?

9. Being mindful of EPA's PSD and Title V Permitting Guidance for GHG dated March, 2011 on page 17, which states the following:

> "The CAA and corresponding implementing regulations require that a permitting authority conduct a BACT analysis on a case-by-case basis, and the permitting authority must evaluate the amount of emissions reductions that each available emissions-reducing technology or technique would achieve, as well as the energy, environmental, economic and other costs associated with each technology or technique. Based on this assessment, the permitting authority must establish a numeric emissions limitation that reflects the maximum degree of reduction achievable for each pollutant subject to BACT through the application of the selected technology or technique. However, if the permitting authority determines that technical or economic limitations on the application of a measurement methodology would make a numerical emissions standard infeasible for one or more pollutants, it may establish design, equipment, work practices or operational standards to satisfy the BACT requirement."

Please propose short-term emission limitations or efficiency based limits for all PSD emission sources. Please provide an analysis that substantiates any reasons for infeasibility of a numerical emission limitation. For the emission sources where numerical emission limitations are infeasible, please propose an operating work practice standard that can be practically enforceable.

10. On page 4-16 of the permit application, it states "the proposed project selects as-observed AVO as BACT for piping components in natural gas service and instrument LDAR for piping components in VOC service." Please specify level of LDAR to be used and the basis of elimination for the other LDAR programs.

Calculations

11. Please provide the percent efficiency used to calculate the annual average heat input capacity for natural gas combustion for the cracking furnaces. Please provide benchmarking data how this heat input capacity was obtained and how it compares to other recently permitted units nationally?

12. Please provide supporting technical data that was used to calculate the CO_2e emission calculations for in the decoking emissions calculations. How was the mole ratio of CO_2/CO derived or obtained? Please provide a technical discussion how the estimation of one decoke per month per furnace was obtained? Please indicate if benchmark data was used in this estimation?

13. Aforementioned on page 2-1 of the permit application, it is indicated that "the furnaces will fire imported natural gas or a blended fuel gas that consists of imported natural gas and tail gas." Please provide the blended fuel gas analysis results to determine the fuel's carbon content factor used in equation C-5 from 40 CFR 98, Subpart C to calculate GHG emissions rates. What will be ExxonMobil's preferred method of monitoring and recordkeeping for the determination of fuel quality, i.e., continuous gas chromatograph, fuel meters, etc.,

D

Memo

To: ExxonMobil Chemical Company Baytown Olefins Plant Permit File (NSR-8-1-20)
From: Aimee Wilson
Date: August 29, 2013
Subject: Meeting with ExxonMobil and their Counsel

On August 29, 2013, EPA and the applicant had a meeting to discuss technical details relating to comments from Sierra Club during the public notice and comment period for the ExxonMobil Baytown Olefins Plant. The meeting was held at the applicant's request. Attendees were:

EPA: Jeff Robinson, Brian Tomasovic, Aimee Wilson
Winstead PC (applicant's counsel): Rebecca Rentz
ExxonMobil (applicant): Ben Hurst

The meeting started off with a discussion on the possibility of submitting information by ExxonMobil that provided their perspective on the public comments. EPA responded that the applicant could submit material in response to the public comments received by EPA, but that EPA is responsible for developing responses to the comments and that we were not asking them to respond to the public comments. ExxonMobil representatives indicated that they would be convening among themselves after the meeting to decide the format in which they want to provide information to EPA that presents their perspective on the comment. We indicated that any new material submitted would become a part of the permitting record.

The applicant then wanted to discuss the comments from Sierra Club individually.

Comment A of the Sierra Club letter was discussed first. ExxonMobil stated Sierra Club incorrectly calculated the lb of CO_2/lb of ethylene for the Baytown Olefins Plant and that they would be willing to provide the calculation. The applicant also stated that the Baytown facility should not be compared to INEOS since the INEOS facility has a flare and was adding only 1 furnace to their existing plant instead of 8 furnaces like ExxonMobil Baytown.

Comment B was then discussed. ExxonMobil stated that Sierra Club incorrectly calculated the specific energy consumption (SEC) for the Baytown Olefins Plant. The applicant stated that using application data would result in a value that may not be the same as the actual operating parameters of the plant once constructed. The applicant also stated they do not think SEC is an appropriate metric for comparing facilities. The applicant also stated that the October 2012 response to EPA contains all the data needed to show that the plant design is energy efficient. ExxonMobil also stated they had reviewed the document "Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry", June 2008, Lawrence Berkley Lab

Report LBNL-964E. The applicant stated they could provide a document identifying which measures they are implementing at the Baytown Olefins Plant.

Comment C regarding Carbon Capture and Storage was discussed briefly. ExxonMobil stated they had not prepared anything to discuss. EPA stated they had a question on the $735,400,000 value given in the October 2012 response on page 23. EPA asked that ExxonMobil provide clarification information on this number as it was presented in the permit application.. EPA also stated that ExxonMobil may want to consider providing information on the project cost without CCS.

Comment D was discussed. EPA stated that a review of the application may be needed to ensure downstream units are affected units. . EPA would also look at other permits issued in Region 6 that discussed “affected” units.

Comment E was briefly discussed. EPA stated that a an additional review of leakless technology may be needed by EPA.

ExxonMobil stated they were not prepared to discuss Comment F.

Comment G was only briefly discussed. ExxonMobil stated that the information submitted following their review of the draft permit and SOB clearly stated their position on the operating conditions that were revised and no longer matched the initial application.

E

From:	Hurst, Benjamin M
To:	Wilson, Aimee
Cc:	Robinson, Jeffrey; Kovacs, Jeffrey K
Subject:	PSD-TX-102982_GHG_Clarifying Information
Date:	Friday, September 06, 2013 9:47:30 AM
Attachments:	2013.09.06_PSD-TX-102982_GHG_Clarifying Information.pdf

Aimee,

We are providing clarifying information (attached) with regard to certain items, information, assertions, etc. in the Sierra Club comment letter on draft permit PSD-TX-102982-GHG for the Baytown Olefins Plant. If you have any questions, please contact me at (281) 834-6110.

Thank you,

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

We are providing clarifying information with regard to certain items, information, assertions, etc. in the Sierra Club comment letter (SC Letter)[1]. The bullets below are not a complete analysis or response to the SC Letter and therefore may be supplemented by ExxonMobil in the future. Failure to address any items, information, assertions, etc. in the SC Letter is not to be considered tactic endorsement or agreement. We would be glad to discuss or answer any questions that EPA may have in future communications.

The following bullets reiterate the application basis for the proposed Baytown Olefins Plant (BOP) (draft permit PSD-TX-102982-GHG ("Draft BOP Permit")) and correct calculations made in the SC Letter:

- In "*A. The Permit Should Include an Emission Rate Based on the Production of Ethylene at the Facility*" on page 2 of the SC Letter, Sierra Club did not use the correct draft permit information to calculate the "production efficiency" cited in their comments. The SC Letter states, "*The production efficiency of the Baytown Plant is therefore 1,479,665 tons CO_2e emitted annually per 1,650,000 tons of ethylene produced. This equates to 0.90 tons of CO_2e per ton of ethylene, which is less efficient than the 0.85 rate at the INEOS plant.*" The draft permit correctly states in the Process Description, "*The new ethylene unit will increase the production capacity of the plant by approximately 2 million metric tons per year of polymer grade ethylene. Other products produced by the Baytown Olefins Plant include fuel gas, mixed C3 and C4 hydrocarbon streams, and other lower hydrocarbon streams.*" Using only the ethylene production capacity of 2 MT/y (which converts to 2,204,623 tons / year), the calculated value of the "production efficiency" is approximately 0.67 tons of CO_2e per ton of ethylene. Please note that this value does not account for the "*Other products produced by the Baytown Olefins Plant include fuel gas, mixed C3 and C4 hydrocarbon streams, and other lower hydrocarbon streams*" noted in the draft permit which would result in an even lower value on a per ton of total output basis.

  Although the corrected tons of CO_2e per ton of ethylene for the proposed project is less than that cited for Ineos, please note that:

  (1) This response is not an indication of support for a "production efficiency" in tons of CO_2e per ton of ethylene. On the contrary, achieving a high thermal efficiency by establishing and monitoring energy efficiency surrogates such stack exhaust gas exit temperatures and excess oxygen present in the exhaust gas already exist in the Draft BOP Permit.

[1] Letter correspondence, RE: ExxonMobil Baytown Olefins Plant –Permit No. PSD-TX-102982-GHG, from Mr. Travis Ritchie, Sierra Club, to Ms. Aimee Wilson, US EPA Region 6, on July 8, 2013.

(2) A comparison of the proposed BOP project to the Ineos project is inappropriate because:

(a) the difference in project scope – the proposed BOP project is a grass root facility, including furnaces, flares, engines, etc., and the Ineos project is a one furnace expansion of an existing furnace block. A single furnace being placed into operation with several existing furnaces that do not operate under imposed efficiency targets may be able to commit to and operate reliably and economy at lower stack exhaust gas temperatures because of the operational flexibility provided by the unconstrained furnaces.

(c) the difference in furnace feed – the proposed BOP project includes ethane feed, and the Ineos project includes ethane, naphtha, raffinate, and debutanizer natural gasoline feed.

- In "*B. The Draft Permit Does not Require the Most Efficient Processes*" on pages 3 through 5 of the SC Letter, Sierra Club states, "*Vendor literature for cracking furnaces indicates that innovations over the last twenty years have reduced CO_2 emissions by 30 percent using furnaces that achieve greater than 95 percent thermal efficiency.*" The cited vendor literature is marketing/sales brochure not sufficient as vendor guarantee, technical design document, or industry benchmark. On page 16 of the document, Technip states, "*This document… is not intended to be a binding contractual document. Any information contained herein shall not result in any binding obligation on the part of Technip, any of its affiliates, and is provided for informational purposes only.*"[2]

- In "*B. The Draft Permit Does not Require the Most Efficient Processes*" on page 4 of the SC Letter, Sierra Club states, "*A common measure of energy consumption for ethane cracking is the specific energy consumption (SEC) per ton of ethylene produced. Modern plant values for SEC are 14 GJ/tonne of ethylene for ethane cracking (13 MMBtu/ton, HHV). The SEC for the Baytown Plant is not reported in the record for this case. However, the data provided allow for an estimate by backing into the calculation. The draft permit allows eight cracking furnaces, each with a maximum design heat input of 515 MMBtu/hr and duct burners with a combined maximum design heat input of 773 MMBtu/hr (HHV). (Draft Permit at p. 2) Thus, the total annual heat input to produce 1.65 million tons of ethylene from ethane is 42,862,680 MMBtu/yr. The corresponding SEC rate is therefore 26 MMBtu/ton. This rate is much higher than the 13 MMBtu/ton SEC that modern plants can achieve.*"

  The Sierra Club inappropriately uses environmental air permit application data to estimate a highly complex measure of actual energy consumption. That fact notwithstanding, the Sierra

[2] *Ethylene Production*, Technip – Group Communications – October 2012.

Club used incorrect air permit application data in their calculations. The Draft BOP Permit correctly states in the Process Description, "*The new ethylene unit will increase the production capacity of the plant by approximately 2 million metric tons per year of polymer grade ethylene. Other products produced by the Baytown Olefins Plant include fuel gas, mixed C3 and C4 hydrocarbon streams, and other lower hydrocarbon streams.*"[3] In addition, the annual heat input from the steam cracking furnaces and the Train 5 duct burner used to estimate the emissions of CO_2e is 37,887,000 MMBtu/yr.[4] Using only the ethylene production capacity of 2 MT/y (which converts to 2,204,623 tons / year) and the correct annual heat input value, the corrected SEC (based on environmental air permit application data) is 17.19 MMBtu/ton, which is much lower than the value calculated by Sierra Club.

In addition, the document cited by Sierra Club states, "*In order to be able to compare different processes and feedstocks (with different yields for the various products) another allocation has to be used. In order to exclude effects from changing product yields, energy consumption should be allocated over all products formed in a particular process (on a mass basis).*"[5] As pointed out in the Draft BOP Permit Process Description, "*Other products produced by the Baytown Olefins Plant include fuel gas, mixed C3 and C4 hydrocarbon streams, and other lower hydrocarbon streams.*"[6] The 17.19 MMBtu/ton calculated above does not account for the other products that will be produced in the proposed BOP plant.

Furthermore, the value of 13 MMBtu/ton cited by Sierra Club is a "best estimate"[7] of the SEC for North American steam crackers based on an average product mix. In summary, it does not represent an actual SEC of an operating plant for which the configuration, feedstock input, product mix, etc. can be compared to the proposed project to ensure an appropriate comparison.

Because of the detailed design and/or operational data necessary to (1) calculate a SEC and then (2) compare facilities/projects on an SEC basis, the SEC cannot be accurately calculated from air permit application data and is not an appropriate energy efficiency parameter for benchmarking GHG BACT.

- In "*B. The Draft Permit Does not Require the Most Efficient Processes*" on pages 3 through 5 of the SC Letter, Sierra Club states, "*The revised BACT analysis should also fully explore other widely recommended efficiency measures disclosed elsewhere that are not even mentioned*

[3] http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/exxonmobil-baytown-olefins-draftpermit.pdf
[4] http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/exxonmobil-olefins-response.pdf
[5] http://www.energystar.gov/ia/business/industry/industrial_LBNL-44314.pdf
[6] http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/exxonmobil-baytown-olefins-draftpermit.pdf
[7] http://www.energystar.gov/ia/business/industry/industrial_LBNL-44314.pdf

in the record for this case."[8] The SC Letter specifically references the "Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry".[9] The relevant efficient measures in the referenced document are incorporated into the project as cited in the application record below.

- ***Heat generation*** – *specifically control of air-to-fuel ratios using oxygen analyzers on the exhaust gas streams and use of Low NOx burner technology.*
  The draft permit requires oxygen analyzers to maintain appropriate air-to-fuel ratios. Also, as discussed in an October 2012 application supplement submitted to EPA ("October 2012 Letter"), the ExxonMobil proprietary burner technology uses air staging and integral flue gas recirculation to minimize NOx emissions without compromising the burner stability and performance. Typical staged fuel low-NOx burners use small diameter fuel gas injection holes that are prone to plugging. The staged air burners are intrinsically safer and more robust than typical staged fuel low-NOx burners.

- ***Heat transfer and heat containment in heaters*** – *burning off carbon and reducing heat loss through opening and casings.*
  The draft permit requires decoking of the furnace tubes. Also, as discussed in the October 2012 Letter, the design specification will include details such as the use of seal bags at each furnace penetration to limit air ingress over the life of the furnace. It will also specify the insulation to minimize casing heat losses.

- ***Flue gas heat recovery*** – *recovery flue gas heat for air preheat, steam generation, incineration, etc.*
  As discussed in the May 2012 Application and October 2012 Letter, the design specifications will include use of economizers, steam generation from process waste heat, and/or feed preheat.

- ***Other – controls, maintenance and electric heaters***
  As discussed in the May 2012 Application and October 2012 Letter, the proposed BOP plant will include robust process controls. Elimination of electric heaters does not apply to the proposed steam cracking furnaces.

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[8] See, e.g., Maarten Neelis, Ernst Worrell, and Eric Masanet, Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry, June 2008, Lawrence Berkeley National Lab Report LBNL-964E. Available at: http://www.energystar.gov/ia/business/industry/Petrochemical_Industry.pdf?28f1-c5cb

[9] Maarten Neelis, Ernst Worrell, and Eric Masanet, Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry, June 2008, Lawrence Berkeley National Lab Report LBNL-964E. Available at: http://www.energystar.gov/ia/business/industry/Petrochemical_Industry.pdf?28f1-c5cb

- In "*C. The Cost Analysis for Carbon Capture and Sequestration is Invalid, 3. ExxonMobil's Cost Analysis Is Faulty, d) Averaging the Cost Estimates of Separate CO_2 Streams is Misleading*" on pages 12 through 13 of the SC Letter, Sierra Club states, "…*the utility plant would most likely be simple cycle or combined cycle natural gas fired turbine. This stream would have a lower concentration of CO2 (4 vol%) than the cracking furnaces (8 - 12 vol%). From both a cost and design perspective, ExxonMobil should not combine these two streams and instead should analyze each process separately*." However, we believe that the economies of scale indicate that separate CCS systems would not be more cost effective. Furthermore, the cost analysis for CCS for the proposed project assumed the furnaces and boilers would both fire blended fuel gas (i.e., a blend of natural gas and tail gas). Therefore, the cost analysis was based on the same CO_2 concentration (approximately 4.7%) in the exhaust stream of the furnaces and the utility boiler. The use of the same CO_2 concentration in the exhaust stream of furnaces and the utility boiler is indicated on page 22 of the October 2012 Letter[10] on a mass basis.

  As such, the cost analysis for CCS did not overstate the operating cost of CCS by lumping together cost of CCS for the cracking furnace with the cost of CCS from the additional utility plant.

o In "*G. Operating Conditions, 2. Stack Temperatures*" on page 18 of the SC Letter, Sierra Club states, "*Responses 6.A and 6.B (pages 16-17) and 11 (pages 28-29) assert that the Baytown Plant will operate with an exhaust stack temperature at or below 325 F during on-line operation to assure efficient operation. They also quote a range of 309 to 340 F for other similar projects. The draft permit Conditions II 7 and III.A.1.j limit the furnace gas exhaust temperature to <340 F, for the same reasons asserted by ExxonMobil. However, 340 F is the upper end of the range for other furnaces, which does not satisfy BACT. The permit should at a minimum adopt ExxonMobil's assertion that the Baytown Plant will maintain efficiency based on 325 F. Further, EPA should consider whether a lower temperature, as low at 309 F, would result in greater efficiency and thereby constitute BACT.*"

  The type of feedstock into a steam cracking furnace has an effect on stack exhaust gas temperature. Liquid feed (e.g, naphtha) cracking furnaces are able to achieve lower exhaust gas temperatures since liquid enters the furnace at close to ambient temperatures, whereas, gas (e.g., ethane) is conditioned (e.g., heated to 30 – 40 ºF above saturation) before it enters a steam cracking furnace. Therefore, it is inappropriate to compare the stack exhaust gas temperature for gas crackers (such as those proposed by the ExxonMobil and Chevron Phillips GHG applications) to gas/liquid crackers proposed by the other Region 6 applicants.

  The maximum exhaust gas temperature of 340 ºF ensures energy efficient operation of the proposed steam cracking furnaces. The difference in thermal efficiency between a gas

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[10] http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/exxonmobil-olefins-response.pdf

exhaust temperature of 325 ºF and 340 ºF is about 0.5% absolute, which is less than the calculation uncertainty and typical assumptions on heat loss through the furnace casing (assume ~2% of the firing rate). ExxonMobil increased the proposed maximum allowable exhaust gas temperature from 325 ºF to 340 ºF to allow for a longer operating time between shutdowns over the life of the project.

As stated in the Draft BOP Permit Statement of Basis, the thermal efficiency of the furnaces is 92% based on a 2% casing heat loss and the 340 maximum stack temperature. Increased shutdowns (as much as double) over the life of the equipment to achieve an arbitrarily low temperature target will reduce the overall efficiency of the furnaces over the life of the unit which will directionally increase CO_2 as well as other criteria pollutants. Increased shutdowns may result in the following process operation requirements that will drive down long-term energy efficiency and increase overall emissions:

- Inefficient modes of operation – Start-ups after a shutdown are energy intensive with minimal or no output of ethylene, tail gas, steam, etc. making them very inefficient modes of operation.
- Reduced efficiency of the furnaces – Steam cracking furnaces are designed for efficient operation with minimal shutdowns. Each time a convection section is washed it does not allow for the recovery of 100% of the heat losses, due to fouling and tube fin oxidation/corrosion. In addition, each convection section washing introduces opportunity for damaging the refectory, thus increasing casing loss and directionally increasing GHG emissions.
- Increased NOx emissions – Each time a furnace is cycled through shutdown and start-up there are discrete periods when the NO_x control technology (i.e., SCR) cannot operate properly because of low stack gas temperatures. During these periods, NOx emissions may be as high as 6 times normal operating emissions on a pound per million British thermal unit basis.
- Increased Decoking emissions – After each time a furnace is cycled through shutdown and start-up, coking rates trend higher for a period of time due deterioration/damage of the chromium oxide layer in the radiant tubes. It can take up to 6 months for the chromium oxide layer to fully reform. During this period, more frequent decoking is required to maintain efficient operation releasing additional emissions of PM, PM_{10}, $PM_{2.5}$, CO, and CO_2e.

The maximum exhaust gas temperature of 340 ºF is 10 ºF lower than the maximum exhaust gas temperature of 350ºF established in Chevron Phillips' GHG permit.

- In "*G. Operating Conditions, 4. Work Practice Standards and Operating Limits*" on pages 18 of the SC Letter, Sierra Club states, "*ExxonMobil's October 16, 2012 responses include as Attachment 4, Table 3-2 a list of proposed "Work Practice Standards and Operating Limits." The Region should verify that, at a minimum, all of the proposed work practice standards and operational limits are included in the draft permit.*" The following table provides a summary of how the Table 3-2 items have been addressed.

Emission Point		**Emission Unit Work Practice Standard, Operational Requirement, or Monitoring**	**Reference**
EPN	**Name**		
XXAF01-ST through XXHF01-ST	XXA through XXHF Furnace Combustion Vent	Consume pipeline quality natural gas, or a fuel with a lower carbon content, as fuel to the furnace section	S.C. III(A)(1)(a)
		Maintain the furnace exhaust stack temperature ≤ 325 °F during online operation (furnace producing ethylene) on a 365-day rolling average basis	Table 1 and S.C. III(A)(1)(j), 340 deg. F on a 12-month rolling basis
		Maintain furnace exhaust stack CO ≤ 50 ppmv @ 3% O2 during online operation on a 12-month rolling average basis	-- [1]
		Monitor fuel gas composition with a fuel gas analyzer daily with an analyzer that meets the requirements of 40 CFR 98.244(b)(4)	S.C. III(A)(1)(c)(iii)
		Calibrate and perform preventative maintenance checks of the continuous oxygen and carbon monoxide stack monitors per 40 CFR 60 Appendix B4 every quarter	S.C. III(A)(1)(d) and S.C. III(A)(1)(g) for O_2 monitors [1]
		Calibrate and perform preventative maintenance checks of the fuel gas flow meter per the requirements of 40 CFR 98.33(i) and quality assurance requirements of 40 CFR 98.33(i)(2) & (3)	S.C. III(A)(1)(c), annual
		Perform and maintain records of online burner inspections when indicated by CO levels >100 ppmv @ 3% oxygen for a one-hour average and during planned shutdowns	-- [1]
XXAB-DEC through XXGH-DEC	XXA/B through XXG/H Furnace Decoke Vent	Maintain furnace exhaust stack CO ≤ 50 ppmv @ 3% O2 during online operation (furnace producing ethylene) on a 12-month rolling average basis	-- [1]
FLAREXX1 and FLAREXX2	Staged Flare System	Maintain a minimum heating value and maximum exit velocity that meets 40 CFR § 60.18 requirements for the routine streams routed to the elevated flare including the assist gas flow	S.C. III(A)(3)(a)
		Continuously monitor and maintain a minimum heating value of 1,000 Btu/scf of the waste gas (adjusted for hydrogen) routed to the multi-point ground flare system to ensure the intermittent stream is combustible; however, if a lower heating value limit can be demonstrated to achieve the same level of combustion efficiency, then this lower limit will be implemented	S.C. III(A)(3)(f), 800 btu/scf
		Continuously monitor the flow rate to the multi-point ground flare to demonstrate that flow routed to the multi-point ground flare system exceeds 4 psig; however, if a lower pressure can be demonstrated to achieve the same level of combustion efficiency, then this lower limit will be implemented	S.C. III(A)(3)(j)

		Continuously monitor the composition of the waste gas contained in the flare system header and record the heating value of the flare system header through an online analyzer located on the common flare header, sufficiently upstream of the diverting headers to the elevated flare and the multi-point flare, calibrated and maintained at least annually	S.C. III(A)(3)(i)
		Continuously monitor and record the flow to the elevated flare through a flow monitoring system	S.C. III(A)(3)(j)
		Continuously monitor the steam flow to the elevated flare through a flow monitoring system and record the steam to hydrocarbon ratio	S.C. III(A)(3)(j)
		Continuously monitor FLAREXX1 for flame presence	S.C. III(A)(3)(k)
		Continuously monitor the staged flare system pilots for presence of flame	S.C. III(A)(3)(k)
BOPXXFUG	Fugitives	Conduct daily as-observed AVO inspection for piping components in non-VOC natural gas service	S.C. III(A)(5)(b)
		Maintain 28 VHP with CNTQ LDAR program for piping components in VOC service	S.C. III(A)(5)(a) , 28VHP only
HRSG05	HRSG05 Duct Burners	Consume pipeline quality natural gas, or a fuel with a lower carbon content, as fuel to the duct burners	S.C. III(A)(2)(b)
		Maintain a minimum thermal efficiency ≥ 70% on a 12-month rolling average	S.C. III(A)(2)(a)
		Maintain exhaust stack CO concentration ≤ 7.4 ppmvd @ 15% O2 on a 12-month rolling average	-- [2]
		Perform and maintain records of online burner inspections when indicated by CO levels >100 ppmv @ 15% oxygen for a one-hour average and during planned shutdowns	-- [2]
		Monitor fuel gas composition with a fuel gas analyzer daily with an analyzer that meets the requirements of 40 CFR 98.244(b)(4)	S.C. III(A)(2)(i) [3]
		Calibrate and perform preventative maintenance checks of the continuous carbon monoxide stack monitors per 40 CFR 60 Appendix B4 every quarter.	-- [2]
		Calibrate and perform preventative maintenance checks of the fuel gas flow meter per the requirements of 40 CFR 98.33(i) and quality assurance requirements of 40 CFR 98.33(i)(2) & (3)	S.C. III(A)(2)(c), annually
		Calculate and record the thermal efficiency of HRSG05 monthly	S.C. III(A)(2)(g) , 12-month rolling basis
DIESELXX01 – 05	Backup Generator Engines	Maintain intermittent and infrequent use or less than 120 hours of operation for testing and maintenance annually	S.C. III(A)(4)(d)
DIESELXXFW1 and DIESELFW2	Firewater Booster Pump Engines	Maintain intermittent and infrequent use of less than 120 hours of operation for testing and maintenance annually	S.C. III(A)(4)(d)

[1] Draft TCEQ Permit No. 102982 includes Special Condition No. 7c(3), limiting the furnaces to "50 parts per million by volume, dry (ppmvd) carbon monoxide (CO) corrected to 3 percent oxygen on a 12-month rolling average," for normal operations.
[2] Thermal efficiency limit directly incorporated in permit. CO limit deemed duplicative.
[3] Permit condition reference appropriate monitoring requirements.

F

U.S. Environmental Protection Agency
October 2011

Responses to Public Comments on the Proposed Prevention of Significant Deterioration Permit for the Palmdale Hybrid Power Project

(pages omitted)

standpoint throughout the community, not get built as a result of it? Does additional manufacturing not get built as a result of this selling of this credit or selling of this increment? What manufacturing facility can't come here because the threshold of significance has reached beyond the air quality standards?"

Response: The commenter does not explain how the issues raised by the City of Lancaster in the CEC proceeding relate to the CAA criteria applicable to EPA's proposed PSD permit action for the PHPP. To the extent these issues concern increment consumed by the PHPP and associated economic issues for the local communities, please see Responses 2 and 6.

We also note that the City of Lancaster submitted comments directly to EPA on the proposed PSD permit; please see Responses 1-4 above.

37. **Comment:** The commenter stated that the CO_2 sequestration analysis that determined CCS to be technically infeasible for this project was actually an issue of cost and not technical feasibility. The commenter states that the natural gas industry is familiar with pipeline construction and so it is unlikely that the logistics of constructing a pipeline are beyond the industry. The commenter provides information from the CEC describing the construction of 8.7 miles of natural gas lines through existing right of ways (ROWs) that will be designed and constructed by the Southern California Gas Company. The commenter also provides information from the CEC regarding the construction of 35.6 miles of transmission lines that would be constructed on new and existing ROWs, which would travel through and near a mixture of disturbed and undisturbed areas, which include desert areas, agricultural properties, industrial and residential areas. The commenter states that these routes extend into the mountains that are claimed to be insurmountable for a CO_2 line.

Response: As noted by the commenter, the natural gas pipeline and power transmission lines needed for the Project will be built on new or existing ROWs. Despite the potential for CO_2 sequestration as part of enhanced oil recovery (EOC) in the lower San Joaquin Valley, there are currently no CO_2 pipelines in California. In order to build the CO_2 pipeline the applicant would need to obtain the ROWs for approximate 50-100 miles to a sequestration site. It is not clear that the applicant could obtain the necessary ROWs.[13] The power to obtain ROWs is usually limited to "public utilities". The proposed facility will not operate as a public utility, so it is not clear that the applicant has the authority to obtain the needed ROWs outside the city limits. The barriers referenced in the Fact Sheet were not intended to imply that building a "long" pipeline through "mountains" was the logistical barrier.

However, given that there is limited data in EPA's record concerning potential logistical barriers relating to the building of CO_2 pipelines for the PHPP or other technical or logistical barriers to implementing CCS for the Project, we are revising our BACT analysis to assume, for purposes of the analysis, that potential technical or logistical barriers would

[13] See "Carbon Dioxide Pipelines:, California Carbon Capture and Storage Review Panel, August 10, 2010. Available at: http://www.climatechange.ca.gov/carbon_capture_review_panel/meetings/2010-08-18/white_papers/Carbon_Dioxide_Pipelines.pdf

not make CCS technically infeasible for the PHPP. As a result, CCS would be the top-ranked control option, and we proceed to Step 4 of the top-down BACT analysis to consider CCS. Our analysis assumes that 90% of CO_2 emissions would be captured.

GHG BACT Analysis – Step 4 - CCS Cost Analysis

As provided in the CEC's PMPD, the estimated capital costs for the PHPP are $615-$715 million dollars. For comparison purposes, if these capital costs were annualized (over 20 years) they are about $35 million. In comparison, the estimated <u>annual</u> cost for CCS is about $78 million, or more than twice the value of the facility's annual capital costs.

Estimated Annual Cost for CCS[14]	
	$/year
CO_2 Capture and Compression	$75,944,187.00
CO_2 Transport	$1,566,747.00
CO_2 Capture Storage	$878,067.00
Total Annual Cost	**$78,389,001.00**

Accordingly, based on these costs, CCS is being eliminated as a control option because it is economically infeasible. BACT for this project remains the thermal efficiency associated with a natural gas-fired combined cycle power plant.

38. **Comment:** The commenter stated that EPA would create a no build zone near potential carbon sequestration sites if it chooses to exclude polluters who chose to develop away from sequestration sites or who chose not to prepare adequate studies for their projects. The commenter states that the analysis should be real, with real numbers on cost and polluters that choose to locate away from sequestration sites should not get a free ride.

    Response: The commenter's first remark is unclear and as a result EPA does not understand how it relates to EPA's BACT analysis for GHGs for the PHPP. EPA believes that each PSD permit applicant must seriously consider all available technologies. As described in Response 37 above, EPA has fully considered CCS as part of the BACT analysis for the PHPP, and CCS was eliminated in this case due to economic infeasibility.

39. **Comment:** The commenter questioned whether tree planting could be a control technology. Additionally, the commenter questioned how many trees the applicant would need to plant to offset the GHG emissions from the Project. The commenter questioned whether algae ponds or changed forestry and farm practices could be used as GHG control technologies. The commenter questioned whether GHG controls can be located in another

[14] The cost were estimated by using EPA's GHG Mitigation Strategies Database and The Report of the Interagency Task Force on Carbon Capture and Storage (August 2010). This information is available at http://ghg.ie.unc.edu:8080/GHGMDB/ and http://www.epa.gov/climatechange/downloads/CCS-Task-Force-Report-2010.pdf, respectively. In each case, the lowest cost between the two sets of information was used for this analysis.

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Statement of Basis

Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit for the Chevron Phillips Chemical Company, Cedar Bayou Plant

Permit Number: PSD-TX-748-GHG

October 2012

This document serves as the statement of basis for the above-referenced draft permit, as required by 40 CFR 124.7. This document sets forth the legal and factual basis for the draft permit conditions and provides references to the statutory or regulatory provisions, including provisions under 40 CFR 52.21, that would apply if the permit is finalized. This document is intended for use by all parties interested in the permit.

I. Executive Summary

On December 19, 2011, the Chevron Phillips Chemical Company (Chevron Phillips) Cedar Bayou Plant submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions from a proposed modification. On March 19, 2012, Chevron Phillips submitted a revised application. In connection with the same proposed project, Chevron Phillips submitted a PSD permit application for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on December 14, 2011. The project at the Cedar Bayou Plant proposes to construct a new ethylene production unit (Unit 1594) consisting of eight ethylene cracking furnaces and supporting equipment to produce polymer grade ethylene. After reviewing the application, EPA Region 6 has prepared the following Statement of Basis (SOB) and draft air permit to authorize construction of air emission sources at the Chevron Phillips, Cedar Bayou Plant.

This SOB documents the information and analysis EPA used to support the decisions EPA made in drafting the air permit. It includes a description of the proposed facility, the applicable air permit requirements, and an analysis showing how the applicant complied with the requirements.

EPA Region 6 concludes that Chevron Phillip'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 requested by EPA and provided by Chevron Phillips, and EPA's own technical analysis. EPA is making all this information available as part of the public record.

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Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- CO_2 capture and storage (up to 90%)
- Low-Carbon Fuel (approximately 40%)
- Energy Efficient Design
- Good Combustion Practices

CO_2 capture and storage is capable of achieving 90% reduction of produced CO_2 emissions and thus considered to be the most effective control method. Use of low-carbon fuel, energy efficient design, and good combustion practices are all considered effective and have a range of efficiency improvements which cannot be directly quantified; therefore, the above ranking is approximate only. The estimated efficiencies were obtained from Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy and Plant Managers (Environmental Energy Technologies Division, University of California, sponsored by USEPA, June 2008). This report addressed improvements to existing energy systems as well as new equipment.

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

<u>Carbon Capture and Sequestration</u>

EPA considers CCS to be an available control option for high-purity CO_2 streams that merits initial consideration as part of the BACT review process, especially for new facilities. As noted in EPA's GHG Permitting Guidance, a control technology is "available" if it has a potential for practical application to the emissions unit and the regulated pollutant under evaluation. Thus, even technologies that are in the initial stages of full development and deployment for an industry, such as CCS, can be considered "available" as that term is used for the specific purposes of a BACT analysis under the PSD program. In 2010, the Interagency Task Force on Carbon Capture and Storage was established to develop a comprehensive and coordinated federal strategy to speed the commercial development and deployment of this clean coal technology. As part of its work, the Task Force prepared a report that summarized the state of CCS and identified technical and non-technical challenges to implementation.[9] EPA, which participated in the Interagency Task Force, supported the Task Force's conclusion that although current technologies could be used to capture CO_2 from new and existing plants, they were not ready for widespread implementation at all facility types. This conclusion was based primarily on the fact that the technologies had not been demonstrated at the scale necessary to establish confidence in

[8] U.S. Department of Energy, *Carbon Sequestration Program: Technology Program Plan*, page 20-23
[9] See *Report of the Interagency Task Force on Carbon Capture and Storage* available at http://www.epa.gov/climatechange/policy/ccs_task_force.html

their operations. EPA Region 6 has completed a research and literature review and has found that nothing has changed dramatically in the industry since the August 2010 report, and there is no specific evidence of the feasibility and cost-effectiveness of a full scale carbon capture system for the project and equipment proposed by Chevron Phillips.

Chevron Phillips developed a cost analysis for CCS that provided the basis for eliminating the technology in step 4 of the BACT process as a viable control option based on economic costs and environmental impact. The majority of the cost for CCS was attributed to the capture and compression facilities that would be required. The total annual cost of CCS would be $160,000,000 per year. The addition of CCS would increase the total capital project costs by more than 25%. That cost exceeds the threshold that would make the project economically viable. EPA Region 6 reviewed Chevron Phillip's CCS cost estimate and believes it adequately approximates the cost of a CCS control for this project and demonstrates those costs are prohibitive in relation to the overall cost of the proposed project. Thus, CCS has been eliminated as BACT for this project.

Economic infeasibility notwithstanding, Chevron Phillips also asserts 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 CCS would increase emissions of NOx, CO, VOC, PM_{10}, SO_2, and ammonia by as much as 30%. The proposed plant is located in the Houston, Galveston, and Brazoria (HGB) area of ozone non-attainment and the generation of additional NOx and VOC could exacerbate ozone formation in the area. Since the project is located in an ozone non-attainment area, energy efficient technologies are preferred over add-on controls such as CCS that would cause an increase in emissions of NOx and VOCs to the HGB non-attainment area airshed.

<u>Low-Carbon Fuel</u>

The use of low-carbon fuel is economically and environmentally practicable for the proposed project. By using plant tail gas in the furnaces, the project requires less purchased natural gas, resulting in cost savings. Further, combustion of high-hydrogen fuel in lieu of higher carbon-based fuels such as diesel, coal, or even natural gas reduces emissions of other combustion products such as NO_x, CO, VOC, PM_{10}, and SO_2, providing environmental benefits as well.

<u>Energy Efficient Design</u>

The use of an energy efficient furnace and unit design is economically and environmentally practicable for the proposed project. By optimizing energy efficiency, the project requires less fuel than comparable less-efficient operations, resulting in cost savings. Further, reduction in fuel

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