

Exhibit 8

ExxonMobil Chemical Company
Baytown Olefins Plant
Prevention of Significant Deterioration Permit for Greenhouse Gas Emissions
PSD-TX-102982-GHG

Responses to Public Comments

U.S. Environmental Protection Agency
November 25, 2013

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I. Summary of the Formal Public Participation Process

The U.S. Environmental Protection Agency, Region 6 (EPA) proposed to issue a Prevention of Significant Deterioration (PSD) permit to ExxonMobil Chemical Company Baytown Olefins Plant on June 7, 2013. The public comment period on the draft permit began June 7, 2013 and closed on July 8, 2013. EPA announced the public comment period through a public notice published in *The Baytown Sun* on June 7, 2013 and on Region 6's website. EPA also notified agencies and municipalities on June 3, 2013 in accordance with 40 CFR Part 124.

The Administrative Record for the draft permit was made available at EPA Region 6's office. EPA also made the draft permit, Statement of Basis and other supporting documentation available on Region 6's website, and available for viewing at the Sterling Municipal Library in Baytown, TX.

EPA's public notice for the draft permit also provided the public with notice of the public hearing. The public notice stated that "Any request for a public hearing must be received by the EPA either by email or mail by July 1, 2013, and must state the nature of the issues proposed to be raised in the hearing...EPA maintains the right to cancel a public hearing if no request for a public hearing is received by July 1, 2013, or the EPA determines that there is not a significant interest. If the public hearing is cancelled, notification of the cancellation will be posted by July 3, 2013 on the EPA's Website <http://yosemite.epa.gov/r6/Apermit.nsf/AirP>. Individuals may also call the EPA at the contact number listed above to determine if the public hearing has been cancelled." During the comment period, EPA did not receive any written requests for a public hearing. EPA posted its announcement that there would not be a hearing on July 3, 2013. EPA received one comment letter from Sierra Club on July 8, 2013.

II. EPA's Response to Public Comments

This section summarizes the public comments received by EPA and provides our responses to the comments. EPA received one comment letter from Sierra Club on July 8, 2013.

Response to Sierra Club's Comments

Sierra Club submitted detailed comments on the draft permit and statement of basis that we have summarized below (in their order of appearance in the comment letter) and to which we have provided responses.

Comment 1: The permit should include an emission rate based on the production of ethylene at the facility (in tons of CO₂e per ton of ethylene produced). Condition II of the draft permit only establishes emissions limits on a 12-month total, rolling monthly; this annual emission limit does not ensure that the plant is operating at the most efficient level. An output based limit will allow for comparisons with different production facilities for purposes of setting appropriate permit limits. A GHG PSD permit for INEOS Olefins facility provides such a limit (0.85 lb CO₂e/lb ethylene). A 2006 source also has survey

results from facilities with output based information in the form of CO₂/ton ethylene. Information submitted by the applicant suggests the project's production efficiency would equate to 0.90 tons of CO₂e per ton of ethylene, which is less efficient than the permit limit for INEOS. The Region must “at the very least” analyze or explain why the Baytown Plant cannot meet the INEOS limit. The results of a specific energy consumption evaluation would perhaps even lead to the Baytown Plant having a rate that is lower than 0.85 tons CO₂e/ton ethylene produced.

Response:

As an initial matter, the commenter has provided these comments based on a mistaken understanding of the estimated production capacity. See Comments at FN 5 (“These comments assume production of 1.5 million metric tons...”). ExxonMobil Baytown Olefins Plant (referred to elsewhere in this document as Exxon or EMBOP) will have an estimated production rate of 2 million metric tons according to initial information provided by the applicant, and as verified by supplemental and clarifying information provided after the comment period.¹ Our draft permit and statement of basis had correctly recited that the proposed project increases ethylene production by an estimated 2 million metric tons. With this estimated production capacity, the production rate for ExxonMobil's project is in fact more efficient than INEOS at a rate of 0.67 tons of CO₂e/ton of ethylene produced. This value includes only the amount of ethylene produced, and if the chemical products other than ethylene that will be produced are included in this rough metric, this number becomes even lower. It is also important to note that the INEOS project has fundamental differences from the project proposed by ExxonMobil. The INEOS facility was permitted to add a single furnace to an existing olefins production unit. Contrastingly, ExxonMobil proposes to build a new olefins production unit. INEOS will utilize a variety of feedstocks including ethane, naphtha, raffinate, and debutanizer natural gasoline feed, whereas ExxonMobil will only utilize ethane as a feedstock. There is a significant difference between the heat requirements to crack a gaseous feedstock versus a liquid feedstock. Further these feedstocks result in different end product amounts and types. Accordingly, attempts to directly compare these facilities—even where comparisons would indicate ExxonMobil has potentially higher efficiencies—have limited utility.

To the commenter's request that we establish an output based limit for the facility, we do not feel, in the circumstance of this permitting action, that such a limit is necessary or appropriate. While we acknowledge that considering an output-based emission limit is encouraged, PSD and Title V Permitting Guidance for Greenhouse Gases (March 2011) (hereinafter “GHG Guidance”) at 46, in this case, we took account of anticipated variability in production (based on demand) and the fact the products stream will have chemical products other than ethylene, and determined an appropriate annual emissions limit in tons per year, which is backed by our determination that the best way to monitor the efficiency of the furnaces was for ExxonMobil to monitor the exhaust temperature and to limit the maximum firing rate.

¹ Exxon submitted information on May 3, 2013 that indicated the production output would be 2 million metric tons per year of ethylene. <http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/exxonmobil-baytown-olefins-comments05132013.pdf> In addition, Exxon submitted a PDF providing “clarifying information” to Region 6 on September 6, 2013. This is part of our administrative record and posted with other principle parts of the record at: <http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/exxonmobil-baytown-response090613.pdf>

In addition, we consider the permit to be consistent with the recommendations in the GHG Guidance regarding use of work practices. The Guidance states on page 46, “In addition to a permit containing specific numerical emissions limits established in a BACT analysis, a permit can also include conditions requiring the use of a work practice such as an Environmental Management System (EMS) focused on energy efficiency as part of that BACT analysis.” In this case, EPA has decided that a numerical limit in tons per year of CO₂e coupled with permit conditions requiring process monitoring and work practice standards will ensure efficient operation and will appropriately reflect BACT for GHGs.

Comment 2: The application (Section 4.2.1.3) asserts the cracking furnaces will use an energy efficient design, but the application and the administrative record fail to present information to allow an assessment of this claim. The draft permit does not include any conditions “requiring the use of energy efficient design.” Baytown plant appears to be an inefficient production design compared to other facilities. “Vender literature” now states that cracking furnaces can now achieve greater than 95% thermal efficiency.² Sierra Club calculations indicated the Baytown plant’s furnace “contemplated in the draft permit are less efficient than 20 year old designs and do not satisfy BACT.” Modern plants have a specific energy consumption (SEC) of 14GJ/tonne of ethylene for ethane cracking (13 MMBtu/ton, HHV), and Sierra Club estimates “by backing into the calculation” (8 cracking furnaces with “a maximum design heat input of 515 MMBtu/hr” and duct burners with a combined “773 MMBtu/hr (HHV)) a total annual heat input 42,862,680 MMBtu/yr to produce 1.65 million tons of ethylene from ethane, which corresponds to a specific energy consumption of 26 MMBtu/ton—“much higher than the 13 MMBtu/ton” that modern plants can achieve. Before considering add-on technologies, the “Region must first establish the BACT limit foundation by setting the limit based on the most energy efficient production design.”

Response:

As an initial matter, some of this comment is predicated on an incorrectly calculated “SEC” value. Putting aside for the moment the issue of what inputs are appropriate or reliable to arrive at such a value or its appropriateness as a permit limit, we believe the correct calculation—while trying to follow the commenter’s methodology—results in an approximate SEC value of 17.2 MMBtu/ton. This is based on the MMBtu/yr values ExxonMobil provided in the October 16, 2012 response.³ When establishing the proposed emissions cap for the furnaces, ExxonMobil elected to use a lower firing rate for the furnaces. They estimated 79,609 MMBtu/yr per furnace for firing natural gas, and 3,809,831 MMBtu/yr per furnace for firing a blended fuel gas in each furnace. If you add 79,609 and 3,809,831 and multiply this by 8 (for all eight furnaces) you get a total annual heat input of 37,887,000 MMBtu/yr. This is less than the 42,862,680 MMBtu/yr that the commenter calculated with the maximum firing rate of the furnaces. Dividing the total annual heat input by 2,204,623 tons (converted from 2 million metric tons) of ethylene produced results in an SEC of 17.2. Consistent with what was explained in our response to comment 1, this value only accounts for the amount of ethylene produced and does not include the other products

² http://www.technip.com/sites/default/files/technip/publications/attachments/Ethylene_October_2012_9.pdf

³ <http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/exxonmobil-olefins-response.pdf>

produced in the olefins process. If the metric would encompass all areas of production, the value would be lower still.

We consider the value of 13 MMBtu/ton proffered by Sierra Club as reflecting the SEC of “modern plants” to be of problematic utility to this permitting action. This figure does not represent an actual SEC value for an actual operating plant for which the configuration, feedstock, product mix, etc. can be compared to the proposed project to assure a meaningful comparison. Because the large variation in plant configurations, output capacity, feed stock, and the production of other products greatly influences the SEC value, we do not believe this measurement allows for useful comparisons among otherwise dissimilar projects or promotes a firm understanding of an individual project’s efficiency.

In addition, direct comparisons of thermal efficiencies are possible without need to utilize the complicated SEC metric. The ExxonMobil furnaces have a minimum estimated efficiency of 92%. This is only slightly less efficient than the furnace selected by the Williams Olefins, Geismar Ethylene Plant in Louisiana.⁴ In addition, the maximum exhaust temperature for ExxonMobil is lower than the temperature established for INEOS (in PSD-TX-97769-GHG) (see response to Comment 20) and less (i.e. more constraining) than that established for Chevron Phillips (in PSD-TX-748-GHG): lower exhaust temperatures are reflective of a more efficient process utilizing less heat input and greater heat recovery.

The commenter is mistaken in stating that information on the efficient design aspect is lacking and mistaken in stating that those design aspects are not required. In fact, the Statement of Basis discusses specific technologies utilized by the furnaces at pages 10 to 11. Moreover, some of these technologies, are expressly referenced in permit terms and conditions (see special permit condition III.A.2.a requiring the use of the heat recovery steam generator (HRSG) and economizer), and all of the technologies are reflected by the furnace efficiency used in the permit limits. We also, of course, expect and require ExxonMobil to construct in accordance with its submitted application. See pg. 1 of the Final Permit; see also 40 CFR 52.21(r)(1).

Comment 3: The application does not provide any support for the assertion that the facility “will use a proprietary furnace design to minimize its carbon footprint” (citing Application at p. 4-3). The Region must fully disclose the efficiency of the various project components and include a review of more efficient options.

Response:

Since the intent behind this comment with its emphasis on “disclos[ure]” of “proprietary” design information is unclear, we wish to clarify that our GHG BACT determination is not based on any submitted confidential business information (CBI), and we have no CBI in our administrative record.

⁴ Prevention of Significant Deterioration Permit Number PSD-LA-759 issued by the Louisiana Department of Environmental Quality to Williams Olefins LL, Geismar Ethylene Plant Expansion Project (Agency Interest Number 5565, activity number PER20110004). Available at <http://edms.deq.louisiana.gov/app/doc/querydef.aspx>

Contrary to commenter's assertions about inadequate disclosure, the "various project components" that together make the furnaces efficient are discussed in several parts of the submitted application (and in follow-on applicant submittals), all of which were made available for inspection and public comment. References to some of these details have been provided in our Responses to Comments 2 and 4, but as previously noted the assigned limits for the furnace reflect application of these design elements to the operations of each furnace as an emissions unit. As such, we do not necessarily agree with the commenter's characterization that we are dealing with "options" and "various project components" such that we need to dwell on whether the right combinations of technology choices are being implemented. Instead, as was stated in the SOB (page 9), we recognize the effectiveness of energy efficient design but identify it as taking shape in this permitting action "as a range of efficiency improvements which cannot be directly quantified."

Responding to a request for available "benchmark data" for the pyrolysis furnaces, ExxonMobil explained that such data is not readily available (for the furnace burners) or "particularly useful" (for the pyrolysis furnaces), but went on to provide further details on the features of the proprietary design that result in the furnaces operating at a high efficiency, including such details as the fundamental component of the economizer for heat recovery, the optimization of design to decrease coking potential, and the design principles of the burner technology that will be utilized.⁵ ExxonMobil also stated that the percent efficiency of the burners "is not a relevant or applicable performance metric to pyrolysis furnace burners". ExxonMobil also stated in the response at page 28 "the estimated furnace efficiency during on-line operation is 92% based on a 2% casing heat loss and 325 °F maximum stack temperature". As noted above, this thermal efficiency is only slightly less than that of the Williams Olefins facility. In addition, ExxonMobil will equip each furnace with a CO analyzer at the stack to monitor combustion. ExxonMobil proposed a limit of no more than 50 ppmv CO corrected for 3% oxygen on a 12-month rolling average basis. CO is a direct indicator of good combustion which is achieved through good operating and maintenance practices. CO measurement coupled with adherence to an exhaust stack temperature limit of 340 °F⁶ ensures the furnace is operated with complete combustion without compromising thermally efficient operation. We believe the public record provides ample information to document these various design aspects.⁷ Moreover, the submitted comment appears to be lacking in sufficient precision or specificity for us to understand what, if any, adjustments are appropriate for our permit determination.

Comment 4: The BACT analysis should fully explore widely recommended efficiency measures that are not even mentioned in the record. As the sole example provided, the commenter cites a 2008

⁵ See ExxonMobil Response Submitted on October 16, 2012 at enclosure pages 17, 26.

⁶ Please see response to Comment 20 for information on exhaust stack temperature limit of 340 °F versus 325 °F.

⁷ For example, Exxon Mobil's response explained: "...[P]roprietary burner technology uses air/fuel pre-mixing to maximize burner stability and performance over a large operating window of fuel gas pressure and composition. The burners for the proposed project will be designed and shop-tested to accommodate the fuel gas composition range and optimize the burner performance for the design operating window." The response further states that: (1) the proprietary burner technology uses air staging and integral flue gas recirculation to minimize NOx emissions; (2) furnaces will be equipped with oxygen analyzers; and (3) "excess oxygen at the burners is controlled and minimized via an application resetting the flue gas draft at the furnace bridge wall during normal operation," which minimizes excess air to the extent complete combustion and maximum thermal efficiency is achieved.

document, “Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry,” available at

http://www.energystar.gov/ia/business/industry/Petrochemical_Industry.pdf?28f1-c5cb

Response:

In fact, ExxonMobil will implement many of the efficiency measures described for furnaces that are mentioned in pages 57-59 of that document. These efficiency measures are also identified in the Statement of Basis (SOB). (Indeed, the SOB cited this same document in support. See SOB at p. 9).

To illustrate, on the issue of heat generation, the commenter-cited document states “A first opportunity to improve the efficiency of heat generation is to control the air-to-fuel ratio in furnaces.” This is achieved in the draft permit in Special Permit Condition III.A.a.d. through e., requiring the use of an oxygen analyzer and limiting the oxygen concentration of 10% during normal operations. In another instance, the ExxonMobil furnaces will be equipped with ultra low NOx burners, consistent with the recommendation in the cited document to achieve additional 2% energy efficiency through use of low NOx burners.

On the issue of heat transfer and heat containment in heaters, the commenter-cited document states, “There can be several ways to improve heat transfer such as the use of soot blowers, burning off carbon and other deposits from radiant tubes and cleaning the heat exchange surfaces.” The draft permit in Special Permit Condition III.A.1.k. and l. requires ExxonMobil to monitor the furnaces for coke buildup and to perform decokes on the furnaces. In addition, we are revising the draft permit so that the final permit will require a convection section wash to be performed every three years.

For flue gas heat recovery, Page 11 of the SOB indicates the furnaces will utilize the following to recover heat from the process:

- Economizer - Use of heat exchanger to recover heat from the exhaust gas to preheat incoming Steam Drum feedwater to attain thermal efficiency.
- Steam Generation from Process Waste Heat - Use of heat exchangers to recover heat from the process effluent to generate high pressure steam. The high pressure steam is then superheated by heat exchange with the furnace exhaust gas, thus improving thermal efficiency.
- Feed Preheat - Use of heat exchangers to increase the incoming temperature of the feed, thereby reducing furnace firing demand.

To meet its assigned limits, ExxonMobil will have to implement good combustion and maintenance practices, including: good air/fuel mixing in the combustion zone; sufficient residence time to complete 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.

We note that the commenter did not cite to any specific pages of the cited 132 page document or to any measures that are discussed within it. Moreover, not all of the discussion in that document is applicable to this project. For example the switch from electric heaters to fuel fired heaters is not applicable to steam cracking furnaces.

In conclusion, EPA has required and ExxonMobil will implement many of the measures identified in the document “Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry,” and these measures have been incorporated into the permit as enforceable permit conditions.

Comment 5: The draft permit should include a limit on “specific energy consumption” or “SEC,” which the commenter earlier describes as “a common measure of energy consumption for ethane cracking.” Such a limit (in MMBtu/ton) would provide a “direct measure” of energy efficiency and corresponding GHG emissions.

Response:

We do not agree with the commenter that a limit on “specific energy consumption” or “SEC” could give a “direct” measure of GHG emissions, and we do not believe such a limit is needed for this particular permit, which otherwise includes appropriate emission limits with proper recordkeeping and reporting procedures to ensure the limits are achieved. For additional discussion on the calculation of SEC please see our response to comment 2. While we agree with the commenter that the suggested SEC metric correlates to a type of measured efficiency, its value would be affected by many variables, making it difficult to derive and translate to appropriate minimum permit contents. Developing an SEC with the necessary degree of accuracy would require an energy analysis of both thermodynamic and theoretical energy requirements and energy losses. Monitoring to meet this metric would require determination of the SEC for the pyrolysis furnaces and the SEC from energy consumed by compression and separation. The energy consumption in an ethane cracking process for the compression and separation sections of the process are high. Accordingly, a calculated figure under the SEC metric would largely present the energy intensiveness inherent to the process. We believe the monitored energy efficiency surrogates of temperature, oxygen concentration, CO continuous emissions monitoring system (CEMS), and heat input monitoring as provided for in the draft permit will appropriately ensure ongoing efficiency and will make for easier permit administration and compliance assurance for the units covered by this modification.

Comment 6: The Region’s CCS conclusions are invalid. EOR revenues from the sale of CO₂ can offset CO₂ costs. The commenter cites sources that estimate \$33 per ton⁸ revenues for EOR or \$5-20 per ton “even without EOR.” The commenter asserts that CCS costs would also be offset by “tax credits of \$10-\$20 per ton of CO₂ in accordance with Internal Revenue Code Section 45Q.” Reducing the net costs with revenues and tax credits is a critical component of the cost effectiveness calculations, and the Region must consider these issues, especially because elimination of CCS is proposed in step 4 on the grounds of costs. The applicant’s analysis does not include information on the potential market value

⁸ Although the commenter cites \$33/ton, the source in fact provides the lesser value of \$33/tonne.

that Denbury Resources (with a CO₂ pipeline 30 miles from the plant) would offer for the purchase of Baytown's captured CO₂. The analysis also does not consider other potential markets for the sale of CO₂ for other industrial applications.

Response:

We acknowledge the commenter's suggestion that this administrative record may benefit from a discussion of whether revenues from sales of captured CO₂ may be possible, and if so, whether those revenues could be appropriately applied in the BACT cost analysis to partially offset the estimated cost of GHG controls. We acknowledge, as stated in the GHG Guidance, that there may be cases where the economics of CCS may be more favorable, an example being where "the captured CO₂ could be readily sold for enhanced oil recovery." GHG Guidance at 43. In developing cost estimates for CCS, it would have been prudent for EMBOP to have addressed whether captured CO₂ may be sold. However, even assuming market demand exists for EMBOP's CO₂ stream, we do not necessarily agree with the commenter that "\$33/ton" is a conservative estimate or that revenues from sales for enhanced oil recovery could be maintained for the life of the project. Various published reports or studies cite the prospective purchase price of CO₂ for enhanced oil recovery to range from as low as \$15 to as much as \$45 per metric ton. The price may vary widely depending upon the price of oil per barrel and the availability of CO₂ in or near the particular oil production field. Ultimately a price would have to be negotiated between EMBOP and a prospective contractual partner and the price could be less than the assumed estimates above on a cost per metric ton basis. In addition, EPA's proposed NSPS for EGUs for emissions of CO₂ (signed on September 20, 2013) projected costs for supercritical pulverized coal (SCPC) and integrated gasification combined cycle (IGCC) units with no CCS (i.e., units that would not meet the proposed emission standard) and for those units with partial capture CCS installed such that their emissions would meet the proposed 1,100 lb CO₂/MWh standard. EPA also included costs for those same units when EOR opportunities are available in the proposed NSPS. EPA included a "low EOR" case assuming a low EOR price of \$20 per ton of CO₂, and a "high EOR" case of \$40/ton. These EOR price estimates are net of the costs of transportation, storage, and monitoring (TSM).

Assuming EMBOP had a client or partner willing to purchase CO₂ for enhanced oil recovery, and further assuming EMBOP could recover approximately 90 percent of its CO₂ emissions from the steam cracking furnaces (801,770 metric tons/883,800 short tons),⁹ the potential revenue at \$15 per metric ton would be approximately \$12 million per year. Assuming a low EOR price of \$20 per ton and a high EOR purchase price of \$40 per ton as projected in EPA's proposed NSPS, these projected purchase prices would only generate approximately \$16 million and \$32 million respectively. EMBOP estimated that its annual operating costs for CCS including capture, transport (and/or storage) would be \$205 million for full-scale CO₂ capture, transportation, and geologic sequestration. Even if EMBOP could generate \$16 million in revenue from CO₂ sales, this revenue would only cover approximately 8 percent of the estimated annual operating costs for add-on CCS controls. Assuming the high EOR price of \$40

⁹ Note that in the NSPS proposal referenced above, EPA proposed a standard based on partial CCS – i.e. less than a 90% capture rate.

per ton would yield potential revenues of approximately 16 percent of the annual operating costs, this still would not appear to make CCS economically viable for this project.

In addition, just because a company can recover CO₂ does not mean they have a contractual customer or partner willing to purchase the CO₂. The commenter first assumes that Denbury Resources would purchase Baytown's captured CO₂ emissions, but there is no evidence that this is the case. Furthermore, requiring CCS for this facility would require the applicant to clear numerous logistical hurdles such as obtaining contracts for offsite land acquisition for pipeline right-of-way, construction of the transportation infrastructure, and prospective business development of a customer(s) who is willing to purchase the CO₂.

The commenter also raises the issue of tax credits for conducting CCS. The Internal Revenue Service program for *Credit for Carbon Dioxide Sequestration Under Section Q45* allows qualified facilities to claim the credit where at least 500,000 metric tons of qualified CO₂ is captured during the taxable year. As an initial matter, we do not agree that these discussed tax credits are "critical," or even necessarily relevant, to calculated cost effectiveness. The inclusion of a subsidy would not likely be appropriate for a cost analysis, unless income taxes were included in the analysis. Income tax cost considerations were not used in the cost study submitted by ExxonMobil,¹⁰ and we think the long-term uncertainty, speculativeness, and over-complexity of these considerations would make it advisable to exclude them from consideration in the BACT analysis.¹¹

In any event, the available credit is \$20 per metric ton of qualified CO₂ that is captured and disposed of in secure geological storage; and \$10 per metric ton of qualified CO₂ that is captured and used as a tertiary injectant in a qualified enhanced oil or natural gas recovery project (EOR project). ExxonMobil's Baytown project permitted potential to emit in short tons would be equivalent to approximately 890,855 metric tons of CO₂ (steam cracking furnaces only). To be hypothetically eligible for the tax credit, ExxonMobil would need to recover over 56% of their CO₂ assuming their annual emissions equaled their potential to emit. In addition, assuming ExxonMobil could recover 90 percent of their potential to emit or 801,770 metric tons of CO₂ per year, it would arguably represent approximately \$24 million in value (assuming \$20 per ton revenues for CO₂ sale and \$10 metric ton business tax credit reductions in tax liability = \$30 X 801,770 metric tons). There is no guarantee that ExxonMobil could recover enough CO₂ to qualify for either tax credit since they would be attempting to recover from a low concentration and low volume flue gas stream versus a process gas stream with a higher CO₂ concentration. Even assuming it were appropriate to consider these speculative offsets in the cost analysis, we do not think they would be sizeable enough to make the cost of CCS economically feasible for this project (taking a total annualized cost of more than \$200 million dollars per year into account).

¹⁰ See pages 22-25 of the October 16, 2012 submittal. <http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/exxonmobil-olefins-response.pdf>

¹¹ This judgment is consistent with that reflected in the New Source Review Workshop Manual (Draft NSR Manual) and the EPA Pollution Control Cost Manual (2002), which the commenter has otherwise cited as support (see, e.g., comment 9 and 10 of this RTC). From the NSR Workshop Manual, p. b.11: "Income taxes...are not properly part of economic costs." From the Control Cost Manual: "...subsidies...distort how the direct application of a tax works. Therefore, this Manual methodology does not consider income taxes.")

It is important to note that although specific component CCS technologies exist and have been in use for decades, integrated CCS for a steam cracking unit has not been demonstrated in practice and does not currently exist at any scale. Exxon Mobil discussed in its application that carbon capture in this case would require “first-of-a-kind” technology complicated by numerous emission points from the steam cracking furnaces. ExxonMobil estimated that the furnace exhaust streams which utilize natural gas as its primary fuel would generate a low volume and low concentration CO₂ flue gas stream which in turn would make it more challenging to recover the CO₂. ExxonMobil outlined in their application and application supplements their estimated capital and operating costs for the capture, drying, and compression technologies that would be needed for CCS at the ExxonMobil Baytown plant. These costs were estimated by ExxonMobil at over \$253 per ton of CO₂ avoided or \$204.6 million annually to avoid CO₂ emissions from the furnaces, build the required utility plant to operate the carbon capture system, and construct the pipeline system for CO₂ transport. ExxonMobil estimated the total capital expenses of a carbon capture system of approximately \$735,400,000 million. ExxonMobil also estimated that the capital projects costs could increase the cost of the project by more than 25 percent¹² which in turn would make the project economically unviable.

At present, the Department of Energy (DOE) – National Energy Technology Laboratory (NETL) is collaborating with industry through the Industrial Carbon Capture and Storage (ICSS) program in cost sharing arrangements to demonstrate CO₂ emission capture technology from industrial sources and to either sequester or beneficially reuse them. ExxonMobil does not have the benefit of such an arrangement for its project. We understand that DOE selected Air Products and Chemicals, Inc. (Air Products) and Leucadia Energy to receive DOE funding under the American Recovery and Reinvestment Act (ARRA) for a “large scale” CO₂ capture and sequestration project at Valero’s Port Arthur Refinery in Port Arthur, Texas and Lake Charles Cogeneration in Lake Charles, Louisiana respectively.

Air Products retrofitted two steam methane reformers at hydrogen production plants at the Valero Port Arthur Refinery with a vacuum swing adsorption system to separate CO₂ from the process gas stream, followed by compression and drying processes. The compressed CO₂ will be delivered to the Denbury Green Pipeline for transport to Texas EOR projects in the West Hastings and Oyster Bayou oil fields. The process will concentrate the initial process gas stream containing 10-20 percent CO₂ to greater than 97 percent CO₂ purity. The technology will be designed to remove more than 90 percent of the CO₂ from the process gas stream. The approximate capital cost of the project is \$431 million of which \$284 million is provided by the DOE. It is important to note that the DOE is providing over 65 percent of the funding for the project. Air Products is also receiving 45Q tax credits at a rate of \$10 per metric tonne for EOR and \$20 per metric tonne for sequestration. This tax credit is only available for 75 million metric tonnes of CO₂.

¹² See email from ExxonMobil to Aimee Wilson on February 8, 2012 available at <http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/exxonmobil-baytown-olefins-resp2epa02082013.pdf> and also see the September 20, 2013 submittal available at <http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/exxonmobil-baytown-response092013.pdf>

Another project being funded by the DOE at Leucadia Energy (Leucadia Energy, LLC is an affiliate of Lake Charles Cogeneration) will recover CO₂ from a petroleum coke-to-chemical (methanol, hydrogen, and other by products) plant in Lake Charles, LA. This project will be recovering CO₂ from the syngas cleanup process after gasification of petroleum coke. The process will concentrate the initial process gas stream containing 30-40 percent CO₂ to greater than 99 percent CO₂ purity. The technology will be designed to remove more than 90 percent of the CO₂ from the process gas stream. The project is expected to recover 4.5 million metric tonnes per year of CO₂. The compressed CO₂ will be delivered to the Denbury Green Pipeline for transport to Texas EOR projects in the West Hastings oil field. The approximate capital cost of the project is \$436 million of which \$261 million is funded by the DOE. It is important to note that the DOE is providing over 60 percent of the funding for the project. Leucadia was also awarded \$1 billion in tax-exempt Gulf Opportunity-Zone Bonds (“GO Zone Bonds”) that were issued into escrow in April 2008.

Keeping in mind that CCS for cracking furnaces would be a “first of its kind” application, there is no guarantee that ExxonMobil could recover enough CO₂ to qualify for either tax credit since (as noted above) they would be attempting to recover from a low concentration and low volume flue gas stream versus a process gas stream with a higher CO₂ concentration. Further, ExxonMobil does not have the advantage of having 60-65 percent of the project’s investment from the DOE.

Finally, the commenter argues there exists a responsibility to “consider other potential markets for the sale of CO₂ for other industrial applications.” We are not aware of any such markets of any practical import or that could materially alter our conclusions. We recognize there are industrial end-uses other than EOR for CO₂ (e.g., food and beverage manufacturing, pulp and paper manufacturing, and metal fabrication), but we expect these to also be unavailable, infeasible or cost ineffective for the project for similar and additional reasons. There is no suggestion that the uses could potentially defray costs for these relatively untested markets or significantly reduce emissions.¹³ It is not clear whether the commenter is proposing an unbounded analysis of all industrial applications for CO₂ in all its markets, however marginal. Because this portion of the submitted comment is lacking in specificity and clarity, we are unable to otherwise give a meaningful or detailed response. See *Northside Sanitary Landfill v. Thomas*, 849 F. 2d 1516, 1520 (D.C. Cir. 1988) (comments must be of sufficient specificity to warrant detailed agency response).

Comment 7: The Region’s determination that CCS is too expensive in relation to total project costs is not a valid basis for rejection in Step 4 of the BACT analysis. ExxonMobil used an “undisclosed and nonstandard cost method” in analyzing CCS to be non-cost effective. Even assuming the cost estimate were reasonable, ExxonMobil did not provide any support for the claim that annualized costs of \$204.6 million would render the project unviable. ExxonMobil states, “The addition of CCS is expected to increase the total capital project costs by more than 25%. That cost likely exceeds the threshold that would make the project economically viable,” which the commenter characterizes as a “blanket and unsupported assertion.” The commenter cites *Alaska Dep’t of Env’tl. Conservation v. EPA*, 540 US 461,

¹³ 88% of captured CO₂ goes to EOR use. Any other end uses (unlike EOR) do not necessarily permanently sequester CO₂. <http://www.epa.gov/climatechange/ccs> last accessed 11/18/13.

466 (2004) on the issue of declaring a technology economically infeasible without needed financial information. The Region made no attempt to demonstrate that CCS was unsuitable for CCS compared to other facilities, and the Region must consider the “average cost effectiveness of CCS.” The SOB did not include a cost-per-ton calculation, but this must be used to justify a less effective option, by finding it to be beyond the cost borne by other sources of the same type in applying that control alternative. Elimination on costs in Step 4 “is intended only as a safety valve for when impacts unique to the facility make application of a technology inapplicable to that specific facility.” To reject CCS, costs of pollutant removal must be “disproportionately high for the specific facility compared to the cost of control at other facilities,” and the record has no such comparison. The region cannot simply reject CCS because there are no other BACT determinations requiring it. There has to be a first instance where a control is determined to be BACT, since BACT has a “technology-forcing function.”

Response:

While the Draft NSR Manual does caution against eliminating a potential control technology from consideration as BACT by looking only at affordability relative to the source, our GHG Guidance recognizes that “there is not a wealth of GHG cost effectiveness data from prior permitting actions for a permitting authority to review and rely upon when determining what cost level is considered acceptable for GHG BACT.”¹⁴ Consequently, the GHG Guidance states that “it may be appropriate in some cases to assess the cost-effectiveness of a control option in a less detailed quantitative (or even a qualitative) manner,” including whether the cost of CCS is “extraordinarily high and by itself would be considered cost prohibitive.”¹⁵ Consistent with this approach, we believe that it is reasonable at this time to evaluate the economic impacts of CCS as a percentage of the overall project cost until more data from similar permitting actions become available. The Environmental Appeals Board (EAB) also recently found that this approach was reasonable and consistent with our GHG Guidance, explaining that elimination of CCS where it is found to be cost-prohibitive in comparison to the entire project “was neither inappropriate nor impermissible.” *See In re: City of Palmdale (Palmdale Hybrid Power Project)*, PSD Appeal No. 11-07, slip op. at 54-55 (EAB September 17, 2012). We therefore disagree with the commenter and continue to believe that our rejection of CCS as GHG BACT in Step 4, based on its prohibitively high cost in comparison to the overall project cost, was appropriate and in accordance with guidance and with EAB precedent.

The commenter’s request that we examine and compare this project to other facilities does not change our conclusion. We generally agree with the assertion that ExxonMobil makes in their application that there were no global examples where capture of CO₂ from a low pressure, low CO₂ concentration flue gas has been demonstrated at a scale and reliability necessary for application in a compliance - based scenario. We also agree with information provided by ExxonMobil indicating that the steam cracking furnace process used for ethylene production is not a comparable process to hydrogen production, especially with respect to the purity of CO₂ in the stack, which they estimate to be less than 8 percent CO₂ concentration. In addition, we agree with ExxonMobil’s stated need for a utility plant that in turn

¹⁴ GHG Guidance at 43.

¹⁵ GHG Guidance at 42.

would generate CO₂ which would have a CO₂ concentration of approximately 3-4 percent (combined exhaust streams of cracking furnaces and utility plant would be approximately 5 percent). The current DOE funded project with Air Products at the Valero Port Arthur Refinery appears to be utilizing a higher CO₂ concentration process stream (10-20 percent). Another project being funded by the DOE at Leucadia Energy (Leucadia Energy, LLC is an affiliate of Lake Charles Cogeneration) will recover CO₂ from a petroleum coke-to-chemical (methanol, hydrogen, and other by products) plant in Lake Charles, LA. This project will be recovering CO₂ from the syngas cleanup process after gasification of petroleum coke. The project will also be using a higher CO₂ concentration flue gas stream of 30-40 percent. Although specific component CCS technologies exist and have been in use for decades, integrated CCS for a steam cracking unit has not been demonstrated in practice and does not currently exist at any scale.

As noted in earlier responses, we generally agree with the applicant that carbon capture in this case would require “first-of-a-kind” technology complicated by numerous emission points from the steam cracking furnaces. ExxonMobil calculated a cost effectiveness of “over \$253/ton CO₂e” and we generally agree with their analysis. In addition, we noted the case-specific environmental impacts of operating a CCS system. These other impacts, coupled with the costs of CCS, have led to the elimination of the CCS technology under Step 4 of the top down BACT analysis. ExxonMobil estimated that the furnace exhaust streams which utilize natural gas and/or fuel gas would contain low purity CO₂ which in turn would make it more challenging to recover the CO₂. The cost study included capital and operating costs for the capture, drying, and compression technologies that would be needed for CCS at the ExxonMobil Baytown plant. We generally concur with ExxonMobil’s cost estimation of over \$253 per ton of CO₂ avoided or \$204.6 million annually to achieve 90 percent CO₂ emissions capture. (We also acknowledge ExxonMobil’s statements that operation of a CCS system has energy and environmental impacts that may be considered alongside the cost of CCS.) They estimated the total capital expenses of constructing a carbon capture system of approximately \$735,400,000 million. These economic costs were developed under the assumption that the source could deliver CO₂ gas to the Denbury Green Pipeline for EOR purposes and that it had a viable customer to purchase the CO₂. Based on our review of the submitted cost study and our experience in reviewing cost studies for similar projects, we find these estimates to be credible. Thus, the CCS capital projects costs could increase the cost of the project by more than 25 percent, and we reasonably believe that such increases would make the project economically unviable.

Given this conclusion, it is not necessary to further address the comment regarding cost-effectiveness of CCS for this project. Put another way, having demonstrated by reasonable, objective means that the cost of the control technology are disproportionately high,¹⁶ it is not necessary to further assess the cost-effectiveness of those disproportionately costly controls.

Additionally, EPA has eliminated CCS on economic and other Step-4 grounds in all of its recent PSD permit BACT determinations for ethylene production units (e.g., BASF/Fina; Chevron Phillips Cedar Bayou; Equistar La Porte; Equistar Olefins 1&2; INEOS Olefins & Polymers). We agree this portrays the case-by-case nature of looking at CCS.

¹⁶ See Draft NSR Manual at B.31-32.

Comment 8: The region should also consider the costs of failing to control GHG emissions, expressed as the social cost of carbon. The commenter cites a range of \$28 to \$893 per ton of CO₂. If the cost per ton of CO₂ controlled with CCS at Baytown is lower than the social cost of carbon, then CCS would be a more economic choice and the costs are even more reasonable.

Response:

The economic concept of a “social cost of carbon” has recognized regulatory uses, but we are aware of no instance where it has been applied to individual permitting actions involving determinations of technology-based permit limits. EPA and other federal agencies have used the social cost of carbon (SCC) in rulemakings where a regulatory impact analysis is conducted in accordance with Executive Orders 12866 and 13563. The SCC monetizes damages associated with an incremental increase in carbon emissions in a given year. It includes (but is not limited to) changes in net agricultural productivity, human health, property damages from increased flood risk, and the value of ecosystem services to climate change. See e.g., 77 FR at 62927 (Oct. 15, 2012 (use of SCC in final rules establishing controls on GHG emissions from new model year 2017-2025 light duty motor vehicles)). Thus, the social cost of carbon can be a useful measure to monetize the benefits of CO₂ reductions from regulatory actions that impact cumulative global emissions.¹⁷

However, in determining BACT, we consider the “economic impacts” of the technologies under consideration for control of a pollutant subject to PSD. See CAA Section 169(3) (defining BACT). In contrast, the social cost of carbon is a monetized measure of environmental effects – in other words, a monetized assessment of potential risk from the pollutant emission. But BACT determinations are not risk-based. (Similarly, in determining BACT for criteria pollutants, permitting authorities do not directly assess monetized potential benefits of controlling (for example) particulate matter and ozone precursors; these are not economic costs of the control.) Thus, the social cost of a pollutant should not be mistaken for “compliance cost,” which includes the cost of control, monitoring, testing, and other considerations, which is more typically calculated when assessing BACT costs.

In this regard, the EPA Administrator recognized the harm of GHG emissions in finding that greenhouse gas concentrations in the atmosphere may reasonably be anticipated to endanger public health and welfare (the so-called endangerment finding for GHGs),¹⁸ which (in combination with the substantive regulation of GHG emissions from new light duty motor vehicles) has resulted in application of the statutory BACT requirement to GHGs from major emitting facilities. EPA has noted in the context of evaluating environmental impacts that “it is generally unnecessary to explicitly consider or justify the environmental benefits of reducing the pollutant subject to the BACT analysis,

¹⁷ Further background and details on the social costs of carbon estimations that are presently being used by EPA are provided in other EPA documents. See, e.g., Regulatory Impact Analysis for the Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, 5-36 to 5-39, available at <http://www.epa.gov/ttnecas1/regdata/RIAs/EGUGHGNewSourceStandardsRIA.pdf>. It appears that the upper end of the commenter- cited-range (i.e., \$893 per ton) far exceeds the estimates being used in current economic analyses by the federal government.

¹⁸ 74 FR 66496 (Dec. 15, 2009).

since these benefits are presumed under the CAA’s mandate to reduce emissions of each regulated pollutant to the maximum degree achievable.” GHG Permitting Guidance 39. The avoidance of economic harm and danger of GHG emissions is accordingly already recognized when a permitting authority applies the “maximum degree of reduction” to the pollutant in consideration of the statutory factors.

Although it is unclear if the commenter proposes a weighing of costs and benefits in this BACT determination, we note that EPA has never interpreted BACT as requiring such a cost-benefit analysis. Rather, EPA has long interpreted the requirement as requiring use of the most stringent control technology that is available unless the applicant demonstrates that this is not achievable, considering economic, environmental, or energy impacts. See, e.g. Background Statement on the EPA’s Top-Down Policy (June 13, 1989), transmitted by memorandum of John Calcagni (June 13, 1989). We note further that Congress indicated explicitly where it intended EPA to include cost-benefit considerations in the Act (see CAA section 173 (a)(5) (issuance of permits where the permitting authority determines, among other things, that “an analysis of alternative sites, sizes, production processes, and environmental control techniques ... demonstrates that benefits of the proposed source significantly outweigh the environmental and social costs imposed)).

We have explained at our response to Comment 7 our basis for determining the cost considerations which have led us to reject CCS as a control option for this project. We note further that even were we to accept the commenter’s premise as to the relevancy of social cost of carbon in determining economic impacts (for example, as a potential measure for evaluating whether CCS is reasonably cost effective for this project), the economic impacts of CCS here (expressed as dollars per ton of GHG removed) would far exceed the measures of social cost of carbon accepted by the federal government. However, even considered this way, the comparison the commenter urges would involve a type of cost-benefit analysis, comparing the cost of control with the (monetized) benefits of pollutant removal (expressed as SCC). As stated above, EPA has never interpreted BACT as requiring cost-benefit analysis and is not doing so here.

Comment 9: The region does not follow the cost methodology set out in the Draft NSR Manual for CCS. The cost analysis lacks the “design basis,” the “battery limits,” a list of each piece of equipment and its cost, or the source of the proffered “lump-sum cost data for the capture and compression plants, which are the major cost items.” It also lacks process flow diagrams, design drawings; heat, energy and material balances; type and amount of amine; and temperatures, pressures, flow rates, and specific chemical species in the gas streams to be treated. The validity of the design cannot be verified, which impairs the ability to evaluate the reasonableness of the CCS cost estimates.

Response:

Although the Draft NSR Manual provides guidance on performing cost calculations for control options, cost analyses often vary in complexity and specificity. EPA has acknowledged that a less detailed analysis may be more appropriate in certain instances. See GHG Permitting Guidance at 42.

ExxonMobil's permit application and supplemental responses to EPA on October 16, 2012 clearly reflected the design basis and equipment that would be needed to install a CCS system. This information was available in the public record at the time the draft permit was at public notice. ExxonMobil identified in its application the specific plants and functional process equipment that would be needed for CCS. For example, the Carbon Capture Plant would include CO₂ compressors and intercoolers, an amine absorber system, a CO₂ regeneration/purification system, blowers, piping, and duct work. It also identified the need for a Utility Plant which included a boiler, boiler feedwater/treatment system, a cooling tower, utilities header, and piping. The permit application and supplement clearly highlighted that an amine absorber system would need to be located in close proximity to the eight sources to minimize the extensive duct work required to route each of the eight exhaust stacks together, minimize size of the required air blower, maximize on-stream operation, and achieve approximately 90 percent recovery of CO₂ from the exhaust gas. The Furnace Section CO₂ Capture Plant was specified to accept 1,350 tons of total furnace exhaust gas per hour to remove 92 tons of CO₂ per hour. ExxonMobil noted that this design was sized for the current proposed project, which will not recover the hydrogen contained in the Tail Gas and will instead blend it with natural gas fuel gas system. Further, ExxonMobil noted that if they were to pursue the option to recover this hydrogen, the carbon capture system would be insufficiently sized to process the flue gas flow rate of eight combined furnaces firing natural gas blended with a recovered hydrogen stream.

ExxonMobil further noted that a dedicated utility plant would be required to meet the steam and power requirements for the furnace section CO₂ capture plant, indicating that this new utility plant would generate its own GHG emissions. They included in their CCS design both the capture of CO₂ from the furnace exhaust stacks as well as the additional CO₂ emissions generated by the utility plant. The Utility Plant CO₂ Capture Plant was designed to accept 380 tons of utility plant exhaust gas flow per hour to remove approximately 26 tons of CO₂ per hour in an additional amine absorber located near the utility plant emission sources.

ExxonMobil highlighted that its amine regeneration and CO₂ compression equipment would be centrally located to receive the concentrated rich amine streams from the Furnace Section and Utility Plant CO₂ Capture Plants. This design imposes movement of rich and lean amine streams between the two capture plants, as well as cooling water supply and return streams. In addition, they provided the carbon capture and compression cost estimates in the aggregate including both their capital and operating expenses associated with the site-specific carbon capture plant. While a CCS system has never been designed or constructed at an ethylene production plant, ExxonMobil clearly prepared an evaluation for CCS that provided and highlighted the equipment needs and plants that would be required for CCS on this project. In addition, they provided an analysis of their pipeline construction costs to transport CO₂. We thus disagree with the commenter that the validity of the design could not be verified and that the reasonableness of the costs could not be evaluated based on the permit application and supplemental responses provided to EPA that were included in the permitting record made available for public comment.

Comment 10: Costs of CCS should have been calculated according to the Control Cost Manual to assure consistency of BACT decisions. ExxonMobil's October 16, 2012 responses to the Region do not fully explain the cost methodology. It is evident that ExxonMobil in reporting costs to the nearest penny prepared a detailed cost analysis, but it was not available for public review. The Region must make this information available and allow public comment on it. Based on information that was available, ExxonMobil appears to have used an "all-in" method for its CCS costs, which would include "invalid" items such as inflation, escalation, owner's costs, and allowance for funds used during construction. The costs are presented in 2016 dollars (escalation), and the relied-upon DOE/NETL Report (for costs for transport and storage liability) used the costing methodology known as "levelized cost of electricity" which has cost items contrary to the "BACT 'overnight method'." ExxonMobil did not disclose a costing methodology for capture and compression costs or supporting material for capital and operating costs, but the cost estimate of \$245.70 per tonne of CO₂ avoided is substantial higher than the \$60-114 range in the DOE/NETL report. The region must evaluate CCS cost effectiveness with the overnight cost method.

Response:

We acknowledge that consistency in decision making is a primary objective of the BACT analysis, and further acknowledge that the OAQPS Control Cost Manual has been a recommended and utilized resource in the development of cost projections made for the control of criteria pollutants. However, the Cost Manual states that "new and emerging technologies are not generally in the scope of [the] Manual. The control devices included in [the] Manual are generally well established devices with a long track record of performance." Control Cost Manual, 6th Ed., at 1-3. In addition (and perhaps even more so), the Control Cost Manual predates the era of GHGs becoming newly subject to regulation and did not anticipate the considerations that might apply to its permitting. Since cost development for CCS is not contemplated by the Control Cost Manual, many applicants addressing PSD for GHGs have sensibly utilized the best available information on costs for CCS technology, with many of them drawing on resources provided by the U.S. Department of Energy and using methodologies consistent with that literature, including, for example, the DOE/NETL Report cited by the commenter.

In this context, we would consider application of the Control Cost Manual or its methodology to CCS to potentially run counter to the stated consistency objective; moreover, the commenter has not pointed to any permitting case where CCS costs were strictly developed under the Control Cost Manual, much less one where utilizing that methodology was material an overall determination regarding CCS as BACT. We note that the costs of CCS may be more sensitive to location and other unique factors than conventional add-on controls, so the considerations (i.e., that costs appear excessive or unreasonable) that ordinarily warrant the provision of more detailed and comprehensive cost data do not apply in the same way. We generally agree, however, that any BACT determination finding CCS to be cost effective under one costing methodology makes it important for subsequent cost studies prepared by other permit applicants to provide data and calculations sufficient to make comparisons and take proper account of relevant differences in costing approaches.

Here, we note that the overnight capital cost does not take into account financing costs or escalation, and hence is not an actual estimate of construction cost. Investors in the energy industry typically look to the Levelized Cost of Energy (LCOE) for comparing generation technologies (e.g. solar, natural gas) in the long term, as it includes ongoing fuel, maintenance, and operation costs. The U.S. Department of Energy tracks and makes publicly available levelized cost of energy figures for competing technologies. In addition, there are no specific regulatory provisions that prohibit EPA from utilizing estimated capital costs with future escalation in its BACT determination when under these specific circumstances large scale carbon capture sequestration add-on controls have never been attempted at an ethylene production plant. We believe the projected capital and operating costs relied upon for this BACT determination still make CCS for this project economically unviable.

Comment 11: ExxonMobil provided information suggesting the CCS cost analysis assumed a capital recovery factor of 0.2, which is excessive. The Control Cost Manual requires the capital recovery factor be taken from the social rate of interest and the expected equipment lifetime to annualize capital costs. EPA used 0.8% and a 20 year term in recent “similar calculations” which makes a capital recovery factor of 0.0543, reducing the annual capital cost for the Baytown Plant analysis from \$245.7/ton of CO₂ avoided (table 4-1) to \$122/ton CO₂ avoided.

Response:

The capital charge rate of 19 percent used to estimate the annualized capital cost for CCS appears to be consistent with the Draft NSR Manual in that it appears to include fixed annual costs, plant overhead, taxes, insurance, and capital recovery charges. ExxonMobil utilized a higher interest rate (14 percent) for the BOP project due to the uncertainty in return on a major venture of this nature as compared to those of the commercial bond market, due to CCS technology for ethylene cracking furnaces being unproven and undemonstrated in a real world scenario. ExxonMobil assumed a 20-year equipment life for this project. They also assumed a 14 percent interest rate, and tax/insurance rate of 4 percent, a capital recovery factor of 15 percent with the capital charge rate being 19 percent for the project. In addition, we examined fixed charge factors utilized in other projects and technical literature for CCS technology on various power plant configurations (pulverized coal, IGCC, and natural gas) where fixed charge rates range from 10-17 percent, the most common range appearing to be 13-15 percent. In addition, most of the GHG PSD permitting applications where EPA Region 6 has issued a final permit have utilized cost recovery factors of 14-17 percent with varying assumptions on number of years utilized in the cost recovery. It must be emphasized that there is no requirement that ExxonMobil utilize the same or “similar calculations,” and in any event the commenter has not referenced any examples for our evaluation. For what would be a first-of-its-kind CCS project, there are no provisions that preclude a prospective source from using its best cost estimate of what the prospective add-on pollution control option may cost and how it might recover its investment. It is reasonable that the prospective costs for installing a CCS system on an ethylene production process for the first time would cost more than other industrial sectors where partial carbon capture has been undertaken or full capture is being attempted. What the commenter might believe is an excessive cost estimate in this case may be wholly attributable

to developing a cost estimate for a CCS system on what would be a “first-of-its-kind” project for ethylene cracking furnaces.

Comment 12: ExxonMobil’s estimated annual operating costs for CCS (\$72.6/ton) are not supported in the record. For example, the amount of amine assumed, power required, fuel required, or assumed unit cost is not disclosed. The Region must make this information available and allow public comment on it. ExxonMobil’s costs appear to be grossly overestimated. The analysis assumes a dedicated boiler and cooling tower are necessary for the CCS process without considering whether integration with the existing utilities is feasible. The Region should require ExxonMobil to provide support for the statement that “an entire utility plant will be necessary to install CCS.” Operating costs as assumed in a 2010 DOE/NETL report for removing 4.9 million tons CO₂ from a 550 MW boiler suggest the operating expenses for ExxonMobil should be \$20-30/ton of CO₂e.¹⁹ ExxonMobil’s cost are much higher without any explanation as to why they are higher.

Response:

A permitting authority must have a reasonably accurate idea of what the cost-effectiveness of a control option is, but this does not make the provision of “detailed and comprehensive project cost data” necessary for every BACT determination, particularly when estimated costs may be “obviously excessive in relation to the removal efficiency” of the technology. See *In re: Masonite Corporation*, PSD Appeal No. 94-1, 5 E.A.D. 551, 566 (EAB Nov. 1, 1994) (*citing* Draft NSR Manual at B.35 (“normally the submittal [by the applicant] of very detailed and comprehensive project cost data is not necessary.”)). When cost projections appear excessive or unreasonable (e.g., in light of recent cost data), an applicant may need to supply additional details that would better document the projections.

In this case, we do not believe the comment has shown the costs are unsupported or grossly overestimated. In response to Region 6’s request, ExxonMobil provided a site-specific cost analysis that included a breakdown of costs for carbon capture, transport, and storage.²⁰ The site-specific carbon capture estimate was broken down into several line items to illustrate the costs included in the calculation. The transport and storage data figures were based on the same 2010 DOE/NETL report cited by commenter.²¹ The commenter’s concern pertains only to annual operating costs of carbon capture (i.e., approximately 30% of the total projected costs). The comment does not dispute the validity of a significant fraction of those operating costs, which are themselves only part of total costs.

¹⁹ *Cost and Performance Baseline for Fossil Energy Power Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity*, November 2010. Available at: http://www.netl.doe.gov/energy-analyses/baseline_studies.html

²⁰ See ExxonMobil October 2012 submittal, pages, 22-25, available at <http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/exxonmobil-olefins-response.pdf>

²¹ We note for a superficially similar project permitted in Region 6 (which, as here, authorized the addition of 8 steam cracking furnaces with similar heat rates), the applicant prepared a highly simplified analysis to estimate an annualized cost of over \$160 million dollars per year. See Application for PSD-TX-748-GHG (2012) (Permit for Chevron Phillips Cedar Bayou Plant, available at http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/chevron_response031912.pdf). ExxonMobil has used a substantially different, relatively more detailed approach to estimate total annualized costs of \$204 million per year. Taking account of the fact that cost estimates used in BACT are typically accurate to within ± 20 to 30 percent (GHG Guidance at 39), we do not agree that costs appear to be “grossly overestimated,” much less in view of the fact that the commenter’s claim pertains only to the annual operating costs of capture.

The commenter's contention that operating costs for ExxonMobil should be in the range of the \$20-30/ton is unpersuasive for several reasons. First, the commenter's calculation example points to a supposed operating expenses scenario in the DOE/NETL report that found "total annual O&M costs of \$4,599,292," which is not accurate. This total is based solely on the assumed costs of water, MEA solvent, NaOH, and H₂SO₄, and corrosion inhibitor. Confusingly, the comment acknowledges additional expenses for compression, amine auxiliaries, and fuel, but the sources for these assumptions are unclear. The commenter also appears to omit labor costs for operation and maintenance, but the commenter's reference for annual "O&M Expenses" (i.e., "Exhibit 4-30") indicates these costs alone would exceed maintenance material costs. Finally and more significantly, the operating expenses shown in Exhibit 4-30 (applicable to a subcritical pulverized coal electric generating station of 550 MW) are not transferrable to ExxonMobil's wholly different type of facility. ExxonMobil has noted, and we agree, that their project would not be comparable to such a fossil-fueled power plant in at least two ways: (1) the steam cracking furnaces will have a greater number of stacks and a much lower volumetric flow rate; and (2) the steam cracking furnaces will have a relatively low purity CO₂ stream (although this is mentioned largely in contradistinction to "industrial facilities with high-purity CO₂ streams"). While ExxonMobil presents these points to address their separate concerns on technical feasibility, these distinctions would expectedly figure in cost projections, and significantly impact operating expenses. See *In re: City of Palmdale (Palmdale Hybrid Power Project)*, PSD Appeal No. 11-07, Slip. Op. 55-56 (EAB Sept. 17, 2012) (a claim of "grossly inflated" costs may not be demonstrated with inapplicable cost data).

A refinement of these estimated costs would not materially change our conclusions regarding projected overall costs. Cost estimates used in BACT are typically accurate to within ± 20 to 30 percent (GHG Guidance at 39).

The commenter's cost concerns regarding the need for a utility plant appear to relate primarily to capital expenditures (e.g., the need for a dedicated boiler and cooling tower). We find the need for these additional units to be unremarkable and adequately supported by fact that significant energy and cooling water requirements apply to the recovery and purification of CO₂ from the furnace flue gas. The only alternative which the commenter proposes—that the applicant integrate the CCS process with "existing utilities" or demonstrate its infeasibility—is neither cost-free, nor something that may be freely assumed of this type of facility. We generally agree a site-specific cost analysis may look to integration with existing utilities when appropriate, but this is less likely appropriate for a modification of a chemical production facility that may not be expected to have un-utilized excess power capacity (unlike an EGU) or excess steam in sufficient and reliable quantities. The need for sufficient and reliable quantities of steam and power is particularly important for the contemplated continuous use of CCS (which is energy intensive). ExxonMobil reasonably projected increased criteria pollutant emissions of 11 percent—largely attributable to the additional fuel consumption from application of CCS.²² In sum, we do not agree the cost estimations for utility plant infrastructure require additional record justification, and ExxonMobil's representations regarding the need for the utility plant are not lacking in credibility. In

²² ExxonMobil indicates that any excess power is credited against plant operating expenses in their cost estimation. See ExxonMobil October 2012 submittal, <http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/exxonmobil-olefins-response.pdf>

any event, we note as a final matter that the capital expenditures for the utility plant are little more than 5 percent of total estimated costs, and we see no potential for additional documentation on the utility plant to change our overall conclusions regarding the selection of BACT without application of CCS.

Comment 13: ExxonMobil overstates CCS operating costs by including control of the utility plant CO₂ stream in the CCS analysis, when this stream should be analyzed separately. If a utility plant is necessary it will likely be fired by natural gas in a low concentration stream that would be less economical to capture than the higher concentration cracking furnace stream. The Region must investigate the feasibility of capturing a portion of the processes and conduct a tiered evaluation of the cost of capturing CO₂ from each stream. This would allow the Region to consider whether BACT requires CCS on some, but not all, of the Baytown Plant's process. A cost per ton of CO₂ avoided for each stream is necessary.

Response:

The commenter appears to selectively advocate for CCS from the cracking furnaces, but does not appear to advocate for CCS for CO₂ capture from a utility plant that is necessary to generate power to operate a CCS system if it were selected as an add-on control for BACT. We agree that a utility plant would create a low concentration CO₂ flue gas stream. In this case the installation of a CCS system is validly assumed to require installation of a utility plant to provide energy to operate the CCS system. We disagree that if CCS is being evaluated as an add-on control for the project that the total costs of potentially recovering this CO₂ stream should not be considered as part of the economic considerations for this project which would include the cost to construct and operate the utility plant. We have elected to treat the entire CCS system from carbon capture, energy needs, compression, and storage in the overall economic or cost consideration for BACT. Doing otherwise, would not fully account for the prospective economic, energy, and environmental impacts of applying CCS as a control option for this project.²³

Comment 14: ExxonMobil appears to have only considered the Denbury Pipeline, but the coastal plains region contains 65 percent of the country's estimated carbon storage resources. The Region's analysis did not even attempt to identify or provide cost estimates for any of the region's geologic formations.

Response:

The CCS scenario evaluated in the administrative record was based on the nearest available outlet for carbon storage and still found to be cost prohibitive; going further afield to look at other capture opportunities presents costs that would be higher still and thus, by definition, cost prohibitive. Assuming some amount of CO₂ was captured and the facility developed a system for injection on-site or nearby into a geologic formation for geologic sequestration, this would involve additional costs to the facility

²³ We also note that the CCS cost study had not based its costs on a lower concentration stream coming from the utility plant. See ExxonMobil submittal from September 6, 2013 available at <http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/exxonmobil-baytown-response090613.pdf>

(e.g., to perform a geotechnical engineering analysis for suitability of the subsurface formations, to permit injection wells, to obtain mineral rights or subsurface leases for injection purposes, to construct and operate an injection well with appropriate insurance or financial assurance mechanisms for the CO₂ injection and sequestration system). EPA utilized a \$3.80 metric/ton CO₂ per year as the cost for complying with underground injection control program for carbon dioxide (CO₂) geologic sequestration for wells (75 FR 77230-77303) in an IGCC scenario. If the IGCC scenario could be directly applied to ExxonMobil's project, the estimated cost for just complying with EPA's geologic sequestration rules assuming the project is capturing only 90% or 801,770 metric tons of CO₂ a year would be an additional \$3,046,726 a year. That is under the assumption that only one injection well was required. The potential recovered volume might require multiple wells. As we noted earlier, the cost to recover CO₂ from an exhaust or flue gas stream with a lower concentration of CO₂ may cost more on a per ton basis than an IGCC scenario due to the construction and subsequent operational costs of the carbon capture system. The economics of installing and operating CO₂ capture system are unreasonably disproportional to the project construction costs and the annualized operating costs without CCS. Requiring this additional scenario for carbon storage would still render this project economically unviable when added to the capital construction costs of CCS estimated at \$735,400,000. Therefore, we are not persuaded that the installation of add-on controls for CO₂ should be required as part of our BACT determination.

Comment 15: ExxonMobil asserts that CCS should be eliminated based on energy and environmental impacts, which the Region acknowledges, "without indicating whether it agrees with ExxonMobil." Energy impacts that are "significant or unusual" should be examined in a BACT analysis, but extra fuel or electricity is factored into the economic impacts analysis. There are no unique energy issues such as fuel scarcity or supply constraints to render CCS infeasible. The SOB asserts that CCS would increase non-GHG pollutants by as much as 11% in a non-attainment area where additional NO_x and VOC could exacerbate ozone formation in the area. This reasoning is invalid because the Draft NSR Manual states, "the environmental impacts is not to be confused with the air quality impacts." An increase in criteria pollutants does not constitute an adverse environmental impact.

Response:

EPA has stated that the costs associated with direct energy impacts should be calculated and included in the economic impacts analysis (see GHG Guidance at 39), and ExxonMobil's cost study for CCS (citing fuel costs in operating expenses and including the capital costs for a utility plant) is consistent with this guidance. However, this does not mean applicants and permitting authorities should not continue to examine whether the energy requirements for each control option result in any significant or unusual energy penalties or benefits. Where such energy impacts are identified, they should be discussed in the record. In this case, the statement of basis accurately noted the added energy and fuel requirements of CCS, which is well substantiated in the underlying record.²⁴ The energy intensity of the process to purify and compress a CO₂ stream is widely known and not questioned, in any case, even as it may be *particularly* intensive for larger streams with comparatively low CO₂ concentrations, as is the case here.

²⁴ See, e.g., applicant discussion on page 20-21, October 2012 application supplement, available at <http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/exxonmobil-olefins-response.pdf>

However, since energy impacts are not the basis for EPA's elimination of the CCS option in this case, we need not and do not reach a judgment here as to whether the energy consumption demands from applying CCS to ExxonMobil's project would be significant or unusual in the context of this permit or as a general matter.

On the issue of environmental impacts and the noted ozone precursor increases, we first note the commenter did not provide the full quote from the Draft NSR Manual. Read in its entirety, the statement only clarifies that the environmental impacts analysis and air quality impacts analysis are separately required and that neither of them should be overlooked when they are applicable: "The environmental impacts analysis is not to be confused with the air quality impact analysis (i.e., ambient concentrations), which is an independent statutory and regulatory requirement and is conducted separately from the BACT analysis." Draft NSR Manual at B.49. This does not mean, as the comment suggests, that other air pollutant emissions may not be studied or referenced when considering environmental impacts in Step 4. In fact, such an assertion is contradicted by language in the same paragraph: "...[T]he environmental impacts portion of the BACT analysis concentrates on impacts other than air quality (i.e. ambient concentrations) due to emissions of the regulated pollutant in question..." Id (emphasis added); See also GHG Guidance at 39-41²⁵ and NSR Workshop Manual at B.49. The GHG Guidance (with specific reference to the scenario where a control technology for one regulated NSR pollutant would lead to increases of other regulated NSR pollutants) states that permitting authorities have flexibility in deciding how to weigh the trade-offs associated with emissions control options. See GHG Guidance at 41. Thus, we disagree that any additional emissions of air pollutants that may be attributed to the use of a control option cannot be validly considered as part of the statutory requirement to consider "environmental...impacts." CAA section 169(3). The collateral increases of other air pollutants (other than the one that is "in question" for a BACT limit) are certainly a type of "environmental impact." It therefore is reasonable for EPA to consider potential increases in ambient levels of ozone attributable to CCS, were the project to include such GHG control.

In conducting the energy, environmental and economic impacts analysis, permitting authorities have "a great deal of discretion" in deciding the specific form of the BACT analysis and the weight to be given to the particular impacts under consideration.²⁶ As earlier noted, this includes weighing trade-offs of increases in other non-GHG pollutants. When weighing any trade-offs between emissions of GHGs and emissions of other regulated NSR pollutants, EPA focuses on the relative levels of GHG emissions rather than the endpoint impacts of GHGs. We believe it is appropriate to focus on the amount of GHG emission reductions that may be gained or lost by employing a particular control strategy and how that compares to the environmental or other impacts resulting from the collateral emissions increase of other regulated NSR pollutants. EPA did so in this case by evaluating the collateral increases of non-GHG pollutants that would occur if CCS were employed at the site. We indicated in our Statement of Basis that implementation of CCS would result in as much as a 11% increase in NO_x, CO, VOC, PM₁₀, and SO₂ emissions. In addition, we believe that because the facility is located in an existing ozone non-

²⁵ For example: "...[I]n selecting the BACT limit for carbon monoxide (CO) for a facility in an area that is nonattainment for ozone, a permitting authority may need to assess whether it is more important to select a less stringent control for CO emissions to avoid an unacceptable increase in NO_x emissions associated with the CO control technology." p. 40.

²⁶ *In re Hillman Power*, 10 E.A.D. at 684.

attainment area [Houston, Galveston, and Brazoria (HGB) non-attainment area], the generation of additional NO_x and VOCs (that is not otherwise offset) would potentially exacerbate ozone formation in the area. The State of Texas has made significant progress in reducing ozone levels in the Houston area. If given the option of selecting energy efficiency measures as part of our BACT determination in this specific case or potentially increasing non-GHG pollution from the project by as much as 11 percent by requiring add-on CO₂ controls, we determined that in this case requiring add on controls for CO₂ would not be a beneficial outcome for the Houston, Galveston, and Brazoria (HGB) non-attainment area. Although this factor, by itself, is not decisive, nonetheless it supports the decision that there are adverse cost and environmental implications of requiring a BACT limit based on use of CCS, such that EPA is not requiring that level of control.

Comment 16: Debottlenecking is a physical change in the method of operation, though not necessarily a change in the emission unit itself, that may result in an increase in emissions. The addition of eight new cracking furnaces constitutes a change in the method of operation for the entire Baytown facility, including downstream units that receive its byproducts. GHG BACT should be required for downstream units.

Response:

EPA regulations state that BACT applies to those emission units at which a net emissions increase would occur at the source as a result of a physical change or change in the method of operation. 40 C.F.R. 52.21(j)(3). EPA has interpreted these provisions to mean that BACT applies in the context of a modification to only an emissions unit that has been modified or added to an existing facility. GHG Permitting Guidance at 24 n. 57. In supplemental information submitted by the applicant on September 20, 2013, the applicant indicated the debottlenecked units that will have an increase in GHG emissions attributable to this project are boilers A, B, C, and D, and Trains 1, 2, 3 and 4. These units are not being modified as defined at 40 CFR 52.21(b)(2). The applicant states that they will only have an increase in utilization of the units. A physical change or change in the method of operation does not include “an increase in the hours of operation or in the production rate, unless such change would be prohibited under any federally enforceable permit condition.” 40 C.F.R. 52.21(b)(2)(iii)(f). Although these units will collectively experience an increase in GHG emissions of 110,000 tpy of CO₂e, the debottlenecked units are not being physically changed or experiencing a change in the method of operation at the ExxonMobil facility and therefore. Thus, these units do not have to be evaluated for BACT.

Comment 17: The emissions calculations and BACT analysis for fugitives is flawed. The draft permit incorrectly dismisses leakless technology by stating they are used for highly toxic or otherwise hazardous materials. This is not their only use. BAAQMD in California uses leakless technology in “every petroleum refinery” in the District. It is reasonable and technically feasible. ExxonMobil states that leakless technology requires unit shutdowns for repair, but all fugitive components require the same general shutdown procedures and shutdown protocol. Leakless components should be BACT. Relying solely on AVO is not reasonable, because a petrochemical plant has chemicals in the background air that could mask the mercaptans detected from leaking natural gas. Texas guidance says AVO programs may

only be applied to inorganic compounds that cannot be monitored by instrument, although in “limited instances” it may be applied to odorous organic compounds such as mercaptans. Methane can be monitored by instrument. The rejection of LDAR based on economic practicality that cannot be verified is a baseless conclusion. BAAQMD supervises LDAR programs at five refineries; there is no basis to conclude LDAR would not be cost effective here. Fugitive controls can only be eliminated when unique circumstances are demonstrated and uniquely excessive costs for the facility compared to other similar facilities.

Response:

Although the commenter has alleged that the “emissions calculations” for fugitives are “fundamentally flawed” (comments pg. 15), the comment provides no explanation to support this statement or any specific information to demonstrate how the calculation could be improved. For this project, fugitive process emissions are estimated to be only 1 tpy of CH₄ (21 TPY of CO₂e), which is less than 0.0001% of project CO₂e emissions. (These estimated emissions are also well below 0.001% of the lowest threshold established by the tailoring rule.) Even as this amount of CO₂e might be characterized as nominal or *de minimus*, our draft permit nevertheless addresses these fugitive emissions, and we consider them to be addressed appropriately for purposes of finalizing the permit. While reasonable efforts should be made to address the issue of GHG fugitives, this particular amount of pollutants is not of serious concern (as a relative area of focus).

As was noted in our draft permit, and as has been the case for other GHG PSD permits issued to date in Region 6, the final permit does not contain a numeric emission limit for fugitive GHG emissions. Instead, because technological limitations on the application of measurement methodology make imposition of a numeric emissions standard infeasible on the estimated annual “leaking” of one ton of CH₄, we are authorized to address these specific project emissions through design, operational, or work practice standards, including process monitoring. See 40 CFR 52.21(b)(12). Moreover, we note that where a numerical emission limitation cannot be established, the reductions achievable by non-numerical measures need only set forth the emissions reductions achievable by implementation of such a standard “to the degree possible.” In this context, the ranking of controls, costing of controls, and traditional method for considering BACT statutory factors is not easily conducted. To illustrate, the draft permit proposed implementation of an LDAR instrumented monitoring program for process lines in VOC service and further proposed that those lines that are not in VOC service, but contain methane be monitored using an AVO method weekly. These control measures might best be characterized as process monitoring or work practice standards, and they would not be expected to entail any construction costs---only the costs of applying personnel to the required task of inspecting, recordkeeping, and taking remedial actions, as necessary. LDAR or AVO inspections conducted daily or even hourly, instead of weekly would increase the chances that a fugitive leak is detected and addressed at an earlier time, but it is not possible to “set forth the emission reduction achievable” by these

measures. Because of this, a PSD permit writer is unable to compare these options incrementally or by cost effectiveness in any conventionally recognized manner.²⁷

The comment has raised three issues: (1) “leakless technology,” (2), the alleged unreasonableness of applying AVO methods alone (which, to reiterate, applies in the draft permit to those lines that contain methane but are not in VOC service), and (3) rejection of LDAR based on economics (which, to reiterate, was not in fact rejected for process lines in VOC service). Before offering a response to these issues, it is noteworthy that the comment relates primarily to statements in the submitted application and statement of basis. No comments on the particular terms and conditions of the draft permit or suggestions for alternate terms and conditions have been presented. We also appreciate the commenter’s provision of a reference to rules applicable in the Bay Air Quality Management District, but find the comment to be non-specific on how, if at all, this reference might be applied to permit terms and conditions.

On the issue of “leakless technology,” we have reviewed supplemental information provided to us by ExxonMobil for the purpose of clarifying our understanding of the issue.²⁸ While our SOB (p. 26) used the term “leakless technology,” we believe that this term, by itself, is potentially ambiguous and subject to misinterpretation. As is clear in reading the SOB’s narrative, however, our statements on so-called leakless technology had centered on the appropriateness of leakless valve technology for fuel lines. As explained in Exxon’s supplemental information, the design must rely (at least in part) on flanged connections to allow maintenance and repairs on the fuel line without necessitating the clearing of a larger area or a full shutdown. This contradicts the commenter’s assertion that “all fugitive components require the same general shutdown procedure for repair.” Accordingly, we conclude that safety and efficiency of repair concerns (implicating both technical infeasibility and cost) apply such that requiring non-flanged connections on the fuel line as a permit condition would be inappropriate. (See SOB p. 26, citing “the risk of unit shutdown for repair”). The comment does not demonstrate how differences in components that are already monitored components would materially change the estimated 1 tpy fugitive methane, especially relative to other project emissions that are many orders of magnitude larger.

On the alleged unreasonableness of AVO methods, we acknowledge the commenter’s statement that a large petrochemical plant may have other background odors that would mask the mercaptans that would be present in leaking natural gas. While the comment has characterized the mercaptans as being present “in tiny amounts,” this amount is not relevant to the efficacy of AVO methods. Additionally, even if odor masking were an issue for this inspection method, we cannot agree that AVO is merely “an individual ‘sniff-test’” as the commenter has asserted (comments p. 15). This disregards the audio and visual components of the inspection program.

²⁷ It may be intuitive that the labor costs of daily inspections are roughly seven times those of weekly inspections, but this is not necessarily an appropriate consideration of costs, much less for whatever little reduction from 21 tpy might be achieved by more frequent or more equipped inspections for leak detection and repair.

²⁸ See PSD-TX-102982 “Clarifying Information” submitted on September 27, 2013.

Finally, the comment objected to the failure of the permit to require LDAR methods. As with the comment on AVO methods, the comment is only relevant to lines that contain methane but are not in VOC services, and it is therefore only relevant to a fraction of the total estimated fugitives. We agree with the comment that a basis of elimination on cost effectiveness grounds is not well demonstrated, nor for the reasons earlier discussed could it be well demonstrated with anything other than novel techniques for describing cost effectiveness. We do not believe that an effort toward that end is necessary, however. While operating conditions or work practices might be ranked and organized by the rigorousness of the process monitoring contemplated for the permit (e.g., frequency, duration, recordkeeping, or techniques applied), we do not think this exercise would be helpful here where there is a negligible difference in emissions. See *In re Prairie State Generating Company* (p. 34-38) (finding that a full cost analysis is not required when a control technology has comparable control effectiveness). See also Draft NSR Manual B.20-21 (a fully detailed evaluation in Step 4 may not be needed, if there “is a negligible difference in emissions” between control alternatives).

Accordingly, the permit terms and conditions regarding fugitive emissions are justified as BACT for this project. We have also attempted, consistent with our recent permitting practices in Region 6, to make these conditions work well with fugitive monitoring requirements that will be applied to other pollutants at the plant, thus building on compliance requirements and methods that the source is already familiar with, as developed by the Texas Commission on Environmental Quality (TCEQ). When TCEQ is able to serve as the PSD permitting authority for GHGs, we expect they will be better positioned, as necessary, to calibrate their fugitives monitoring program to unique considerations for GHGs that would apply in individual permitting actions. For our purposes, we typically expect that the LDAR program prescribed by the state permitting authority for VOCs in the applicant’s PSD permit for non-GHG emissions would also apply for GHG emissions of methane. In this case the applicant is obtaining a minor NSR Permit (permit number 102982) for non-GHG emissions that will be included into their existing plantwide applicability limit (PAL) permit (permit number PAL6). The TCEQ permit number 102982 requires that lines in VOC service implement the TCEQ 28VHP LDAR program. EPA incorporated Special Permit Condition III.A.5.a. requiring ExxonMobil to implement the TCEQ 28VHP LDAR program on process lines in VOC service. In addition, EPA incorporated Special Permit Condition III.A.5.b. to require ExxonMobil to implement an auditory, visual, and olfactory (AVO) method on natural gas piping components and for process lines not in VOC service, but containing methane. We note that ExxonMobil’s permit terms and conditions to address fugitive emissions could not be considered any less stringent than those recently given to other olefin production units among the GHG PSD permits issued in Region 6. In the absence of an applicable NSPS for GHGs that addresses fugitives and piping components, we believe the approach applied in this permitting action is appropriately stringent.

Comment 18: BACT should include a flare gas recovery system. The ExxonMobil analysis calculated \$134.2 per ton of CO₂e removed, but it assumed a capital charge rate of 19% and an expected equipment life of 20 years. A capital recovery factor of 0.0543 (compared to 0.195 used by ExxonMobil) reduces the control cost to 35.5 per ton of CO₂e. In any event, the conclusion that \$134.2 per ton is not cost effective is not supported and can only be supported by comparing it to “the range of cost effectiveness values for other similar permit decisions.” If the costs are in the range of costs borne by other similar

facilities, it is assumed to be cost effective unless unusual circumstances exist at the source. Similar industries are widely using flare gas recovery so unusual circumstances should not be present here and have not been demonstrated. Costs are also more favorable on the basis of dollars per ton of total pollutant removed since emissions of other pollutants and criteria pollutants are also reduced using the control.

Response:

We have further evaluated the use of a flare gas recovery system (FGRS) in response to the comment. ExxonMobil has provided additional information to our administrative record making clear that it can achieve a BACT limit at the elevated flare (FLAREXX1) based on the use of FGRS. We are assigning such a limit in this permit to make use of the Baytown Olefins facility's otherwise unrelated plans to commission FGRS at other parts of the facility. This technology will be used in addition to the low-carbon fuel, good operation and maintenance, and staged flaring previously selected as BACT.

As a first measure, we evaluated ExxonMobil's submitted information to ensure those plans do not trigger PSD requirements or implicate modifications of emissions units that would be in the scope of this GHG PSD permit. After this review, we conclude neither issue is present. The FGRS system will already be in operation some time before ExxonMobil completes construction under this GHG PSD permit. We understand that ExxonMobil's FGRS project would recover gas from two existing flares at the existing facility and route the recovered product stream to existing boilers (EPN: E-7-1)²⁹ and/or cogeneration trains (EPNs: HRSG1, HRSG2, HRSG3, and HRSG4). The new elevated flare (FLAREXX1) will be able to tie into that system without changing the design of this FGRS planned for the existing plant. Under the circumstances, assigning a BACT limit to FLAREXX1 based on flare gas recovery would not result in a modification to the existing plant flare gas sinks (i.e., boiler or trains) since the units are already authorized to use process waste gas (i.e., plant tail gas) as fuel in TCEQ Permit Nos. 3452/PSD-TX-302M2/PAL6. Moreover, an actual increase in GHG emissions attributable to the combustion of the proposed project elevated flare gas in the existing plant flare sinks is not expected since an equivalent amount of blended fuel gas (on an MMBtu/hr basis) will be removed from the fuel feed to the units. We therefore conclude that application of this BACT limit to FLAREXX1, under the revised permit, will not require modifying those emissions units that would productively utilize the recovered flare gas as fuel for their processes. The modification of those units would be covered by a separate earlier state-issued authorization to construct that would commission the use of flare gas recovery on existing parts of the facility.³⁰

The FGRS will only recover gas that would otherwise be controlled by the elevated flare; it will not recover any of the gases that would be controlled by the ground flare. It is technically infeasible to recover gas from the ground flare (FLAREXX2). The ground flare is needed to control large volume,

²⁹ Boiler A, Boiler B, Boiler C, and Boiler D share a common stack and thus are issued the same emission point number (EPN).

³⁰ ExxonMobil represents that the project to install FGRS at the existing plant would not increase the existing plant-wide applicability limits (PALs) or require the application of PSD or nonattainment new source review. ExxonMobil will therefore obtain an authorization to construct from TCEQ's minor new source review program.

high pressure gas streams that are generated on an intermittent basis from activities such as significant maintenance events and unit shutdowns.³¹ These vent streams also cannot be controlled by the elevated flare for the same reasons that make control by FGRS infeasible.

Although the GHG emission limits are reduced under the revised permit, the elevated flare will still be required as a safety device for some routine and intermittent flaring from the proposed project. ExxonMobil has proposed to capture a minimum of 70% of the flow volume going to the elevated flare. ExxonMobil states that to recover greater than 70% is technically infeasible. In order to collect more than 70% of the flare gas to the elevated flare (FLAREXX1), the planned FGRS at the existing plant would require a larger compressor to process the gas, upgrades to the plant electrical infrastructure such as supply, substations, cable, etc. to operate the larger system, and modification to additional flare gas sinks(s) at the Baytown Olefins Plant to accept the additional gas. Despite this assertion of technical infeasibility, ExxonMobil also provided a cost analysis to show that the incremental costs associated with modifying the planned FGRS to recover more than 70 percent of the gas is cost prohibitive. To increase the flare gas recovery from 70 to 85 percent would cost approximately \$938/ton of CO₂e avoided. Any further increase in collection of flare gas beyond 85 percent would result in an incremental cost greater than \$938/ton of CO₂e avoided. EPA agrees with the applicant's analysis that capturing greater than 70 percent is not economically achievable in this case. Since this system is already in the development stage, the cost of routing a portion of the elevated flare gas stream is cost effective in this case, but we cannot apportion costs from the separate project or furnish and make conclusions on a specific cost effectiveness value that applies in this permitting action. Thus, the submitted cost analysis to which the commenter takes objection no longer applies.

We note that Flare Gas Recovery (FGR) has not traditionally been utilized at Olefins Plants. FGR is more commonly found at refineries.³² However, one Olefins plant in the U.S. has installed FGR, and EPA has data to demonstrate that it has been working well for over a year. Therefore, the use of FGR has been demonstrated as technically feasible at an existing olefins facility. Although the use of FGR is technically feasible for the ExxonMobil Baytown olefins facility, it may not be technically or economically feasible for all scenarios and therefore should be considered in BACT analysis only on a case-by-case basis. Further, while it is not clear that capture rates greater than 70 percent are technically infeasible, EPA believes it is technically infeasible to consider the complete removal of a flare at an olefins plant. The only technically practical and safe way to manage large gas flows (such as emergency and MSS) is through a flare. Therefore, complete capture is not technically feasible.

The addition of FGRS to the elevated flare (FLAREXX1) will reduce the emissions of the elevated flare from 39,054 tpy CO₂e to 13,038 tpy CO₂e. EPA has revised the permit to include a BACT limit for the elevated flare (FLAREXX1) based on the recovery of a portion of the flare gas stream by the FGRS. The elevated flare (FLAREXX1) and the ground flare (FLAREXX2) were under a combined emission

³¹ See ExxonMobil Submittal dated October 16, 2012 available at <http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/exxonmobil-olefins-response.pdf>

³² See EPA White Paper "Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry" (October 2010) at www.epa.gov/nsr/ghgdocs/refineries.pdf.

cap in the proposed draft permit. In an effort to clarify the emission limits for both flares, we have eliminated the emissions cap. The details of this limit and its supporting compliance measures are as follows:

- The elevated flare (FLAREXX1) shall be connected to the flare gas recovery system (FGRS) associated with the existing plant. The FGRS will collect a minimum of 70% of the flare gas from the elevated flare on a 12-month rolling average basis.
- The recovered flare gas shall be used as a fuel in any of the following emission units: Boiler A, Boiler B, Boiler C, Boiler D (Boiler A – D share a common stack: E-7-1), Train 1 (HRSG1), Train 2 (HRSG2), Train 3 (HRSG3), and Train 4 (HRSG4)³³.
- The Permittee shall keep daily records of the volume of gas collected by the FGRS from the elevated flare (FLAREXX1), the volume of gas flared in the elevated flare (FLAREXX1). Flow measurement shall be determined by continuous measurement of the flow of the recovered and flared flows for the elevated flare gas using an operational non-resettable elapsed flow meters, or a computer that collects, sums, and stores electronic data from the continuous fuel flow meters as a totalizer.
- The elevated flare shall not have emissions exceeding 13,038 TPY of CO_{2e}.
- The ground flare shall not have emissions exceeding 51,485 TPY of CO_{2e}.

Comment 19: For the steam cracking furnaces, the region should include a monitoring requirement for burner efficiency based on the CO concentration as provided in the ExxonMobil's October 16, 2012 responses (pages 13-15). ExxonMobil represents this will ensure good combustion efficiency of the burners is maintained, and the commitment should be incorporated into the permit.

Response:

We agree with this comment and the permit has been revised. The following Special Permit Conditions have been added to Section III.A.1.

- Permittee shall install and maintain a CO CEMS and perform preventative maintenance checks every quarter per 40 CFR 60 Appendix B4.
- The Permittee shall maintain a CO concentration at or below 50 ppmv corrected for 3% oxygen on a 12-month rolling average.

Comment 20: ExxonMobil's October 16, 2012 responses (pages 16-17 and 28-29) assert the plant will operate with an exhaust stack temperature at or below 325 °F to assure efficient operation. The permit should adopt a limit based on 325 °F as a limit and should consider whether lower temperatures (based on lower temperatures used for other similar projects) would promote efficiency and constitute BACT.

³³ This condition applies to recovered gas from the flare authorized for construction by this permit and does not authorize any modification of these listed emission units.

Response:

We believe our initial temperature of 340 °F was appropriate. We have some technical concerns that meeting the lower temperature will generate more emissions. However, we also acknowledge some efficiency benefits from the lower temperature. The commenter has not provided any specific information on the degree of emission reductions that might be achieved at lower temperatures or addressed the applicant's reasons for preferring a higher temperature. We view this as being case specific and not necessarily applicable to our review of exhaust stack temperatures at other projects. In this case, based on additional information provided by the applicant, our assessment is that any potential efficiency benefits from a lower temperature is offset by other forms of efficiency losses and emissions increases that could result from restricting exhaust gas temperatures to 325 °F.

The type of feedstock used in a steam cracking furnace has an effect on stack exhaust temperature. A liquid feed cracking furnace is able to achieve a lower exhaust temperature since the liquid feed enters the furnace at close to ambient temperature. A gaseous feed cracking furnace will have a higher exhaust temperature since the feed is heated to 30 – 40 °F above saturation before it enters the cracking furnace. Therefore, it is not practical to compare the stack exhaust temperature for gaseous feed cracking furnaces (as proposed by ExxonMobil) with cracking furnaces that can accept a gas and liquid feed (such as BASF permitted by Region 6). BASF was permitted at 309 °F. BASF proposed to use a large variety of feedstocks (liquid and gaseous) and not solely ethane as ExxonMobil has proposed. BASF would use ethane, propane, butane, and naphtha as feedstocks.

ExxonMobil requested that the maximum exhaust temperature be raised to 340 °F from 325 °F prior to public notice. ExxonMobil provided information showing that meeting the lower temperature would require more frequent washings of the convection section. This would require more furnace shutdowns and startups which would increase coke formation and increase loads on the on-line furnace causing lower energy efficiency during those periods. In addition, on September 6, 2013 ExxonMobil provided additional information to support the higher exhaust temperature. Lowering the temperature to 325 °F would require ExxonMobil to double the number of shutdowns performed on the furnace. Startups after a shutdown are energy intensive and very energy inefficient. During startups and shutdowns there are periods when the NOx controls (i.e., SCR) cannot operate due to low stack gas temperature. During these periods, NOx emissions may be as high as 6 times the normal operating emissions on a pound/MMBtu basis causing an increase in overall plant NOx emissions. Coking rates also increase with each startup and shutdown. The more frequent the furnace is cycled through startups and shutdowns, the more frequent the furnace has to be decoked to maintain efficient operation. Each decoke generates emissions of PM, PM₁₀, PM_{2.5}, CO, and CO_{2e} which would increase the plant's overall emissions. The lower temperature proposed by Sierra Club would also require more frequent convection section washes. 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 and corrosion. Each convection section wash introduces the opportunity for damage to the refractory, thus increasing casing loss and increasing GHG emissions.

The temperature of 340 °F is still consistent with other BACT determinations for cracking furnaces with gaseous feeds. INEOS was permitted with an exhaust gas temperature of 340 °F and Chevron Phillips was permitted with an exhaust temperature of 350 °F. There is no increase in GHG emissions associated with the higher maximum exhaust temperature, and the increased temperature does not decrease the efficiency of the furnaces.

Comment 21: The permit should contain conditions for periodic washes of the convection section and maintenance of seal bags to manage air ingress. The maintenance practices are on the October 16, 2012 response at page 18.

Response:

We agree to add a condition requiring a wash of the convection section of the furnaces when the furnace exceeds the BACT limit of 340 °F. A condition has also been added to perform a visual inspection of the air ingress seal bags whenever the oxygen analyzers indicate an oxygen concentration > 10 mole % (dry). The following Special Permit Conditions have been added to Section III.A.1.

- The Permittee shall perform a visual inspection of the air ingress seal bags when the O₂ analyzer indicates an oxygen concentration greater than 10% as stated in A.III.1.e.
- Exceedance of the temperature specified in III.A.1.o. shall require a wash of the convection section of the furnace that is out of compliance with the temperature requirement.

Comment 22: The October 16, 2012 responses provide Attachment 4, Table 3-2, which lists proposed “Work Practice Standards and Operating Limits.” The region should verify, at a minimum, that these listed items are in the permit.

Response:

The work practice standards and operational limits are included in the permit. The table below identifies the Special Permit Condition in the permit that requires the work practice, operation requirement, or monitoring practice indicated.

Emission Point		Emission Unit Work Practice Standard, Operational Requirement, or Monitoring	Special Permit Conditions (S.C.)
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.m., 340 °F on a 365-day rolling average basis
		Maintain furnace exhaust stack CO ≤ 50 ppmv @ 3% O ₂ during online operation on a 12-month rolling average basis	This is added to the permit at SC.III.A.1.k.

Emission Point		Emission Unit Work Practice Standard, Operational Requirement, or Monitoring	Special Permit Conditions (S.C.)
EPN	Name		
		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.b.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.f. and S.C. III.A.1.g. For O ₂ monitors and S.C.III.A.1.j. for CO monitors
		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. annually
		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	This is added to the permit at SC.III.A.1.1.
XXAB-DEC through XXGH-DEC	Furnace Decoke Vents	Maintain furnace exhaust stack CO ≤ 50 ppmv @ 3% O ₂ during online operation (furnace producing ethylene) on a 12-month rolling average basis	This is added to the permit at S.C. III.A.1.k.
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.g., III.A.h., and 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.

Emission Point		Emission Unit Work Practice Standard, Operational Requirement, or Monitoring	Special Permit Conditions (S.C.)
EPN	Name		
BOPXXFUG	Fugitives	Conduct daily as-observed AVO inspection for piping components in non-VOC natural gas service	S.C. III.A.5.c.
		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 $\geq 70\%$ on a 12-month rolling average	S.C. III.A.2.a. and III.A.2.g.
		Maintain exhaust stack CO concentration ≤ 7.4 ppmvd @ 15% O ₂ on a 12-month rolling average	EPA required the applicant to monitor the duct burners for thermal efficiency in lieu of CO concentration.
		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	EPA required the applicant to monitor the duct burners for thermal efficiency in lieu of CO concentration.
		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. IV.A.1.c.
		Calibrate and perform preventative maintenance checks of the continuous carbon monoxide stack monitors per 40 CFR 60 Appendix B4 every quarter.	EPA required the applicant to monitor the duct burners for thermal efficiency in lieu of CO concentration.
		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.

Comment 23: The following miscellaneous issues in the draft permit are noted:

-The GHG limits in Table 1 are set so that there is one limit for all eight cracking furnaces. (See page 8, Note 3) When one or more of the units are down, this would allow the other operating units to operate less efficiently than would otherwise be considered as BACT. The Region should set GHG BACT limits for each emission unit, not for a group of emission units.

Response:

EPA disagrees and has established individual limits to promote efficiency for each furnace as a maximum firing rate, maximum exhaust temperature, and a CO concentration, and this prevents the scenario raised by the commenter where a unit being down allows less efficient operation of other operating units. These parameters are adequate to ensure proper and efficient operation of the emission units on an individual basis. This is distinct from the annual emissions cap for CO₂e emissions assigned to the furnaces as a group, and this limit was set to be lower than the PTE for all emission units combined.

-Page 10 of the draft permit provides: "The Permittee shall monitor the furnace for coke buildup and perform a decoke when needed." The permit should be revised to clarify what "when needed" means. Further, ExxonMobil's October 16, 2012 Response 8.A (page 26) lays out decoking design and procedures to assure efficient operation. The Region should require these parameters as permit conditions. Finally, the permit should limit the amount of coke that can form.

Response:

EPA determined that the response referred to addresses design parameters that ExxonMobil will install and that they do not constitute a permit condition in themselves. Monitoring of the furnace for coke buildup is required by the cited provision, but EPA disagrees that a limit be given for the amount of coke that can be formed or that it is feasible to better define when a decoke is needed. The condition is meant to leave room for operator judgment because excess coking increases GHG emissions, but excess decoking may be counterproductive and increase GHG emissions, as well. Many factors influence coke formation, and our technical position is coke formation will be minimized by following the permit conditions in the permit.

-Draft permit section III.A.1 includes two sub-sections "c."

Response:

This will be corrected in the final permit.

-The draft permit does not contain any monitoring to demonstrate compliance with the flare efficiencies of 98% for the elevated flare and 99% for the ground flare in Condition III.A.3.b (Draft Permit p. 11) The condition is therefore not enforceable as a practical matter. The Region should revise the permit condition to include monitoring to demonstrate compliance.

Response:

The draft permit at Special Condition III.A.3.a. requires the elevated and ground flares to meet the requirements of 40 CFR 60.18. In addition, there is another monitoring requirement at Special Condition

III.A.f. which requires a minimum heating value of 800 Btu/scf for the ground flare. Special Conditions III.A.3.i. and j. require the Permittee to monitor and the composition of the gas being combusted and record the heating value of the combusted gases at both flares. Special Condition III.A.3.j. requires for both flares the measurement and recording of the flow of gas and steam being combusted along with the steam to hydrocarbon ratio. The monitoring of these parameters will ensure efficient operation of the flares. In addition, please see conditions V.G. and V.H. for initial performance testing requirements for the elevated flare and the ground flare. Condition V.G. states “Elevated flare (FLAREXX1) compliance determinations shall be made following the requirements in 40 CFR sections 65.147(b)(3)(i) through 65.147(b)(3)(iv). 40 CFR Part 65 Subpart G clearly states that “An owner or operator is not required to conduct a performance test to determine percent emission reduction or outlet regulated material or TOC concentration when a flare is used” 65.147(b)(1). Condition V.H. allows EMBOP to request an equivalency determination for the ground flare. The equivalency determination will specify the parameters at which the flare must be operated at and has to be approved by EPA Compliance Assurance and Enforcement Division.

III. Revisions in Final Permit

The following is a list of changes for the *ExxonMobil Baytown Olefins Plant (PSD-TX-102982-GHG) Prevention of Significant Deterioration Permit, Final Permit Conditions*.

1. Equipment List

Page 2 contains an equipment list and has been modified as follows:

FIN	EPN	Description
FLAREXX1 FLAREXX2	FLAREXX1 FLAREXX2	Staged Flare System (Combustion Unit). <u>Consisting of an elevated flare (FLAREXX1) and ground flare (FLAREXX2).</u>

This administrative change is made to clarify the emission point number of the elevated flare and the ground flare.

2. Section II. Annual Emission Limits

Table 1. Annual Emission Limits

FIN	EPN	Description	GHG Mass Basis		TPY CO ₂ e ^{1,2}	BACT Requirements
				TPY ¹		
FLAREXX1	FLAREXX1	<u>Staged Flare System Elevated Flare</u>	CO ₂	86,574 [§] <u>11,641</u>	90,539 [§] <u>13,038</u>	<u>Use of a flare gas recovery system (FGRS) minimum 70% recovery. See permit condition III.A.3.l.</u>
			CH ₄	415 [§] <u>37</u>		
			N ₂ O	5 [§] <u>2</u>		

FIN	EPN	Description	GHG Mass Basis		TPY CO ₂ e ^{1,2}	BACT Requirements
				TPY ¹		
FLAREXX2	FLAREXX2	Ground Flare	CO ₂	<u>50,303</u>	51,485	Use of Good Combustion Practices. See permit condition III.A.3.
			CH ₄	<u>12</u>		
			N ₂ O	<u>3</u>		
DIESELXX01 DIESELXX02 DIESELXX03 DIESELXX04 DIESELXX05	DIESELXX01 DIESELXX02 DIESELXX03 DIESELXX04 DIESELXX05	Backup Generator Engines ⁶⁵	CO ₂	223 ⁶⁵	554 ⁶⁵	Use of Good Operating and Maintenance Practices. See permit condition III.A.4.
CH ₄	1 ⁶⁵					
N ₂ O	1 ⁶⁵					
DIESELXXFW1 DIESELXXFW2	DIESELXXFW1 DIESELXXFW2	Firewater Booster Pump Engines	CO ₂	67 ⁷⁶	398 ⁷⁶	Use of Good Operating and Maintenance Practices. See permit condition III.A.4.
CH ₄	1 ⁷⁶					
N ₂ O	1 ⁷⁶					
BOPXXFUG	BOPXXFUG	Fugitive Emissions	CH ₄	No Emission Limit Established ⁸⁷	No Emission Limit Established ⁸⁷	Implementation of LDAR/AVO program. See permit condition III.A.5.
Totals⁹⁸			CO ₂	<u>1,466,916</u> <u>1,442,261</u>	CO₂e <u>1,479,665</u> <u>1,453,293</u>	
			CH ₄	<u>179,112</u>		
			N ₂ O	<u>29,28</u>		

1. The TPY emission limits specified in this table are not to be exceeded for this facility and include emissions from the facility during all operations and include MSS activities.
2. Global Warming Potentials (GWP): CH₄ = 21, N₂O = 310
3. The GHG Mass Basis TPY limit and the CO₂e TPY limit for the steam cracking furnaces applies for all eight furnaces combined.
4. The GHG Mass Basis TPY limit and the CO₂e TPY limit for the furnace decoke vents is for all four furnace decoke vents combined.
- ~~5. The GHG Mass Basis TPY limit and the CO₂e TPY limit are for the entire staged flare system (EPNs: FLAREXX1 and FLAREXX2).~~
- ~~5.~~ 6. Up to five generators are allowed, however; total power output will not exceed 3.0 MW for all generators combined. The GHG Mass Basis and CO₂e TPY emissions stated in this table are for all Emergency Generator Engines combined regardless of the number installed.
- ~~6.~~ 7. The GHG Mass Basis and CO₂e TPY emissions stated in this table are for both Firewater Booster Pump Engines (EPNs: DIESELXXFW1 and DIESELXXFW2) combined.
- ~~7.~~ 8. Fugitive process emissions from EPN BOPXXFUG are estimated to be 1 TPY of CH₄, and 21 TPY CO₂e. In lieu of an emission limit, the emissions will be limited by implementing a design/work practice standard as specified in the permit.
- ~~8.~~ 9. Total emissions include the PTE for fugitive emissions. Totals are given for informational purposes only and do not constitute emission limits.

The changes to the emission limit tables were to add a BACT emission limit for the elevated flare (FLAREXX1) based on flare gas recovery of 70%, and to give each flare its on stand alone emission limit eliminating the emissions cap proposed in the draft permit. The changes also required footnotes to

the emissions limit table to be renumbered and resulted in lowering the sitewide emission totals on the table.

3. Section III. Special Permit Conditions for the Steam Cracking Furnaces

This section was relettered due to the duplication of special condition III.A.1.c.

- ~~e.~~ d. Permittee shall calibrate and perform preventative maintenance check of the fuel gas flow meters and document annually.
- ~~d.~~ e. Permittee shall install, operate, and maintain an O₂ analyzer on the furnaces (XXAF01-ST, XXBF01-ST, XXCF01-ST, XXDF01-ST, XXEF01-ST, XXFF01-ST, XXGF01-ST, and XXHF01-ST). Oxygen concentration shall be a maximum of 10 mole % (dry) during normal operations, not including commissioning, startup, shutdown, decoke, and hot steam standby.
- ~~e.~~ f. Oxygen analyzers shall continuously monitor and record oxygen concentration in the furnaces (XXAF01-ST, XXBF01-ST, XXCF01-ST, XXDF01-ST, XXEF01-ST, XXFF01-ST, XXGF01-ST, and XXHF01-ST). It shall reduce the oxygen readings to an averaging period of 15 minutes or less and record it hourly.
- ~~f.~~ g. A relative accuracy test audit (RATA) is required once every four quarters in accordance with 40 CFR Part 60, Appendix F, Procedure 1, § 5.1.1.
- ~~g.~~ h. The oxygen analyzers shall be quality-assured at least quarterly using cylinder gas audits (CGAs) in accordance with 40 CFR Part 60, Appendix F, Procedure 1, § 5.1.2.

This change was made to correct an error in the letter sequence of the special conditions due to a duplication error.

4. Section III.A.1. Special Permit Conditions for Steam Cracking Furnaces

Special Permit Conditions III.A.1.i. through l. and p. were added as follows:

- i. The Permittee shall perform a visual inspection of the air ingress seal bags when the O₂ analyzer indicates an oxygen concentration greater than 10% as stated in A.III.1.e.
- j. Permittee shall install and maintain a CO CEMS and perform preventative maintenance checks every quarter per 40 CFR 60 Appendix B4.
- k. The Permittee shall maintain a CO concentration at or below 50 ppmv corrected for 3% oxygen on a 12-month rolling average.
- l. Permittee shall perform and maintain records of online burner inspections when indicated by CO levels >100 ppmv corrected to 3% oxygen for a one-hour average and during planned shutdowns.
- p. Exceedance of the temperature specified in III.A.1.o. shall require a wash of the convection section of the furnace that is out of compliance with the BACT limit.

This change was made to add the requirements for inspecting the air ingress seal bags when exceeding oxygen limits, CO monitoring, CO limit, requirement to perform burner inspections as indicated by CO

levels, and to perform a convection section wash when the BACT limit is exceeded. This change also resulted in the subsequent conditions being renumbered.

5. Section III.A.3. Special Permit Conditions for Staged Flaring
Special Permit Conditions III.A.3.1. through n. were added as follows:

- The elevated flare (FLAREXX1) shall be connected to the flare gas recovery system (FGRS) associated with the existing plant. The FGRS shall collect a minimum of 70% of the flare gas from the elevated flare on a 12-month rolling average basis.
- The recovered elevated flare gas shall be used as a fuel in any of the following unmodified emission units: Boiler A, Boiler B, Boiler C, Boiler D (Boiler A – D share a common stack: E-7-1), Train 1 (HRSG1), Train 2 (HRSG2), Train 3 (HRSG3), and Train 4 (HRSG4).
- The Permittee shall keep daily records of the volume of gas collected and sent to the FGRS from the elevated flare (FLAREXX1) by continuous measurement of the flow of the recovered elevated flare gas using an operational non-resettable elapsed flow meter, or a computer that collects, sums, and stores electronic data from the continuous fuel flow meter as a totalizer.
- The elevated flare (FLAREXX1) shall not have emissions exceeding 13,038 TPY of CO₂e.
- The ground flare (FLAREXX2) shall not have emissions exceeding 51,485 TPY of CO₂e.

These changes were made to add a BACT limit and associated monitoring for the elevated flare. This change also resulted in the subsequent conditions being renumbered.

IV. Endangered Species Act (ESA)

EPA determined that issuance of the proposed permit will have no effect on twelve (12) listed species, as there are no records of occurrence, no designated critical habitat, nor potential suitable habitat for any of these species within the action area. Because of EPA's "no effect" determination, no further consultation with the USFWS and NMFS was needed.

V. Magnuson-Stevens Fishery Conservation and Management Act

Based on the information provided in the Essential Fish Habitat (EFH) Assessment, EPA concludes that the issuance of the PSD permit allowing ExxonMobil construction of a new ethylene production unit within the existing Baytown facility will have no adverse impacts on listed marine and fish habitats. The assessment's analysis, which is consistent with the analysis used in the biological assessment, shows the project's construction and operation will have no adverse effect on essential fish habitats.

VI. National Historic Preservation Act (NHPA)

EPA determined that because no historic properties are located within the area of potential effect (APE) and that a potential for the location of archaeological resources is low within the construction footprint

itself, issuance of the permit to ExxonMobil will not affect properties on or potentially eligible for listing on the National Register. On June 12, 2013, EPA sent a letter to the State Historic Preservation Officer (SHPO) requesting concurrence on EPA findings for LPEC's cultural survey. The SHPO sent a letter with concurrence to the EPA on July 11, 2013.