Exhibit 3

La Paloma Energy Center
Prevention of Significant Deterioration Permit for Greenhouse Gas Emissions
PSD-TX-1288-GHG

Responses to Public Comments

U.S. Environmental Protection Agency
November 6, 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 La Paloma Energy Center on March 20, 2013. The public comment period on the draft permit began March 20, 2013 and closed on April 19, 2013. EPA announced the public comment period through a public notice published in *Valley Morning Star* on March 20, 2013 and on Region 6's website. EPA also notified agencies and municipalities on March 14, 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 Harlingen Public Library in Harlingen, 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 April 15, 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 April 15, 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 April 17, 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 April 14, 2013. EPA received one comment letter from Sierra Club on April 19, 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 April 19, 2013.

Analysis of 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: In considering the appropriate control technologies to be permitted, the Region must keep in mind that Texas is vulnerable to the serious impacts of climate change, including drought and sea level rise.

Response:

In making the endangerment finding for greenhouse gases (GHGs) pursuant to Clean Air Act (CAA) section 202(a), the Administrator identified the increased risk of serious adverse effects from extreme events, including droughts and surges and flooding in coastal areas (from sea level rise and more intense storms). See "Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act." 74 FR 66496 (December 15, 2009). Consistent with applicable guidance, this PSD permitting action does recognize that there are compelling public health and welfare reasons for BACT to require all GHG reductions that are achievable, considering economic impacts and the other listed statutory factors.[1] Contrary to the commenter's suggestion, however, potential regional variations in the severity of an air pollutant's impacts are not one of these statutory factors. Consequently, it would be inappropriate to hold permit applicants to different standards depending on where they seek to build, especially in light of the fact that GHGs contribute to climate change regardless of their point of origin.

Comment 2: The region must establish the GHG BACT limit based on "the most efficient, lowest polluting turbine design technology." The SOB states the BACT limits for CO_2 will vary depending on which of three turbine models the permit applicant selects. The GHG emission rate that is achievable by the "most efficient turbine design" in the size class must be BACT. The record does not demonstrate the infeasibility of using the turbine model with the lowest CO_2e/MW-hr or demonstrate a "sufficient site-specific basis to reject that technology."

Response:

EPA has determined that BACT for this facility is combined cycle technology with efficient turbine design, and does not agree that each gas turbine model is a different control technique that must be compared against other models, with one model necessarily being chosen over the others. Because the project is defined by the permit applicant as having a production capacity range of 637-753 megawatts (MW) of gross electrical power, EPA has established alternative sets of BACT limits for combined cycle technology that will apply based on the capacity of the turbine selected by the applicant from among efficient turbine models that have comparable control efficiencies.

[1] PSD and Title V Permitting Guidance for Greenhouse Gases (March 2011) at 40. [Hereinafter "GHG Guidance"]

The permit application states that the business purpose of the La Paloma Energy Center (LPEC) is to generate 637-735 MW of gross electrical power near the City of Harlingen in an efficient manner while increasing the reliability of the electrical supply for the State of Texas. See Revised Application (March 12, 2013), Page 15. The application also indicates that the applicant has not yet selected the optimal turbine capacity for the project and seeks to have the flexibility make that decision later in the project development process[2]. The regulation of electricity in Texas creates indeterminacy regarding LDEC's future customer base and creates a need to accommodate flexibility and uncertainty in its planned operating capabilities. Texas has its own agencies that are tasked to assess the State's short- and long-term energy needs and have jurisdiction over planning and policy for the provision of electricity,[3] and uncertainty remains because LDEC has not yet obtained all of the regulatory approvals under that process.

The applicant will ultimately have to select a turbine capacity within the range specified for the project, and the permit establishes limits based on the GHG rates achievable for different turbine models with capacities in the range that is described in the permit application. The selection of the GE 7FA turbine would result in a 637 MW electric generating unit (EGU); selection of the Siemens SGT6-5000F(4) turbine would result in a 681 MW EGU; and selection of the Siemens SGT6-5000F(5) turbine would result in a 735 MW EGU. The configuration options for this project have been included in the permit and have been made available for public comment.

LPEC's original application (received April 30, 2012) had proposed a single GHG BACT limit based on an averaging of the performance of turbines within the desired capacity range, but we think it is more consistent with the BACT requirement to assign specific limits that would apply to each of the capacities contemplated in the application, as revised. A gas turbine's type, model, and capacity will affect the achievability of emission limits, including relevant output-based limits for NO_x, GHGs, and other pollutants. The approach reflected in the permit ensures that the applicant is required to meet the lowest GHG level that is achievable with the turbine that is optimally sized for the particular capacity that the applicant ultimately selects within the size range specified in the application.

There are multiple factors, independent of air quality permitting, that influence the selection of a particular turbine model by a permit applicant. Efficiency of the gas turbine is an important and recognized factor, but is not the sole factor, nor is it necessarily a dominant factor. An applicant may consider other factors, including but not limited to: reliability requirements, the experience of the utility with the operation and maintenance service of the particular manufacturer and turbine design, and the peak demand which must be met based on regulatory decisions and other factors. In this instance, LPEC's permit applications indicate that the applicant has not yet determined the precise amount of power it will supply, but rather specifies a capacity range that the project is designed to meet.

If each turbine model is operated at maximum capacity, the Siemens SGT6-5000F(4) and SGT6-5000F(5) turbines are marginally more efficient because of their higher capacity. However, if the applicant ultimately determines for business reasons unrelated to air quality permitting that it desires to supply power at the lower end of the capacity range, then this efficiency would not necessarily be achieved if the permit applicant is required to install two turbines capable of producing 735 MW, and

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[2] Email from Scott Stringfellow to Aimee Wilson on February 8, 2013 regarding La Paloma's operation capacity. http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/la-paloma-email020813.pdf

[3] A 2013 report to the state legislature provides further background information. "Report to the 83rd Texas Legislature: Scope of Competition in Electric Markets in Texas, Public Utility Commission of Texas, January 2013, available at http://www.puc.texas.gov/industry/electric/reports/scope/2013/2013scope_elec.pdf.

operate them at less than full load to produce 637 MW of electrical power. The commenter's approach of selecting the lowest limit achievable based on the efficiency of the largest turbine in the specified capacity range would disallow particular turbine models or power plant-sizing scenarios altogether. This might force the permit applicant to oversize the turbine for its intended use and operate a turbine at less than its optimal capacity. It might also unnecessarily increase the cost of the project.

The BACT analysis conducted in this permitting action treats current combined cycle combustion technology with efficient turbine design, and without regard to particular turbine models or capacities, to be an "available control option," beginning in the first step of top-down analysis. LPEC will be required to construct in accordance with its permit application, and may only construct and operate on the basis of its ultimate selection of the capacity for the project within the range specified in the permit application. The three turbine models are current and updated models that have capacities within the specified range and are representative of the emission reductions achievable with combined cycle combustion technology. As stated in LPEC's application, all construction scenarios within the specified capacity range would utilize "Modern F-Class" combustion turbines combined with HRSG and other common additional features. PSD permit application at 5.1.

We also note that "combined cycle combustion turbines"—are described as a collective option in the PSD and Title V Permitting Guidance for Greenhouse Gases: "…combined cycle combustion turbines, which generally have higher efficiencies than simple cycle turbines, should be listed as options when an applicant proposes to construct a natural gas-fired facility."[4] We do not read the guidance to require that the entire universe of available combined cycle gas turbines (CCGTs) be listed (in Step 1) and differentiated (in Steps 2-5) as separate candidate control options.

When there are multiple control technology alternatives under consideration that result in essentially equivalent emissions, EPA has recommended that permit applicants exercise some judgment in deciding which alternatives to examine in detail in the subsequent steps of the top-down BACT process. *In re: Prairie State Generating Station*, 13 E.A.D. 1, 25 (EAB 2006) (quoting the NSR Workshop Manual at B.21-B.22). While this observation has been made in the context of determining whether it is necessary to examine technologies with equivalent performance beyond Step 2 of the top-down BACT process, a similar logic can be extended to the situation presented here where there are multiple models within a category of control technology identified as an option at Step 1 and each model has a comparable control efficiency. If the different models employ the same technology that has been demonstrated in practice, there is little value in assessing the technical feasibility of each model independently. Furthermore, the ranking of each model is not meaningful where the models employ the same technology and have comparable control efficiencies.

To illustrate the comparability of the three turbine models at issue here, we note that the commenter has argued that manufacturer's claims regarding efficient performance tend to be conservative by "0.5 to 1.0 percent." With this in mind, even taking the commenter's own data projections on efficiency into consideration (Comments at 5, "Table 1"), the expected differences in efficiency are no greater than the equipment manufacturer margins meant to allow for variations in manufacturing tolerances and test uncertainties. These differences are also mere fractions of the compliance margin. We agree with the commenter that variability between different manufacturers or models of the same type of technology should be considered when the differences are so appreciable that a model might be characterized as poorly designed or non-representative of the efficiency capabilities of the technology category. This is not the case here. As was stated in the SOB, the three turbine models under consideration are some of

[4] See PSD and Title V Permitting Guidance for Greenhouse Gases, March 2011, 29.

the most efficient CCGTs based on their lower heat rate in comparison to other models. SOB pg. 12. It bears noting that the GE 7FA turbine model that the commenter has characterized as being the "least efficient," and therefore unacceptable, model for consideration as a "Candidate BACT Technology" is precisely the turbine model contemplated for use in the permits recently issued for the 570 MW Palmdale Hybrid Power Project and the 590 MW LCRA Thomas Ferguson Plant. The commenter elsewhere touts the BACT limits established for those projects without taking issue with the turbine models being installed. Comments pp. 10-11. Thus, in all cases and turbine selection scenarios, we find that BACT will be based on efficient turbine design.

The Environmental Appeals Board has explained many times that BACT is a "site-specific determination resulting in the selection of an emission limitation that represents application of a control technology or methods appropriate for the particular facility." Russell City Energy Ctr., PSD Appeal Nos. 10-01 to 10-05, slip op. at 20 (EAB Nov. 18, 2010). In this case, we have proposed and received comments on BACT limits for a gas-fired combined cycle EGU that may use any of three turbine models, under what are essentially three contemplated capacity scenarios, in accordance with the submitted application. BACT itself is expressed as only an emission limitation, but our case-specific determination has appropriately accommodated the three different capacity scenarios within the range envisioned in the application.

Comment 3: The PSD provisions do not allow the permitting authority to select a higher emitting technology based on the applicant's preference of different turbine designs. The BACT requirement is defined as "the maximum degree of reduction for each pollutant…" LPEC's application identifies the Siemens SGT5-5000F(6) turbines as having the lowest GHG emissions on a CO_2e/MW-hr basis. Sierra Club asserted that even lower limits are achievable with the Alstom KA24-2 unit, which should provide the basis for setting the BACT limit.

Response:

As stated above in response to Comment 2, we disagree with the commenter's assertion that the different models of CCGTs are different technologies for purposes of this BACT analysis. The PSD provisions do not forbid permit terms and conditions that provide an applicant with the flexibility to consider factors independent of air quality permitting, like turbine capacity, in its selection among equipment vendors so long as the PSD requirements have been addressed and the public has been able to comment on all scenarios covered by the authorization to construct. As previously stated, each of the turbine models within the capacity range described in the application and addressed by the terms and conditions of the draft permit are representative of the efficiencies to be obtained from CCGT technology. Because the application describes the business purpose as supplying power within a specific capacity range, we have developed a case-specific limit appropriate to each scenario within that range.

Notwithstanding the commenter's assertions, we have no record basis to consider these particular turbine models to be "poor-to-average" performers among available turbine models in the size class. As we noted in our prior response, an emission limit based on the installation of the GE 7FA model has been selected as BACT in at least two other permitting decisions. Accordingly, we do not feel it is necessary to dictate selection of a particular turbine model or turbine capacity among three with comparable performance in the circumstances of this permit. We consider this approach to be consistent with EPA guidance and consistent with our obligations in establishing a case-specific BACT limit for a facility that accommodates the capacity range described in the permit application that will fulfill the applicant's business purpose. We address the commenter's assertion on Alstom KA24-2 more directly in response to Comment 6.

Comment 4: The Region must establish the "BACT limit foundation" by setting the limit based on the most energy efficient technology design. In this case, more efficient options were considered, but the draft permit improperly set the BACT limit based on the least-efficient turbine design. The SOB dismisses the importance of the efficiency differences in the turbine models. The SOB's statement that the three designs "are some of the most efficient combined cycle turbines" dismisses recognizable and achievable energy efficiency gains in a way that contradicts the GHG Guidance, which discusses how a "a more energy efficient technology burns less fuel than less energy efficient technology on a per unit of output basis."

Response:

Again, we disagree with the commenter's assertion that each CCGT model necessarily represents a distinct or different type of technology. While the commenter cites a discussion of the importance of energy efficiency in the GHG Guidance, the commenter omits the details of the supporting example, which is based on the comparative efficiencies between boilers designed to operate at supercritical steam conditions and those that are designed to operate at subcritical steam conditions.[5] This distinction is not similar to the distinctions that may be found between current, comparably efficient CCGTs. Thus, we disagree with the comment that the BACT analysis conducted in support of the permit contradicts the GHG Guidance.

We are also unsure what the phrase "BACT limit foundation" refers to. Insofar as BACT cannot be less stringent than any applicable standard of performance under the NSPS, see CAA 169(3), this concept is often referred to as the "BACT floor." If this is what the commenter means by "BACT limit foundation," we note that at the present time, EPA has not completed an NSPS establishing GHG standards that would apply to LPEC. Therefore, there is no BACT floor dictating the minimal level of stringency of the BACT limits in LPEC's permit. To the extent that comment refers to some other concept, we must dismiss the commenter's concern for lack of clarity.

Comment 5: The SOB's statement that the final selection of turbine design may be based on "other considerations [such as] capacity of the turbine, cost, reliability and predicted longevity" is irrelevant for purposes of the BACT analysis. Turbine vendors that can meet the GHG emission limit of the most energy efficient turbine model are free to compete for LPEC's business.[6]

Response:

The commenter appears to be conflating factors that the applicant appropriately may consider in choosing a turbine that meets the applicant's business purposes regarding capacity with factors EPA may consider in conducting a BACT analysis. The factors in the SOB cited by the commenter are considerations independent of air quality permitting that the applicant may consider in its ultimate

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[5] Supercritical and subcritical boilers are distinct boiler designs that operate at different steam pressures with an absolute efficiency difference of up to 2.3%. GHG Guidance at FN 52 and FN 82. The turbine models presented by the application, already highly efficient, cannot be so distinguished.

[6] The comment letter submitted for this draft permit contains references to an applicant and permitting authority not involved in this permitting action; it appears parts of the comment letter are based on similar comments submitted for a proposed EGU in Washington State. Here, we assume the commenter intended to refer to LPEC and not PSE (Puget Sound Energy) as stated in the text of the letter.

turbine selection decision among the efficient models identified as BACT. Given that the applicant has described its purpose as supplying power within a specific capacity range, we have accordingly used our discretion, within permit terms and conditions made available for public comment, to allow for the post-issuance selection of one of three efficient turbine models that have capacities within the desired range. We did not, as the commenter alleges, consider these factors "for purposes of the BACT analysis."

LPEC's permit is not the first PSD permit to afford the permit holder the flexibility to later choose between multiple turbine models. The RACT/BACT/LAER Clearinghouse illustrates that multiple permitting authorities have drafted and issued permits allowing for post-issuance selection of turbine models, including in cases where the selection would be consequential to the operative limits of the permit. See, e.g., RBLC IDs CA-1051, CA-1052, TX-0052, TX-0482, AZ-0049, FL-0203, OK-0070, NC-0095, OR-0027, OR-0033, PA-0278 (draft). In this permitting action, we similarly think it is reasonable to set case-specific BACT limits according to each turbine option that may be used to meet the business purpose described in the application.

Comment 6: The applicant states that the purpose of the project is to generate 637 to 735 MW of power. The Region's BACT analysis must consider the entire range of electric generation technologies that can meet this purpose. The 664 MW Alstom-KA24-2 design reflects the maximum degree of reduction and provides the applicable BACT emission limit (833 lb CO_2e/MWh(net)). LPEC is also close to the next size class of combined cycle gas turbine, so the Region should require the applicant to demonstrate that larger, more efficient designs are infeasible or would fundamentally change the project.

Response:

The application states more fully that the business purpose of the project for a new combined cycle EGU is to generate 637-735 MW of gross electrical power near the City of Harlingen, while increasing the reliability of the electrical supply for the state of Texas. CCGTs are a technology that maximizes energy efficiency relative to many other fossil fuel-fired EGUs, including--for example--simple cycle gas-fired turbines. The application presents the source as a combined cycle EGU that is intended to utilize locally available pipeline natural gas and available infrastructure to support delivery of the fuel in adequate volume and pressure to the facility. See Application at 2.1. All of the turbine model scenarios for which the draft permit has assigned output-based BACT limits are acceptable for meeting this business purpose and may be the appropriate basis for a BACT limit that will apply when the source is built and begins operation.

The commenter suggests the 664 MW Alstom KA24-2 turbine is the most efficient turbine. However, the comment provides no actual performance or technical data to support this conclusion. Table 1 of the comment letter lists Sierra Club's proposed BACT limits for candidate turbines. It is unclear how the commenter calculated the emission rates given in CO_2 lb/MWh. The commenter also provided an excel file as attachment A to the comment letter. This file shows data for numerous combustion turbines that includes emission rates in CO_2 lb/MWh. These values range from 691.5 - 2,222.1 CO_2 lbs/MWh(gross). The file also contains a column that provides the boiler/turbine manufacturer. Using the sort feature in the Excel spreadsheet provided by Sierra Club, it is possible to display only those facilities that have "Alstom" equipment. Three facilities are identified in the file as having Alstom equipment, Astoria Energy, Empire Generating Company, and Port Washington Generating Station. The emission rates for these three facilities ranged from 778 - 892 CO_2 lb/MWh(gross). As a result of the comments received from Sierra Club, EPA looked more closely at these facilities permits and found that all three had GE turbines equipped with Alstom heat recovery steam generators (HRSG), not Alstom turbines. Further, it is unclear from the data provided in Attachment A, which facilities have duct burners.

On the issue of requiring evaluation of the next turbine size class, we do not believe the commenter has furnished adequate grounds to make us question the project planning inherent in LPEC's application with regard to turbine class size. The BACT limits in the permit are based on a size class (Modern F-Class) appropriate to the basic business purpose described in the permit application. We decline to require a different project size or require that the source have different electric generating capacity than proposed in the application.

While nothing prevents this applicant or other applicants from considering and utilizing the particular turbine model that the commenter has characterized as having more favorable performance characteristics (based at least on heat rate and the commenter's projected CO2e/MWhr limit), we do not agree that the BACT analysis dictates emission limits from that particular turbine model or brand.

Finally, we note that EPA guidance emphasizes that energy efficiency should be considered in BACT determinations for all regulated NSR pollutants (not just GHGs). GHG Guidance at 21. Considering "the most energy efficient technologies in the BACT analysis helps reduce the products of combustion which includes not only GHGs but other regulated NSR pollutants (e.g., NOx, SO2, $PM/PM_{10}/PM_{2.5}$, CO, etc.)." While the commenter relies on a published source for performance specifications, the commenter has not furnished technical details that would distinguish the Alstom turbine or any other turbine in the size class as representing a different technology than turbines covered by the draft permit. As earlier stated, we consider the turbines covered by the draft permit to be comparably efficient and we do not believe the commenter has provided a sound basis to differentiate them for BACT purposes. EPA looked at the emission data attached to the submitted comments in CO_2 lb/MWh for facilities that are located in Texas, Louisiana, Mississippi, and Alabama. Looking at only these states, since they are likely to have similar meteorological, elevation, and other conditions (i.e., salty gulf air) to LPEC, the achieved emission rate range found was 766 - 2,222 CO_2 lb/MWh. The average value is 1,053 CO_2 lb/MWh and the median value is 977 CO_2 lb/MWh. EPA's proposed BACT limit for LPEC is comparable to the GHG BACT limit determinations that have already been made nationally for combined cycle combustion turbines for projects in this generation capacity range.

Comment 7: The BACT limits in the draft permit are skewed because the Region calculated the limits based on gross output rather than net output. "Net emission rates" are more appropriate because they account for all of the pollution emitted from the turbines and energy that is used on-site. Actual GHG emissions at LPEC will be significantly higher than the permitted limits, and the Region should set BACT limits based on net emission rates. Additionally, the commenter states that company websites and the 2012 Gas Turbine World Handbook provide different heat ratings than those provided by the applicant. The commenter requests that performance specifications be reviewed and updated, as necessary.

Response:

We disagree with this comment for several reasons. First, the proposed NSPS for fossil-fuel fired EGUs set standards of performance for combined-cycle plants based on gross output. To maintain consistency with the proposed NSPS, which will represent the BACT floor for future permitting decisions if finalized, we reasonably chose to set the proposed BACT limits for LPEC based on gross output as well. The proposed NSPS will be taking comments on the use of gross versus net. We also disagree with the commenter's assertion that a BACT limit based on gross output is "skewed" or would fail to account for all GHG emissions from the site (including whatever auxiliary equipment and pollution control equipment may count as emission units of GHGs). We further disagree with the commenter's assertion that actual GHG emissions at LPEC will be significantly higher than the permitted limits based on gross output. Recordkeeping requirements in the permit will assure that information on actual GHG emissions from the EGU are known and available for inspection. While a BACT limit based on gross output does not express the same type of facility performance information as a limit based on net output, it does not mean that total GHG emissions are unknown or unquantifiable (or that net emission rate performance could not be derived from available source data). We believe a limit based on gross output is simpler and more useful for purposes of making and understanding cross-comparisons among facilities, and will potentially simplify other aspects of permit administration. Data in this form may be more broadly available, as well, as demonstrated by the fact that the commenter has compiled and submitted CAMD CEMS annual performance data that is based on gross output. The permit requires monitoring and recordkeeping to account for all GHG emissions from the source.

For informational purposes only, the BACT limits expressed as "net" are shown in the table below.

Turbine Model	Net Heat Rate (Btu/kWh) (HHV) Without Duct Burner Firing	Output Based Emission Limit (lb CO_2/MWh) net without duct burning	Output Based Emission Limit (lb CO_2/MWh) net with duct burning
General Electric 7FA	7,527.5	894.7	945.2
Siemens SGT6-5000F(4)	7,649.0	909.2	944.4
Siemens SGT6-5000F(5)	7,771.7	923.7	965.7

We recognize that an examination of net emission rates may be useful for understanding and minimizing whatever GHG emissions may be attributable to on-site energy demands. In this case, the draft permit imposes maintenance requirements and other work practice standards in addition to the assigned BACT limit that will also serve to continuously promote the facility's efficiency from a net output standpoint.

We agree with the commenter on the importance of being clear and accurate on the heat rate information being utilized for the permitting action. We agree with the commenter's suggestion that manufacturer websites and third-party publications may be useful references for such information, but we ultimately and necessarily rely on applicant-submitted information regarding technical specifications unless we have reason to believe that it is invalid or not informed by contact with the original equipment manufacturers.[7] We are using Tables 5-1 through 5-3 of the permit application for site-specific heat rate information, and the applicant attested to the accuracy and reliability of the ratings data used in the permitting action.[8]

Comment 8: Some adjustment to the "new and clean" ISO emission rates may be appropriate for equipment variation, in-use degradation, part load performance, and duct firing if adequately supported in the record. The permit record provides no "information or citations to any independent or objective basis for the proposed adjustments." The proposed 12.3 percent compliance margin is excessive and unsupported. The "Gas Turbine World Handbook" explains that manufacturer performance

[7] Even the commenter-cited GTW Handbook (page 66) cautions that contact with original equipment manufacturers is a "must" for confirming the accuracy of ratings data.
[8] August 8, 2013 submittal from Larry Moon to Aimee Wilson. http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/la-paloma-response08082013.pdf

specifications are conservative and that higher, reasonable costs would enable "as much as a 1.5 percent gain in overall plant efficiency."

Response:

We appreciate the commenter's acknowledgement that the facility will not be able to operate without a reasonable compliance margin that makes assumptions for equipment variation, in-use degradation, and performance variability under less than ideal conditions (e.g., with respect to loading, temperature, and atmospheric pressure). In developing the appropriate compliance margin for the permit, we are guided by Environmental Appeals Board (EAB) precedent. The EAB has held that: "…PSD permit limits are not necessarily a direct translation of the lowest emissions rate that has been achieved by a particular technology at another facility, but [] those limits must also reflect consideration of any practical difficulties associated with using the control technology….[P]ermit writers retain discretion to set BACT levels that 'do not necessarily reflect the highest possible control efficiencies but, rather, will allow permittees to achieve compliance on a consistent basis.*"* *In re Newmont Nev. Energy Inv., LLC*, 12 E.A.D. at 441-42 (EAB) 2005) (internal citations omitted). The EAB has also emphasized the need for a compliance margin to reflect the considered judgment of the permit issuer and to be well-supported in the record. *In re Mississippi Lime Company*, PSD Appeal No. 11-01, Slip Op. at 26-33.
The GHG Guidance also recognizes that BACT limits should allow compliance on a consistent basis based on the particular circumstances of the technology and the facility at issue, and thus may consider a safety factor unique to those circumstances in setting a limit. GHG Guidance at 44. LPEC's permit requires BACT to be continuously met throughout the facility's life, and consistent with guidance, the compliance metrics employed under the permit terms shall utilize longer term averages as opposed to more conventional short-term averages (e.g., 3- or 24-hr rolling averages). GHG Guidance at 47.

We understand that there may be cases where a safety margin crosses the line from permissible to impermissible, and we share the commenter's concern that the compliance margin for this permit not be set in a way that is inappropriately large. Mississippi Lime at 27. At the same time, even with several GHG BACT determinations for CCGTs and known performance data from existing CCGTs available, we lack the best data points—namely long-term performance data for facilities operating under a GHG BACT limit—to account for uncertainties in how the compliance margin should be set. As data becomes more available in the coming years, we expect that better, more refined understandings of the appropriate compliance margins for this facility type will be developed. We also believe the safety factor needs to be assessed somewhat differently in cases such as LPEC's, where the GHG BACT limit is not based on add-on controls that may be adjusted and improved as necessary over the life of a facility.

The commenter has criticized the proposed 12.3 percent compliance margin as being excessive and unsupported. In general, EPA Region 6 has allowed up to a combined margin of 12.3 percent, and we have seen similar margins utilized by other EPA Regions and State permitting authorities. We looked at compliance margins that have been applied to other draft or finalized GHG BACT determinations for gas-fired combustion turbines. While our safety margin is at the higher end of the range of safety margins applied to similar projects, we believe it is technically supported (see the responses to Comments 9-11) and not inappropriately large.

In the GHG PSD Permits issued by Region 6 for Calpine (for Deer Park and Channel Energy) we adjusted the heat rate limit for their turbines using a 3.3 percent design margin reflecting the possibility that the constructed facility would not be able to achieve the design heat rate, a 6 percent performance margin reflecting efficiency losses due to equipment degradation prior to maintenance overhauls, and a

3 percent degradation margin reflecting the variability in operation of auxiliary plant equipment due to use over time. LPEC proposed these same margins in its permit application, and after careful review, we have concluded that they are supported by the record in this case.

Similarly, the Virginia Department of Environmental Quality used compliance margins when Green Energy Partners/Stonewall determined the base heat rate for their proposed turbines. These margins included a 3.4 percent performance margin reflecting the efficiency losses due to permanent and recoverable combustion turbine degradation, a 1.2 percent degradation margin reflecting operational variation and auxiliary power degradation, and a 7.1 percent degradation margin reflecting the energy losses over time of the steam turbine system including, but not limited to CT gas performance. These margins add up to 11.7 percent.

In addition, EPA Region 1 issued permit number 052-042-MA14 to Pioneer Valley Energy Center (PVEC) in Westfield, MA, which utilized compliance margins in determining a BACT limit for a CCGT. EPA Region 1 established an emission limit for PVEC that would only apply during the initial stack test, and established a BACT limit that could be met for the life of the plant that accounted for degradation and other factors that are not controlled by PVEC. In the fact sheet[9] for the permit, EPA Region 1 outlined the factors that influence turbine efficiency over time. They state, "EPA expects a decrease in efficiency of 2.5% over time for a well-operated turbine."[10] EPA Region 1 also states, "The actual effect of temperature on a combined cycle turbine will vary depending on the turbine's design. The variation can be as much as 10%."[11] EPA Region 1 determined that "BACT is met by an emissions limit that is 8.5% higher than the corrected value which must be met during the initial test."

Another example is the Russell City Energy Center (RCEC) permit issued by the Bay Area Air Quality Management District (BAAQMD). BAAQMD adjusted the design base heat rate limit for the turbines using a 3.3 percent design margin reflecting the possibility that the constructed facility would not be able to achieve the design heat rate. BAAQMD then allowed a 6 percent performance margin reflecting efficiency losses due to equipment degradation prior to maintenance overhauls, and a 3 percent degradation margin to account for potential degradation associated with various uncertainties regarding facility operation, such as variation in natural gas pressure and quality, variability in cooling water quality, degradation in turbine exhaust flow, and degradation in heat recovery boilers and steam turbine. These margins (later upheld under challenge before the EAB) are identical to those that we believe are appropriate for LPEC.

A final example, for a permit also reviewed by the EAB, is Pio Pico Energy Center issued this year by EPA Region 9. In this case, EPA Region 9 allowed the use of three margins totaling 7.4 percent. EPA Region 9 used a 1.4 percent margin to account for variability in turbine performance due to changes in the ambient conditions, a 3 percent margin for the variability in the new unit (due to variations in the manufacturing, assembly, construction, and actual performance), and a 3 percent margin for degradation in performance over time.

[9] EPA Region 1 fact sheet for PVEC is available at http://www.epa.gov/region1/communities/pdf/PioneerValley/FactSheet.pdf

[10] "Combined-cycle Gas & Steam Turbine Power Plants" by Rolf Kehlhofer.

[11] "Thermodynamic performance analysis of gas-turbine power-plant" by M.M. Rahman. Available at http://www.academicjournals.org/ijps/PDF/pdf2011/18Jul/Rahman%20et%20al.pdf

Consistent with these actions and for the reasons we provide below in response to Comments 9-11, we believe that the safety margin in the draft permit is acceptable and will allow La Paloma to achieve compliance on a consistent basis.

Comment 9: There is no basis for the Region to allow a 3.3 percent compliance margin to account for a shortfall in the design heat rate. The 2012 Gas Turbine World Handbook advises that manufacturers' ratings tend to be conservative by 0.5 to 1.0 percent. A 3.3 percent shortfall in heat rate would cost over $9.5 million per year, or $250 million over the life of the facility in added fuel costs, which illustrates how manufacturers could risk liability for underperformance of their units. If anything, vendor specifications are inherently conservative and actual performance will be more efficient.

Response:

At the outset, we do not understand manufacturer performance ratings to be directly comparable to "vendor specifications," as the latter term may be more specifically used in the market for pollution control devices. While we recognize that manufactured turbines are designed to meet customer performance specifications, corrected to ISO conditions, they are not necessarily specified to meet and comply with particular GHG emission control rates. If manufacturer performance guarantees specific to long-term compliance with GHG emission limitations were available, they would be welcome and potentially useful to the development of appropriate BACT limits.

While the design base heat rate reflects what the engineers aim to achieve in designing the facility, the design and construction of a combined-cycle power plant involves many assumptions about anticipated performance of the many elements of the plant, which are often imprecise or not reflective of conditions once installed at the site. As a consequence, LPEC calculates an "Installed Base Heat Rate," (see page 49 of the application) which represents a design margin of 3.3 percent to address such items as equipment underperformance and short-term degradation. According to information provided by LPEC, a design margin of up to 5 percent is typical in the commercial terms for the engineering, procurement, and construction contracts for a combined-cycle power plant.[12] Normally, the performance guarantees from the combustion and steam turbine original equipment manufacturers and the contractual terms require demonstration that the project, as constructed, achieves the design output and heat rate, subject to a plus or minus 5 percent margin. For example, if the tested output is more than 95 percent of the guaranteed output, or the tested heat rate is less than 105 percent of guaranteed heat rate, the original equipment manufacturer and engineering, procurement, and construction contractor can declare substantial completion and pay liquidated damages to compensate for the performance shortfalls. The design margin also reflects some tolerance for uncertainties associated with the plant's auxiliary load. EPA has reduced the 5 percent design margin to 3.3 percent. This reduction is based on LPEC's assertion that with their expertise and experience in combined cycle power plant construction, they have confidence in a reduced margin, requesting a 3.3 percent margin in their permit application. The portion of our compliance margin attributable to shortfalls in the design heat rate takes proper account of vendor specifications as well as performance guarantees. In our considered judgment we do not find a basis to adjust it further downward.

Comment 10: The performance compliance margin of 6 percent for "anticipated degradation of the equipment over time between regular maintenance cycles" is far too high. Even 3 percent is likely to be

[12] This information is verified from supplemental documentation provided by the applicant on August 8, 2013. http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/la-paloma-response08082013.pdf It also corresponds with information utilized by BAAQMD in issuing a permit to Russell City Energy Center.

too high for newly designed and constructed units that employ efficient designs. The Region needs to consider more detailed information, such as CAMD data, to ascertain the extent to which top-performing units experience the assigned degradation factor. The record must demonstrate that a degradation factor is necessary and appropriate and represents the reasonable and unavoidable degradation of the facility.

Response:

The performance margin for equipment degradation relates to the combustion turbine and steam turbine generators. On August 8, 2013, LPEC submitted supporting documentation for the proposed performance compliance margin of 6 percent. LPEC cites California Energy Commission publication CEC-200-2010-002; Cost of Generation Model Users Guide Version 2 dated March of 2010. Figure 24 of this publication provides a clear illustration of the performance degradation of combustion turbines through the life of the unit. This "sawtooth curve" indicates the potential degradation and performance recovery following major service. This publication also references GE Technical Bulletin GER-3567H; GE Gas Turbine Performance Characteristics, which states, "Typically, performance degradation during the first 24,000 hours (the normally recommended interval for the hot gas path inspection) is 2% to 6%." The sawtooth curve in the CEC publication uses the view that the degradation will be limited to 2 percent between inspections and that 75 percent of that performance will be recovered resulting in a 20-year degradation of 4.5 percent. Moreover, according to quoted vendor documentation,[13] the anticipated recoverable and non-recoverable degradation in heat rate between major maintenance overhauls is approximately 5.2 percent. The 5.2 percent figure represents the average, and not the maximum or guaranteed rate of degradation for gas turbines. Considering the atmospheric conditions, high heat, humidity, and semi-corrosive salt air at the project location, LPEC has taken a slightly more conservative view of this degradation. LPEC projects the potential degradation to be 3 percent between inspections (considerably less than the potential 6 percent) and assuming the same 75 percent performance recovery, calculated a 20-year degradation of 6.0 percent. EPA has determined that, for the purposes of deriving an enforceable BACT limitation on the proposed facility's heat rate, gas turbine degradation may reasonably be estimated at 6%. We recognize uncertainties in the estimation of degradation and this is only part of a larger compliance margin with uncertainties of its own. The commenter has not provided any detail on how CAMD data could be meaningfully utilized. It would not appear to be statistically sound to attribute variability in CAMD data to performance degradation because the performance data is influenced by many factors (capacity, turbine model, meteorological conditions, maintenance programs, etc.) and as illustrated here is only a fraction of the compliance margin.

Comment 11: The 3 percent degradation margin to reflect the variability in operation of auxiliary plant equipment due to use over time is not supported and should be eliminated. The margin purports to account for "other elements" of the EGU, but wrongly assumes these elements will cause plant-wide degradation of 3 percent. "Ancillary equipment" consumes only 3-4 percent of the gross generation total, so the degradation of auxiliary plant equipment could not cause an additional 3 percent loss in overall plant efficiency.

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[13] Responses to Public Comments on Draft Federal Prevention of Significant Deterioration Permit Russell City Energy Center, February 2010, Bay Area Air Quality Management District Application Number 15487. http://www.baaqmd.gov/~/media/Files/Engineering/Public%20Notices/2010/15487/PSD%20Permit/B3161_nsr_15487_res-com_020410.ashx?la=en

Response:

Degradation of auxiliary plant equipment does cause losses of overall plant efficiency and is not related to that equipment's consumption of generated electrical output (parasitic load). The degradation margin for the auxiliary plant equipment also encompasses the heat recovery steam generators (HRSGs). This accounts for the scaling and corrosion of the boiler tubes over time as well as minor potential fouling of the heating surface of the tubes. Similar to the HRSGs, scaling and corrosion of the condenser tubes will also degrade the heat transfer characteristics and thus the performance of the steam turbine generator. Given that combustion turbine degradation accounts for the majority of the performance loss, as well as the large variation in operating parameters (fuels, temperatures, water treatment, cycling conditions, etc.), little operating data has been gathered and published that illustrate a clear performance degradation characteristic. According to some quoted manufacturer estimates, [14] the degradation curves predict a recoverable and non-recoverable degradation in gas turbine exhaust flow of 3.75 percent over the 48,000 hour maintenance cycle. This reduction of turbine exhaust flow affects the performance of the HRSG. Accordingly the effects of the degradation must be accounted for, and EPA has allowed similar 3 percent degradation margins for auxiliary plant equipment in other permits; see the LCRA Thomas C. Ferguson CCPP in Horseshoe Bay, Texas Permit Number PSD-TX-1244-GHG[15] and the Russell City Energy Center in Hayward, California Permit Number 15487.[16] EPA has determined in its engineering judgment that a 3 percent degradation margin for auxiliary plant equipment is a reasonable and appropriate estimate for this permitting action.

Comment 12: The permit should rely on in-use emissions data for efficient CCGTs in determining the achievable BACT limit. In-use emissions data for the M501G turbines correlates well with the "new and clean" rate, plus a 10 percent compliance margin.

Response:

We agree that the experience of other sources, including performance data, may be useful in considering what emission limit represents BACT and can be helpful in evaluating whether limits can be achieved and complied with on a continuous basis. Performance data, particularly for units operating and complying with GHG BACT emission limits, will likely be increasingly available and valuable for determining future GHG BACT limits. We also recognize that manufacturer's data, engineering estimates, and the most recent regulatory decisions may be useful in arriving at an appropriate GHG BACT determination. In fact, all three of these types of information were used in developing the proposed BACT limits for this permit. The suggested 10 percent compliance margin is not appreciably different from the 12.3 percent margin we are using and appears to be consistent with our discussion in response to Comment 8.

After reviewing the performance data and accompanying arguments concerning that data that the commenter has submitted, we continue to believe that our proposed emission limits are appropriate BACT for LPEC's site specific conditions. In fact, the recent performance data for CCGTs in Texas

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[14] Responses to Public Comments on Draft Federal Prevention of Significant Deterioration Permit Russell City Energy Center, February 2010, Bay Area Air Quality Management District Application Number 15487. http://www.baaqmd.gov/~/media/Files/Engineering/Public%20Notices/2010/15487/PSD%20Permit/B3161_nsr_15487_res-com_020410.ashx?la=en

[15] Permit available at http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/lcra_final_permit.pdf

[16] Permit available at http://www.baaqmd.gov/~/media/Files/Engineering/Public%20Notices/2010/15487/PSD%20Permit/B3161_nsr_15487_psd-permit_020410.ashx?la=en

submitted by the commenter as Attachment A supports, rather than refutes, our conclusion. For more details, see our response to Comment 15.

At the same time, we question the comparability of the facilities in Table 2 of the comment letter that the commenter has identified as being “low emitting CCGTs”. The table is based on data they have gathered from CAMD CEMS Annual Data. Since gas turbines need air for their appropriate function, it is important to note that large gas turbine performance can be changed by any site specific parameters that affect the density and/or mass flow of the air intake to the compressor. Typical ambient conditions from referenced ISO conditions are typically 59 F/15 C and 14.7 psia/1.013 bar. Every turbine model has its own projected temperature-effect curve which can be dependent on cycle parameters and internal component efficiencies as well as mass air flow. It is important to note that ambient air temperatures potentially affect turbine output, heat rate, heat consumption, and exhaust flow. Other parameters such as humidity also affects output and heat rate. This may be further impacted in larger turbines for water makeup and/or steam injection for NOx control. Simply providing data for a select number of facilities with combustion turbines in Table 2 does not account for different meteorological conditions where those turbines are being operated, and certainly in turn does not account for the site specific conditions that will affect LPEC’s operation and the efficiency of their proposed turbines.

Comment 13: The use of supplemental duct burners will result in additional emissions and reduce efficiency of the facility. Adjustments for this were added to the 12.3 percent compliance adjustment, but this is flawed. The BACT analysis should consider alternatives to duct burners including battery storage, a small combustion turbine, or using the auxiliary boiler for supplemental steam. The heat rate from duct burning is approximately the same, or worse, than the efficiency of new internal combustion engine generators. There are numerous alternatives not addressed in the permit record.

Response:

Duct burning involves burning additional natural gas in the ducts to the heat recovery boiler, which increases the temperature of the exhaust coming from the combustion turbines and thereby creates additional steam for the steam turbines. The duct burner firing provides additional power generation capacity during periods of high electrical demand. The installation of duct burners in the HRSG is a common practice where there is a potential need for additional or supplemental power during specific operating conditions or electrical grid requirements. The installation of the duct burners will increase the cost of the HRSG by 10 percent to 15 percent, which represents less than a 1 percent increase in the cost of the project. More important to the emissions discussion, the efficiency of supplementary firing is significantly higher than that of a stand-alone auxiliary boiler. While the facility will have a boiler, it will only operate for CCGT startups and is effectively a stand-alone auxiliary boiler and will not be available for supplementary firing. The document “Technology Characterization: Gas Turbines,” prepared for the Environmental Protection Agency Climate Protection Partnership Division by Energy and Environmental Analysis, provides the following discussion regarding supplemental firing:

Since very little of the available oxygen in the turbine air flow is used in the combustion process, the oxygen content in the gas turbine exhaust permits supplementary fuel firing ahead of the HRSG to increase steam production relative to and [sic] *unfired unit. Supplementary firing can raise the exhaust gas temperature entering the HRSG up to 1,800 deg. F and increase the amount of steam produced by the unit by a factor of two. Moreover, since the turbine exhaust gas is essentially preheated combustion air, the fuel consumed in the supplementary firing is less than that required for a stand-alone boiler* *providing the same increment in steam generation. The HHV efficiency of incremental steam production from supplementary firing above that of an unfired HRSG is often 85% or more when firing natural gas.*

Duct burning is an efficient way of generating additional power to meet peak demand from the combustion turbine exhaust. While supplemental duct burners do add additional emissions, they also produce additional electrical output to the grid. Duct burners provide electrical output at a lower capital cost. The addition of duct burners provides the benefit of greater plant output, better control of plant thermal efficiency, more efficient process steam production, steam production at reduced gas turbine load, and can compensate for changing ambient conditions.[17] The comment is not clear on whether the listed alternatives are for supplemental steam or self-standing peak energy production. We understand the suggestion on use of an auxiliary boiler to be for supplemental steam production, but we reject it for not being as efficient as supplemental duct firing. The commenter has not demonstrated that any of the alternatives for supplemental steam provide the same operational capabilities and control in response to periods of high electrical demand. To the extent that the commenter is suggesting alternatives in the form of independent peak power production we are unable to meaningfully respond because the comment is vague and would appear to implicate alternatives that would redefine the source.

Comment 14: The calculation of the BACT limits is inconsistent with the draft permit's compliance monitoring provisions. The SOB calculates the BACT limit to include duct firing, but the initial performance testing would occur without duct burner firing. This discrepancy demonstrates the adjustment for duct firing is improper.

Response:

The permit will be revised to clarify that the BACT limit and the initial performance testing both take account of duct burner firing. The BACT limits include emissions from duct burner firing and emissions from combustion of fuel in the turbines. The initial compliance test requires the duct burners to be firing. Permit condition VI.D. states: "The turbine shall be tested at or above ninety percent (90%) of maximum load operations for the atmospheric conditions which exist during testing. The duct burners shall be tested at their maximum firing rate[18] within the mechanical limits of the equipment for the atmospheric conditions which exists during the performance test while the turbine is operating as close to base load as possible. The tested turbine load shall be identified in the sampling report. The permit holder shall present in the performance test protocol the manner in which stack sampling will be executed in order to demonstrate compliance with the emissions limits contained in Section II." The permit condition the commenter referred to, III.A.1.a., contained an error and shall be corrected to state:

"To determine this BACT emission limit, Permittee shall calculate the limit based on the measured hourly energy output MWh(gross), while the CTG is operating at or above 90% of its design capacity without maximum duct burnering firing and the results shall be corrected to ISO conditions (59^{o}F, 14.7 psia, and 67% humidity)."

Comment 15: The compliance margins proposed for the draft permit are so large that every CCGT design in the size range sought by the applicant, including the oldest and least efficient designs, would

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[17] "Heat Recovery Steam Generators Design Options and Benefits", James Hunt, January 5, 2008; *Cogeneration & On-Site Power Production*. Available at http://www.cospp.com/articles/print/volume-9/issue-3/features/heat-recovery-steam-generators-design-options-and-benefits.html

[18] The proposed permit stated "its" and not "their" maximum firing rating. We are making a minor grammatical correction to use the plural form in the final permit.

be able to comply with the proposed BACT emission limit for the GE Model 7FA turbine of 934.5 lb CO_2/MWh. In providing a compliance margin to address operating conditions, there is a real risk that the BACT limits no longer serve the purpose of requiring the use of the best available control technology. One solution is to apply a "new and clean" emission rate where compliance is established at the time of the start of commercial operations. A new and clean emission rate would be based on the manufacturer's published ratings. Testing would be conducted at full rated load and as close to ISO conditions as reasonably possible. Thereafter, a separate, rolling annual emission limit would be enforced to assure that the unit is maintained and operated in an efficient manner.

Response:

We intend to issue a permit that will allow LPEC to comply with an appropriate BACT limit on a consistent basis. Compliance will be demonstrated through various measures, including appropriate recordkeeping and reporting procedures. Whether the BACT limits could be achieved by other sources is not material to the determination of BACT for this source. Moreover, the commenter's assertion that the BACT limits would accommodate even the oldest and least efficient designs is not only largely unsupported, but highly unlikely given the sizeable and steady heat rate improvements for gas-fired turbines that have been made just in the last decade.[19] It is also important to note that the BACT limits established by EPA in the draft permit must be met over the multi-decade life of the facility, which necessarily includes anticipated degradation of mechanical performance that may not be fully recovered even by the best maintenance practices. See our earlier response to Comment 10.

The commenter also submitted performance data to support its assertions, but our review reveals that the data actually contradicts the commenter's position. For example, we considered the 2011 CEMS data from CAMD, expressed as lbs of CO_2/MWh gross, for Texas combined-cycle EGUs (which likely experience similar deviations from ISO conditions that would be expected in Harlingen, TX). The data for ten out of the fifteen CCGTs for that year indicates that they emitted at a rate above the proposed 934.5 lb CO_2e/MWh limit (for the GE7FA Turbine model). Moreover, because these CCGTs were installed relatively recently, in the 2006-2008 timeframe, their performance will potentially degrade further in future years of operation. It therefore appears that not every CCGT in the size and range would be able to comply with the proposed BACT limit. This supports our conclusion that the BACT limit, including its safety margin, is appropriately stringent in this case.

Facility Name	Date Permit Issued/Model	Gross Load MWh	CO_2 tons	CO_2 ton/MWh	CO_2 lb/MWh
Nueces Bay – EPN:8	2008 – GE 7FA	1,093,548	474,830.57	0.434	868
Nueces Bay – EPN: 9	2008 – GE 7FA	1,092,722	474,132.62	0.434	868
Barney M. Davis – EPN: 4	2008 – GE 7FA	1,081,929	480,942.45	0.444	889
Brazos Electric Power - Jack County Generation Facility – EPN: CT-4	2008 – GE 7FA	500,344	256,032.5	0.512	1,023

[19] F Class Turbines became commercially available in the early 1990s with routine evolutionary upgrades to thermal performance. See, e.g., Dr. Justin Zachary, "Turbine Technology Maturity: A Shifting Paradigm," *Power*, 2008, http://www.powermag.com/issues/features/Turbine-technology-maturity-A-shifting-paradigm_68_p2.html.

Facility Name	Date Permit Issued/Model	Gross Load MWh	CO_2 tons	CO_2 ton/MWh	CO_2 lb/MWh
Brazos Electric Power - Jack County Generation Facility – EPN: CT-3	2008 – GE 7FA	552,802	284,545.59	0.515	1,029
Barney M. Davis – EPN: 3	2008 – GE 7FA	1,064,646	491,149.84	0.461	923
Victoria Power Station – EPN: 9	2008 - MH1501F	624,568	286,319.35	0.458	917
Colorado Bend Energy Center – EPN: CT1B	2006 – GE Model PG 7121EA	390,451	187,164.29	0.479	959
Colorado Bend Energy Center – EPN: CT1A	2006 – GE Model PG 7121EA	374,549	183,007.71	0.489	977
Navasota Odessa Energy Partners - Quail Run Energy Center – EPN: CT1A	2007 – GE model PG 7121EA	182,842	99,562.42	0.544	1,089
Paris Energy Center – EPN: HRSG1	GE 7EA	190,186	104,562.82	0.550	1,100
Paris Energy Center – EPN: HRSG2	GE 7EA	190,100	102,457.68	0.539	1,078
Navasota Odessa Energy Partners - Quail Run Energy Center – EPN: CT1B	2007 – GE model PG 7121EA	174,277	89,264.31	0.512	1,024
NRG Cedar Bayou 4 – EPN: CBY41	2007 – Siemens SGT6-5000F	104,128	66,737.02	0.641	1,282
NRG Cedar Bayou 4 – EPN: CBY41	2007 – Siemens SGT6-5000F	98,587	62,945.85	0.638	1,277

We appreciate the commenter's suggestion that the permit set a "new and clean" initial limit. If we correctly understand the commenter's proposal, a similar route was followed in the permit that EPA Region 1 issued to Pioneer Valley. In response to this suggestion, we reviewed our draft permit terms and conditions for initial compliance testing and believe they are appropriate and will meet the goal of allowing the source, regulatory authorities, and the public to verify that the source will be performing within the BACT limits. If LPEC obtains a formal performance verification of its design rating with the original equipment manufacturer, we expect that information to also be kept on file and used, as appropriate, in the analysis of the initial compliance testing results. The PVEC permit had an initial emission limit of 825 lb CO_2e/MWh(grid) that would only apply during the initial stack test. [20] For ongoing compliance, the PVEC permit establishes an 895 lb CO_2e/MWh(grid) emission limit, which is 70 lbs CO_2e/MWh(grid) higher than the initial stack test emission limit . The 895 lb CO_2e/MWh(grid)

[20] Page 24 of the Fact Sheet for the Pioneer Valley Energy Center Permit Number 052-042-MA14 issued by U.S. EPA Region 1. http://www.epa.gov/region1/communities/pdf/PioneerValley/FactSheet.pdf

emission limit is met beginning at 365 days after startup. However, we decline to specifically assign an "initial emission limit" or a "new and clean limit" for LPEC because it is not equivalent to or required for establishing a BACT limit.

Comment 16: The Region did not adequately explain why the site-specific conditions at LPEC prevent the facility from using a solar-thermal hybrid configuration and from achieving similar emissions to those permitted for the Palmdale Hybrid Power Project (PHPP).

Response:

The PSD permit for the PHPP in Palmdale, California incorporated solar power generation into the BACT analysis, but that determination expressly stated that it did not imply that other sources must necessarily consider alternative scenarios involving renewable generation in their BACT analyses. In the particular case of the PHPP, the solar component was part of the applicant's project as defined in the permit application. Therefore, the permit's requirement that PHPP construct the solar component as a requirement for BACT did not fundamentally redefine the source. In this case, the permit applicant did not include renewable generation in its project purpose, so we are not required to consider the various ways in which solar thermal generating equipment could possibly be integrated into the plans for LPEC. While such equipment may be viably employed to enhance overall thermal efficiency, we decline to require its evaluation here, believing that to do so would constitute redefining the source.

Comment 17: The Pioneer Valley Energy Center (PVEC) was identified as more likely to operate at baseload conditions, while LPEC will operate as a load cycling unit. However, neither the draft permit nor the application require LPEC to operate as a load cycling unit and there is no justification for setting emission rates that differ from PVEC based on a different level of operation. The draft permit allows operation at full load for 8,260 hours per year and 500 hours of startup, shutdown, and maintenance, which is "not consistent with the assumption that the plant will operate on a limited basis as a load cycling facility."

Response:

The regulation of electricity in Texas creates indeterminacy regarding LPECs future customer base and creates a greater need to accommodate flexibility and uncertainty in its planned operating capabilities compared to EGU project development common to other states.[21] The Electric Reliability Council of Texas (ERCOT) manages the flow of electric power to 23 million Texas customers, representing 85 percent of the state's electric load. As the independent system operator for the region, ERCOT schedules power on an electric grid. ERCOT dispatches power plants based on capacity, heat rate, and efficiency. LPEC engaged a consulting firm to prepare dispatch studies that considered the capacity and heat rates of the current assets on the electrical grid and compared them to LPEC to forecast the proposed facility's order in ERCOT's dispatch queue. LPEC anticipates that the new facility will have sufficient capacity at a high enough efficiency that ERCOT will dispatch its generation as base load.[22]

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[21] Texas has its own agencies that are tasked to assess the State's short- and long- term energy needs and jurisdiction over planning and policy for the provision of electricity. A 2013 report to the state legislature provides further background information. "Report to the 83rd Texas Legislature: Scope of Competition in Electric Markets in Texas, Public Utility Commission of Texas, January 2013, available at http://www.puc.texas.gov/industry/electric/reports/scope/2013/2013scope_elec.pdf.

[22] Email from Scot Stringfellow to Aimee Wilson on February 8, 2013. http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/la-paloma-email020813.pdf

However, there may be other factors that affect the operation of the electrical grid that LPEC cannot effectively forecast and model, such as climate and weather patterns, the addition of future generation resources, population/growth patterns, etc. Additionally, it is ultimately the grid operator's decision to dispatch generation to best serve the demand and ensure the stability of the system. It is for this reason that LPEC's plans include the operational flexibility of a load cycling unit. Once LPEC receives a Standard Generation Interconnection Agreement (SGIA) with its respective Transmission Service Provider (TSP) and has an issued air quality permit, ERCOT will include the facility in the "Capacity, Demand and Reserves Report." Once this occurs, LPEC will have a better understanding of the anticipated dispatch operation. LPEC will need to be able to meet any dispatch load requirements with ERCOT and to be able to also operate "on demand" as ordered by ERCOT to supply electricity during periods of a shortfall due to temporary outages of other EGUs or due to weather extremes. We also note that Texas has relatively high demand for air conditioning for its summer season, so it is not unreasonable to expect that LPEC will operate under different conditions than PVEC.

LPEC's permit does not require it to operate on a limited basis, so it does have the flexibility to operate under baseload conditions and less than baseload conditions, provided it meets the BACT limits. LPEC has not fully confirmed the details of its electricity customer base, but LPEC's November 1, 2012 submittal[23] and email dated February 8, 2013[24] indicates that LPEC intends to be a "base load" EGU in contrast to a "load following" EGU, which may shut down or curtail output when demand for electricity is lowest. We note and agree with LPEC's statement in its application that "operating an [EGU] as a base load is more efficient than operating as a load cycling unit to respond to fluctuations in customer electricity or steam demands." We also agree with the applicant's observation that efficiencies will vary based on geographic variance from ISO conditions and variability in turbine, HRSG, and steam turbine designs. As a result, the LPEC and PVEC facilities likely will have different performance rates and their future performance data will be reflective of their different designs and other factors reflected in their BACT limits.

We acknowledge that PVEC has a lower initial emission limit (which only is met during the initial stack testing and is not established as a BACT limit to be met during normal operation), but we do not agree with the commenter's assertion that this limit is "much lower" or "far below" the proposed BACT limits for LPEC. Contrary to the commenter's assertion that the PVEC permit has a "much lower permitted GHG BACT limit," LPEC would have a lower long-term BACT limit were it not for the duct burners; the PVEC facility does not have duct burners. Assuming no duct burner firing at LPEC, the BACT limits would range from 875 lbs CO_2e/MWh to 887.7 lbs CO_2e/MWh depending on the turbine selected[25]. The long-term BACT limit for PVEC is 895 lbs CO_2e/MWh. Consequently, the BACT limits for LPEC are largely equivalent, if not more efficient, than the PVEC's BACT limit.

Because LPEC may operate on a full-time base-load basis, LPEC has not requested limits on operational capacity in its permit, and we believe the draft permit assigns the appropriate BACT limits for a reasonable range of load operations. We are not placing operation limits in the permit that would limit LPEC's operational flexibility by forcing it to operate "on a limited basis as a load cycling facility."

[23] Submittal dated November 1, 2012 from Larry Moon to Aimee Wilson. http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/la-paloma-resp2questions11-01-2012.pdf
[24] Email from Scott Stringfellow to Aimee Wilson dated February 8, 2013. http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/la-paloma-email020813.pdf
[25] These values can be found in Tables 51-, 5-2, and 5-3 of the application.

Comment 18: LPEC has a higher heat rate than all the other projects cited in the SOB. The BACT limits are not comparable to these lower limits. There are no site-specific reasons explaining why LPEC cannot meet the lower limits established in numerous other BACT determinations. The Region cannot justify and has not defined its assertion that the proposed BACT limits for LPEC are comparable.

Response:

We disagree with the commenter. While the electrical output of the proposed LPEC facility is greater than other facilities in the table below, we find that the heat rate for the LPEC turbines is comparable to, if not better than, the heat rates indicated in other combined cycle-power plants' permitting records. Heat rate is a common measure of system efficiency in a steam power plant. It is defined as the energy input to a system, typically in Btu/kWh, divided by the electricity generated, in kW. Efficiency is measured by taking the useful output energy and dividing it by the input energy. Heat rate is the inverse of efficiency. Increasing plant efficiency lowers the heat rate.

LPEC's heat rate is not higher than the other projects identified in the SOB, as illustrated in the table below. The two Calpine facilities in Texas both have a net heat rate of 7,730 Btu/kWh without duct burner firing. This is higher than the net heat rate for LPEC without duct burner firing for two of the three proposed turbines. LPEC's net heat rate would be between 7,527.5 and 7,771.7 Btu/kWh without duct burner firing depending on which turbine is selected (see response to Comment 7 above). The Siemens SGT6-5000F(5) turbine is the only one of the three proposed that has a heat rate higher than the Calpine facilities. Also, the BACT limits for LPEC (if converted to net) without duct burner firing are lower than the BACT limits for both Calpine facilities, except for the limit for the Siemens SGT6-5000F(5) turbine. The BACT limits for LPEC would be 0.447 to 0.462 tons CO_2/MWh (net) without duct burner firing depending on which turbine is selected. Based on this information, LPEC has a lower (more efficient) heat rate than both Calpine locations in Texas, if LPEC selects the GE7FA or Siemens SGT6-5000F(4) turbine models.

LPEC also has a lower heat rate than the Lower Colorado River Authority (LCRA) facility. LCRA has a heat rate limit of 7,720 Btu/kWh (net) without duct burners. This is lower than the net heat rate without duct burner firing for LPEC if the Siemens SGT6-5000F(5) turbine is selected which has a net heat rate of 7,771.7 Btu/kWh. The heat rate for the GE 7FA and Siemens SGT6-5000F(4) turbines are lower at 7,527.5 and 7,649 Btu/kWh, respectively. The BACT limit for LCRA is 0.459 tons CO_2/MWh (net), whereas LPEC's limit, when similarly converted, would be 0.447 to 0.462 tons CO_2/MWh (net) without duct burner firing, depending on which turbine is selected). Based on this information, LPEC is more efficient than LCRA if LPEC selects the GE7FA or Siemens SGT6-5000F(4) turbine models.

As shown in the table below, the LPEC facility is also comparable to other permitted facilities and the BACT limits proposed for LPEC are as stringent as the comparable facilities.

Company/Location	MW Capacity	Combustion Turbine Heat Rate (Btu/kWh)	BACT Limit
La Paloma Energy Center Harlingen, TX	General Electric 7FA – 637 MW Siemens SGT6-5000F(4) – 681 MW Siemens SGT6-	General Electric 7FA - 6,674 Btu/kWhr (HHV) without duct burner firing and 7,051 Btu/kWhr (HHV) with duct burner firing Siemens SGT6-5000F(4) -	General Electric 7FA – 934.5 lbs $CO_2/MWh_{(gross)}$ with duct burning 874.2 lbs $CO_2/MWh_{(gross)}$ without duct burner firing

Company/Location	MW Capacity	Combustion Turbine Heat Rate (Btu/kWh)	BACT Limit
	5000F(5) – 735 MW	6,782 Btu/kWhr (HHV) without duct burner firing and 7,045 Btu/kWhr (HHV) with duct burner firing Siemens SGT6-5000F(5) - 6,891 Btu/kWhr (HHV) without duct burner firing and 7,204 Btu/kWhr (HHV) with duct burner firing	Siemens SGT6-5000F(4) – 909.2 lbs $CO_2/MWh_{(gross)}$ with duct burning 886.8 lbs $CO_2/MWh_{(gross)}$ without duct burner firing Siemens SGT6-5000F(5) – 912.7 lbs $CO_2/MWh_{(gross)}$ with duct burning 882.4 lbs $CO_2/MWh_{(gross)}$ without duct burner firing
Lower Colorado River Authority (LCRA), Thomas C. Ferguson Plant Horseshoe Bay, TX	590 MW	7,720 (net) does not have duct burners	0.459 tons CO_2/MWh (net)
Palmdale Hybrid Power Plant Project Palmdale, CA	570 MW CC + 50 MW Solar	7,319	0.387 tons CO_2/MWh (net)*
Calpine Russell City Energy Center Hayward, CA	600 MW	7,730	7,730 Btu/kWh (net) equivalent to 792.9 to 815.5 lbs CO_2e/MWh (net)
Cheyenne Light, Fuel & Power/Black Hills Power Inc. Cheyenne, WY	220 MW		1,100 lb CO_2e/MWh(gross)
Pacificorp Energy – Lake Side Power Plant Vineyard, UT	629 MW		950 lb CO_2/MWh (gross) = 0.475 tons CO_2/MWh (gross) with duct burner firing
Kennecott Utah Copper – Repowering South Jordan, UT	275 MW		1,162,552 tpy CO_2e
Pioneer Valley Energy Center Westfield, MA	431 MW (natural gas)	2,542 (MMBtu/kWh)	895 lbs $CO_2e/MWh_{(grid)}$
Calpine Deer Park Energy Center Deer Park, TX	348 MW	7,730 (net) -without duct burner firing	0.46 tons $CO_2/MWh_{(net)}$
Calpine Channel Energy Center Pasadena, TX	348 MW	7,730 (net) -without duct burner firing	0.46 tons $CO_2/MWh_{(net)}$

*The Palmdale facility BACT limit is reduced due to the offset of emissions from the use of a 50 MW Solar-Thermal Plant that was part of the permitted project.

Comment 19: The Region must consider alternative locations for the LPEC project if distance from carbon sequestration opportunities or water supply issues are obstacles to the use of Carbon Capture and Storage (CCS). Section 165 of the Clean Air Act "requires the Region to consider alternatives to the proposed project that would reduce the emissions of pollutants." The EGU should be located close to an enhanced oil recovery site. The applicant has not identified transmissions constraints that require locating the plant at the proposed site.

Response:

We disagree. While CAA section 165(a)(2) affords a permitting authority the discretion to consider alternatives to the proposed project, we do not interpret this section to mandate consideration of a potentially limitless number of alternative site locations. Indeed, section 165(a)(2) requires only that a public hearing be held "with opportunity for interested persons . . . to appear and submit written or oral presentations on the air quality impact of such source, *alternatives thereto*, control technology requirements, and other appropriate considerations." (emphasis added). Thus, the burden is on interested persons, such as the commenter, to suggest potential alternatives to the project. The EAB has concluded similarly, holding that "the permitting authority is not required 'to conduct an independent analysis of available alternatives.'" *In re Prairie State Generating Company*, PSD Appeal No. 05-05, slip op. at 20 (EAB Aug. 24, 2006). Rather, "in the PSD context '[t]he extent of [the permitting authority's] consideration and analysis of alternatives need be no broader than the analysis supplied in public comments.'" *Id.* Here, the permit applicant's project purpose is to provide power near the City of Harlingen, TX. The commenter has not suggested any alternative locations near Harlingen, TX that would satisfy the applicant's project purpose while simultaneously providing better access to enhanced oil recovery sites. Instead, the commenter suggests that EPA, as the permitting authority, must undertake this potentially boundless review in the first instance. Without more information from the commenter regarding potential alternative sites, we do not believe that the CAA or EAB precedent requires such a review, nor do we believe that our time and administrative resources would be well-served in doing so at our discretion.

Comment 20: The permit record provides an inadequate basis to reject CCS in Step 4 of the BACT analysis. The record provides no site-specific analysis supporting the rejection of CCS. The Region should require a more detailed analysis of sequestration opportunities near the proposed site. The applicant's statement that no geologic formation sites have yet "been technically demonstrated for large-scale, long-term CO_2 storage" is not sufficient. The applicant's statement that an enhanced oil recovery site is fifteen miles distant, without further "effort to research or characterize that reservoir," does not suffice.

Response:

We disagree with the commenter's assertion that CCS has been rejected with inadequate justification. Consistent with EPA's GHG Guidance, we determined in Step 2 that overall CCS was a technically feasible control technology for LPEC. In Step 2 of the BACT analysis, the applicant observed that CCS has not, as yet, been applied to power plant gas turbine exhausts, "which have considerably larger flow volumes and considerably lower CO_2 concentrations" than petroleum refining and gas processing industries. In Step 4 of the BACT analysis, we evaluated the site-specific economic impacts and water and energy demands that would result if CCS were required as BACT for LPEC. In light of the high costs and adverse energy and environmental impacts that were found, EPA reasonably eliminated CCS from further consideration as BACT.

The commenter's suggestion that we did not consider the challenges of CCS on a site-specific basis is not correct. We explained that the addition of CCS would result in site-specific water supply challenges, including increased water consumption that could not be met with the effluent supply (of up to 7 million gallons) that LPEC intends to use. We discussed the need for pipeline construction and the proximity, remoteness, and uncertainties associated with candidate sites for geologic sequestration and enhanced oil recovery operations. The permit applicant listed the quantity and type of additional major pieces of equipment that would need to be installed for a site-specific CCS system at LPEC. Finally, the record provides the estimated costs of CCS, including estimations for the cost of capturing, transporting, and storing the proposed facility's CO_2 emissions. In providing these estimates, the permit applicant based its costing methodology on a U.S. Department of Energy document titled, "Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity," Revision 2, November 2010, DOE/NETL/1397.

We further note, a primary challenge in evaluating CCS, including its feasibility and costs, on a natural gas combined cycle unit is the capacity assumptions made on the power plant. Most economic models for CCS on CCGT units assume baseload operations (greater than 75 percent capacity). In 2009, the average capacity factor of CCGT plants in the U.S. was 42.2 percent.[26] Using U.S. Energy Information Agency (EIA) data, M.J. Bradley & Associates estimated that only six NGCC power plants in the U.S. had capacity factors greater than 70 percent in 2010, and only one of these power plants had a capacity factor above 75 percent. They also determined that only 15 power plants (55 generation units) had a capacity factor of at least 65 percent. Three of these power plants (with 13 units) were located in Texas. However, it is important to emphasize that no company has constructed a CCGT power plant with full-scale integrated CO_2 capture, transport, and geologic sequestration. Currently, the CCS projects under construction or with known plans for construction in the U.S. (Mississippi Power Kemper County, NRG W.A. Parish, and Summit Power Texas Clean Energy Project) all utilize coal as their primary fuel and are receiving significant Department of Energy's (DOE) funding. At this time, there are no full-scale CCS demonstration projects for CCGT plants being funded by the DOE.

Further, Southern California Edison Company investigated the application of CCS technologies for natural gas-fired combined cycle (NGCC)[27] power plants. The report *Technical and Regulatory Analysis of Adding CCS to NGCC Power Plants in California (November 2010)* included a technical analysis of CCS technologies that are commercially available and applicable to NGCC units. More specifically, the analysis included general descriptions of the technology, where it is being used and demonstrated, how it can be applied to NGCC units, and a summary of impacts to plant performance (heat rate and output), cost (capital and cost of electricity), and site issues (water use and land requirements). During natural gas combustion in an NGCC plant, the concentration of CO_2 in the exhaust stream or flue gas is low, typically 3.0 percent or less by volume. This is much lower than other types of power plants that burn coal where the CO_2 concentration may be as high as 15 percent by volume in the post-combustion flue-gas stream. The low concentration of CO_2 in NGCC flue gas adds to the challenge of CO_2 capture when compared with coal-fired power plants [post-combustion] or integrated gasification combined cycle (IGCC) plants [IGCC would typically remove the CO_2 during the gasification process, not in a post-combustion process]. For NGCC plants to implement a CO_2 capture process, additional equipment would be required due to the low concentration of CO_2 in the flue gas, which in turn translates to

[26] Policies to Advance the Business Case for Natural Gas Combined Cycle Power Plants with Carbon Capture and Storage; Prepared by Tom Curry and Austin Whitman; M.J. Bradley & Associates LLC; November 2011.
[27] Natural Gas Combined Cycle (NGCC) and Combined Cycle Gas Turbines (CCGT) are synonyms and can be used interchangeably.

significant impacts on the power unit output, efficiency, and possibly the cost of electricity. The major challenge for post-combustion CO_2 systems is the use of amine driven technologies that require significant heat and power for amine stripping and for compression and drying of the water saturated CO_2 that leaves the stripping process. This reduces the overall net capacity and efficiency of the NGCC plant to produce electricity.

Numerous studies have been conducted to estimate the capital and operating costs of applying CCS to fossil-fuel fired power plants. Southern California Edison analyzed data from both the California Energy Commission and the U.S. Department of Energy in their study. The Southern California Edison study produced comparison data for NGCC plants with and without CCS. The table below summarizes their findings:[28]

	California Energy Commission/California Department of Conservation (2008) and Katzer and Herzog (2008)		DOE (2007)		DOE (2010)	
Type of Plant	NGCC w/o CO_2 Capture	NGCC w/ CO_2 Capture	NGCC w/o CCS	NGCC w/CCS	NGCC w/o CCS	NGCC w/CCS
Gross Output	-	-	570.2 MW	520.1 MW	262.5 MW	235.3 MW
Reduction in Gross Plant Output	-	-	-	5.80%	-	10.40%
Net Output	500 MW	500 MW[1]	560.36 MW	481.9	257.9	216.6
Reduction in Net Plant Output	-	-	-	14%	-	16%
Capital cost, $/kW net	845	1,670	554	1,172	-	-
Increase in Capital Cost for CO2 Capture, $/kW net	-	-	-	618[2]	-	953[3]
% Increase in Plant Capital Cost	-	97%	-	112%	-	-
Tons CO2/Year Emitted	1,510,319	176,951	1,661,720	166,172	866,074	86,602

[28] Technical and Regulatory Analysis of Adding CCS to NGCC Power Plants in California; Prepared for Southern California Edison Company, November 2010, by CH2MHill

	California Energy Commission/California Department of Conservation (2008) and Katzer and Herzog (2008)		DOE (2007)		DOE (2010)	
Type of Plant	NGCC w/o CO_2 Capture	NGCC w/ CO_2 Capture	NGCC w/o CCS	NGCC w/CCS	NGCC w/o CCS	NGCC w/CCS
Tons CO2/Year Captured	-	1592388*	-	1,495,548	-	779,472
Tons CO2/Year Avoided	-	1,333,368	-	1,495,548	-	779,472
CO2 Capture Costs	-	\$66/ton CO_2 avoided	-	\$83/ton CO_2 avoided	-	-
Levelized Cost of Electricity	\$0.0601/kWh (does not include CO_2 transport, storage, MMV)	\$0.0849/kWh (does not include CO_2 transport, storage, MMV)	\$0.068/kWh (include CO_2 compressor, pipeline transport, storage, MMV)	\$0.0974/kWh (include CO_2 compressor, pipeline transport, storage, MMV)	\$0.06126/kWh (include CO_2 compressor, pipeline transport, storage, MMV)	\$0.094/kWh (include CO_2 compressor, pipeline transport, storage, MMV)
Increase in Cost of Electricity	-	41%	-	43%	-	53%
Heat Rate, Btu/kWh (HHV)	6,808	7,977	6,717	7,808	7,629	9,054
Reduction in Efficiency	-	14.70%	-	14%	-	16%
Plant Water Use, MGD	-	-	3.6	6.7	1.45	1.79
% Increase in Plant Water Use	-	-	-	86.90%	-	23%

1 - In the CEC Study, net output is maintained at 500 MW for the design of the "new" NGCC unit with CCS. Therefore, the heat input to the "hypothetical" CTs is increased by 17% to provide sufficiently hot exhaust gas to generate the steam required for the CO2 capture system.

2 - Includes entire CCS system

3 - Includes CO_2 capture and compression, but not pipeline and storage system

* The amount of the CO_2 captured is not the same value as the difference in the number of tons emitted for the "with" and "without" cases. This is because the NGCC w/CO2 capture case is apparently based on increasing the size of the hypothetical NGCC unit to maintain the 500 MW net output for this study, requiring 17% more heat input (natural gas) to make up for the losses in output, thereby producing 17% more CO_2. This is followed by 90% capture of the CO_2 from the exhaust gas stream from the larger unit. The DOE study assumes that the same equipment is used. However, the gross and net input values are much lower for the CCS case, due to additional internal load and less steam going to the steam turbine generator. The number of tons captured is the same as the tons avoided. In the case of a retrofit, the net output would not be maintained due to the significant amount of additional internal load.

The data from the table above summarizes two scenarios in the report. The California Energy Commission analysis is based on adding CO_2 capture only to NGCC technology (without pipeline transportation or storage costs) and is representative of what would occur with the design/planning for a new NGCC plant, whereas, the DOE analyses are more representative of what might occur if an existing NGCC plant were retrofitted with a CO_2 capture system. The California Energy Commission indicated a 41 percent increase in the cost of electricity and over a 14 percent net loss in efficiency for a hypothetical 500 MW output NGCC power plant. In addition, to produce the 500 MW output, the California Energy Commission indicated that the heat input to the combustion turbines would need to increase by 17 percent just to provide sufficient hot exhaust gas to generate the steam required to operate the CO_2 capture system. While the California Energy Commission analysis did not project increased water demands, it is clear that the DOE analyses for retrofitting existing NGCC units with CO_2 capture required substantial increases in water use. LPEC projected in their permit application significant increases in water use if CCS were to be installed. LPEC estimated that they would need 4 to 5 million gallons of water per day for condenser cooling and boiler make-up service without CCS and that with CCS they may need 7.6-9.5 million gallons of water, resulting in a potential increase in water consumption of approximately 90 percent. Another significant figure of note in the California Energy Commission study is the increased plant capital cost of 97 percent to add CCS to a NGCC plant. LPEC estimated that their site-specific plant costs would increase approximately 119 percent if it added full-scale CCS to its proposed project (LPEC estimated the construction cost is $443.8 million without CCS and $974 million with CCS). This estimate does not appear to be drastically out of line with the data from the California Energy Commission's results summarized in the Southern California Edison Company report. Even if a determination were made to require partial CCS by requiring CCS on just one of the proposed units at the project instead of both units, the projected additional project costs would still add an additional $265 million to the project, which would increase the project costs by more than 50 percent. Further, if CCS were installed at the proposed LPEC facility, we would expect (as described above) a similar loss in plant efficiency and the need to burn additional fuel to increase the plant's heat input to provide sufficient power to operate the CO_2 capture system while still delivering electricity to the grid.

The U.S. Department of Energy's National Energy Technology Laboratory also released its report "*Life Cycle Analysis: Natural Gas Combined Cycle (NGCC) Power Plant*" on September 30, 2010, which evaluated the emissions footprint of NGCC technology. The analysis examined two NGCC energy conversion cases with two natural gas supply scenarios (one scenario was imported natural gas and the other domestic natural gas). In summary, the study compared the Life Cycle Inventory & Cost of two NGCC plants, one with and one without CCS. It was shown that CCS could be added to an NGCC facility to reduce the cost of the Life Cycle Global Warming Potential. However, adding CCS increased the Levelized Cost of Electricity by 42 percent. Another tradeoff from the addition of CCS was the necessity for more water and land use. The NETL study indicated approximately 44 percent more water is needed for cooling applications using a carbon capture process. Also, additional land would be necessary to install a CO_2 pipeline.[29] As indicated earlier, LPEC has estimated its water use without CCS to range from approximately 4-5 million gallons per day, and with CCS from 7.6-9.5 million gallons per day with CCS, resulting in a water use increase of approximately 90 percent. The proposed construction site is located in an area that the National Weather Service has currently classified as "extreme" drought in their "Long Term Drought Indicator Blend Percentiles." We believe the installation of a CCS system would not be a beneficial use of water resources for this particular project

[29] Life Cycle Analysis: Natural Gas Combined Cycle (NGCC) Power Plant; September 30, 2010; DOE/NETL-403-110509; U.S. Department of Energy, National Energy Technology Laboratory

due to the substantial increase in use of available water resources in an area that is currently experiencing a prolonged extreme drought.

Comment 21: The record does not include a breakdown of the CCS cost estimate. The cost projections were accepted "without any record of an independent analysis." The "blank record deprives the public of an opportunity to review and comment on the cost projections" of CCS. The CCS costs do not include estimated revenue from the sale of CO_2 for enhanced oil recovery. A conservative estimate of the market price of CO_2 is "$33/tonne." The Region must correct the CCS cost analysis to include a reasonable projection of revenues from CO_2.

Response:

EPA's GHG Guidance provides that cost estimates used in BACT are typically accurate to within ± 20 to 30 percent (GHG Guidance at 39), but it must also be acknowledged that there is limited data and consequent uncertainty concerning the costs of GHG BACT in general, and CCS for NGCCs in particular. For purposes of evaluating CCS in this permitting action, we considered it appropriate to assess the cost-effectiveness of CCS in a less detailed quantitative manner and found it appropriate to use qualitative considerations as well.

Although there may be other approaches, we believe it was acceptable for the applicant to cite and utilize the DOE "Cost and Performance Baseline" Report.[30] We note, meanwhile, that the commenter has neither referenced this report nor acknowledged its use and its provision of a relatively detailed breakdown of cost assumptions for CCS as tailored to a combined-cycle EGU. Nor has the commenter referenced or acknowledged the CCS cost estimations that have been developed for Region 6 GHG PSD permitting actions for similarly-sized gas-fired combined-cycle EGUs that are both pending (e.g., NRG Cedar Bayou) and finalized (PSD-TX-1244-GHG; PSD-TX-979-GHG; PSD-TX-955-GHG). We examined the records for those actions and found that LPEC's estimated costs are not appreciably different from cost estimations being developed for similar facilities (for example, in the metric of cost/ton of CO_2 avoided, LPEC's estimations are roughly within ± 20 percent of other applicants).[31] As such, we have no basis to believe: 1) the cost estimations have unacceptably deviated from those recently developed at other known, similar projects; or 2) the applicant failed to use the resource cited for its cost methodology. Accordingly, we cannot agree that the record is "blank" or that the commenter has been deprived of the opportunity to comment on the economic impacts of CCS. The commenter had the opportunity to review the furnished information and to even develop cost estimations of its own, but this was not done, and the commenter has not suggested the CCS cost estimations are incorrect to such an extent that they would materially affect the consideration of the economic impacts. In any event, on August 9, 2013, the applicant provided an additional breakdown of the cost estimates for CCS which further confirms our review. In addition, we've provided additional analyses in response to Comment 20

[30] Since the LPEC developed its estimations, we note the addition of a supplement to the report "Updated Costs (June 2011 Basis) for Selected Bituminous Baseline Cases" (August 2012), available at http://www.netl.doe.gov/energy-analyses/pubs/BaselineCostUpdate.pdf . We note this as it may be useful in the future development of updated and refined cost estimates for CCS; however, we do not deem it to materially change our determinations on CCS in the BACT analysis for this permitting action, because the report's combined cycle captured case experience 4 percent increase, notwithstanding refined, lower fuel cost projections. Id. at 48.

[31] In response to the comment, we also examined the *2005 IPCC Special Report on Carbon Capture and Storage* which provides estimations, within a defined "moderate" confidence level, in setting forth technology and system cost estimates for CCS at a new natural gas combined-cycle EGU. Even without indexing to current year costs, it would appear LPEC's estimations do not substantially deviate from those estimations, either.

above documenting the potential range of economic, energy, and environmental impacts if CCS were required at this site. The response to Comment 20 above is also responsive to Comment 21.

We acknowledge the commenter's suggestion that this permitting record may benefit from a discussion of whether revenues from CO_2 sales may be possible, and if so, whether those revenues could be appropriately applied to partially offset the cost of 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 CO_2 could be readily sold for enhanced oil recovery." GHG Guidance at 43. In developing cost estimations for CCS, it would have been prudent for LPEC to have addressed whether captured CO_2 may be sold to generate revenue. However, even assuming market demand exists for LPEC's CO_2 stream, we do not necessarily agree with the commenter that "$33/tonne" 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 CO_2 for enhanced oil recovery to range from as low as $15 to as much as $45 per metric ton. The commenter indicates that a "conservative" market price for CO_2 is $33 per metric ton, which is purely speculative. The price may vary widely depending upon the price of oil per barrel and the availability of CO_2 in or near the particular oil production field. In addition, EPA's proposed NSPS for EGUs for emissions of CO_2 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 CO_2/MWh standard. EPA also included costs for those same units when EOR opportunities are available. EPA included a "low EOR" case assuming a low EOR price of $20 per ton of CO_2, and a "high EOR" of $40/ton. These EOR prices are net of the costs of transportation, storage, and monitoring (TSM).

As noted earlier, various published reports or studies cite the purchase price of CO_2 for enhanced oil recovery to range from as low as $15 per metric ton to as much as $45 per metric ton. Assuming LPEC had a client or partner willing to purchase CO_2 for enhanced oil recovery, and further assuming LPEC could recover approximately 90 percent of its CO_2 emissions under its maximum permitted scenario (2,614,988 metric tons), the potential revenue at $15 per metric ton would be approximately $39.2 million per year. Obviously, the potential revenue would increase if the purchase price was higher than $15 per metric ton. Assuming a low EOR purchase price of $20 per metric ton and a high EOR purchase price of $40 per metric ton as projected in EPA's proposed NSPS, these projected purchase prices would only generate approximately $52.3 million and $104.6 million, respectively. LPEC estimated that its annual operating costs for CCS including capture, transport (and/or storage) would be $271 million for full-scale CO_2 capture, transportation, and geologic sequestration to the SACROC pipeline in west Texas. Even if LPEC could generate $52.3 million in revenue from CO_2 sales, this revenue would only cover approximately 19 percent of the estimated annual operating costs for add-on CCS controls. Further, even assuming the "conservative" market price advocated for by the commenter would only yield approximately $86.3 million in revenue or a little over 31 percent of the estimated annual operating costs for add-on CCS controls. Assuming the high EOR price of $40 per metric ton would yield potential revenues of approximately 38% of the annual operating costs, this still would not appear to make CCS economically viable for this project. There do not appear to be any existing commercially viable enhanced oil recovery operations near the proposed project because the closest pipeline networks are well over 300 miles away (CO_2 Pipeline Network in Permian Basin and Denbury Green Pipeline northeast of Houston, Texas). In addition, just because a company can recover CO_2 does not mean they have a contractual customer or partner willing to purchase the CO_2. As noted in the GHG Guidance, we recognized the significant logistical hurdles that the installation and operation of a CCS system presents that set it apart from other add-on controls that are typically used to reduce emission of other regulated pollutants such as NO_x or SO_2. In this case, CCS would be an add-on control for GHGs and would require a second party willing to accept and utilize the CO_2 for enhanced oil recovery purposes. Without a contractual customer who is willing to purchase the CO_2 in this case, the commenter is asking EPA to attempt to arrange a contractual marriage through a BACT determination between LPEC and some currently unknown entity who is willing to prospectively utilize the CO_2. Essentially, 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 develop a customer(s) who is willing to purchase the CO_2. It should also be noted that while EPA has estimated potential revenues for the sale of CO_2 above, the actual price of CO_2 may vary from location to location depending upon CO_2 availability in the area, EOR reservoir/formation characteristics, and the price per barrel of oil. Ultimately a price would have to be negotiated between LPEC and a prospective contractual partner and the price could be less than the assumed estimates above on a cost per metric ton basis. These obstacles alone make CCS for this specific site and project economically infeasible and possibly even technically infeasible.

Comment 22: There is no basis to reject CCS due to economic impact unless the costs for the proposed facility have been compared to the costs of control at other facilities (e.g., Southern Kemper IGCC plant and the Summit Texas Clean Energy Project) and found to be disproportionately high. The "NSR Manual" states that "applicants generally should not propose elimination of the basis of economic parameters that provide an indication of the affordability of a control alternative relative to the source." The region must instead determine that the cost-per-ton of emissions reduced and the incremental costs are beyond the cost borne by other sources of the same type in applying the control alternative. It is invalid to reject CCS on the basis of its excessive costs in relation to the overall costs of the project.

Response:

The commenter has listed several projects that differ significantly from the proposed project in scale, funding, and fuel types. As we explained in our response to Comment 20, the economics of CCS vary considerably between NGCCs and coal-fired EGUs due to differences in the purity of their respective CO_2 streams, among other things. As a result, we believe it would be inappropriate to compare the economic impact of installing CCS at LPEC, an NGCC facility, to the federally funded projects referenced by the commenter. While the 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."[32] 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."[33] 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 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

[32] GHG Guidance at 43.
[33] GHG Guidance at 42.

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 EAB precedent.

Comment 23: The rejection of CCS based in part on the lack of available water is not sufficiently supported. The record must consider other or supplementary water sources. The analysis should consider a smaller facility or a smaller CCS system that demands less water or project relocation to an area with more adequate water supplies.

Response:

As an initial matter, we must point out that CCS was rejected in Step 4 primarily due to its excessive costs. Therefore, regardless of whether the adverse environmental impacts associated with water usage could be mitigated, we would still decline to require CCS as GHG BACT. However, we also disagree that the record does not adequately support our decision that CCS would substantially increase water usage at LPEC in an area that has extremely limited water resources. LPEC estimated that CCS would require the facility to increase its water usage from 4 - 5 million gallons per day to 7.6 - 9.5 million gallons per day, an increase of approximately 90 percent. Because the proposed construction site is located in an area that the National Weather Service has currently classified as "extreme" drought, we believe that the installation of CCS would not be a beneficial use of such limited water resources. Indeed, the commenter acknowledged that "the three years from 2011 to 2013 have been among the driest on record." Finally, the record illustrates that LPEC will be utilizing generally scarce water supplies from a specified source (i.e., Harlingen Waste Water Treatment Plant[34]). The commenter has not suggested any alternative water supplies from which LPEC might obtain the water necessary to support a CCS system.

In regards to the commenter's suggestion that we consider other alternatives to the proposed project, such as a smaller facility or a different location with more adequate water supplies, we decline to do so for the same rationale we provided in response to Comment 19. It is the commenter's burden to suggest specific alternatives to the proposed project that might improve air quality without fundamentally redefining the source. Here, the commenter has failed to provide any details of how LPEC could construct a smaller facility while still providing 637-735 MW of power. Similarly, the commenter has not proposed any additional sites near Harlingen, TX that might have more adequate water supplies. Consequently, we are not required to consider such alternatives and will not do so at our discretion in this case.

Comment 24: EPA must consider the option of partial CCS to reduce costs and reduce water requirements. Partial capture allows a plant to maximize electrical output in peak periods to increase revenue and limit CCS costs.

Response:

Regarding partial carbon capture options in the United States, Florida Power & Light's (FPL) 300MW Bellingham Cogeneration Plant in Massachusetts has demonstrated that CO_2 could be captured from an NGCC power plant post-combustion. Each of the plant's combustion turbines were equipped with HRSGs that produced high pressure steam for production of additional electricity in a steam turbine

[34] Email from Kathleen Smith to Alfred Dumaual dated January 30, 2013. http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/la-paloma-wastewater-provider013013.pdf

generator, and low pressure steam for export to an adjacent CO_2 Recovery Plant. FPL used an Econamine FG absorption system to scrub CO_2 from approximately 13-15 percent of the slipstream exhaust gas where the CO_2 concentration ranged from 2.8 - 3.1 percent. The plant was able to recover approximately 320-350 tons/day of 95+% pure CO_2, which was then sold to buyers for food-grade uses. The capture costs were estimated to be approximately \$100/ton of CO_2 from this use of a partial carbon capture system.[35] Of notable significance is the fact that, once the plant changed its operational status from operating as a base-load unit to operating as a peaking unit, the feasibility and practical consequence of attempting to implement a CCS system, even in a partial capture scenario, diminished and the system was shutdown. Even if LPEC could utilize a partial capture option under their maximum proposed permitting scenario (3,196,097 short tons of CO_2 per year) by recovering a comparable amount of CO_2 to the FPL Bellingham Cogeneration Plant of up to 15% of the slipstream exhaust gas, this would be equivalent to approximately 479,414 short tons per year. Assuming the capture costs approximate the estimated \$100/ton of FPL Bellingham, this would yield an annual cost of capture of approximately \$48 million per year without any cost considerations for transport and/or geologic storage. LPEC has also estimated its annual operating cost without CCS and the cost with CCS. LPEC estimates its annual operating and maintenance costs without CCS to be approximately \$6.8 million. With full CCS, LPEC estimates its annual operating and maintenance costs to be approximately \$11.3 million, an increase of approximately 66 percent in the operating and maintenance costs at the power plant alone. That cost does not account for the additional annualized costs for construction/operation for CO_2 transport and storage that would occur. Additionally, information provided by Fluor to EPA Region 6 indicates that the current estimate for Utility and Chemical costs for a gas turbine power plant exhaust (comparable to FPL Bellingham) to be approximately \$31.50 per ton of CO_2 captured.[36] Even assuming the partial capture of CO_2 (15 percent) at \$31.50 per ton would yield an annual cost of \$15.1 million per year in additional operational costs to capture CO_2. This would be an increase of approximately 122 percent above LPEC's estimated annual operating costs without CCS.

However, assuming this amount were captured and the facility developed a system for injection on-site or nearby into a saline water formation for geologic sequestration, this would involve additional costs to the facility. These costs would include the costs to perform a geotechnical engineering analysis for suitability of the subsurface formations, injection well permitting, obtaining mineral rights or subsurface leases for injection purposes, injection well construction and then operational costs of the injection well in conjunction with obtaining insurance or financial assurance mechanisms for the CO_2 injection and sequestration system. EPA used \$3.80 metric tonne CO_2/year as the cost for complying with underground injection control program for CO_2 geologic sequestration for wells (FR Vol. 75, No 237, pages 77230-77303) in an IGCC scenario. If the IGCC scenario could be directly applied to the NGCC scenario, the estimated cost for just complying with EPA's geologic sequestration rules, assuming the project is capturing only 15 percent or 435,830 metric tonnes of CO_2 a year, would be an additional \$1,656,154 a year. As we noted earlier, the cost to recover CO_2 from an exhaust or flue gas stream with a lower concentration of CO_2 may cost more on a per ton basis than in an IGCC scenario due to the construction and subsequent operational costs of the CCS system. The economics of installing and operating either full-scale CCS or partial CCS are unreasonably disproportionate to the project construction costs and the annualized operating costs without CCS. Requiring this add-on control would make the project economically unviable.

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[35] Technical and Regulatory Analysis of Adding CCS to NGCC Power Plants in California; Prepared for Southern California Edison Company, November 2010, by CH2MHill

[36] Email from John Gilmartin, Principal Process Engineer for Fluor to Aimee Wilson, EPA Region 6 on August 5, 2013. http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/la-paloma-econamine080513.pdf

The BACT analysis appropriately considered CCS at a high, approximately "the most," effective level of control. While we have provided a response to the comment on partial CCS, the commenter has not suggested an alternative level of control efficiency or identified regulatory decisions that have included an evaluation of partial controls that would support consideration of a partial control option in any useful way for our BACT analysis for LPEC. The commenter's assertion that the costs of partial CCS would be lower was vague, unsupported, and speculative, and the commenter did not provide a record basis to support its assertion that partial CCS would be a viable, economic control option.

Comment 25: The SOB identifies leak detection and repair handheld analyzers and remote sensing technologies as the most effective controls for natural gas fugitive emissions, but rejected it as not economically practicable. The Region did not quantify the difference between these controls and the next level of control in terms of control effectiveness or incremental cost-effectiveness. The Region had no basis to reject LDAR or remote sensing because there is no evidence that installing and operating LDAR or use of remote sensing would cause "uniquely excessive costs at LPEC compared to other electric generating facilities." The Region's rejection of LDAR and remote sensing (as not economically practical and because of the relatively small amount of fugitive GHGs) does not comply with the analysis required in Step 4 of BACT.

Response:

The commenter has misunderstood or mischaracterized the analysis applied to fugitive emissions. We understand that the requirements for satisfying BACT as applied to fugitive emissions of VOCs are likewise being applied, at no additional cost of note, to fugitive emissions of methane. If more burdensome work practice standards for VOCs are in consideration for the source (based, for example, on requirements applicable to an area that is nonattainment for ozone) those work practices could also be applied to the control of fugitive methane emissions for little or no additional cost. The incremental differences in estimated control effectiveness between the two programs, particularly in relation to total project emissions, are not so great that it would be useful to study costs for GHGs in terms of incremental cost effectiveness.[37] In circumstances where the difference in emissions between control options is not meaningful, there is little basis or precedent for the detailed analysis of control costs and comparisons to other facilities pressed by the commenter. 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). BACT, as it applies to the relatively insignificant fugitive emissions of GHGs that could be estimated for the project, is not based on a quantitative emission limit, and there is little basis or precedent for the detailed analysis of control costs and comparisons to other facilities pressed by the commenter. See 40 CFR 52.21(b)(12)(the emissions reductions achievable through a work practice standard must only be set forth "to the degree possible"); 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.). 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. However, in this case due to the very low VOC content of natural gas, LPEC is not subject to any VOC leak detection programs under its TCEQ issued PSD permit. Therefore, we found that due to the small amount of emissions estimated from fugitive emissions (0.01 percent of total sitewide CO_2e emissions)

[37] Though not specifically acknowledging control effectiveness for GHGs, the Texas Commission on Environmental Quality does provide updated estimations of controls efficiencies for its various LDAR programs: http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/control_eff.pdf

that a daily AVO inspection was adequate in this instance. We do note, however, that LPEC's permit terms and conditions to address fugitive emissions are no less stringent than those recently given to other CCGT EGUs as BACT in 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 26: The Region must analyze the increased air pollution that will result from growth in upstream natural gas production and distribution associated with increased natural gas use at LPEC as required by Clean Air Act section 165(a)(6). Moreover, upstream emissions should also be considered in its evaluation of CCS as BACT and its evaluation of alternatives to the proposed project.

Response:

As an initial matter, the statutory requirement at CAA 165(a)(6) is to consider "air quality impacts projected for the area" as a result of growth associated with such a facility. It is unclear whether the comment's generalized reference to natural gas production and distribution implicates impacts that "result" from LPEC or would be for "the area". In any event we do not believe it is necessary for applicants or permitting authorities to assess impacts from GHGs in the context of the additional impacts analysis required by CAA section 165(a)(6) for a variety of practical reasons. Most notably, climate change modeling and evaluations of risks and impacts of GHG emissions are typically conducted for changes in emissions orders of magnitude larger than the emissions from individual projects analyzed in PSD permit reviews. Thus, as we explained in our GHG Guidance, "the most practical way to address the considerations reflected in the . . . additional impacts analysis is to focus on reducing GHG emissions to the maximum extent. In light of these analytical challenges, compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis . . . requirements of the rules related to GHGs."[38] Accordingly, we believe the requirements of CAA section 165(a)(6) are satisfied by the BACT limits we established in LPEC's PSD permit, which will ensure that the facility reduces GHG emissions to the maximum extent considering the statutory factors.

Moreover, to the extent the commenter is alleging that there would be air quality impacts from non-GHGs that could be associated with growth attributable to LPEC, we note that our permitting action applies only to GHGs. As was explained in the SOB, LPEC has sought a PSD permit for multiple regulated NSR pollutants other than GHGs from the TCEQ. That state agency, as the approved permitting authority for those pollutants, will apply all applicable statutory and regulatory requirements regarding additional impact analyses. We do not intend to require a separate or duplicative analysis to address associated growth impacts when we have no reason to distrust that TCEQ has conducted the required analyses and made them available for public comment in the state's PSD permitting process.

Comment 27: Solar auxiliary preheat must be considered in the BACT analysis. The BACT analysis should consider the potential increase in efficiency achievable by using a solar hybrid design configuration in place of duct burners. This technology could be integrated without "redefining the project and without sacrificing the load shaping capabilities of the facility." This technology should be the basis for the BACT emission limit.

[38] GHG Guidance at 48.

Response:

We disagree with the commenter's view that requiring construction of a hybrid power project that incorporates solar auxiliary preheat would not redefine the source. While we acknowledge there may be many ways for solar thermal processes to be integrated with a facility that intends to use steam to generate electricity, we believe that requiring such processes in combination with fossil-fuel combustion would represent the merging of distinct and different source types. While Region 9 required 50 MW of solar energy as part of its BACT determination for the Palmdale Hybrid Power Project NGCC facility, the permit applicant in that case had proposed the solar project as part of its project purpose, which included supporting California's goal of increasing the percentage of renewable energy in the State. Indeed, Region 9 specifically explained that it incorporated the solar project into its BACT determination not because it was required to do so, but because doing so was compatible with the permit applicant's goals and would therefore not redefine the source:

[W]e note that the incorporation of the solar power generation into the BACT analysis for this facility does not imply that other sources must necessarily consider alternative scenarios involving renewable energy generation in their BACT analyses. In this particular case, the solar component was a part of the applicant's Project as proposed in its PSD permit application. Therefore, requiring the applicant to utilize, and thus construct, the solar component as a requirement of BACT did not fundamentally redefine the source. EPA has stated that an applicant need not consider control options that would fundamentally redefine the source. However, it is expected that each applicant consider all possible methods to reduce GHG emissions from the source that are within the scope of the proposed project.[39]

Here, LPEC did not include a solar energy component as part of its project in its permit application. Furthermore, the commenter has not explained how LPEC might incorporate such a solar component into its project, or even whether it has or can acquire the land necessary to do so, without redefining the source. Consequently, we disagree that solar auxiliary preheat must be considered in our BACT analysis for this facility, and we decline to exercise our discretion to require its consideration.

Comment 28: The annual emissions limits are excessive because they assume continuous facility operations for 8,760 hours, including operations at full capacity and 100 percent duct firing and 500 hours of emissions from maintenance, startup, and shutdown. This contradicts the SOB's characterization of the project as a "load cycling unit" that justified a weaker lb/MWh limit. The duct burners are not intended and should not be permitted to operate at 100 percent for the entire year. The duct burners should have an annual hours of operation limit that reflects reasonable system-wide operation. The Region must revise the draft permit to reflect more realistic annual emission limits.

Response:

As indicated in the response to Comment 17, LPEC is anticipating that they will be able to operate as a base-load facility. However, until they are dispatched by ERCOT, their plans include the operational flexibility of a load cycling unit. The facility will need to be able to meet any contractual load with ERCOT and to be able to also operate "on demand" as ordered by ERCOT to supply electricity during periods of a shortfall due to temporary outages of other electric generating units or due to weather extremes. It is possible LPEC may not operate on a full-time base-load basis, but we believe the permit

[39] U.S. EPA, "Responses to Public Comments on the Proposed Prevention of Significant Deterioration Permit for the Palmdale Hybrid Power Project," at 40 (Oct. 2011), *available at* http://www.epa.gov/region9/air/permit/palmdale/palmdale-response-comments-10-2011.pdf.

assigns the appropriate BACT limits for the EGU for a reasonable range of load operations. Further, the BACT limits proposed for the LPEC facility would remain unchanged whether it operates as base-load or as a “load cycling unit”. The BACT limits established are as stringent as those in other recent permitting actions and will be met during all loads of operation by LPEC. The MW output for LPEC is based on the proposed operational parameters, with the maximum electricity generated by the steam turbine generator to be 271 MW. This value is based on firing the duct burners at maximum firing capacity.

Comment 29: The Region cannot summarily exempt LPEC from GHG BACT limits during Maintenance, Startup and Shutdown. There is no on-the-record determination as to whether compliance with existing permit limitations is infeasible during startup and shutdown. The blanket exemption fails to comply with BACT requirements, and the permit must ensure that emissions are minimized to the extent achievable during periods of MSS.

Response:

We agree with the commenter that the draft permit’s statement that the “BACT limit . . . does not apply during MSS” is subject to misinterpretation and requires clarification. While we agree that all periods of operation must be subject to the statutory BACT requirements, which include the requirement to have a continuous and enforceable emission limit at all times, startup emissions cannot be included in the lbs of CO_2/MWh limits for practical reasons. During startup, a large portion of the energy input to the combustion turbines is used for heating the turbine casings and rotors, boiler tubes, main steam piping, and other portions of the thermal system, rather than the production of electricity. During this startup period, the steam turbine does not generate electricity in a combined-cycle mode until the thermal equipment is at an appropriate operating temperature and sufficient steam has been produced in the HRSG. Therefore, while the short-term emissions of GHGs during startup do not exceed the hourly emissions during normal operations, the lack of electricity generation during startup means that compliance with the primary BACT limits, which are expressed in lbs of CO_2/MWh, would be negatively affected if startup hours were included. Essentially, with no power output, the denominator in the lbs of CO_2/MWh efficiency measurement will be zero.

As a result, we have added the following startup emission limits, including a tons of CO_2/hr BACT limit, to LPEC’s permit. The startup emission limits apply only during startup hours. The table below will be included in the permit as Table 3.

Turbine Model	tons CO_2/hr	tons CO_2e/yr	Heat Input (MMBtu/hr)
GE 7FA	73	36,000	1,230.6
SGT6-5000F(4)	97	48,362	1,626
SGT6-5000F(5)	94	47,119	1,584.2

Additionally, we have determined that startup emissions shall be limited through a limit on the number of hours of startup on a 12-month rolling basis, as was proposed in the draft permit. We agree that this limit was not clearly stated and have added special permit condition III.A.4.e. to state:

“Startups are limited to 500 hours on a 12-month rolling basis.”

The permit will also be revised to specify that only startup emissions are excluded from the primary BACT limit (lbs CO_2/MWh). Special permit condition III.A.4.h. (formerly condition III.A.4.d.) will be revised to state:

"The 12-month rolling average BACT emission limitations in Special Condition III.A.1. (lb CO_2/MWh) do not include periods of startup and shutdown."

III. Revisions in Final Permit

The following is a list of administrative and clarifying changes for the *La Paloma Energy Center(PSD-TX-1288-GHG) Prevention of Significant Deterioration Permit, Final Permit Conditions*.

1. Cover Sheet
   The cover sheet titled "Prevention of Significant Deterioration Permit for Greenhouse Gas Emissions Issued Pursuant to the Requirements at 40 CFR §52.21" has been modified to state the following:

The signature line has been changed from David F. Garcia, Acting Director to Wren Stenger, Director.

This administrative change is made as a result of a personnel change.

2. Section II. Annual Emission Limits

Table 1A. Annual Emission Limits[1] - General Electric 7FA

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[1,2]	BACT Requirements
				TPY[1]		
U1-STK	U1-STK	Combined Cycle Combustion Turbine/Heat Recovery Steam Generator[4]	CO_2	1,261,820	1,263,055	934.5 lb CO_2/MWh (gross) with duct burning.[5] See Special Condition III.A.1. Startup emissions limited to 500 hours per year and 73 tons CO_2/hr. See Special Conditions III.A.1. and III.A.4.e.
			CH_4	23.4		
			N_2O	2.4		
U2-STK	U2-STK	Combined Cycle Combustion Turbine/Heat Recovery Steam Generator[4]	CO_2	1,261,820	1,263,055	934.5 lb CO_2/MWh (gross) with duct burning.[5] See Special Condition III.A.1. Startup emissions limited to 500 hours per year and 73 tons CO_2/hr. See Special Conditions III.A.1. and III.A.4.e.
			CH_4	23.4		
			N_2O	2.4		

1. Compliance with the annual emission limits (tons per year) is based on a 12-month rolling average.
2. The TPY emission limits specified in this table are not to be exceeded for this facility and include emissions from the facility during all operations and include MSS activities.
3. Global Warming Potentials (GWP): CH_4 = 21, N_2O = 310
4. The annual emissions limit for the combustion turbines is based on operating at maximum duct burner firing for 8,260 hours per year, and operating during startup, shutdown, and maintenance (MSS) for 500 hours per year. The annual emission limit includes emissions from MSS.
5. The lb/MWh BACT limit for the combustion turbine does not apply during startup ~~MSS~~.

Table 1B. Annual Emission Limits[1] - SGT6-5000F(4)

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[1,2]	BACT Requirements
				TPY[1]		
U1-STK	U1-STK	Combined Cycle Combustion Turbine/Heat Recovery Steam Generator[4]	CO_2	1,415,907	1,417,263	909.2 lb CO_2/MWh (gross) with duct burning.[5] See Special Condition III.A.1. Startup emissions limited to 500 hours per year and 97 tons CO_2/hr. See Special Conditions III.A.1. and III.A.4.e.
			CH_4	26.27		
			N_2O	2.6		
U2-STK	U2-STK	Combined Cycle Combustion Turbine/Heat Recovery Steam Generator[4]	CO_2	1,261,820	1,263,055	909.2 lb CO_2/MWh (gross) with duct burning.[5] See Special Condition III.A.1. Startup emissions limited to 500 hours per year and 97 tons CO_2/hr. See Special Conditions III.A.1. and III.A.4.e.
			CH_4	23.4		
			N_2O	2.4		

1. Compliance with the annual emission limits (tons per year) is based on a 12-month rolling average.
2. The TPY emission limits specified in this table are not to be exceeded for this facility and include emissions from the facility during all operations and include MSS activities.
3. Global Warming Potentials (GWP): CH_4 = 21, N_2O = 310
4. The annual emissions limit for the combustion turbines is based on operating at maximum duct burner firing for 8,260 hours per year, and operating during startup, shutdown, and maintenance (MSS) for 500 hours per year. The annual emission limit includes emissions from MSS.
5. The lb/MWh BACT limit for the combustion turbine does not apply during startup ~~MSS~~.

Table 1C. Annual Emission Limits[1] - SGT6-5000F(5)

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[1,2]	BACT Requirements
				TPY[1]		
U1-STK	U1-STK	Combined Cycle Combustion Turbine/Heat Recovery Steam Generator[4]	CO_2	1,594,162	1,595,712	912.7 lb CO_2/MWh (gross) with duct burning.[5] See Special Condition III.A.1. Startup emissions limited to 500 hours per year and 94 tons CO_2/hr. See Special Conditions III.A.1. and III.A.4.e.
			CH_4	29.5		
			N_2O	3		

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[1,2]	BACT Requirements
				TPY[1]		
U2-STK	U2-STK	Combined Cycle Combustion Turbine/Heat Recovery Steam Generator[4]	CO_2	1,594,162	1,595,712	912.7 lb CO_2/MWh (gross) with duct burning.[5] See Special Condition III.A.1. <u>Startup emissions limited to 500 hours per year and 94 tons CO_2/hr. See Special Conditions III.A.1. and III.A.4.e.</u>
			CH_4	29.5		
			N_2O	3		

1. Compliance with the annual emission limits (tons per year) is based on a 12-month rolling average.
2. The TPY emission limits specified in this table are not to be exceeded for this facility and include emissions from the facility during all operations and include MSS activities.
3. Global Warming Potentials (GWP): CH_4 = 21, N_2O = 310
4. The annual emissions limit for the combustion turbines is based on operating at maximum duct burner firing for 8,260 hours per year, and operating during startup, shutdown, and maintenance (MSS) for 500 hours per year. <u>The annual emission limit includes emissions from MSS.</u>
5. The <u>lb/MWh</u> BACT limit for the combustion turbine does not apply during <u>startup</u> ~~MSS~~.

The changes to the emission limit tables were to add a BACT emission limit for startups and to clarify the emission limit for startups.

3. Section III. Special Permit Conditions
III.A.1. Combustion Turbine Generator (CTG) BACT Emission Limits

Table 2. BACT Emission Limits for Combustion Turbines on a 12-month rolling average

Turbine Model	Gross Heat Rate, with duct burner firing (Btu/kWh) (HHV)	Output Based Emission Limit (lb CO_2/MWh) gross with duct burning	<u>Startup Emission Limit (lb CO_2/hr)</u>
General Electric 7FA	7,861.8	934.5	<u>73</u>
Siemens SGT6-5000F(4)	7,649.0	909.2	<u>97</u>
Siemens SGT6-5000F(5)	7,679.0	912.7	<u>94</u>

This change was made to include the additional BACT emission limit that applies during startup.

4. Section III. Special Permit Conditions
Special Permit Condition III.A.1.a. was revised as follows:

a. Within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days of the date of initial startup of the combustion turbine generators, the Permittee shall perform an initial emission test for CO_2 and use emission factors from 40 CFR Part 98. The Permittee shall ensure that GHG emissions from the Combustion Turbine Generator and heat recovery steam generator (U1-STK and U2-STK) into the atmosphere do not exceed the limits in lbs CO_2/MWh (gross) from Table 2, during the test. To determine this BACT emission limit, Permittee shall calculate the limit based on the measured hourly energy output (MWh (gross)), the CTG is operating at, or above 90% of its design capacity with~~out~~ duct burner~~ing~~ firing and the results shall be corrected to ISO conditions (59^{o}F, 14.7 psia, and 67% humidity). If the CTG does not meet the design emissions limit, then the Permittee shall remedy the CTG's failure to meet the design emissions limit, and will make corrections to the CTG and will only combust fuel to perform required tuning and modifications necessary to demonstrate compliance.

This change was made to clarify that the duct burners shall be fired when performing the initial performance test.

5. Section III. Special Permit Conditions
Special Permit Condition III.A.4. Requirements during combustion Turbine (U1-STK and U2-STK) Startup and Shutdown was revised as follows:

c. Startup and shutdown emissions shall not exceed the BACT emission limits in Table 2.
d. The maximum heat input shall be limited to the values identified in Table 3 during startup.
e. Startups are limited to 500 hours on a 12-month rolling basis.
f. The startup emissions and heat input limits are also shown in Table 3 below.

Table 3. Startup Emissions and Heat Input Limitations

Turbine Model	BACT Emission Limit (tons CO_2/hr)	Annual Emission Limit (tons CO_2e/yr)	Maximum Heat Input (MMBtu/hr)
GE 7FA	73	36,600	1,230.6
SGT6-5000F(4)	97	48,362	1,626
SGT6-5000F(5)	94	47,119	1,584.2

g. ~~c.~~ Permittee must record the time, date, fuel heat input (HHV) in MMBtu/hr and duration of each startup and shutdown event in order to calculate total CO_2e emissions. The records must include hourly CO_2 emission levels as measured by the fuel flow meter and/or O_2 emission monitor (or CO_2 CEMS with volumetric stack gas flowrate) and the calculations based on the actual heat input for the CO_2, CO_2e, O_2, N_2O, and CH_4 emissions during each startup and shutdown event based on the equations represented in the permit application. These records must be kept for five (5) years following the date of such event.
h. ~~d.~~ The 12-month rolling average BACT emission limitations in Special Condition III.A.1. does not include periods of startup~~ and shutdown~~.

These changes were made to add a BACT emission limit for startups and to include a heat rate limitation on startups.

6. Section VI. Performance Testing
Special Condition VI.D. was revised as follows:

D. The turbine shall be tested at or above ninety percent (90%) of maximum load operations for the atmospheric conditions which exist during testing. The duct burners shall be tested at their ~~its~~ maximum firing rate within the mechanical limits of the equipment for the atmospheric conditions which exists during the performance test while the turbine is operating as close to base load as possible. The tested turbine load shall be identified in the sampling report. The permit holder shall present in the performance test protocol the manner in which stack sampling will be executed in order to demonstrate compliance with the emissions limits contained in Section II.

This change was made to fix a grammatical error.

IV. Endangered Species Act (ESA)

EPA determined that issuance of the proposed permit will have no effect on fifteen (15) 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. Those fifteen species include: piping plover, Eskimo curlew, interior least tern, smalltooth sawfish, Rio Grande silvery minnow, jaguar, West Indian manatee, South Texas ambrosia, star cactus, Texas ayenia, green sea turtle, Kemp's ridley sea turtle, leatherback sea turtle, loggerhead sea turtle, and Atlantic hawksbill sea turtle.

However, based on the information provided in the Biological Assessment and by the U.S. Fish and Wildlife Service (USFWS), EPA determined that the issuance of the permit may affect, but is not likely to adversely affect, the Northern Aplomado falcon, Gulf Coast jaguarundi and the ocelot. EPA and La Paloma (as EPA's designated non-federal representative) engaged in informal consultation with the USFWS's Southwest Region, Corpus Christi, Texas Ecological Services Field Office and the sub-office in Alamo, Texas. During consultation, USFWS indicated that they have recently released Northern Aplomado falcons in Cameron County, outside of the action area, and that there is potential that the falcon could forage within the action area or perch on transmission lines being constructed for this project. The USFWS also indicated that an irrigation canal located adjacent to the facility as well as other vegetated areas within the action area may provide travel or migration corridors for the ocelot or jaguarundi. USFWS provided recommendations for additional protections of all of these species, which La Paloma has committed to implement. By letter dated March 7, 2013, EPA requested USFWS's written concurrence with EPA's "may effect" determination. USFWS concurred on October 24, 2013.

V. 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 La Paloma Energy Center will not affect properties on or potentially eligible for listing on the National Register. On March 25, 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 April 1, 2013.