U.S. Environmental Protection Agency
Pacific Southwest - Region 9
Clean Air Act Permit

Response to Public Comments on Proposed Prevention of Significant Deterioration Permit

Palmdale Energy Project
PSD Permit No. SE 17-01

April 2018

1. Introduction – Summary of the Public Participation Process

On August 17, 2017, the U.S. Environmental Protection Agency, Region 9 (EPA), provided public notice of, and requested public comment on, the EPA's proposed action relating to a Clean Air Act (CAA or Act) Prevention of Significant Deterioration (PSD) permit application (Application) for the construction of a natural gas-fired combined-cycle power plant known as the Palmdale Energy Project (hereinafter, the Project or PEP). The EPA proposed to issue a PSD permit that would grant conditional approval, in accordance with the PSD regulations governing EPA-issued PSD permits (40 CFR 52.21), to Palmdale Energy, LLC (Applicant) for the Project. The permit would authorize the Applicant to construct and operate the Project, which includes two natural gas-fired combustion turbines, an auxiliary boiler, two emergency engines, circuit breakers, and fugitive equipment leaks.

The EPA announced its proposed permit decision and the public comment period, which included a public hearing, through public notices published on the EPA's website on August 17, 2017. The EPA also distributed the public notices to the necessary parties in accordance with 40 CFR part 124, including notices sent by mail and email on August 17, 2017. Parties notified by Region 9 included agencies, organizations, and public members for whom contact information was obtained through a number of different methods, including requests made directly to the EPA through the EPA Region 9's website. Additionally, we also notified schools, daycare centers, and places of worship near the Project.

Prior to the issuance of this proposed PSD permit decision for the PEP and the commencement of the public comment period on the proposed decision, the EPA held a public information meeting on the PEP application on Saturday, August 5, 2017 at the Sgt. Steve Owen Memorial Park, Stanley Kleiner Activity Center in Lancaster, California. The meeting was announced on July 7, 2017 using the same methods used for announcing the proposed permit decision. As stated in the announcement, the purpose of the public information meeting was to provide the public with an overview of the Application, to discuss the Project from an air quality perspective, and to answer questions related to air quality impacts. The meeting began with introductions followed by a presentation by Lisa Beckham of the EPA's Region 9 Air Permits Office, who provided an overview of the Project. As the meeting was not held during the formal public comment period, the EPA did not formally record remarks from those in attendance but responded to questions posed by attendees.

After the start of the comment period, EPA Region 9 staff also provided an overview of the EPA's proposed PSD permit for interested parties via a webinar that was held on August 30, 2017. The webinar was announced on August 23, 2017, using the same methods for announcing the proposed permit decision. As stated in the announcement, the purpose of the webinar was to provide an overview of the proposed permit, a demonstration of how to find information related to the EPA's proposal, and how to comment on the proposed action. The announcement also explained that the webinar was for informational purposes, and that the EPA would not be accepting comments during the webinar. Comments needed to be submitted in writing by October 6, 2017 or at the public hearing on September 21, 2017.

All data submitted by the Applicant as part of the Application was made available for public review as part of the administrative record for our proposed PSD permit. The administrative record, including the proposed PSD permit, documentation of Region 9's analysis (a Fact Sheet, per 40 CFR 124.8), the Application, and other supporting information, was made available through the Region 9 website at: https://www.epa.gov/caa-permitting/palmdale-energy-project-prevention-significant-deterioration-psd-permit. The proposed PSD permit for the Project and the EPA's August 2017 Fact Sheet for the proposed permit (hereinafter Fact Sheet) were also available for public review at the following locations:

- Antelope Valley Air Quality Management District, 43301 Division Street, Suite 206, Lancaster, CA 93535;
- Palmdale City Library, 700 East Palmdale Boulevard, Palmdale, CA 93550-4742;
- Lancaster Regional Library, 601 W. Lancaster Boulevard, Lancaster, CA 93534-3398; and

- Quartz Hill Library, 42018 N. 50th Street West, Quartz Hill, CA 93536-3590.

As noted above, as part of the public participation process for soliciting comment on our proposed PSD permit for the Project, the EPA provided notice of and held a public hearing to receive written and oral comments, which took place on September 21, 2017, pursuant to 40 CFR 124.12, at the Sgt. Steve Owen Memorial Park, Stanley Kleiner Activity Center in Lancaster, CA. A court reporter recorded all oral comments that were presented at the public hearing. The hearing transcript is included in the administrative record for our final permit decision.

2. The EPA's Responses to Public Comments

The purpose of this document is to respond to every significant issue raised in the public comments received during the public comment period and to explain what changes have been made in the final PSD permit for the Project (hereinafter Final Permit) as compared with our proposed PSD permit. As described in more detail in Section 3, a redline-strikeout version of the final permit showing the changes from our proposed permit is available with our final permit decision. All timely comments were fully considered, regardless of the method used to submit them.

This section summarizes and/or provides excerpts from all significant public comments received by the EPA on our proposed PSD permit decision for the PEP and provides our responses to the comments, including an explanation of what changes have been made, if any, in the Final Permit as a result of those comments. In some instances, similar comments may be grouped together by topic into one comment summary, and addressed by one EPA response. For ease of reading and brevity, we have generally removed citations and references to attachments from our comment excerpts and summaries, but those citations can be found in the original comments. The full text of all public comments and other documents relevant to our PSD permit decision for the Project are available through a link at our website, https://www.epa.gov/caa-permitting/prevention-significant-deterioration-psd-permits-issued-region-9#issued, or at www.regulations.gov (Docket ID # EPA-R09-OAR-2017-0473).

Commenters:

Each set of comments is available through the online docket at www.regulations.gov, Docket ID: EPA-R09-OAR-2017-0473. For reference, the 4-digit docket document ID is provided below in parentheses following the commenter's name; docket document IDs follow the format: EPA-R09-OAR-2017-0473-XXXX (unique 4-digit document ID).

Oral commenter

- Jack Ehernberger – Public Hearing Transcript (0019), also submitted separate written comments)

Written commenters:

- Jacqueline Ayer (on behalf of Save Our Rural Town) (0012)
- Jacqueline Ayer (on behalf of Save Our Rural Town) – Includes 2 Attachments (0013)
- Linda Sheppard (0014)
- Gregory S. Darvin, Senior Meteorologist, Atmospheric Dynamics, Inc. (on behalf of the Applicant) (0015)
- Center for Biological Diversity, California Communities Against Toxics, Desert Citizens Against Pollution and Sierra Club, National Air Team (collectively referred to hereinafter as "Conservation Groups") – includes 15 Exhibits (0016)
- Jack Ehernberger – Copy of comments concerning the Palmdale Hybrid Power Project to the California Energy Commission from 2011 (0017)

- Jack Ehernberger – emailed comments (0018)
- Lee Claus, Director of Cultural Resources Management, San Manuel Band of Mission Indians (0020)

Comments and Responses on the Proposed Prevention of Significant Deterioration Permit for the Palmdale Energy Project

Pollution and Health Effect Concerns

Comment 1:

Commenter: Linda Sheppard (0014)

The commenter questioned why the plant would be built at all. She is concerned that her area has bad air quality, that California has enough electricity now, and that the electricity generated is being sold out of state.

The commenter asserted that the drift of pollution goes over 2 elementary schools and a soccer complex. She stated that as a former primary teacher, she knows that many children in her area suffer with breathing problems.

The commenter further asserted that global warming is a real issue. She stated that it is up to the EPA to protect air quality, and requested that the EPA not issue the permit, further stating that any amount of pollution is too much.

Response 1:

The commenter did not provide details regarding her comment, such as which air emissions from the Project are of concern; however, the EPA acknowledges that there is an ozone air quality problem in the Antelope Valley. The Antelope Valley is currently designated as a severe ozone nonattainment area because the area exceeds the EPA's health-based air standard for ozone. The EPA's health-based air standards are known as the National Ambient Air Quality Standards (NAAQS).

However, the PSD permit issued by the EPA in this action addresses only those NAAQS pollutants for which the local area has been designated by the EPA as attainment or unclassifiable. The CAA and its implementing regulations[1] provide that prior to the issuance of a PSD permit, the EPA must determine that the permit applicant has demonstrated that the project to be permitted will not cause or contribute to a NAAQS or PSD increment violation for the pollutants that are addressed by the permit. The EPA is issuing a final PSD permit for the PEP because we have determined that the Applicant has demonstrated that the Project will meet this requirement and all other applicable PSD requirements. In making this NAAQS demonstration, the modeling analyses that were conducted by the Applicant appropriately examined impacts from the Project in areas outside the fenceline of the Project, including the areas that concern the commenter, and the EPA determined that the information presented demonstrated the Project's compliance with the applicable NAAQS and PSD increments. Section 7 of the Fact Sheet describes the modeling that was conducted and provides a detailed discussion of the EPA's analysis supporting this determination.

We also note that, while beyond the scope of our PSD permit action, the Act contains additional requirements that must be met for major sources, like power plants, that would be located in an ozone nonattainment area before such sources may be granted preconstruction approval. These requirements, referred to as Nonattainment New Source Review or NNSR, help ensure that a new project will not interfere with reasonable further progress toward attaining the ozone standards. These additional NNSR requirements include the application of pollution control technology that meets the Lowest Achievable Emission Rate (LAER), and the requirement that the

[1] As noted above, the governing regulations for an EPA-issued PSD permit are found at 40 CFR 52.21.

applicant obtain emission reductions from other pollution sources to offset the emission increases from the project of the pollutants that cause ozone – oxides of nitrogen (NO_X) and volatile organic compounds (VOC). The Antelope Valley Air Quality Management District (AVAQMD), the local air permitting authority, administers the NNSR permitting program in the Antelope Valley, and issued the NNSR permit (known as a Final Determination of Compliance or FDOC) for this Project after determining that the Applicant met the applicable NNSR requirements.

Thus, given the protections in the Act with which the Applicant must demonstrate compliance to obtain approval to construct and operate the Project, we do not expect this Project to lead to a violation of the NAAQS in any area, including those areas of concern identified by the commenter.

Regarding global warming, the Final Permit for the Project applies emission limits that represent the Best Available Control Technology (BACT) for emissions of greenhouse gases (GHGs)[2], consistent with CAA requirements. GHGs have been identified by the EPA as the major contributors to climate change. For a new major stationary source, like the PEP, GHGs become subject to regulation under the PSD program when the source is a major stationary source for a regulated NSR pollutant other than GHGs, and will emit, or will have the potential to emit, 75,000 or more tons per year (tpy) of carbon dioxide equivalent emissions (CO_2e). Once the PSD program is triggered for GHGs for a new major stationary source, the Permittee must apply BACT for GHGs to the new major stationary source. 40 CFR 52.21(j). In this case, we have determined that the Project will meet these PSD BACT requirements that relate to pollutants that contribute to climate change.

The commenter also asserted that California has enough electricity now, and that electricity is being sold out of state, which appears to be a suggestion that the EPA deny the PSD permit application for the Project based on a lack of need for the Project. In this case, the EPA does not agree that it should deny the permit application for the Project for the reason stated by the commenter. Regarding the question of need for electricity from the Project, the relevant portion of the CAA is section 165(a)(2), which provides that PSD permitting authorities must provide the public with the opportunity to comment on "the air quality impact of [the proposed] source, *alternatives thereto,* control technology requirements, and other appropriate considerations[.]" CAA § 165(a)(2), 42 U.S.C. § 7475(a)(2) (emphasis added). The EPA's Environmental Appeals Board (EAB or Board) interprets this language to allow, but not require, a PSD permitting authority to consider a no-build alternative. *See In re Prairie State Generating Co.,* 13 E.A.D. 1, 32-33 (EAB 2006); *In re City of Palmdale*, 15 E.A.D. 700, 742-43 (EAB 2012). The EAB has made clear that the permit issuer does not have an obligation to independently investigate alternatives beyond those raised in public comments, including a no-build alternative. Further, the Board has observed the importance of this limitation on the permit issuer's obligation, particularly where the evaluation of need for additional electrical generation capacity would require a rigorous and robust analysis and would be time-consuming and burdensome for the permit issuer. In such circumstances, the permit issuer is granted considerable latitude in exercising its discretion to determine how best to apply scarce administrative resources. *Id*.

The EPA has noted previously that, in California, to conduct a reasoned analysis to determine the need for a specific natural gas-fired power plant, either within the State as a whole or in a particular geographic location within the State, the EPA would need to consider a myriad of extremely complex factors and detailed information.[3] The Region has the discretion, but is not required, to conduct an independent analysis of the need

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[2] For purposes of the PSD permitting program, GHGs is the air pollutant defined in 40 CFR 86.1818-12(a) as the aggregate group of six greenhouse gases: carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. 40 CFR 52.21(b)(49)(i).

[3] We note that there are State agencies within the State of California that do generally consider such questions, including the California Energy Commission and the California Public Utilities Commission. However, we are not evaluating or deferring to the analyses or determinations of any such agencies concerning the need for the PEP or similar electrical generating units in making our PSD permit decision for the PEP.

for the PEP in the context of this PSD permit proceeding. *See In re Pio Pico Energy Center*, 16 E.A.D. 56, 73-83 and n.15 (EAB 2013) (upholding Region 9's decision not to conduct an independent analysis of the need for the facility at issue); *In re City of Palmdale*, 15 E.A.D. at 742-46 (same). In this case, the EPA does not believe that it would be appropriate for the EPA to conduct the type of rigorous and robust analysis that would be required to definitively determine the need for the PEP in the context of this PSD permit decision.

In sum, we are issuing a final PSD permit for the Project because we have determined that the Applicant has demonstrated that the Project will comply with all applicable requirements of the PSD program at 40 CFR 52.21.

Downtown Lancaster Ambient Monitoring Station Data Insufficient to Conclude that the Antelope Valley is in Attainment for $PM_{2.5}$

Comment 2:

Commenter: Jacqueline Ayer (on behalf of Save Our Rural Town)

The two comment excerpts below reflect comments from the commenter identified above.

The commenter expressed concern that the EPA has failed to install ambient monitors to establish the attainment status of Antelope Valley. The commenter also expressed concern about local adverse health effects data in Antelope Valley, specifically chronic obstructive pulmonary disease (COPD) and asthma. The commenter asserted that the data from the ambient monitoring station in downtown Lancaster provide an insufficient basis for the EPA to conclude that the Antelope Valley is in attainment for $PM_{2.5}$, and pursuant thereto, to issue a PSD permit. The commenter also asserted the following points:

As I understood from the meeting last week, you are able to collect air samples to take a snapshot of particulate matter equal to or less than 10 micrometers in diameter (PM_{10}) and particulate matter equal to or less than 2.5 micrometers in diameter ($PM_{2.5}$) concentrations in the Antelope Valley as part of this PSD permit effort. Based on the email I received, it appears that the EPA has chosen not to take this step. So now I would like to know what the EPA is going to do about air quality in the Antelope Valley which (based on the COPD and asthma data I have already provided) provides residents with the poorest quality of respirable air in the nation and is an egregious example of non-existent "clean air" environmental justice.

The local authorities have willfully and intentionally failed to install the ambient monitors needed to establish the attainment status of the Antelope Valley. This has allowed these same local authorities to avoid developing the type of pollution control regulations that are so desperately needed in the Antelope Valley to protect the health and safety of residents.

Attached please find a picture taken last Sunday on a breezy day in the Antelope Valley; note the reddish-brown layer of haze that is so thick that it obscures the view of the Tehachapi Mountains less than 30 miles away. Just so you know, the reddish-brown color of the haze is not NO_2 and it is in fact the exact same color as the dirt in the Antelope Valley. Do you really think that that the prevalence of ambient dust in the Antelope Valley as shown here is not an air quality problem and does not pose a health risk? So now I want to know what the EPA is going to do about it.

I would like to provide you with supplemental information regarding the extent to which windblown dust in desert areas with little vegetation and high agricultural penetration can be a major source of $PM_{2.5}$. Attached please find the EPA-approved SIP for the portion of Imperial Valley that is designated non-attainment for $PM_{2.5}$. Please note that 80% of their $PM_{2.5}$ comes from four sources: Unpaved road dust, fugitive windblown dust, farming, and "managed burning" (i.e., "ag" burning). Very little of their $PM_{2.5}$ comes from mobile sources.

Here in the Antelope Valley, we have everything that Imperial Valley has (limited vegetation, high windblown dust, a significant inventory of agricultural operations - both active and defunct, and ag burning). Additionally, the Antelope Valley has much higher wind speeds than what occurs in the Imperial Valley. In fact, Antelope Valley wind speeds are twice that of the Imperial Valley during the spring and summer months. And, unlike the Imperial Valley, there are 100,000 vehicle trips made every weekday on the 14 Freeway. In other words, the Antelope Valley has hit the "trifecta" in terms of $PM_{2.5}$ sources: high wind-born dust levels, high wind speeds, and a high mobile source inventory. Add to that our significant health problems. As I stated this morning, recent health studies demonstrate just how unhealthy our air quality is. I have attached the health study that was recently released by the County of Los Angeles, and provide highlights below. Please note: the high incidence of COPD in the Antelope Valley is not due to smoking. As set forth in the attached, the percentage of people who smoke in the Antelope Valley is only slightly higher than the percentage of smokers found in the South Bay portion of Los Angeles County. However, the COPD rates in the Antelope Valley are nearly double the rates found in the South Bay area.

I am challenging the EPA's and AVAQMD's "going-in" position that the Antelope Valley is in attainment with $PM_{2.5}$. As I understand it, this conclusion is based solely on monitoring results obtained from the downtown Lancaster ambient monitoring site. If, as you suggest, $PM_{2.5}$ is anthropogenic, then you are advised that your own meteorological data proves that downtown Lancaster is not a reliable sampling location to properly quantify ambient $PM_{2.5}$ levels generated by the 100,000 vehicle trips per day occurring on the 14 Freeway. If, as I suggest, windblown dust is a major source of $PM_{2.5}$ in the Antelope Valley, then downtown Lancaster is also an unreliable sampling location to properly quantify ambient $PM_{2.5}$ levels because the city serves as an "urban filter" which separates the $PM_{2.5}$ sampler from the $PM_{2.5}$ source and prevents the collection of representative data except during "extreme" dust storm events. Either way, data from the ambient monitoring station in downtown Lancaster provide an insufficient basis for EPA to conclude that the Antelope Valley is in attainment for $PM_{2.5}$, and pursuant thereto, issue a PSD permit.

Response 2:

The EPA disagrees that there is insufficient information regarding $PM_{2.5}$ to issue a final PSD permit for this Project. The Antelope Valley has been designated by the EPA as "attainment/unclassifiable" for the $PM_{2.5}$ NAAQS. See [40 CFR 81.305](). The PSD program applies "to the construction of any new major stationary source (as defined in paragraph (b)(1) of this section) or any project at an existing major stationary source in **an area designated as attainment or unclassifiable** under sections 107(d)(1)(A)(ii) or (iii) of the Act." (emphasis added) 40 CFR 52.21(a)(2)(i). See also CAA section 161. Because the Antelope Valley has been designated by the EPA as attainment or unclassifiable for the $PM_{2.5}$ NAAQS, the Applicant for this Project must obtain a preconstruction permit under the PSD program for $PM_{2.5}$.

It is unclear what the commenter is referring in stating that the EPA said it was "able to collect air samples to take a snapshot of PM_{10} and $PM_{2.5}$ concentrations in the Antelope Valley as part of this PSD permit effort." During the public information meeting held on August 5, 2017, and in an email sent the same evening, the commenter raised concerns related to $PM_{2.5}$ in Antelope Valley. In response to those concerns, we reviewed available information related to $PM_{2.5}$ in the Antelope Valley, including recent $PM_{2.5}$ monitoring data, prior to making our proposed PSD permit decision for the Project and did not find any information that substantiated the commenter's claim that the Antelope Valley is not attaining the $PM_{2.5}$ NAAQS. Additionally, we have treated the issues raised in the commenter's August 5, 2017 email as comments on our proposed action and are responding to them in this response.

Additionally, the underlying determination of the Antelope Valley's area designation for the NAAQS is outside the scope of this PSD permit action as such designations are made through a separate regulatory process.

Nonetheless, for informational purposes, below we provide additional discussion regarding the commenter's concerns that the Antelope Valley should be designated as nonattainment for $PM_{2.5}$.

Area designations are based on ambient air monitoring data. See 40 CFR 58 Appendix D, Section 1.1(b). The siting (location) of monitors used to make the area designations must meet certain regulatory requirements, including those in 40 CFR part 58, Appendix D. Section 4.7.1 of 40 CFR 58 Appendix D refers to the minimum monitoring requirements for $PM_{2.5}$ network design criteria relevant to the selection and establishment of ambient air quality monitoring stations needed to achieve an adequate monitoring network. The ambient air monitoring sites in Antelope Valley, including the Lancaster-Division Street monitor (AQS ID: 06-037-9033), are located within Los Angeles County, which is part of the Los Angeles-Long Beach-Santa Ana, CA metropolitan statistical area (MSA). The ambient $PM_{2.5}$ monitoring network within this MSA meets the substantive requirements of 40 CFR part 58 Appendix D, including the requirement under Section 4.7.1 to include at least one $PM_{2.5}$ monitoring site located at neighborhood or larger scale in an area of expected maximum concentration in the MSA. Furthermore, the Lancaster-Division Street monitor meets the other substantive requirements of 40 CFR part 58, including siting at an adequate spatial scale of representativeness to support the monitoring objective of NAAQS compliance.[4]

The $PM_{2.5}$ area designation for the Antelope Valley is based on the air monitoring data obtained from the Lancaster-Division Street monitor, which the EPA has determined fulfills the requirements for designating an area. Currently, there are two $PM_{2.5}$ NAAQS – an annual standard and a 24-hr standard.[5] The EPA mostly recently reviewed these standards in 2012 and lowered the annual standard to 12 micrograms per cubic meter ($\mu g/m^3$), but retained the 24-hour standard of 35 $\mu g/m^3$ that was set in 2006. 78 Fed. Reg. 3085 (Jan. 15, 2013). The Antelope Valley (which is the Los Angeles County portion of the Mojave Desert Air Basin) was designated as attainment/unclassifiable for the annual $PM_{2.5}$ standard on January 15, 2015 (80 Fed. Reg. 2206) and for the 24-hour $PM_{2.5}$ standard on November 13, 2009 (74 Fed. Reg. 58688).

We also disagree with the commenter's assertion that the fact that Imperial County is a $PM_{2.5}$ nonattainment area demonstrates that there is a similar problem in Antelope Valley because the two areas have similar air quality characteristics (such as limited vegetation, high windblown dust, a significant inventory of agricultural operations). The main distinction between Antelope Valley and Imperial County with respect to $PM_{2.5}$ considerations is the proximity of the U.S – Mexico border to Imperial County and transport of $PM_{2.5}$ and associated precursors from the City of Mexicali, in Mexico, to monitors located 0.7 miles north of the border in Imperial County. The monitoring site in Imperial County that is near the border has historically measured higher concentrations than the rest of the county. Imperial County also has monitoring sites located farther away from the U.S – Mexico border, in the cities of Brawley and El Centro, which are also surrounded by sources similar to those found in Antelope Valley. Comparison of the most recent $PM_{2.5}$ data show that the annual averages calculated from January 1, 2017 to October 31, 2017 for monitoring sites in Brawley, El Centro, and Lancaster are fairly similar at 8.75, 8.28, and 7.16 $\mu g/m^3$, respectively. While we agree that there are some similarities between the two areas, this is not necessarily an indication that the Antelope Valley is not attaining the $PM_{2.5}$ NAAQS.

In sum, the Antelope Valley is designated as unclassifiable/attainment for the $PM_{2.5}$ NAAQS and that determination followed the proper regulatory process and requirements.[6]

[4] See Annual Network Plan, California Air Resources Board, July 2017 at 33-38.

[5] See https://www.epa.gov/criteria-air-pollutants/naaqs-table.

[6] We also determined that Lancaster-Division Street monitor is adequately representative for purposes of modeling $PM_{2.5}$ for the Project because the location is more urbanized than the PEP site, and thus considered conservative for representing background concentration data. See Fact Sheet at page 51.

The commenter also raised concerns regarding health issues in the Antelope Valley. The commenter is concerned that existing health problems are directly related to a $PM_{2.5}$ problem that has not been identified by the EPA. However, the health issues identified in the information provided by the commenter (asthma and COPD) are not surprising because the area is designated as nonattainment for the 2008 ozone NAAQS. Specifically, the area is categorized as "severe 15" nonattainment for the 2008 ozone standard, meaning local air quality conditions violate the EPA's primary health-based standards for ozone and are between 0.113 and 0.119 parts per million (ppm) compared to the standard of 0.075 ppm. Our August 2017 Environmental Justice Analysis for the PEP (hereinafter "EJ Analysis") specifically identified the health issues raised by the commenter as being associated with elevated ozone levels. EJ Analysis at 8. We do not agree that the existence of the health problems in the Antelope Valley can specifically be tied to an unidentified $PM_{2.5}$ problem. Our EJ Analysis also discussed the steps being taken by the EPA, California, and the local air districts to address the ozone problem in Antelope Valley:

> With respect to ozone levels in the Antelope Valley, the EPA, the State of California and the local air districts are working diligently through the air quality planning process under the CAA to ensure that there is a comprehensive plan with adequate controls for attaining the 75 parts per billion (ppb) NAAQS for ozone.[7] The EPA is currently reviewing the State of California's 2016 plan for the Western Mojave Desert ozone nonattainment area, which includes the Antelope Valley. This plan and the State's analysis of it may be found on the California Air Resources Board (ARB) website at: https://www.arb.ca.gov/planning/sip/planarea/mojavesedsip.htm#2016. The plan was open for public comment before it was adopted by the local air districts and before it was adopted by the State. When the EPA proposes action on this plan, there will be an additional comment period on that action.
>
> The FDOC issued by the District addresses ozone precursors – NO_X and VOC – as the Project does not directly emit ozone. Ozone is a regional pollutant that forms through photochemical reactions with NO_X and VOC. While this Project will add ozone precursors, the Applicant is required to obtain offsets for its emissions increases from reductions in NO_X and VOC emissions from other nearby sources. As such, we do not expect the Project to interfere with attainment of the ozone NAAQS.

EJ Analysis at 8-9.

Temperature Inversion Concerns

Comment 3:

Commenter: Jack Ehernberger (0018)

The commenter asserted that the Antelope Valley is subject to nocturnal temperature inversions which cap or "put a lid on" the mixing of PEP emissions and thereby keep them concentrated near the ground. The commenter is also concerned that the nocturnal temperature inversion will also strongly affect sound and noise propagation. The commenter asserts that without modeling data of the atmospheric sound focusing effects in Lancaster and Palmdale, the Air Quality modeling for the Project is seriously incomplete. The commenter was glad to see some treatment added on sound and acoustic annoyances, but stated that on the sound annoyances, the same issue pertains, and that it's very sensitive to the atmospheric structure in the lower atmosphere because of the phenomena of sound focusing. The commenter asserted that one can have receptor locations miles away from the source where the focus has increased the intensity above the source strength. The commenter stated that the information didn't really deal with that issue to see if the sound comes close to something that would be a concern. But if there is an attempt to model the sound, it also needs to be a good representation of lower atmosphere.

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[7] We note that the EPA has not yet made designations for the 2015 ozone standard of 70 ppb. Plans for attaining the 2015 ozone standard will not be developed until the EPA makes such designations.

The commenter stated that the intent of his oral and written testimony was to recommend and request that the PEP PSD permit not be approved.

Response 3:

To the extent that the commenter is suggesting that our air quality analysis must consider the potential for temperature inversions, we agree. Our ambient air quality impact analysis considers the worst-case conditions, including the worst-case weather conditions. Our analysis relied on meteorological data from the Palmdale Regional Airport, which includes data on wind speed and direction, temperature, pressure, cloud heights, and sky cover, and would include any conditions related to a nocturnal temperature inversion in the area. See Fact Sheet at 71.

The EPA is not required to analyze sound and noise propagation as part of its analysis when issuing a PSD permit. As such, the EPA's permit record does not address sound or noise propagation issues associated with the PEP. The commenter appears to be addressing an analysis conducted by the California Energy Commission (CEC) as part of its licensing process for the Project. Because this comment addresses an analysis that is outside the scope of our PSD permit action, we are not addressing it further. However, for informational purposes, we point the commenter to the CEC's decision for the Project and its analysis of noise and vibration.[8]

Regarding the commenter's request that PEP PSD permit not be approved, the EPA has carefully reviewed and considered the comments submitted by all commenters. However, as discussed in more detail in our other responses, we continue to determine that the Applicant has satisfied the PSD permitting requirements in 40 CFR 52.21 and are therefore issuing a final PSD permit for the Project.

The Fact Sheet Did Not Provide a Basis for the Determination that the PEP is Below the Significance Threshold for Identified Sulfur Containing Pollutants

Comment 4:

Commenters: Conservation Groups (0016)

The commenters asserted, as detailed in the excerpt below, that the Fact Sheet does not provide an explanation of the basis for the statement that the PEP is below the significance threshold for identified sulfur containing pollutants.

40 CFR 124.8(b)(4) requires that fact sheets include a brief summary of the basis for the draft permit conditions including references to the administrative record. The PEP Fact Sheet states that PEP is below the significance threshold for sulfuric acid mist (H_2SO_4), hydrogen sulfide (H_2S), sulfur dioxide (SO_2), total reduced sulfur, and reduced sulfur compounds. However, the Fact Sheet does not provide any references to the administrative record or any other basis for this determination. Thus, the Fact Sheet's conclusion, and resultant lack of BACT emission limits for these sulfur-containing pollutants, are without any support and violate 40 CFR 124.8(b)(4).

Response 4:

We disagree with the commenters' argument that our Fact Sheet's conclusion that certain sulfur-containing compounds from the Project would be below the significance threshold was without support or was otherwise erroneous. We also disagree with the commenters' argument that the lack of BACT emission limits for such compounds is without support or is otherwise erroneous. The Fact Sheet contained the EPA's basis for determining that the Project does not trigger the PSD program for these compounds. Specifically, Table 2 of the Fact Sheet contained our determination that the Project would emit H_2S, total reduced sulfur, and reduced sulfur compounds emissions at less than 1 ton per year, and that sulfur dioxide and sulfuric acid mist emissions would be

[8] See the CEC's Final Commission Decision, Palmdale Energy Project Amendment, Section VI.D – Noise and Vibration.

below the PSD significant emission rate thresholds. Therefore, the Project did not trigger PSD review for these pollutants. Fact Sheet at 11.

Generally speaking, for the combustion of natural gas and diesel, we expect emissions of H_2S, total reduced sulfur, and reduced sulfur compounds to be very low. We expect the sulfur in natural gas and diesel to be oxidized during combustion creating the oxidized sulfur compounds of SO_2 or H_2SO_4.[9] We do not expect sulfur to be reduced through combustion (creating hydrogen sulfide or other reduced sulfur compounds), as the reduction process is the opposite chemical process of oxidation. We also note that natural gas contains very low quantities of sulfur, and Condition 17 of the Final Permit limits the sulfur content in the natural gas used at the PEP. Similarly, the diesel fuel used in the emergency engines will be ultra-low sulfur diesel through the use of nonroad diesel. See Conditions 24.f and 25.f of the Final Permit. We are not aware of any information to suggest that the emissions would be greater than we estimated, nor did the commenters provide any information that indicates that the EPA's determination in this regard was in error. Accordingly, we continue to find that the Project is not subject to PSD review for these compounds and that therefore no further permit conditions relating to these pollutants are warranted.

We also disagree with the commenters that our Fact Sheet did not meet the requirements of 40 CFR 124.8(b)(4) with respect to its discussion of these sulfur-containing compounds. This regulatory provision requires that the EPA provide a brief summary of the basis for the draft PSD permit's conditions. It does not require that the Fact Sheet provide a detailed discussion of the pollutants that are not regulated under the permit. The discussion in the Fact Sheet and this response to comments document is a sufficient explanation on the record to explain why PSD review does not apply to the sulfur-containing compounds at issue for purposes of the Project.

The Auxiliary Boiler Stack Height is Not Consistent with Good Engineering Practice

Comment 5:

Commenters: Conservation Groups (0016)

The commenters stated that the 60-foot stack height for such a small device as the auxiliary boiler does not appear consistent with good engineering practice (GEP). The Fact Sheet must reference where in the administrative record the GEP analysis is.

Response 5:

The EPA disagrees with the commenter that stack height for the auxiliary boiler is inconsistent with GEP. The EPA discussed GEP stack height for the Project in Section 7.4.4 of the Fact Sheet, which also referenced information in the PSD permit application concerning the GEP stack height analysis. All stacks at the PEP will be less than the calculated GEP stack height, and, as such, the actual stack height for each unit was used in the modeling. See Fact Sheet at 68.

The Facility Definition Is Unclear and Unstable

Comment 6:

Commenters: Conservation Groups (0016)

The commenters (in the excerpt below) opined that some stability in how the source is defined needs to be established or no meaningful analysis can occur, in that the PEP facility is framed as a baseload project, a peaker

[9] Because we expect SO_2 and H_2SO_4 to be created by the combustion process, we estimated these emissions to be higher than those for H_2S and reduced sulfur compounds, 11 tpy and 4.8 tpy respectively. These estimates are based on the sulfur content of the fuel and manufacturer's data. See October 2015 Application at Appendix A for emissions calculations and Table 2-9 regarding the manufacturer's information for H_2SO_4.

project and a load-following project. The commenters asserted that this is an unstable description and could be utilized in such a way that it unlawfully narrows the field of "inherently lower-emitting processes/practices/designs."

The application describes the Project as:

> The Palmdale Energy Project (PEP) is proposing to construct and operate a fast start (Flex Plant) 645 MW (nominal average annual rated) natural gas-fired combined-cycle power plant. The Flex Plant design project will operate up to approximately 8,000 hours per year, with an expected facility capacity factor at 60 to 80 percent. However, the dispatch profile may change as market conditions evolve. As a result of the potential dispatch profiles, and to permit the possible worst case operational scenarios, two (2) additional operational profiles were considered beyond the base load case which are based on more of a cycling or peaking type of project.

In the Fact Sheet for the draft permit, the EPA describes the Project in the following manner:

> The Project is designed to provide flexible capacity from natural gas to the California Independent Systems Operator (CAISO) with an expected capacity factor of 60 to 80 percent. Flexible capacity natural gas resources typically operate to meet the ramping and peak load requirements in the morning and late afternoon, helping to integrate the ramp up and ramp down of solar generation provided by other facilities.
>
> …
>
> The Project is designed to act as a load following unit with an expected facility capacity factor of 60 to 80 percent. However, as noted above, the Project is intended to provide flexible capacity to the CAISO, thus the Project's actual dispatch profile must adapt to market conditions, which will result in different operational scenarios at different times. That is, as needed, the plant may act like a peaking plant (approximately 4,320 hours a year) or a baseload plant (approximately 8,000 hours a year), or on an intermediate basis (approximately 5,000 hours a year), to meet the shifting demands of the electric grid.

Because the BACT analysis is limited, and the EPA will not consider a proposed alternative that would "redefine the design of the source," it is critical that the definition is clear, stable and not so tied to the proponent's preferences that no BACT can be applied. The commenters note that in Step 1 of the BACT analysis, the EPA generally considers the capabilities of add-on air pollution control technologies, inherently lower-emitting processes/practices/designs, and combinations of the two that are potentially available and applicable for use at the proposed facility. Add-on controls typically filter and remove pollutants from facility exhaust streams, while inherently lower-emitting processes/practices/designs generate fewer air contaminants in production processes. The EPA encourages permit issuers to "cast a wide net" at this stage of the BACT analysis, thereby compiling a "broad array" of potential emissions control options that they can examine more closely in subsequent steps of the analysis. But consideration of fundamentally different facility types than those proposed by permit applicants generally is not required. If a permitting authority decides that a proposed alternative would constitute a redefinition of the source, it will not list the alternative as a potential control option in Step 1 of its BACT analysis, and it will not consider that option further.

The PEP facility is variously framed as a baseload project, a peaker project and a load following project. This is an unstable description and is so closely tied to the proposed facility and the varying ways it could be utilized that it unlawfully narrows the field of "inherently lower-emitting processes/practices/designs" by definition. As such, in essence, only the PEP facility as designed could fit the description.

For example, here, at Step 1 of the GHG analysis in the Fact Sheet, the EPA rejected the solar hybrid alternative that would reduce GHG emissions because they would "redefine the design of the source" because the project is described as "intermediate load following" or "flexible capacity" and not baseload, although as explained elsewhere in these comments, the EPA itself describes the project as possibly also being used for baseload elsewhere. In this way, the overly broad and unstable definition is used to undermine meaningful BACT analysis and public review of the draft permit.

The commenters asserted that the project definition is so unstable that the EPA cannot fairly conduct a BACT analysis of alternatives. The commenters cited NEPA case law for the proposition that where purpose and need defined by the agency is used to develop alternatives, agencies cannot narrow the purpose and need statement to fit only the proposed project and then shape their findings to approve that project without a "hard look" at the environmental consequences. An agency cannot define its objectives in unreasonably narrow terms, and the statement of purpose and alternatives are closely linked since the stated goal of a project necessarily dictates the range of reasonable alternatives.

Citing additional case law under NEPA, the commenters further asserted that (1) the public review process cannot be used to rationalize or justify decisions already made, and to do so would allow an agency to circumvent meaningful review by simply going-through-the-motions; and that (2) the agency cannot camouflage its analysis or avoid robust public input because the very purpose of a draft and the ensuing comment period is to elicit suggestions and criticisms to enhance the proposed project. The agency cannot circumvent relevant public input by framing the purpose and need so that no alternatives can be meaningfully explored or by failing to review a reasonable range of alternatives.

Response 6:

The commenters are correct that the proposed Project is designed and intended to operate in different modes depending on changes in demand from the electric grid. However, we disagree with the commenters' assertions that the source definition for the Project is overly broad, unstable, or unclear, or that the fundamental business purpose or design of the Project was otherwise improperly defined to avoid the consideration of control options or alternatives or public input thereon.

The Fact Sheet and the Application provided sufficient information to detail the manner in which the Project is intended and expected to operate, which is more variable than that of many proposed natural gas-fired electrical generating units (EGUs) that we have evaluated in the recent past. The Project is generally intended to serve as an intermediate/load-following or flexible capacity unit, which may operate as a peaking plant or temporary baseload plant at times. The source must be able to respond to changes in demand from the electric grid. The source's ability to respond to ramping and peak load needs, as well as operating in different modes in response to market demand, is inherent to the Applicant's basic business purpose and design. As discussed in the Fact Sheet, the current state of the electricity market in California requires highly flexible EGUs that must be able to perform in a variety of situations, which has resulted in the recent development of this Project and other EGUs that differ in certain respects from the types of natural gas-fired EGUs that were typically developed in the past to serve the California electricity market. As part of our GHG BACT analysis, we looked at other recently permitted similar sources in California and concluded that the Applicant's purpose and design is consistent with other recently permitted projects in California. Fact Sheet at 26. As discussed in Response 12 below, we have determined that the business purpose and design was identified by the Applicant for reasons independent of air quality, and the commenters have not demonstrated otherwise. And, we do not believe that it is necessary or appropriate for the Applicant to alter the fundamental business purpose of the Project through the PSD permitting process. In sum, the commenters have not shown that there is any reason to doubt the Applicant's stated purpose of providing flexible capacity in order to satisfy current needs in the California energy market such that the Applicant's stated purpose and design should be considered incorrect or improper.

The commenters' citation to judicial decisions regarding project purpose and the consideration of alternatives in the context of compliance with the National Environmental Policy Act (NEPA) does not change our determination in this regard. We note that judicial decisions interpreting the requirements of NEPA, a wholly different statute that is largely procedural in nature, do not govern our interpretation of the substantive Clean Air Act permitting requirements concerning the application of BACT.[10] The scope of necessary considerations for the two analyses are defined by two completely different schemes. The scope of our review in PSD permitting is governed by the Clean Air Act, its implementing regulations, and our guidance. The analysis of alternatives in this permitting action was fully consistent with the business purpose identified by the Applicant that was chosen for reasons independent of air quality permitting.

The EPA Should Have Considered the Use of Batteries Instead of Duct Burners in Its NO_X and CO BACT Analysis

Comment 7:

Commenters: Conservation Groups (0016)

The comment excerpted below asserted that the EPA's NO_X and carbon monoxide (CO) BACT analysis for the PEP's combustion turbine (CTs) failed to consider using batteries rather than duct burners for meeting peak demand and provides an explanation as to why the commenters believe that batteries need to be considered in the BACT analysis with respect to the duct burners. The commenters provided the following arguments:

In step 1 of the NO_X BACT analysis for the CTs, the EPA failed to consider using batteries rather than duct burners for meeting peak demand. Batteries would reduce both CO and NO_X as well as GHG, which is discussed elsewhere. Therefore, when the EPA does the cost effectiveness analysis in Step 4, the EPA needs to consider the cost per ton by combining the tons of NO_X, CO, and GHG.

Turning to why batteries need to be considered in step 1 of the NO_X and CO BACT analysis for the CTs, batteries are technologically feasible to replace the duct burners, and are the preferred technology for pairing with renewable energy generation, which PEP claims is its purpose. The EPA does not provide a heat rate for the duct burners in the Fact Sheet but we assume both duct burners are in the range of providing 40 megawatts (MW) total of additional energy and are limited to 1500 hours per year. Thus, PEP would need approximately 60,000 megawatt-hours (MWh) annually of storage.

Batteries of this size are commercially available. The world's largest lithium-ion battery system is 100 MW, which is significantly larger than what PEP would need. The EPA failed to consider this system. The system is commercially available because Tesla has already signed a contract for such a system. As of the end of September 2017, the system is already half in place. The 100 MW Tesla system is designed to meet PEP's stated business purpose, that is to smooth out volatility caused by wind and solar generation. This system is so large that even if PEP was concerned about "extended peaks", the battery system could be sized to accommodate that need. But the EPA should not accept unsupported assertions from PEP. PEP would have to show that they will have an uninterruptable supply of natural gas at all times to serve the duct burners for extended peaks to the extent that the EPA requires the same functionality from a battery system.

In addition, just between January and July 2017, 12 MW of utility scale batteries were installed in the U.S. Furthermore, it is likely that the 30 MW battery at Blue Summit Storage is also already operational. Although it is

[10] We further note that actions taken under the Clean Air Act are not major federal actions that can trigger the applicability of NEPA per section 7(c) of the Energy Supply and Environmental Coordination Act of 1974, 15 U.S.C. 793(c)(1). See also 40 CFR 124.9(b)(6).

listed in the planned project table, the U.S. Energy Information Administration (EIA) tables are a few months behind the times and the EIA lists the project as coming on line in August of 2017.

There are also approximately 147 MW of batteries that EIA has said are planned for the U.S. This includes a 25 MW battery paired with a 275-mw natural gas fired combustion turbine at the Mission Rock Energy Center in California. It also includes a 40 MW battery system at the Fallbrook Energy Storage facility in California. It is important to consider that EIA may not be capturing all projects. EIA relies on self-reporting of projects.

Nor is this redefining the source to evaluate a battery system to replace the duct burners, even considering the EPA's incorrect statement of the business purpose of this source. The EPA originally states the purpose of PEP as the following in its Fact Sheet:

> the PEP is designed as an "intermediate load following" facility. This could also be referred to as a "flexible capacity" facility. This type of facility primarily operates to meet the energy market's ramping and peak load requirements in the morning and late afternoon, helping to integrate the ramp up and ramp down of solar generation. The purpose of the PEP is to be able to respond to changes in demand from the electric grid, making this the fundamental business purpose of the facility.

In other words, the grid needs to balance generation and demand. The business purpose of the PEP is to help keep the grid in balance. PEP will be paid to provide this help.

However, to avoid considering battery storage, the EPA itself redefines the purpose of this source in a nonsensical manner. The EPA defines the project as having a purpose of burning natural gas in combined-cycle units. (But no one is in business to buy combustion turbines and burn natural gas. No business gets paid to buy combustion turbines. Rather, the combustion turbines cost the business money. Similarly, no one's business purpose is to burn natural gas as no one is paid to do that. Rather, as the EPA previously explained the business purpose of this facility is to provide intermediate/load following or flexible capacity. In any event, in this section we are only talking about replacing the duct burners with batteries. This would not interfere with the EPA's incorrect statement of the purpose of this project of buying combustion turbines. It would reduce the amount of natural gas PEP burns but again, burning a certain amount of natural gas is not the business purpose of PEP. Furthermore, with a limit of 1,500 hours per year, the duct burners are to meet peak need.

The EPA acknowledges that the duct burners have higher NO_X and CO emission rates than the combustion turbines. Therefore, by eliminating the duct burners and replacing their abilities with those of batteries which are charged from the combustion turbines, the facility can meet lower BACT emission limits.

In addition, batteries could be used to allow the source to better service its stated business need if the source so chose. Batteries add at least one additional function that duct burners cannot. That is duct burners cannot absorb electricity, they can only produce it. Batteries can absorb electricity from the grid, allowing the grid to better deal with rapid ramping which can be caused by solar and wind. At times, various grids in the U.S. have experienced negative wholesale prices because the grid operator has too much electricity on the grid. Other authorities, like ERCOT and BPA, have had to curtail zero NO_X and CO emission wind and solar power generation at various times because of excess generation.

The duct burners provide no solution to these situations. However, if PEP was using batteries rather than duct burners to meet peak load needs, then during periods of excess generation, PEP could actually absorb electricity from the grid. This would increase PEP's ability to meet its stated business purpose. Helping a source to better meet its stated business purpose is not redefining the source.

Batteries may add additional abilities to the facility, such as providing other ancillary support services to the grid, that the duct burners are not capable of. The EPA must consider these in step 4 of its BACT analysis by considering additional income that PEP could generate by providing additional ancillary support services as well as the environmental benefit of the reduction of curtailment of zero emission sources like solar and wind.

Response 7:

In conducting the BACT analysis for this Project, the EPA considered the use of hybrid energy designs that combine natural gas turbines with battery storage, which could potentially offset some need to burn natural gas or increase the efficiency of the CTs. We conducted a literature search to determine the current state of hybrid battery storage technology. See Appendix 3 of the Fact Sheet. Based on the available information, including information from the Applicant, we concluded that a hybrid battery storage design was not technically feasible for the Project. To date, we are only aware of two 50 MW natural gas-fired peaking units that are currently using this design (the GE 50 MW LM6000 Hybrid EGT), and they have been in place less than 1 year. These units are designed to provide stored energy during startup of the combustion units to help reduce the need to idle the units at low loads. The design is very similar to hybrid vehicles that often shut off while stopped at a traffic light but instantly provide stored battery energy when the gas pedal is pressed. See Fact Sheet at 29-30. However, we did not analyze the particular hybrid battery option proposed by the commenters here – using battery storage to eliminate duct burners.

In response to this comment, we have considered the type of hybrid design proposed by the commenters – replacing the duct burners with battery storage – and determined that it is technically infeasible for the Project for the following reasons. Technologies that have not been applied to (or permitted for) full scale operations need not be considered available; an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice. See Office of Air Quality Planning and Standards, U.S. EPA, New Source Review Workshop Manual (draft October 1990) (hereinafter “NSR Manual”) at B.11. In this case, we are not aware that the commenters’ proposed design has been applied on any similar source and the commenters have not provided any examples suggesting that it has. As such, this design – using battery storage in lieu of duct burners – has not been demonstrated to be technically feasible.

In addition, with respect to the potential for technology transfer, we disagree with the commenters that battery storage could “easily” replace duct burners. While each of the duct burners for the Project will be limited to using an amount of fuel that is equivalent to 1500 hours of operation per year, the Applicant has full control over how to use those 1500 hours. Batteries would be limited in how long they could provide energy before running out and needing to be recharged. The Fact Sheet identified that each duct burner for this Project would have a maximum heat input rate of 193.1 million British thermal units per hour (MMBtu/hr). See Fact Sheet at 5, Table 1. For both duct burners, this equates to about 8% of the total heat input of the facility – adding approximately 52 MW to the nominal output of 645 MW for the PEP. With a fuel use limit equivalent to 1500 hours per year for each duct burner, that is approximately 78,000 MWh per year for both duct burners. The commenters cite to the Tesla 100 MW facility as an example of how battery storage on this scale already exists. However, the Tesla battery facility is identified as providing only 129 MWh at a time.[11] This would mean that the Tesla 100 MW battery storage example could provide 52 MW of peak energy for only about 2.5 hours before running out of energy. This would be extremely limiting on a facility that otherwise could access 78,000 MWh per year from duct burners. Such a situation is not likely to work for a load-following facility that may need to ramp up and down multiple times per day and provide additional power for more than 2.5 hours at a time.[12] The commenters’ suggested approach is merely theoretical at this point, and we are not required to conduct an independent

[11] https://techcrunch.com/2017/07/07/tesla-will-build-worlds-largest-battery-storage-facility-for-australian-wind-farm/

[12] For example, as seen in Figure 2 in Response 13, the evening peak in energy demand can typically be about 4 hours, from 4:00 to 8:00 p.m.

analysis of alternatives to the proposed Project beyond those raised by the commenters. In sum, we believe that this approach is technically infeasible for the Project.

Although we are not required to consider alternatives beyond those proposed by the commenters, to the extent the commenters may be arguing that the Project should use multiple batteries to provide the additional power that would otherwise be provided by the Project's duct burners, we also reject this suggestion. Such an approach either would not result in measurable tpy reductions in emissions, or would be cost-prohibitive, depending on the method used to recharge the batteries. The commenters imply that charging the batteries at times when wholesale prices are zero or negative would be free or result in a profit. However, EPA Region 9 staff learned during a September 2017 site visit to the Southern California Energy's Norwalk Facility, where a GE 50 MW LM6000 Hybrid EGT unit is operated, that the batteries at the facility are recharged by the onsite natural-gas fired unit because the operator would otherwise have to pay the regular price for power distribution.[13] In the case of the PEP, any batteries that could be used to replace the duct burners would most likely be recharged by the CTs and would therefore not result in measurable tpy reductions in emissions. Given this lack of emission reductions, batteries would be ranked equal to duct burners in Step 3 of the BACT analysis. We note that there are no usual energy or environmental impacts associated with the use of duct burners that could reasonably eliminate the duct burners under Step 4 of the BACT analysis.[14]

If the Applicant were instead to consider purchasing power to recharge the batteries, the use of batteries to replace duct burners would not be cost effective under Step 4 of the BACT analysis. If we conservatively assumed annualized costs of $14.5 million per year[15] and a reduction of ~170,000 tpy of CO_2e, the average cost effectiveness would be $85/ton of CO_2e removed. Given that GHGs are generally emitted at significantly higher magnitudes than criteria pollutants (10,000 times greater in the case of the PEP), we do not consider $85/ton to be within the range that is cost effective for GHGs under a BACT analysis. Further, it is unclear why the commenters believe that the cost considerations of battery storage should consider reductions of NO_X, CO and GHGs together. Cost analyses are typically conducted on a per pollutant basis and the commenter has not provided a basis for why—or even how-the pollution reductions must be combined. In addition, the elimination of duct burners would be unlikely to result in a significant reduction of CO and NO_X emissions. The duct burners only operate when the CTs are in normal operation, at which time NO_X and CO are well-controlled. The elimination of

[13] See March 6, 2018 Memorandum from L. Beckham to the PEP PSD Permit File, Re: Summary of Air Permits Office Trip to Southern California Agencies and Industrial Facilities.

[14] However, there are potential environmental impacts associated with using lithium ion batteries like the Tesla project. See, for example: Application of Life-Cycle Assessment to Nanoscale Technology: Lithium-ion Batteries for Electric Vehicles, Design for the Environment Program, EPA's Office of Pollution Prevention and Toxics, National Risk Management Research Laboratory, EPA's Office of Research and Development, EPA 744-R-12-001 at https://www.epa.gov/sites/production/files/2014-01/documents/lithium_batteries_lca.pdf.

[15] We assume the Applicant would need at least 4 sets of batteries comparable to the 129MWh project in Australia (two that could operate during a long peaking period and two that are being recharged or waiting for the next peak in demand.) The Tesla batteries for the project in Australia cost at least $50 million. (http://fortune.com/2017/11/23/elon-musk-australia-battery-50-million-bet/) This results in capital costs of $200 million and annualized costs of $6.67 million over 30 years. Additionally, the average cost of electricity for industrial customers in California is $0.1135/kWh. (https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a) At 78,000 MWh per year needed to eliminate duct burners, this is a cost of $8.9 million per year to recharge the batteries. Removing the duct burners will result in fuel savings costs of about $1.1 million per year, assuming a price of $4/1000 scf of natural gas. https://www.eia.gov/dnav/ng/hist/n3045ca3m.htm. Thus, total annualized costs are at least $14.5 million per year. This value is conservative as it does not include any maintenance and operating costs or capital costs beyond purchasing the equipment (such as, site preparation, engineering, supervision, etc.). We also note that a $200 million capital expenditure on batteries is likely to add over 30% to the overall cost to construct the PEP (assuming construction costs $965/kWh for natural gas, https://www.eia.gov/todayinenergy/detail.php?id=26532), which we expect to be around $600 million.

the duct burners would result in a reduction of only about 1.0 tpy of NO_X and 2.6 tpy of CO. As such, even if the reductions of NO_X, CO, and GHGs were combined for the cost efficiency analysis, a large-scale battery system to remove the duct burners would not be cost-effective.

It is unclear what the commenters are referring to in the context of an "uninterruptable supply of natural gas" for the duct burners. The duct burners would only be operating when the combustion turbines are already operating with access to natural gas. Battery storage is clearly limited in how long it can provide energy before running out and needing to be recharged. We acknowledge that being able to provide battery storage for a continuous period of 1500 hours is not the correct metric to determine whether this technology is feasible. But, to be reasonably feasible, the technology would need to be able to provide multiple ramps within a short period of time, for a sufficient duration, in order to meet the load-following needs of the grid. While there may be some configuration of batteries that could theoretically accomplish this, this design has not been demonstrated in practice, it would lead to insignificant reductions in criteria pollutants, was not adequately presented by the commenters for EPA to review, and preliminary analysis suggests that it would have been eliminated at Step 4 as not cost effective.

In sum, we reject the commenters' suggestion to replace the duct burners with batteries as BACT.[16]

The EPA Must Set an Ammonia Slip BACT Emission Limit

Comment 8:

Commenters: Conservation Groups (0016)

The commenters asserted that the draft permit does not have an ammonia slip BACT emission rate. Ammonia is now considered a precursor to $PM_{2.5}$. Thus, the permit needs an ammonia slip rate emission limit based on the Region's BACT analysis. AVAQMD's determination of a 5 ppm limit is not an acceptable substitute for the Region doing its own BACT analysis. However, AVAQMD's inclusion of an ammonia slip emission rate does establish that ammonia is a significant precursor to $PM_{2.5}$ in the Antelope Valley. Furthermore, the significant emission rate for any other pollutant is zero. Thus, the permit needs an ammonia emission limit based on the Region's BACT analysis.

Response 8:

The EPA disagrees that ammonia is considered a $PM_{2.5}$ precursor under the PSD program and that therefore the PSD permit for the Project must include an ammonia slip BACT emission rate. Sources are required to apply BACT only where either a new major stationary source would have the potential to emit significant amounts of (or a major modification would result in significant net emission increases of) a "regulated NSR pollutant." 40 CFR 52.21(j). Ammonia is not a "regulated NSR pollutant" under the PSD program, as that term is defined in 40 CFR 52.21(b)(50). The definition for regulated NSR pollutant specifically identifies the $PM_{2.5}$ precursors that are required to be regulated under the PSD program at 40 CFR 52.21(b)(50)(i)(*b*), and ammonia is not listed.

To the extent that the commenters are referring to the D.C. Circuit Court of Appeals' decision in *NRDC v. EPA*, 706 F.3d 428 (D.C. Cir 2013) (*NRDC*), this decision is inapplicable to PSD permitting. In *NRDC*, the court held that the EPA erred in promulgating regulations for implementing the 1997 $PM_{2.5}$ NAAQS by not applying the nonattainment area planning requirements applicable to particulate matter less than or equal to 10 micrometers in diameter (PM_{10}) in subpart 4, part D of title I of the CAA ("subpart 4"). In particular, the court noted that CAA section 189(e) presumptively requires regulation of $PM_{2.5}$ precursors, including ammonia. 706 F.3d at 436 n.7. The court remanded to the EPA the 2007 $PM_{2.5}$ Implementation Rule and the 2008 $PM_{2.5}$ NSR Rule, and instructed the

[16] To the extent the commenters' reference to the Tesla 100 MW battery system may be meant to suggest the use of an all-battery system to replace the Project's natural gas plant in its entirety, please see our discussion of an all-battery alternative in Response 13.

EPA "to re-promulgate these rules pursuant to Subpart 4 consistent with its opinion." *Id.* at 437. The EPA addressed the court's remand in the 2016 $PM_{2.5}$ SIP Requirements Rule, in which the EPA explained that subpart 4 includes requirements only pertinent to nonattainment areas and that the EPA does not consider the portions of the 2008 $PM_{2.5}$ NSR Rule that address requirements for $PM_{2.5}$ attainment and unclassifiable areas (which would include the definition of "regulated NSR pollutant" at 40 CFR 52.21(b)(50)) to be affected by the court's *NRDC* opinion. Therefore, the EPA did not propose or finalize any revisions to any PSD requirements promulgated in the 2008 $PM_{2.5}$ NSR Rule in response to the court's decision. *See* 81 Fed. Reg. 58010, 58108 (Aug. 24, 2016).

The EPA Should Have Considered EM_X™ in the CO BACT Analysis Through Technology Transfer

Comment 9:

Commenters: Conservation Groups (0016)

The commenters requested that the EPA redo the Fact Sheet to include a technology transfer analysis for EM_X for CO emissions from the CTs, asserting that the Fact Sheet rejects EM_X™ as a control technology for CO emissions from the CTs at step 2 of the BACT analysis, which is an error. The commenters asserted the following:

The Fact Sheet rejects EM_X because the EPA could only find its use on a 1.4 MW combustion turbine. However, the EPA failed to conduct a proper technology transfer analysis to see if EM_X™ could be applied to CTs similar in size to what PEP is proposing. Technology transfer is a well-established principle in BACT analysis. The EPA's rejection of a technology at step 2 because it is not currently in use at a large size turbine is based on a misapplication of BACT, its technology forcing nature and its technology transfer principle. The fact that there is at least one BACT analysis that chose EM_X™ further supports the conclusion that it is technically feasible. BACT is an emission limit. The fact that a large CT with a BACT limit based on EM_X™ chose not to install EM_X™, by itself, is not relevant to a BACT analysis. Sources are free to meet their BACT emission limit in any manner they choose.

Response 9:

The EPA disagrees that further analysis of EM_X™ as a CO control technology for the CTs is warranted. First, the EPA did not reject EM_X™ because we could find it used only on a 1.4 MW CT, as asserted by the commenters. In fact, the 1.4 MW CT referenced in the Fact Sheet was identified as using a catalytic combustion technology called XONON™, and available information indicates that this technology only achieves a CO limit of 5 ppm. Even if we were to include XONON™ technology in Step 3 of our analysis, it would be ranked below the CO limit of 1.5 ppm/2.0 ppm achievable by the chosen technology of oxidation catalyst.

We wish to clarify the Fact Sheet as it relates to how EM_X™ technology was described in the control technology analysis for CO for the Project's CTs. Currently, the manufacturer claims that CO emission rates below 1 ppm are achievable. However, we are not aware of any information that demonstrates that this has been achieved on any unit, regardless of size. We are also not aware that this technology has been demonstrated in practice at greater than 1 ppm for CTs similar to the PEP. The only CT using EM_X™ technology is at the Redding Power Plant. This unit is a 43 MW unit and is generally not considered comparable to large CTs like those at the PEP. There is one similarly sized facility that was permitted to use EM_X™—the Elk Hills Power facility, a 503 MW combined-cycle facility—but EM_X™ technology was never installed. As such, this technology has been in development for over 20 years and only has one example of being installed and the only unit similar to the PEP that was permitted to use the technology ultimately never installed it. The fact that a similar unit to the PEP was permitted to use the technology but never installed it is an important factor, as well as, the fact that there have been no new installations of this technology in the last 15 years. This is sufficient information to determine that this technology is not transferable to the PEP. Therefore, we can eliminate this technology as infeasible under Step 2 of the BACT analysis, as it has never been demonstrated in practice on similar units.

Even if we included EM_X^{TM} at Step 3, as noted, we would not include 1 ppm in Step 3 of the BACT analysis for EM_X^{TM} because we are not aware that this limit has ever been achieved in practice. The Redding Power Plant achieves 2.5 ppm CO; the Elk Hills Power facility was permitted at 4 ppm CO. Thus, even if we had included EM_X^{TM} in Step 3 of our BACT analysis for CO for the CTs, it would still have been eliminated – at 2.5 ppm or 4 ppm – because it would be ranked below the chosen technology of oxidation catalyst which can achieve a CO limit of 1.5 ppm/2.0 ppm.

The EPA Must Redo the PM BACT Analysis to Consider Lower BACT Limits for Similar Units

Comment 10:

Commenters: Conservation Groups (0016)

The comment excerpt below identifies what the commenters believed were two errors in the PM BACT analysis based on BACT requiring the maximum degree of reduction.

In selecting the BACT emission limits for GEN1 and GEN2, the Fact Sheet states: "These emission limits are based on available PM emissions data for this turbine model, and are generally in the range of other recent BACT limits for similar units, as shown in Table 9." This sentence evidences two errors in this BACT analysis.

The first is BACT is the "best" available control technology. It is not the "around as good as" available control technology. Put another way, BACT requires the maximum degree of reduction. (40 CFR 52.21(b)(12)). The Fact Sheet itself explains that step 4 requires an evaluation of the most effective control alternative.

The Fact Sheet goes on to list the Moundsville Combined Cycle Power Plant in West Virginia as having an emission limit of 8.9 pound per hour (lb/hr) and 0.0037 lb/MMBtu. This permit also required inlet air filtration in addition to GCP and natural gas. Therefore, step 4 of the BACT analysis for $PM/PM_{10}/PM_{2.5}$ needs to list 8.9 lb/hr and 0.0037 lb/MMBtu as the first choice as this represents the maximum degree of reduction and the most effective control alternative. The EPA also needs to evaluate inlet air filtration.

The other problem with this BACT analysis is that the EPA based it on the turbine model which PEP claims it will use. But again, BACT is the most effective control technology. A polluter does not get to choose a less protective BACT limit but choosing a higher polluting turbine. Rather, if there is a cleaner turbine that can perform the same basic function as the polluter's preferred turbine, the EPA is required to consider that cleaner turbine. As the EPA failed to do that for the $PM/PM_{10}/PM_{2.5}$ BACT analysis, the EPA must redo the analysis.

Response 10:

The EPA disagrees that a new $PM/PM_{10}/PM_{2.5}$ BACT analysis is warranted for the Project's CTs. The commenters assert that the BACT limits for the Moundsville Combined Cycle Power Plant in West Virginia (8.9 lb/hr and 0.0037 lb/MMBtu) should be listed as the top control option under Step 4. However, the commenters appear to have disregarded the EPA's detailed discussion under Step 3 of the PM BACT analysis for the CTs that appears in the Fact Sheet, which explains why it is not appropriate to assume that an individual existing lb/hr or lb/MMBtu BACT limit for a different facility is necessarily achievable or feasible to meet on an ongoing basis for the CTs at the PEP. In Step 3 of our PM BACT analysis for the CTs, where control options are ranked according to effectiveness, the EPA explained why it is difficult to evaluate PM BACT limits achieved by other combustion turbines as a basis for BACT for the PEP:

- There are no reasonable methods, beyond good combustion practices and the low sulfur fuel requirements, that the permittee could employ to adjust its operations to account for the inherent variability of PM emissions from CTs in order to be able to comply with any emissions limits selected. For this reason, as noted above, some NSR permits for similar facilities do not include any numerical PM emission limits as a component of their PM BACT/LAER requirements.

- In light of the permittee's limited ability to adjust its operations to address the inherent variability of PM emissions from CTs, we need to be particularly careful to ensure that any BACT limit that is selected is technically feasible to meet on an ongoing basis for the life of the facility. Accordingly, potential variability in stack test data for the same turbine model is a significant concern when we consider setting a BACT limit based on such data.

- Without add-on controls, PM emissions are highly dependent on the size of the combustion turbine.

  - For example, a 200 MW combustion turbine will always have PM emissions on a pound per hour basis that is higher than a 100 MW combustion turbine, or even a 150 MW, 175 MW, or 190 MW combustion turbine.

  - On a lb/MMBtu basis – larger combustion turbines are generally more efficient than smaller turbines leading to higher lb/MMBtu emissions for smaller turbines.

Fact Sheet at 22-23.

The basis for the selected BACT limit for the PEP was provided under Step 5 of the BACT analysis. The limit was based on available emissions data for the same turbine model. That data, and our analysis of the data, was provided in Appendix 2 of the Fact Sheet. The commenters have not provided any information that refutes these findings, nor have the commenters otherwise explained why, despite these findings and our reasoning in Step 3 of the BACT analysis, the emission limits for the Moundsville Combined Cycle Power Plant should be considered BACT for the PEP. We also note that the Moundsville Combined Cycle Power Plant is smaller than that PEP at 545 MW versus 645 MW, and, as explained above, PM emissions are highly dependent on the size of the combustion turbine. It is unclear how the Moundsville Combined Cycle Power Plant limits were determined, but in the case of the PEP it is based on specific available data for the same turbine model. As such, we do not have information that indicates that the PEP could achieve the limits as the Moundsville facility. In addition, the commenters are mistaken in their assertion that the EPA must require the use of a different turbine model, particularly of a different size, in order to achieve marginally lower emissions. *See, e.g., In re La Paloma Energy Center, LLC*, 16 E.A.D. 267, 275–284 (EAB 2014).

Finally, we also do not believe further consideration of inlet air filtration is warranted. We consider air filtration to be standard equipment for combustion units to ensure that outside air particles do not damage the equipment, and the application states that inlet air filtration will be used. See the Application for the PEP received on October 15, 2015 (hereinafter "October 2015 Application) at 4.5-6. We have revised the equipment list in the Final Permit to clarify that the Project's CTs will utilize inlet air filtration. This change is shown in the redline-strikeout version of the final permit.

GHG BACT Analysis for Combustion Turbines Does Not Accurately Describe the Project, and Unfairly Limits Consideration of Hybrid Solar Thermal and Battery Storage

Comment 11:

Commenters: Conservation Groups (0016)

The commenters stated their understanding that the BACT analyses for controlling greenhouse gas emissions are to be conducted in the same manner as those for any other regulated pollutant. They alleged that because the

EPA in its Step 1 BACT analysis fails to accurately and clearly describe the project, it unfairly limits the consideration of hybrid solar thermal, and, at Step 2, battery storage. As a result, the EPA's rejection of various BACT for GHGs at Steps 1 and 2 are in error. And, the EPA never even considers other solar components or a combination of solar and battery technologies as alternatives that could be used to reduce GHG emissions. Because additional feasible and available technologies should have been fully considered in the BACT analysis for GHGs but were not, the analysis is in error.

Response 11:

We disagree that the concerns raised by the commenter demonstrate that our BACT analysis was in error. Please see Response 12 regarding the description of the project. We address the commenter's specific concerns related to a hybrid solar thermal design and battery storage (including solar and battery technologies) in Responses 13 and 14, and we address other comments related to the GHG BACT analysis in Comments 15, 16, and 17.

The EPA's Rejection of Hybrid Solar Thermal in the GHG BACT Analysis Was in Error

Comment 12:

Commenters: Conservation Groups (0016)

The commenters alleged that the EPA's rejection of a hybrid solar thermal design to reduce emissions was in error, citing the Fact Sheet, and making the following arguments:

First, the EPA rejected the solar hybrid alternative that would reduce GHG emissions because it would "redefine the design of the source" as the project is described as "intermediate load following" or "flexible capacity" and not baseload, although the EPA itself describes the project as possibly also being used for baseload. As a result, the EPA's reason for rejecting this alternative is not supported.

Further, the EPA's "determination" that the proposed facility design (without the solar hybrid component) was derived for reasons independent of air quality is wrong. The discussion is premised on the fact that renewable generation has to increase in order to reduce GHGs, and the argument that this allegedly creates a need for additional gas-fired units to integrate more of these resources into the energy system. The conservation groups do not agree with these assertions that there is a need for additional fossil fuel energy projects and discusses these issues further below. And clearly the entire point of shifting to renewable energy is to reduce air quality impacts from GHGs. Therefore, for the EPA to argue that the design of this facility is somehow "independent of air quality" is nonsensical. If the project may be used for baseload, as the applicant has stated, then the solar hybrid should be considered as BACT.

Response 12:

The EPA disagrees with the commenters, and we continue to believe that our reasoning for determining that a solar thermal hybrid design would fundamentally redefine the business purpose of the PEP, as was fully explained in our Fact Sheet, is sound. See Fact Sheet at 25-28. As the PEP is primarily intended to serve as an intermediate/load-following source, the ability to operate in a baseload capacity only meets *one* of the design elements of the PEP. To consider a solar thermal hybrid design as an available technology in this case would require the PEP to be exclusively (or at least primarily) operated as a baseload facility. Thus, as summarized below, requiring the Applicant to consider this option would fundamentally redefine its business purpose.

In evaluating whether a solar thermal hybrid design would redefine the business purpose of the PEP, we used a two-step process. First, we looked at the basic business purpose and design elements of the PEP and, second, we considered whether these design elements were inherent to the Applicant's purpose and which if any of the design elements could be changed to reduce pollutant emissions without disrupting the Applicant's basic business purpose.

For the first step, as explained in the Fact Sheet:

> [T]he PEP is designed as an "intermediate load-following" facility. This could also be referred to as a "flexible capacity" facility. This type of facility primarily operates to meet the energy market's ramping and peak load requirements in the morning and late afternoon, helping to integrate the ramp up and ramp down of solar generation. The purpose of the PEP is to be able to respond to changes in demand from the electric grid, making this the fundamental business purpose of the facility. [footnotes omitted] In this case, the source's ability to respond to ramping and peak load needs, as well as operating in different modes in response to market demand, is inherent to the Applicant's basic business purpose and design.

Fact Sheet at 26. This analysis was based on statements in the Application describing the purpose of the Project, including, for example, "[PEP] . . . would allow for a flexible response to changing power market conditions, which is the fundamental business purpose of the proposed facility," and "the assessment of a performance standard was based on a combination of full plant loads, reduced plant loads and rapid plant cycling where the steam turbine may not be utilized which would then allow for a flexible response to changing power market conditions, which is the fundamental business purpose of the proposed facility." See page 2-7 of the October 2015 Application and page 10 of the Applicant's May 2017 response letter, respectively.

Additionally, we considered whether the business purpose and design identified by the Applicant was for reasons independent of air quality. In doing so, we considered whether the stated purpose and design of the PEP was consistent with other recent natural gas-fired combined-cycle power plant projects permitted in California, such as AES Huntington Beach and AES Alamitos. We also looked at available information about the need for flexible capacity units in California. Our review found that the PEP design is similar to that of other natural gas-fired projects in California that are responding to the same market needs and that there is limited demand for baseload units in California. Upon review of the available information, we concluded that "given the current energy needs of California, it is evident that the proposed design of the PEP was derived for reasons independent of air quality, and is intended to serve the energy needs of California." Fact Sheet at 27.

In the second step of our analysis, we looked at the design elements of the PEP and considered whether they could be changed to meet the technical requirements for solar thermal hybrid design without disrupting the Applicant's basic business purpose. As explained in the Fact Sheet:

> We have determined that with respect to the PEP, a hybrid solar thermal design would be incompatible with the Applicant's fundamental business purpose to serve as a flexible capacity facility that *can respond to the energy market's ramping and peak load needs and can operate in different modes in response to market demand*. Solar thermal plants appear to be best suited for baseload facilities *that are intended to operate year-round and that can benefit from solar generation on a regular, routine and extended basis during daytime hours when the sun is shining to increase efficiency and reduce natural gas fuel use*. While solar thermal hybrid designs have the *potential* to reduce fuel use and increase the overall efficiency of a power plant, the solar thermal portion can only offset fuel use when the combustion turbines are in operation, and when the sun is shining, and the amount of fuel offset depends on when the CTs operate and how much the sun is shining at that time.
>
> As explained by the Applicant, in California, currently and into the future, fossil fuel-fired electrical generating units (EGUs) *are not expected to operate significantly during peak solar demand hours*. *Requiring the Applicant to consider a project design that would realize benefits only if operated routinely*

during peak solar demand would redefine the fundamental business purpose of the Project. While, as a flexible capacity resource, the PEP may occasionally be needed to operate during peak solar demand, it would be unreasonable to require the Applicant to consider the solar thermal design for those limited circumstances, given the evidence of the limited demand for fossil fuel-fired EGUs during peak solar demand.

Fact Sheet at 27 (emphasis added).

In sum, we reviewed information provided by the Applicant, information available about similar sources, and information available about the use of baseload units in California to assess whether operating as an intermediate-load following resource is part of the fundamental business purpose of the PEP, and whether operating primarily as a baseload facility would fundamentally redefine the source. Upon review of the available information, we concluded that the Applicant's statements were consistent with similar projects and current energy issues in California and there is no reason to doubt the Applicant's stated business purpose. Further, we concluded that requiring the PEP to alter its design to be used in a primarily baseload capacity would disrupt the Applicant's stated business purpose.

Our review of solar thermal hybrid plants concluded that they are best suited for baseload facilities that will be operating regularly, routinely and for extended periods during peak solar demand hours. Given that the PEP is not intended to, and is not expected to routinely operate in this manner during such periods, requiring the Applicant to consider a control option that would significantly change its intended use as an intermediate/load following unit would fundamentally redefine the source.

We disagree with the commenters' suggestion that the fact that the Project may, at times, operate in the manner of a baseload facility means that the Applicant's business purpose is to provide a baseload facility rather than an intermediate/load following facility, such that we must assume that the Project will generally operate as a baseload facility for purposes of considering control options. The Applicant acknowledged it may at certain times operate more like a baseload facility should market conditions necessitate that mode of operation. This fact does not change the fundamental purpose of the source from an intermediate load/following source to a baseload facility intended to operate at near full load for the majority of each day.

We also disagree with the commenters' assertion that our determination that the business purpose and design identified by the Applicant was for reasons independent of air quality was "nonsensical" because the "point of shifting to renewable energy is to reduce air quality impacts from GHGs." The consideration of whether a project's design elements are "independent of air quality" is meant to ensure that an applicant does not define its business purpose so narrowly as to avoid considering available pollutant control options. The commenters seem to imply that the Applicant's fundamental business purpose and basic design elements of constructing an intermediate/load following natural-gas fired facility were chosen because of the air quality implications of GHG emissions. However, the Applicant is not in the business of creating GHG emissions reductions. Reducing GHG emissions is a broad policy goal in California that has created market conditions for a certain type of natural gas-fired power generation. The Applicant's basic design elements were not chosen to reduce GHG emissions, but instead to respond to market conditions that require this type of power generation in California. The Applicant is in the business of power generation and is constructing the type of flexible facility that it anticipates will meet a need in the California power market.

The commenters also stated briefly that they disagree with the assertion that there is a need for additional fossil fuel energy projects. However, they did not point to any information supporting this opinion. While, for this analysis, we considered whether an intermediate/load following unit such as the Project was in fact a type of resource intended and expected to serve a current need in the California power market, we have not conducted a "needs analysis" for this particular project. Please see Response 1 for additional discussion. To the extent that the commenters are arguing that a fossil fuel resource is not needed to meet the fundamental business purpose of the facility, such that other alternative technologies should be considered as BACT, please see Response 13.

The EPA Should Consider Battery Storage Technologies to Help Balance Solar and Other Renewable Energy and Reduce GHGs

Comment 13:

Commenters: Conservation Groups (0016)

The commenters provided the following arguments concerning consideration of other potential alternative technologies to reduce GHGs, citing several exhibits:

If the real goal is to balance solar and other renewable energy with load, as the applicant states, then the EPA should look at other technologies that would accomplish this goal with far fewer GHG emissions. As a recent study explains:

> Kauai Island Utility Cooperative (KIUC), a public utility with 30,000 customers and peak load and annual energy demand of 78 MW and 430 million MWh, respectively, has taken the lead in transitioning from a fossil fuel-based grid to a model built on solar combined with battery storage. KIUC will replace about 40 percent of overall demand provided by fossil fuels with renewables in the 2015 to 2025 timeframe, increasing the percentage of renewables to 76 percent in 2025. KIUC has two major projects combining solar and battery storage: the SolarCity project consisting of 20 MW of solar and 52 MWh of battery storage (operational as of April 2017) and the AES project consisting of 28 MW of solar and 100 MWh of battery storage (under construction as of June 2017).

To the extent there is a need for "load following" capacity to integrate the world-class solar resources in the Palmdale area into the grid, battery storage could be implemented. Further, these battery storage solutions are technologically feasible and cost competitive.

Utility-scale battery storage has been identified by investor-owned utilities as cost-competitive with combustion turbines for peaking power since 2014. Southern California Edison (SCE), in its November 2014 procurement application to the California Public Utilities Commission (CPUC), stated that its least cost, best-fit resource modeling indicated the acquisition of utility-scale battery storage would be the most economic scenario relative to combustion turbines or other non-fossil resources. The CPUC ultimately approved 100 MW of utility-scale battery storage and 130 MW of behind-the-meter battery storage in response to SCE's November 2014 application.

Separate from the SCE authorization described above, over 100 MW of battery storage (with 400 MWh of storage capacity) was added in Southern California in only nine months from the time the CPUC notified the Southern California utilities to seek additional storage capacity in June 2016. That capacity reached operational status in late 2016 and early 2017. This large-scale, fast-track battery deployment process demonstrated that the long lead time procurement cycles typical of conventional gas-fired generation, based on long-term utility growth forecasts that may never become reality, are not necessary for battery storage procurement.

The lowest published cost for large-scale solar PV with batteries, less than $0.045/kWh, is from Tucson Electric in May 2017. This production cost is substantially below the production cost of $0.059/kWh estimated by EIA for a new gas-fired combined-cycle power plant. The solar component of the project is 100 MW. The battery component is 30 MW rated capacity and 120 MWh of energy storage. Prior to the Tucson Electric announcement, the lowest published cost figures had been for two Kauai Island Utility Cooperative (KIUC) solar with battery projects, by AES and SolarCity. The contract power cost for the 28 MW solar with 20 MW battery facility by AES, contracted in December 2016 at $0.11/kilowatt-hr (kWh), is comparable to that of new peaking gas-fired power plants. In 2015, KIUC signed a similar contract with Solar City for $0.145/kWh. The Solar City project became operational in March 2017. Moreover, batteries can be constructed and installed in a timely way. Tesla recently installed 50 MW in just 2 months to help balance wind and solar resources in Australia.

Response 13:

The commenters suggest that the EPA should consider alternative technologies that would meet the intermediate/load-following business needs of the PEP but with lower GHG emissions. The commenters point to several examples to support their suggestion that fit into two main descriptions: (1) solar with battery storage and (2) large-scale battery storage. However, each of the alternatives proposed by the commenters here -- *i.e.*, full-scale battery storage or a combination of solar and battery storage – would constitute a facility type that is fundamentally different than that proposed by the Applicant and would completely eliminate the fuel chosen by the Applicant -- in this case, natural gas. The EPA believes that elimination of the primary fuel chosen by the Applicant would in this case fundamentally redefine the source. As discussed more below in the context of technical infeasibility, the alternatives proposed by the commenters could not meet the fundamental business need articulated by the Applicant to provide load following capacity.[17] *See* NSR Manual at 13; U.S. EPA PSD and Title V Permitting Guidance for Greenhouse Gases (Mar. 2011) (hereinafter GHG Guidance) at 27-28; *see also In re La Paloma Energy Center, LLC,* 16 E.A.D. 267, 285-86 (Mar. 14, 2014) (citing NSR Manual and GHG Guidance); *In re Arizona Public Service Company, Ocotillo Power Plant*, PSD Appeal No. 16-01, slip op. at 13-14 (EAB Sept. 1, 2016), 17 E.A.D. ___ (same). Relatedly, we also find that these alternative technologies would be technologically infeasible for this Project, while acknowledging that there are significant advancements being made with battery storage.

First, none of the examples provided by the commenter is near the 645 MW size of the PEP. The largest solar with battery storage project identified is 28 MW of solar with 100 MWh of battery storage. The largest all-battery storage project identified by the commenters was 130 MW (with unspecified MWh). The PEP will have the ability to generate over 5 million MWh of power each year. None of the projects identified by the commenter has been demonstrated to have this ability.[18] While we recognize that battery storage is advancing as a method for integrating renewable energy without the need for fossil fuels, it is not yet on the size and scale of combined-cycle combustion turbines. The PEP is not intended simply for small short-term peaking needs, but rather for large-scale needs that can occur when large drops or increases in renewable energy occur for extended periods. For example, Figure 1 below shows the amount of renewable energy provided by solar energy – in yellow – within the California Independent System Operator (ISO) on November 26, 2017 and Figure 2 shows the total energy demand for the same day.[19]

In this example, peak energy demand occurred around 5-6 p.m., shortly after 7,300 MW of solar energy were lost. Overall energy demand peaked on this day at about 27,500 MW, but the highest period of energy demand lasted approximately 4-5 hours during a time when almost no solar energy was available. The PEP is intended to provide

[17] The analysis of the inability of batteries to replace the duct burners is also instructive in demonstrating the inability to meet the Applicant's business purpose with only batteries. *See* Response 7.

[18] There appears to be an error in the information provided by the commenter that relates to the annual MWh demand for the KIUC. The information cited by the commenter states that annual demand is 430 million MWh. However, peak demand for KIUC was identified as 78 MW, resulting in a maximum 683,280 MWh of energy per year. We attempted to verify this number and discovered that annual demand for KIUC is approximately 452 GWh (gigawatt-hours) per year, which is equivalent to 452,000 MWh (as there are 1,000 MW in a GW), an annual demand that is roughly 1000 times smaller than the figure cited by the commenter. See https://energy.hawaii.gov/wp-content/uploads/2014/11/HSEO_FF_Nov2014.pdf at 2.

[19] Information accessed from http://www.caiso.com/TodaysOutlook/Pages/default.aspx on November 27, 2017.

significant amounts of energy during these types of demand fluctuations that can last for numerous hours. None of the projects suggested by the commenters are able to meet this type of need.[20]

Figure 1 Renewable Energy Generation within the California ISO on November 26, 2017

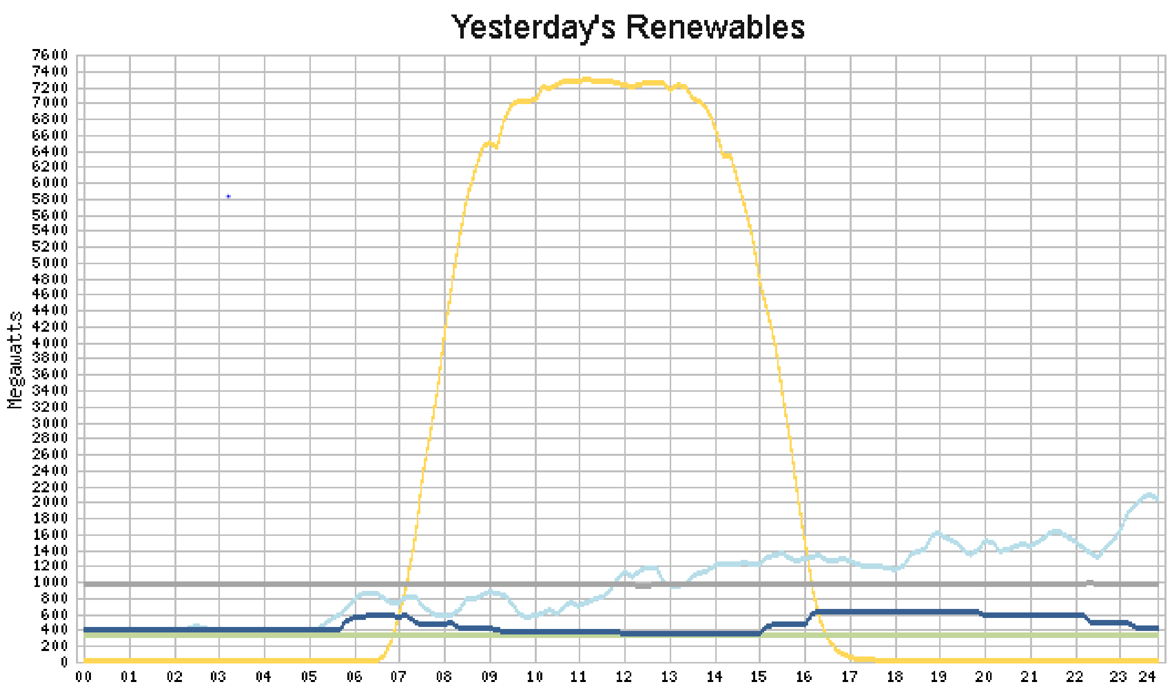
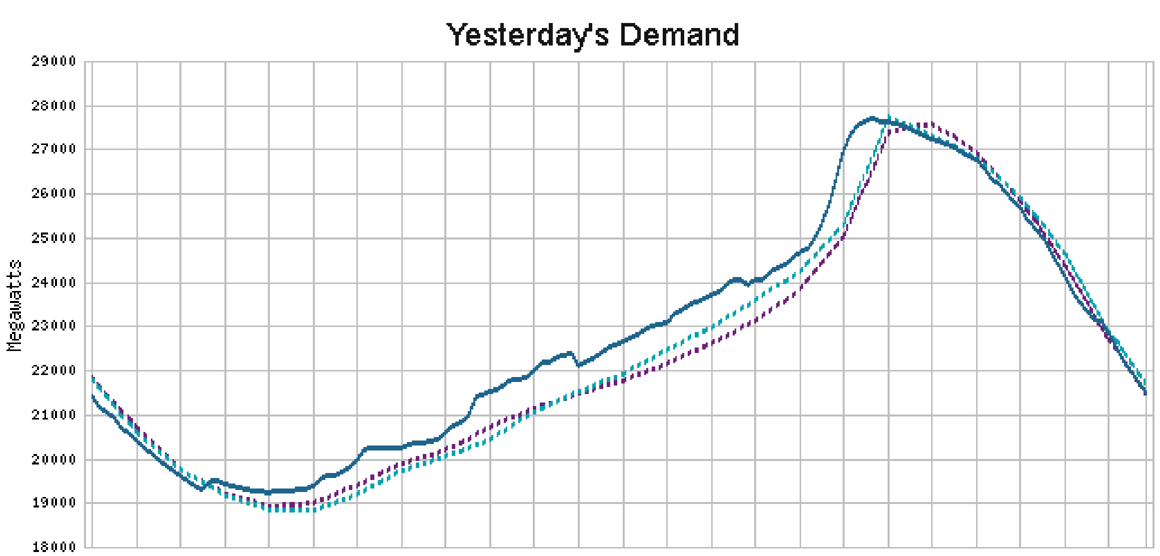


Figure 2 Energy Demand within the California ISO Throughout the Day of November 26, 2017



[20] We are not required to conduct an independent analysis of alternatives to the proposed Project beyond those raised by the commenters.

The EPA's Rejection of Hybrid Battery Storage in the GHG BACT Analysis Was in Error

Comment 14:

Commenters: Conservation Groups (0016)

The commenters argued, as detailed in the following comment summary, that the EPA erroneously rejected hybrid battery storage with the gas turbine as BACT for the PEP, referencing a supporting exhibit.

The EPA rejects the hybrid battery storage with the gas turbine as BACT for GHGs because it has not been demonstrated as feasible, although the EPA identifies an operating plant with this technology. This is in error. First, once again, the EPA's short hand description of the project the analysis as "load following" or intermediate capacity ignores the possible use as baseline and the peaking function is in error. Second, even taking that definition, the EPA's statement that it is "not technically feasible" is unsupported and simply relies on "concerns" raised by the applicant. The EPA describes one project operating in Southern California with this technology with a GE turbine, and admits that both GE and Siemens (the turbine manufacturer proposed for PEP) claim to be able to apply this type of hybrid battery design to a wide range of turbines. Indeed, Siemens is marketing such a system for combined-cycle gas turbines. If the vendors say they can design and build battery hybrid systems for combined-cycle gas plants, that should be sufficient to show this is a BACT, which is intended to be a technology forcing standard.

Response 14:

Energy storage technology is a rapidly growing development in the electrical power supply sector, but, in this case, we continue to find that hybrid battery storage is not technically feasible as BACT for the Project's CTs.

We disagree with the commenters' assertions that this determination of technical infeasibility is unsupported, and further disagree with the premise that technology vendors' stated intent to apply the technology to a wide range of turbines, including for combined-cycle gas turbines, is sufficient to demonstrate that the technology is technically feasible for the Project.

For purposes of a BACT determination, a vendor's statement that it can design and build a particular technology is not alone sufficient as the basis for a BACT determination.[21] The EPA does not consider a vendor guarantee alone to be sufficient justification that a control option will work. See NSR Manual at B.20. In this particular case, the vendors have merely identified that this is a technology they are marketing, and there are no specifics about what the technology has been demonstrated to achieve.

In response to this comment, we again reviewed available information about hybrid battery technology and the only example we found in the world of the technology being employed is in LM6000 Hybrid EGT demonstration project that came online in April 2017. As such, this technology has been in place less than 1 year and this initial project involves two small, 50 MW, simple cycle gas-fired turbines.[22] Further, in September 2017, the EPA Region 9 Air Permits Office staff visited one of the 50 MW demonstration units.[23] While the plant operators reported that the project is thus far a success, the benefits attributed to the batteries (reducing the need to idle at low loads, and being able to be considered spinning reserve) were anecdotal, and we continue to conclude that there is

[21] This is the same reasoning we have used for the NO_X and CO BACT determinations as they relate to EM_X technology.

[22] At the time the Fact Sheet was developed it was unclear that the LM6000 Hybrid EGT project is two installations at two separate facilities. Each facility consists of one 50 MW simple-cycle gas turbine.

[23] See March 6, 2018 Memorandum from L. Beckham, EPA to the PEP PSD Permit File, Re: Summary of Air Permits Office Trip to Southern California Agencies and Industrial Facilities.

insufficient information available to be able to consider the technology demonstrated in practice and thus technically feasible for a large combined-cycle power plant.

Our concerns about technical feasibility relate to the fact that the technology has been in use for only a short period of time on two small 50 MW simple-cycle peaking units. Such peaking units serve a single purpose of providing peak power and typically have very low annual capacity factors, typically less than 5% of their potential electric output on an annual basis.[24] As such, avoiding the fuel and maintenance cost of idling – which may constitute a large portion of annual operating hours – has a significant day-to-day operational value while also reducing GHG emissions. However, the PEP is not solely a peaking facility and will not serve this same purpose, so it is not known if the same value could be achieved using this technology on the PEP, which is expected to operate between 60 to 80% of its potential electric output. The commenter has not provided any additional information that adequately addresses the questions we identified in our Fact Sheet concerning this technology's feasibility for usage with a much larger, combined-cycle facility that is expected to operate at a greater capacity factor than a simple-cycle peaking unit, given that it has only been applied in a very limited capacity for a short period of time and has not been demonstrated in practice on any combined-cycle facility. And, as stated above, we disagree with the commenter that simply because a vendor states that a technology is available, then the technology must be considered technically feasible.

We acknowledge that the information provided by the Applicant related to the use of this technology on large combined-cycle units now appears to be somewhat outdated. But the concerns identified by the Applicant were not our only concerns related to the technology, which generally focus on the technology's newness and the fact that only one demonstration project has been developed to date, which has operated for only a short period of time, and on a very different type of facility. These concerns remain valid and thus we continue to find that the technology is technically infeasible for the Project.

The EPA Failed to Consider the Use of More Efficient Turbines to Control GHGs

Comment 15:

Commenters: Conservation Groups (0016)

The commenters argued that the EPA should have considered more advanced turbines for GHG BACT, citing various references, as detailed in the comment summary that follows.

The PEP proposes to use Siemens SGT6-5000F, however other turbines may be more efficient and reduce GHGs. For example, the G class turbine, SGT6-8000 says it has world class fast cold start and hot restart capability, and 61% net efficiency. Similarly, the H class turbines have 61% efficiency and fast start capability. In contrast, the F class which Palmdale would use only has a 59.3% efficiency. The H class turbine also gets 61% efficiency and the 1x1 configuration is 665 MW which is about the same as Palmdale's 2x1 configuration. Further, the H class turbine also has world class cold start and hot restart capability and these plants can operate from part load simple-cycle up to full-load combined-cycle. And has "excellent peaking capability". Thus, using the G or H class turbine for GHG BACT would mean almost a 2% reduction in GHG emissions which the EPA should have been considered.

In sum, the EPA should have considered using an H or G class turbine as BACT to lower GHG emissions, as there would be nearly equivalent start times and they could provide the same load following function.

[24] See 80 Fed. Reg. 64603 (Oct. 23, 2015).

Response 15:

We disagree with the commenters that it is necessary to consider G and H class turbines in the GHG BACT analysis for the Project.

First, the information referenced by the commenters does not provide information on a G class turbine. The only information we were able to find related to a G class turbine identified an efficiency of 58.8%[25], which is lower than the efficiency of the PEP's F class turbines. We also could not find the information referenced by the commenter stating that the 1 x 1 configuration for the H class turbine is rated at 665 MW – similar to the PEP's size of 645 MW. The information we reviewed from Siemens states that the H class turbine is rated at 310 MW in simple cycle mode, 460 MW in 1x1 combined-cycle mode, and 930 MW in 2 x 1 mode.[26]

We disagree that the turbine models (H class or G class) suggested by the commenter would result in a 2% reduction in GHG emissions from the PEP. The G class turbine is not more efficient than the PEP's turbines, and the increased efficiency of the H class turbine is likely due to its larger size. The H class turbine frame is rated at 310 MW as compared with the F class turbine that is rated at 214 MW. As such, installing the H class turbine would significantly increase the potential overall GHG emissions from the PEP on a mass basis because a larger turbine will burn more fuel and create more GHGs. Each turbine model will have a slightly different efficiency based on its size and we do not think it is appropriate to require the Applicant to consider using a significantly larger turbine model because that model would be 2% more efficient, but could result in overall significant increases in GHG emissions. We continue to determine that the Applicant chose thermally efficient combined-cycle turbines that meet BACT. *See In re La Paloma Energy Center LLC*, 16 E.A.D. at 275–84.

Performance Degradation Rate Used to Set GHG BACT is Not Supported

Comment 16:

Commenters: Conservation Groups (0016)

The commenters argued that the performance degradation rate used by the EPA to set GHG BACT for the PEP is not supported. They further argued that the BACT analysis should consider, and the permit should require, more regular maintenance to decrease degradation, citing various references, as detailed in the comment summary below.

The Fact Sheet states that the applicant included a "performance" compliance margin or degradation rate of 6 percent for anticipated degradation of the equipment over time. Degradation is an important factor to be considered, as the heat rate of the facility may gradually deteriorate slightly between overhauls. However, the EPA's estimate is far too high. To begin with, in setting the new source performance standard (NSPS) for combined-cycle combustion turbines, the EPA used a 5 percent anticipated degradation factor. Region 9 does not explain why it is deviating from EPA headquarters. Moreover, the EPA in setting the NSPS actually acknowledges that the loss is more like 3%; but that they are "being conservative". Note that this assumes that the manufacturer's recommendation for overhaul & maintenance are occurring. This then would be what is called the non-recoverable degradation factor. If Region 9 does not actually believe that degradation will be 6 percent but they are including some sort of safety factor, the record needs to include a justification for a particular safety factor if one exists.

A review of the literature indicates that 6 percent is a significant overestimate given maintenance practices that are widely used and known to improve output (and revenue). Even 3 percent is likely to be too high for newly designed and constructed units that employ efficient designs. Published industry information asserts that good

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[25] http://w5.siemens.com/italy/web/pw/powermatrix/produzionedienergiadafonticonvenzionali/centraliaciclocombinato/macchinerotanti/turbineagas/largescale50hz/pages/sgt6-6000g.aspx

[26] https://www.siemens.com/global/en/home/products/energy/power-generation/gas-turbines/sgt6-8000h.html#!/

maintenance practices, including frequent offline water washing, reduce both the amount of performance degradation and the rate of performance degradation. Detailed testing by Siemens and other manufacturers demonstrates that with advanced cleaning systems, degradation in performance between major overhauls due to compressor fouling can be reduced to negligible levels of less than one percent. One such test shows a reduction in turbine efficiency from 35.3 percent to just 35.2 percent in over 47,000 hours of operation. In addition, regulators need to require adequate maintenance and not just rely on operators who have multiple goals.

If the EPA includes a degradation factor, then it must justify that factor. At a minimum, this means that the EPA needs to consider far more detailed information than it has provided in the Fact Sheet to date and ascertain the extent to which top-performing units – including units with better initial designs and units that employ appropriate maintenance practices – experience the assigned degradation factor. The EPA must make a record demonstrating that a degradation factor is necessary and that the degradation factor used in the permit appropriately represents the reasonable and unavoidable degradation of the facility.

The commenters cite a source that they assert shows that the "recoverable" losses (through blade washing, filter cleaning, etc.) is much larger than the non-recoverable losses. This unit was cleaned about once a week. If cleaned twice a week the decay would be less and presumably, if only cleaned once a month the degradation would be much more. This supports the argument that an aggressive "routine maintenance" program should be part of any PSD GHG permit.

But the EPA has not done this. Rather, the EPA simply accepted the 48,000-hour recommendation for major overhauls as a given. The EPA failed to consider require routine maintenance or more frequent major overhauls as a way to lower the degradation and thus require a more protective GHG BACT emission limit.

Yet, the EPA has acknowledged that mandating maintenance work can be the basis for a GHG BACT limit. In PEP's draft permit, the GHG BACT for the auxiliary boiler is based on yearly tune-ups.

Response 16:

We acknowledge that the underlying basis for the 6% adjustment factor used in the GHG BACT limits for the Project's CTs requires additional clarification; however, we continue to find that this 6% adjustment factor is appropriate in this case. We recognize that use of the term "degradation factor" as used in our Fact Sheet when referring to this adjustment factor was an inadvertent error and oversimplification that did not fully represent all of the considerations for which this 6% adjustment factor was intended to account. In the Fact Sheet, we stated that the 6% "degradation factor" we used was consistent with our analysis for the Pio Pico Energy Center. Fact Sheet at 32. Our analysis for the Pio Pico Energy Center used a 6% adjustment factor, which expressly accounted for more than just turbine degradation, and, in that analysis, we stated that the GHG emission limit needed to account for "various tolerances in the manufacturing and construction of the equipment as well as actual ambient operating conditions." In that analysis, we provided a 3% compliance margin to account for "slight variations in the manufacturing, assembly, construction, and actual performance of the new turbines" and an additional 3% to "account for unrecoverable losses in efficiency the plant will experience over its entire lifetime *as well as seasonal variation in site-specific factors that affect turbine performance such as temperature and humidity* (emphasis added)." Pio Pico Energy Center Fact Sheet at 20-21. As such, we are clarifying that the 6% factor used in setting the GHG BACT limit for the PEP accounts for more than losses of efficiency of the CTs. It is a compliance margin that accounts for various tolerances in the manufacturing and construction of the equipment, losses in efficiency, and actual ambient operating conditions.

It is unclear what the commenters are referring to in in stating that the GHG limit set in the NSPS (40 CFR part 60, subpart TTTT) accounted for a specific 5% degradation factor or in stating that the EPA said it was being conservative and that degradation is closer to 3%. The commenters did not provide a citation for this information and we could not find it, or a reference to such information, in the preambles for the proposed and final rulemakings to which the commenters refer. In fact, in our final rulemaking for the NSPS to which the commenters refer, the EPA arrived at similar conclusion as the commenters, i.e., that very modest decreases in efficiency can be expected over time for natural gas combined-cycle CTs:

> To evaluate degradation further, the EPA reviewed the emission rate information for the 55 oldest NGCC units in our data set (i.e., units that came online in 2000 and 2001). According to the commenters, we should expect to see degradation when reviewing the annual emissions data for these turbines because they are 14 to 15 years old. However, we did not see any sign of degradation. The CO_2 rates for these turbines have little standard deviation between 2007 and 2014. In addition, there were many instances where the CO_2 emission rate of a unit actually decreased with age. This indicates that the efficiency of the unit is increasing, possibly as a result of good operating and maintenance procedures or upgrades to equipment that improved efficiency beyond the original design. Based on these findings, we have concluded that our analysis adequately accounts for potential degradation.

80 Fed. Reg. 64510, 64619 (Oct. 23, 2015).

While we agree with the commenters that turbine degradation alone is expected to be somewhat low, we are unpersuaded that this fact should change the 6% adjustment factor, which, as we are clarifying, accounts for far more variations and factors than the sole issue of losses in efficiency. We must set a BACT limit that is achievable under all operating conditions and that accounts for site-specific factors that may vary over the lifetime of the equipment. As such, our adjustment factor accounts for slight variations in the manufacturing, assembly, construction, and actual performance of the new turbines; unrecoverable losses in efficiency the plant will experience over its entire lifetime; and seasonal variation in site-specific factors that affect turbine performance such as temperature and humidity.[27] In setting the GHG limit in the NSPS, the EPA reviewed all of the existing PSD permits that had been issued at the time of our BACT review for CTs, and found that most GHG BACT limits included similar adjustment factors:

> Finally, most of these permits include compliance margins to account for efficiency losses due to degradation and other factors (e.g., actual operating parameters, site-specific design considerations, and the use of back up fuel). In total, these compliance margins result in a 10 to 13 percent increase in the permitted CO_2 emission limits…"

See 80 Fed. Reg. at 64619. As such, our 6% adjustment factor appears to be significantly lower than that of most other PSD permits. As noted in our Fact Sheet, it is also lower than the two recently permitted sources that are similar to the PEP—AES Huntington Beach and AES Alamitos—both of which used an 8% adjustment factor. Fact Sheet at 32.

The commenters also suggest that the permit should additionally require more routine maintenance to avoid recoverable losses in efficiency (e.g., through biweekly, weekly, or monthly maintenance requirements). The commenters also point to the example of our proposed PSD permit for the PEP, which requires a regular tune-up as BACT for the auxiliary boiler. However, we determined that such a requirement was appropriate as BACT for the auxiliary boiler rather than a numerical limit precisely because we did not think a numerical emissions limit for the auxiliary boiler added any practical value. Fact Sheet at 40. In contrast, with respect to the CTs, we are setting a specific numerical emissions limit that must be achieved at all times. Accordingly, we do not believe that an additional BACT requirement imposing tuneup requirements at short intervals for the PEP's CTs is warranted. Nevertheless, in response to the commenters' concern, to ensure that regular maintenance is conducted, we have

[27] For example, not only will ambient temperatures and humidity vary throughout a calendar year, but such conditions could vary over the lifetime of the facility due to, e.g., climate change. We do not believe that the effect of all the potential factors that could affect compliance with the GHG BACT limit can necessarily be estimated with specificity prior to construction.

added a requirement that the Permittee develop a maintenance plan for the CTs that ensures regular maintenance intervals, consistent with manufacturer's recommendations, for minimizing recoverable losses in turbine efficiency. See Condition 50.e of the Final Permit. This change is shown in the redline-strikeout version of the final permit. And, consistent with the Proposed Permit, Condition 50 of the Final Permit also requires that the Permittee maintain a log of all maintenance activities, including scheduled maintenance.

The EPA Did Not Address Fugitive Equipment Leaks in Its GHG BACT Analysis

Comment 17:

Commenters: Conservation Groups (0016)

The commenters state that while the Fact Sheet discusses sulfur hexafluoride (SF_6) leak prevention, it does not discuss natural gas leak prevention from the combustion turbines, auxiliary boiler, duct burners and natural gas piping and metering equipment. Methane, which is what natural gas mainly is, is a NSR regulated pollutant. Any emissions of methane triggers PSD review for methane. The PEP will invariably emit a non-zero amount of methane through leaks in the piping and other equipment. However, the EPA did not conduct a BACT analysis of methane from leaks at PEP. Leak detection and repair (LDAR) can be achieved in various ways including handheld analyzers and remote sensing technologies, as-observed audio, visual, and olfactory (AVO). At minimum, the EPA needs to address how implementation of these technologies could reduce methane leaks in its GHG BACT analysis.

Response 17:

The commenters are correct that the EPA did not specifically consider potential fugitive methane leaks in its GHG BACT analyses for the PEP. We disagree with the commenter's statement, however, that any increase in methane emissions triggers PSD review for methane. Methane is a GHG, and only becomes subject to BACT as part of PSD review if potential GHG emissions equal or exceed 75,000 tpy. 40 CFR 52.21(b)(49). Consideration of methane in the GHG BACT analysis is warranted in this case specifically because potential GHG emissions from the PEP exceed 75,000 tpy. Below we discuss methane leaks as part of our GHG BACT analysis.

Natural gas-fired power plants use large amounts of natural gas, which is highly combustible, thus minimizing leaks is an important safety and economic consideration in the design and operation of such power plants. Additional information provided by the Applicant indicates that this is the case for the PEP, and that monitoring of natural gas leaks is already a part of the Applicant's design and intended operation of the Project. In general, there are limited opportunities for natural gas leaks to occur from natural gas-fired power plants, given the limited piping that is associated with such facilities.[28] For example, refineries and chemical plants have large quantities of piping and may have *tens of thousands* of potential locations where leaks can occur. In the case of the PEP, we expect less than 200 of such locations.[29] Based on this information, potential emissions from methane leaks are estimated at 0.048 tpy of methane or 1.2 tpy of CO_2 equivalent (CO_2e).[30] For comparison purposes, this represents less 0.0001% of CO_2e emissions from the PEP. While we are evaluating BACT for this equipment, as the potential emissions are extremely small, an extensive, detailed analysis is not warranted, as any available control options will result in negligible reductions in CO_2e emissions. See NSR Manual at B.20-21.

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[28] It is unclear what the commenters are referring to by stating that leak prevention from the "combustion turbines, auxiliary boiler, duct burners" is needed. We do not know what kind of leaking the commenters are referring to beyond leaks from piping associated with this equipment – which is where all of the natural gas will be until it enters the burners of this equipment and is combusted.

[29] See Table 1 in the February 19, 2018 email attachment from Gregory Darvin, Atmospheric Dynamics to Lisa Beckham, EPA Region 9.

[30] *Ibid.*

A review of BACT determinations for equipment leaks in the EPA's RACT/BACT/LEAR Clearinghouse (RBLC) found the most common requirement to be an LDAR program. However, we did not find any examples in the RBLC of BACT for methane equipment leaks from power plants, although we are aware that EPA Region 6 has issued several GHG PSD permits that require AVO checks for fugitive emissions.[31] As indicated by the commenters, typical LDAR programs require routine monitoring of equipment, such as through a gas analyzer and/or AVO checks, and require detected leaks to be repaired within a specified time period. In some cases, there are also standards for the particular equipment installed and requirements that the equipment be tested for leak-free performance. As described below, the information provided by the Applicant for the PEP is consistent with such a program and goes further by including additional monitoring for enclosures.

The Applicant identified potential ways in which methane leaks could occur at the PEP, and provided information about the plans in place for monitoring and promptly addressing potential methane leaks from the PEP's equipment. See information provided by Gregory Darvin, Atmospheric Dynamics in an email dated January 9, 2018.[32] The PEP will include onsite outdoor piping that will run from the interconnection pipeline to the PEP's gas compression system and then to the combustion units. This outdoor piping will consist of short runs of welded piping, flanged isolation valves, flanged control valves, flow meters and a knock out drum to remove minor quantities of condensable liquids. Additionally, the CTs and gas compression equipment will be located in acoustical enclosures to minimize noise impacts.

To minimize leaks, the Applicant's plans include:

1. Enclosures: All potential leaks from the acoustical enclosures housing the gas compression and combustion turbines will be monitored continuously by gas detection equipment, which will detect any natural gas leaks, activate an alarm, and isolate the natural gas supply external to the enclosures (that is, valves outside the enclosures will stop the natural gas supply to the equipment, thereby preventing additional natural gas from entering the enclosures).
2. Outdoor Piping: All piping will be installed in accordance with Industry Codes and Standards (ASME B31.1 – Power Piping) and pressure tested after installation. In accordance with Plant Operating procedures, plant technicians will periodically inspect all piping, flanged connections, and valves using hand held gas leak detection equipment. All leaks will be repaired as soon as possible.

Upon review of this comment, the EPA's RBLC, other permitting actions, and the information provided by the Applicant, we are determining that the existing procedures proposed by the Applicant for the Project – continuous monitoring of enclosures and LDAR for exterior piping – will serve to limit potential methane leaks for GHGs and represent BACT. We are including the Applicant's procedures in the Final Permit with a few additional requirements to ensure adequate enforceability. The additional provisions include a definition of a leak as 10,000 ppmv of methane/natural gas, as well as requirements for at least quarterly monitoring with a handheld analyzer, quality control/quality assurance of monitoring equipment, repairing leaks from piping within 15 calendar days,

[31] For example, see PSD Permit Number PSD-TX-1288-GHG for the La Paloma Energy Center issued November 6, 2013.

[32] The commenters asserted that leaks from metering equipment should be considered. However, the Applicant stated that the Southern California Gas Company's (So Cal Gas) interconnection pipeline will surface at the Palmdale Energy Project Site, where So Cal Gas will install a revenue meter and isolation valves. This equipment is owned and maintained by So Cal Gas, and is not considered to be part of the PEP because it will not be under the control of the Applicant/Permittee. 40 CFR 52.21(b)(6). As such, we do not need to consider it as part of this permitting action. However, we note that the information provided by Applicant stated that So Cal Gas representatives will periodically inspect the line for leaks, including all flanged connections, utilizing hand held leak detection equipment.

and recordkeeping. Please see Conditions 27 and 47.q of the Final Permit. These changes are shown in the redline-strikeout version of the final permit.

The EPA Should Consider 5ppm as BACT for NO_X for the Auxiliary Boiler

Comment 18:

Commenters: Conservation Groups (0016)

In the comment excerpt below, the commenters requested that the EPA redo the NO_X BACT analysis for the auxiliary boiler with 5 ppmvd as the top choice in step 4 of the 5-step top-down BACT analysis for the PEP. The commenters supported their request by stating that there are existing facilities with auxiliary boilers that have 5 ppm NO_X limits. The commenters asserted the following:

The EPA acknowledges that there is one BACT determination for an auxiliary boiler of 5 ppm NO_X. However, the EPA rejects this because it claims this emission rate is not demonstrated in practice. This is a misapplication of BACT for two reasons. One is that the Fact Sheet does not document what auxiliary boilers are achieving in practice, regardless of their NO_X emission limits. The other is that the fact alone that a source has not been built yet does not mean that the EPA is free to ignore this. The EPA's approach would be the opposite of the technology forcing nature of BACT. Not only would the EPA's approach make it impossible for emission limits to get more stringent absent a polluter asking for a more stringent limit, it would allow for BACT limits to get less stringent over time between the time a source gets a limit and "demonstrates in practice" that the limit is achievable. If the EPA believes that demonstrates in practice requires the lifetime of the facility, this could take 30 years. Therefore, the EPA must redo the BACT analysis with 5 ppmvd as the top choice in step 4 of the BACT analysis.

Furthermore, Table 15 of the Fact Sheet states that there are two other facilities in California, AES Huntington Beach Energy Center and AES Alamitos Energy Center, which have 5 ppm NO_X limits based on the use of SCR. The EPA fails to provide an analysis of why it rejected these two examples in refusing to set a NO_X BACT of 5 ppm.

Response 18:

The EPA disagrees that we should revise the NO_X BACT analysis for the PEP's auxiliary boiler in the manner suggested by the commenters or that the BACT limit of 9 ppm that we selected was otherwise inappropriate.

First, the commenters appear to be suggesting that the EPA should assume that the use of ultra-low-NO_X burners (ULNB) as a control technology for the auxiliary boiler would result in an emissions limit of 5 ppm, and therefore this control technology should be ranked with an emissions limit of 5 ppm in Steps 3 and 4 of the BACT analysis for the auxiliary boiler. In contrast, the EPA's NO_X BACT analysis for this equipment considered the use of ULNB as achieving an emissions limit of 9 ppm. In the Fact Sheet's discussion of our BACT analysis for this equipment at the PEP, we noted that there was a 5.0 ppm limit for the Freeport LNG Development LP- Pretreatment Facility, which was required to use only ULNB as a control technology. This BACT limit for the Freeport facility is the oldest of the BACT limits that we considered in this analysis, and there have been no subsequent determinations imposing a BACT limit of 5 ppm by only using ULNB for a boiler. Generally, a BACT analysis would consider the "most recent regulatory decisions and performance data for identifying the emissions performance level(s) to be evaluated . . ." NSR Manual at B.23. An emission limit is not necessarily considered BACT solely because it was required previously of a similar source type. NSR Manual at B.23. And while the most effective level of control must be considered in the BACT analysis, different levels of control for a given control alternative can be considered. NSR Manual at B.23-24. In this case, we eliminated the consideration of a limit of 5 ppm using ULNB, because this particular level of control for this control technology has not been demonstrated to be achieved in practice. The Freeport facility is the only facility with a boiler required to use only ULNB that has been permitted at this level, and it has not yet finished construction and has not undergone initial source testing.[33] Accordingly, we continue to determine that BACT based on the use of ULNB at this time is 9 ppm, which is the limit that has been achieved in practice to date using this control technology. We also note that some of the BACT limits for similar units have lb/MMBtu limits instead of ppm limits. However, none of the units with lb/MMBtu limits using only ULNB are achieving the same level of control as those using SCR (generally about 0.006 lb/MMBtu with SCR and 0.011 lb/MMBtu without SCR). We would like to clarify that the EPA did not indicate that a lower emissions limit would need to be demonstrated for the full lifetime of the equipment before being considered to have been achieved in practice.

It is important to note that there are specific technical and environmental concerns related to the application of ULNB that are germane to the determination of what NO_X emission limits are achievable for a boiler using this control technology. NO_X emissions from boilers are highly dependent on flame temperature. The particular design of a burner can help lower the flame temperature and thus lower NO_X emissions. However, a low flame temperature can also be associated with decreased efficiency and higher CO emissions. As such, manufacturers must develop burners that can achieve desired NO_X levels while still ensuring that the boiler is efficient and will not emit high levels of CO. While lower levels of NO_X may be attainable in some instances, there may be other negative consequences associated with lower NO_X levels when applying this technology. It is possible that a solution for addressing this issue is to achieve lower NO_X emissions through the use of add-on control technology. This appears to be the approach utilized for the other units with limits of 5 ppm of NO_X that are listed in our Fact Sheet (i.e., the AES Huntington Beach Energy Center and the AES Alamitos Energy Center, discussed below). Thus, in addition to the fact that only one facility has been permitted at 5 ppm of NO_X using ULNB alone, and the fact that no facility has yet demonstrated that this limit is achievable in practice using only ULNB, these technical concerns suggest that even if 5 ppm were consistently achievable, this may result in negative boiler performance including a decrease in efficiency and higher CO. Should additional information become available in the future indicating the achievability in practice of this 5 ppm NO_X limit from the utilization of ULNB, it would be appropriate to consider this factor when setting BACT, and it is possible that the limit would not be adopted at step 4 of the BACT analysis due to these other impacts.

The commenter also expressed a concern that the EPA did not document what NO_X emission limit auxiliary boilers are achieving in practice. However, Table 13 of the Fact Sheet documented the control levels we considered as potential BACT limits "as determined by reviewing other BACT determinations and the limits proposed by the Applicant." Fact Sheet at 36. It is unclear what kind of additional documentation the commenter believes we were required to provide in conducting the BACT analysis. Regarding the limit achieved by ULNB, we specifically determined that limit to be 9 ppm after eliminating the 5 ppm limit. This is the same approach used in all of the BACT determinations. To the extent that commenter believes that the EPA should have investigated specific actual emissions data, we do not believe such a level of effort is warranted or reasonable for a unit with such low emissions – about 3 tpy. These units are likely designed and tuned by the manufacturer to meet the specific emission limit, and since there are no add-on controls it is unlikely emissions data would reveal significant new information. As discussed above, lower NO_X emissions can have a negative impact on boiler performance. As such, operators are unlikely to operate the units significantly below the level needed to achieve compliance.

Finally, the EPA did provide an analysis explaining why we did not select as BACT the 5 ppm NO_X limits for the AES Huntington Beach Energy Center and the AES Alamitos Energy Center. The emission limits for these two facilities' boilers were based on the use of selective catalytic reduction (SCR), an add-on control technology. The EPA

[33] The Freeport facility still remains under construction at this time with initial startup not expected before the fourth quarter of 2018. http://www.theislemagazine.com/construction-live.html

rejected the use of SCR in Step 4 of the BACT analysis for the PEP's auxiliary boiler, because we determined that the use of SCR would not be cost-effective. [34] See our Fact Sheet at 37.

CO BACT for the Auxiliary Boiler Must Consider Low Temperature Oxidation Catalyst as Technically Feasible

Comment 19:

Commenters: Conservation Groups (0016)

The commenters asserted that the EPA fails to consider technology transfer of a low temperature oxidation catalyst to set CO BACT for the auxiliary boiler, providing the following arguments:

The EPA states: "While there may be developing technologies for low temperature oxidation catalysts, we are not aware of any such available application for natural gas boilers of this type." The EPA fails to undertake an analysis of whether these low temperature oxidation catalysts can be applied to the type of natural gas boiler at PEP. Ironically, the evidence the EPA cites to is on NASA's "technology transfer" web page.

Furthermore, as with NO_X, the EPA eliminates the lowest CO emission rate it is aware of because the facility with that limit is not yet in operation. This is error for the same reasons explained above. Therefore, the EPA must redo the BACT analysis starting with 25 ppm CO in step 4 of the 5-step top-down BACT analysis for the PEP.

Response 19:

The EPA disagrees that further consideration of a low temperature oxidation catalyst is warranted in the CO BACT analysis for the PEP's auxiliary boiler. The only commercial applications of this technology of which we are aware are for sources with gas streams that are significantly different from, and thus not readily "transferable" to, the CO exhaust stream from an auxiliary boiler.

The technology transfer information provided by NASA referred to in our Fact Sheet and referenced by the commenters is intended for taking NASA-developed technology and expanding its use to new commercial applications. NASA's technology transfer program takes technology that was developed for aerospace purposes and makes it available for licensing in non-aerospace applications.[35] As a government agency, NASA does not develop commercial products. Thus, the information provided in the NASA technology transfer program is for transferring aerospace technology to applications that are not yet commercially available. NASA's technology transfer program is different than "technology transfer" in the BACT context where existing *commercially* available technologies may be transferred to other similar applications. A technology is "available" if it can be obtained through commercial channels or is otherwise available within the common sense meaning of the term. NSR Manual at B.17; see also GHG BACT Guidance at 34. A technology being "available" is a necessary component to be considered in a BACT analysis, and the applicant is not expected to have to develop untested technologies. NSR Manual B.17-18.

The information from NASA concerning this technology states:

> "Originally developed to support space-based CO_2 lasers, the technology has evolved into an array of performance capabilities and processing approaches, with **potential applications** ranging from indoor air filtration to automotive catalytic converters and industrial smokestack applications. The technology has

[34] The Huntington Beach and Alamitos facilities are both located in an extreme ozone nonattainment area and must meet the lowest achievable emission rate (LAER), which does not include the consideration of costs.

[35] See https://technology.nasa.gov/license. For example: "NASA maintains a portfolio of patents that we believe have commercial potential. We make these technologies available to academia and industry through our patent licensing program with a variety of U.S. and foreign patents."

been used commercially in systems that provide clean air to racecar drivers, as well as incorporated into [a] commercially available filtration system for diesel mining equipment. **Backed with extensive research on these technologies, NASA welcomes interest in the portfolio for other commercial and industrial applications**."

NASA Technology Transfer Program, Low Temperature Oxidation, Reduction Catalysts at https://technology.nasa.gov/patent/LAR-TOPS-124. (emphasis added).

While there may be commercially available systems using this technology for filtering ambient air for racecar drivers or inside the cabin of diesel mining equipment, the information from NASA indicates that NASA is looking to partner to make this technology commercially available for other commercial and industrial applications. Nothing in the NASA literature indicates that this technology is currently available for reducing exhaust emissions in industrial applications, such as the boiler at the PEP. We would not consider the comparatively low air flow and ambient air temperature environment inside a race car or the cabin of mining equipment[36] to be sufficiently similar to the high air flow and 300°F boiler exhaust to warrant further scrutiny as an available BACT technology for the auxiliary boiler under the concept of technology transfer.[37]

Next, regarding the commenters' assertion that CO BACT for the auxiliary boiler should be 25 ppm at step 4 of our BACT analysis, we disagree. The commenters appear to be suggesting that the EPA should assume that the use of good combustion practices as a control technology for the auxiliary boiler would result in a CO emissions limit of 25 ppm, and therefore this control technology should be ranked with an emissions limit of 25 ppm in Steps 3 and 4 of the BACT analysis for the auxiliary boiler. In contrast, the EPA's CO BACT analysis for this control technology considered the use of good combustion practices as achieving an emissions limit of 50 ppm. See Fact Sheet at 38. In the discussion of our BACT analysis for this control technology in the Fact Sheet, we noted that there was a 25 ppm CO BACT limit for the Freeport LNG Develop LP – Pretreatment Facility, based on the use of good combustion practices. The commenters argue that it was improper for the EPA to eliminate this CO emission rate based on the fact that the facility with that limit is not yet in operation.

In response, we continue to find that CO BACT for the PEP's auxiliary boiler is 50 ppm based on good combustion practices. The 25 ppm BACT determination for the Freeport facility is the oldest BACT limit that we considered, and there have been no subsequent determinations finding that 25 ppm of CO is BACT for similar boilers. See Fact Sheet Table 15, at page 41. A particular emission limit is not necessarily considered BACT solely because it was required previously of a similar source type. See NSR Manual at B.23. While the most effective level of control must be considered in the BACT analysis, different levels of control for a given control alternative can be considered. NSR Manual at B.23-24. In this case, as noted in our Fact Sheet, we eliminated the consideration of the 25 ppm limit because this emission rate has not been demonstrated to be achieved in practice. There are no add-on emission controls for CO that were proposed in our BACT analysis to meet this 25 ppm limit, and the Freeport facility for which CO BACT was determined to be 25 ppm has not finished construction or undergone

[36] We believe the NASA literature is referring to filtering of the cabin air in mining equipment and do not believe the literature is referring to filtering exhaust gas emissions from diesel mining equipment. Exhaust gas emissions from diesel equipment are not typically low temperature environments, and the literature otherwise suggests that applying the technology to automotive exhaust systems may separately be a potential application for the technology. CO exhaust emissions from mobile diesel engines are typically controlled by a diesel oxidation catalyst or catalyzed diesel particulate filter. This equipment tends to operate in the 400-600° F range. See, for example, http://www.airflowcatalyst.com/new/products/.

[37] As a comparison, we also do not consider the standard commercially available cabin air filters, used in everyday automobiles to remove dust and pollen, as being available for industrial $PM/PM_{10}/PM_{2.5}$ exhaust applications. The size and scale are too significantly different to warrant a reasonable consideration.

initial source testing. The 50 ppm CO limit that we selected is consistent with other recent BACT limits for similar boilers, as demonstrated in Table 15 of our Fact Sheet.[38] See Fact Sheet at 41. We note that the Freeport facility still remains under construction at this time with initial startup not expected before the fourth quarter of 2018.[39] Additionally, please see the discussion in Response 18 where we describe the technical issues surrounding NO_X and CO emissions from boilers. The fact that lower NO_X emissions are typically associated with higher CO emissions and reduced boiler efficiency provides a further reason to be cautious about imposing a new CO BACT limit lower than that that has generally been previously imposed absent data showing that it has been achieved in practice. In sum, we do not believe that the 25 ppm CO limit has been sufficiently demonstrated to be considered in Steps 3 or 4 of the BACT analysis.[40]

Emergency Engines Do Not Have Numerical Emission Standards

Comment 20:

Commenters: Conservation Groups (0016)

The commenters asserted the following:

BACT is an emission limit. (40 CFR 52.21(b)(12)). Units D2 and D3 do not have any BACT emission limits for NO_X, CO, PM, PM_{10} and $PM_{2.5}$. These sources have stacks and thus are easily subject to source testing. Therefore, there is no excuse for not including BACT emission limits for these sources.

The permit must also include BACT emission limits for NO_X, CO, PM, PM_{10} and $PM_{2.5}$ (front and back half) for the emergency generator engine and emergency fire pump engine during normal operations. These sources are capable of being tested and so a work practice is not an acceptable substitute for actual emission limits. The permit must also have testing, monitoring and reporting to determine compliance with these BACT emission limits.

Response 20:

We agree with the commenters that performance testing is necessary for the emergency engines D2 and D3, and should be required in the PSD permit for the PEP. We acknowledge that the language in the Fact Sheet implied that this requirement was only a work practice standard, but that was not our intent as the proposed permit contained performance testing requirements for the PEP's engines. For purposes of BACT, these engines must meet the emission limits in 40 CFR part 60, subpart IIII. We have revised the related conditions for these units in the final PSD permit for the Project so that it is clearer that these engines must comply with emission limits in 40 CFR part 60, subpart IIII. See revised Conditions 24.a and 25.b in the Final Permit. The applicable NSPS limits were provided in Tables 16 and 17 of the Fact Sheet. We are providing them below for further clarification. The PM limits in subpart IIII include both filterable and condensable PM – as such, separate PM_{10} and $PM_{2.5}$ limits are not necessary. The permit already contained sufficient monitoring, testing, and reporting to ensure compliance with these limits, including the performance test requirements in Proposed Permit Condition 40.b (now Final Permit Condition 41.b). See also Conditions 47.m through 47.o, 50, 51, 53, and 54 of the Final Permit.

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[38] Some of the BACT limits we reviewed as part of our analysis had lb/MMBtu limits instead of ppm limits. A 50 ppm limit is equivalent to about 0.037 lb/MMBtu. None of the lb/MMBtu limits were in the range of 25 ppm, which equates to about 0.019 lb/MMBtu.

[39] http://www.theislemagazine.com/construction-live.html

[40] We also note that to the extent that the commenters believe that the EPA should have investigated specific actual emissions data, we do not believe such a level of effort is warranted or reasonable for a unit with such low emissions – about 10 tpy. These units are likely designed and tuned by the manufacturer to meet the specific emission limit, and since there are no add-on controls it is unlikely emissions data would reveal significant new information. The level of CO emissions achieved is going to be a function of the NO_X emission limit, and operators are unlikely to operate the equipment outside the range needed to maintain compliance.

Summary of Applicable NSPS Limits in 40 CFR 60 Part 60, Subpart IIII

Engine Type	NMHC+NO_X (g/kWh)	PM (g/kWh)	CO (g/kWh)
NSPS – Fire Pump Engine	4.0	0.30	5.0
NSPS – Emergency Generator Engine	6.4	0.20	3.5

Also, in considering this comment, we discovered a typographical error in Condition 24 of the Final Permit, which we have corrected. Condition 24 inadvertently did not include the word "emission" prior to the word "standards" to specify that the engines are subject to the "emission standards" in 40 CFR part 60 subpart IIII. The word "emission" has now been added. See Condition 24 of the Final Permit.

The revisions to the permit are shown in the redline-strikeout version of the final permit.

Annual Leak BACT Limit for Sulfur Hexafluoride Not Clearly Enforceable

Comment 21:

Commenters: Conservation Groups (0016)

The commenters asserted the following: With regard to the circuit breakers, they have a 0.5% by weight (calendar year basis) emission limit which appears to be the Region's GHG BACT emission limit for this emission unit. However, the leak detection system is a 10% by weight leak detection system. It does not seem possible for a 10% leak detection system to enforce as a practical matter a 0.5% annual leak rate. Therefore, the permit must have another method to practically ensure compliance with the 0.5% annual leak BACT limit.

Response 21:

We agree with the commenters that the 10% by weight leak detection system is not sufficient by itself for ensuring that the Permittee is meeting the 0.5% annual leak BACT limit. The proposed permit included additional requirements in Condition 46.p, requiring the Permittee to maintain records of the amount of SF_6 added monthly to the circuit breakers. However, in considering this comment, we revised the recordkeeping requirement to require the Permittee to calculate the annual leak rate based on the monthly SF_6 that is added. That is, the leak rate of SF_6 can be determined by assuming that any SF_6 that needs to be added to the circuit breakers is the amount that was lost due to leaks. See Condition 47.p of the Final Permit. This change is shown in the redline-strikeout version of the final permit.

The BACT Limits Do Not Sufficiently Address Startup and Shutdown Conditions for the CTs, Boiler, and Engines

Comment 22:

Commenters: Conservation Groups (0016)

The commenters asserted that the draft permit must have BACT emission limits for the CTs for $PM/PM_{10}/PM_{2.5}$ during startup and shutdown that are enforceable as a practical matter, making the following arguments:

Because the stack test will not be performed during startup and shutdown, the current permit limits do not apply during startup and shutdown as a practical matter. This $PM/PM_{10}/PM_{2.5}$ startup and shutdown emission limit needs to be enforceable as a practical matter and needs to include both filterable and condensable PM_{10} and $PM_{2.5}$.

Similarly, the permit must have BACT emission limits for the auxiliary boiler, the emergency generator engine, and the emergency fire pump engine during startup and shutdown which are enforceable as a practical matter. Emissions during startup and shutdown of these types of units can be exponentially higher than during the stack test and with their relatively low stacks and almost always operating in startup and shutdown mode, they can easily cause or contribute to violations of increments or NAAQS.

Response 22:

The EPA disagrees with the commenters that the permit is deficient for not having separate BACT limits for $PM/PM_{10}/PM_{2.5}$ emissions from the CTs during startup and shutdown. We also disagree with the commenters' argument that it is necessary to set separate BACT limits in our PSD permit specifically for startup and shutdown of the auxiliary boiler and emergency engines. Our reasoning is detailed below.

<u>$PM/PM_{10}/PM_{2.5}$ Emissions from the CTs</u>

First, we do not find that separate BACT limits are necessary for $PM/PM_{10}/PM_{2.5}$ emissions from the CTs during startup and shutdown. As stated in our startup and shutdown BACT analysis for the CTs in the Fact Sheet, we did not find it necessary to set separate startup and shutdown BACT limits for $PM/PM_{10}/PM_{2.5}$ for the CTs because we expect BACT to be met during startup and shutdown, as we expect lower emissions at lower loads. See footnote 56, page 35 of the Fact Sheet. We expect particulate emissions from natural gas combustion to be a function of the sulfur content of the fuel; that is, low sulfur fuels have lower PM emissions. As part of our BACT determination for the CTs we included a limit on the sulfur content of natural gas used at the PEP. See Condition 17 of the Final Permit and Fact Sheet at 23. We are also not aware of any separate numerical emissions limits for startup or shutdown of the CTs being imposed as BACT for $PM/PM_{10}/PM_{2.5}$ in other permits for similar units. As the commenters identify, there is no practical way to measure $PM/PM_{10}/PM_{2.5}$ emissions from the CTs during startup and shutdown because compliance is based on stack testing that cannot be conducted during startup and shutdown events. It is unclear what type of BACT limits during startup and shutdown of the CTs the commenters are suggesting should have been included since stack testing cannot occur during startup and shutdown events.

Further, the clean fuel requirements in Condition 17 and the good combustion and operational practices requirements in Conditions 4 and 16 of the permit apply during startup and shutdown. There is no exemption from any of these requirements for the CTs during startup and shutdown, and therefore no need to impose additional BACT requirements or limits for the CTs during startup and shutdown periods.

<u>Startup and Shutdown BACT Limits for the Auxiliary Boiler, Emergency Generator, and Emergency Fire Pump Engine</u>

Next, we do not find that separate startup and shutdown BACT limits are necessary or appropriate for the auxiliary boiler, the emergency generator, or the emergency fire pump engine, or that emissions from such equipment would be "exponentially higher" during startup and shutdown. (See Response 30 regarding modeling during the startup and shutdown of this equipment.) The emissions from this equipment are relatively minor compared to the emissions from the Project's CTs, and the commenters have not demonstrated that emissions from this equipment during the startup and shutdown of such equipment would be different in nature or substantially higher than the emissions of such equipment during its normal operations such that the emissions could cause the Project to violate the applicable NAAQS or increments.

We are not aware of any permits for similar equipment that have included such limits and the commenters have not identified any nor explained how such limits should be developed or enforced. We are also not aware of any work practice standards for such equipment that would specifically address startup and shutdown of the equipment beyond the requirements that are already included in our permit, and the commenters have not identified any. We note that unit-specific BACT limits for startup and shutdown are typically associated with emission units that need time for the control equipment to reach certain parameters to begin normal operation, as well as to ensure that the permittee begins using the control equipment as soon as practicable. Typically, these limits are set by limiting the duration of startup and shutdown, limiting the emissions during startup and shutdown, and/or establishing certain parameters for when control equipment must begin operating. In contrast, in this case, no add-on control equipment is used to address $PM/PM_{10}/PM_{2.5}$, NO_X and CO emissions from the emergency engines or boiler at the PEP, and thus setting specific startup and shutdown BACT limits for the PEP's engines is not warranted. BACT is achieved during startup and shutdown by the general requirement in Condition 4 of the permit to operate the equipment in a manner consistent with good air pollution control practices for minimizing emissions. Additionally, for the auxiliary boiler, the clean fuel requirements in Condition 17 also further limit $PM/PM_{10}/PM_{2.5}$ emissions during startup and shutdown, and Conditions 24 and 25 require the use of nonroad diesel, a low particulate fuel, which also limits $PM/PM_{10}/PM_{2.5}$ emissions.

Regarding setting filterable and condensable PM BACT limits, we explained in the Fact Sheet that such limits included filterable and condensable PM for the CTs and auxiliary boiler. Fact Sheet at 22, 23 and 38. We are clarifying that although we inadvertently did not state this in the Fact Sheet with respect to the emergency engines, in fact, those BACT limits also include filterable and condensable particulates. See generally 40 CFR 52.21(b)(50)(i)(*a*).

Air Quality Modeling Concerns Regarding Meteorological Data

Comment 23:

(Commenter: Jack Ehernberger)

(Jack Ehernberger (0018))
The commenter asserted: The Project air quality modeling incorporates surface data from PMD (Palmdale Plant 42) with upper air data observations measured in Nevada. On nearly all days the micro-meteorological character of the Nevada data will differ from the PMD meteorology. Merging the data from these disparate sources is very likely to distort the stability and wind shear structures which control dispersion, and is thereby considered an inherent flaw in the plume modeling strategy.

(Jack Eherngerger (0019), public hearing testimony)
The commenter stated:

Concerning the air quality modeling issues of data and procedures, the Palmdale project started out with using Victorville surface data and Nevada upper air data. And that challenged the accuracy of the atmospheric modeling in the lower altitude, say the first 4- to 6,000 feet especially where the winds here can be quite a bit different than they are in Nevada; whereas above 6- or 10,000, they might be quite similar. At lower altitudes, it kind of challenges the issue of fact.

I did not get any clear-cut rebuttal or response or acceptance of those comments. However, in the materials I saw today, it does say that they have redone the aero-mod exercises using Palmdale surface data, which sounds good to me, and also some Nevada data.

In addition, it says they have reached out to Phoenix, Tucson and Yuma and Edwards for additional data. How they use data from all those different sources with the Palmdale surface data kind of begs the issue of getting accurate results from the modeling. So, it's a modeling technical comment. My vote would be to not accept the modeling work.

Response 23:

The EPA disagrees that the modeling analysis conducted by the Applicant is not acceptable. As described below, the Applicant considered a variety of available data sets and then used the most adequately representative information, which is consistent with the EPA's Guideline on Air Quality Models (GAQM) at 40 CFR part 51,

Appendix W, for selecting upper air data. See GAQM Appendix A at Section A.1.b. Upper air data are not always readily available at locations close to where the surface observations are collected, as there are fewer locations where upper air data is measured as compared to surface data. In this case, the data collected from these sites are representative of high altitude desert climates, which we have determined are adequately representative of Palmdale's climate for purposes of PEP's air quality analysis. As such, we do not believe using this data in conjunction with the Palmdale surface data is likely to "distort" the results of the modeling. Below, we describe how this data set was selected.

Eight upper air data sites were considered for this application. These were the Mercury-Desert Rock Airport in Mercury, NV; Edwards AFB near North Edwards, CA; Vandenberg AFB in Lompoc, CA; Miramar Air Station in Miramar CA; Las Vegas, NV; Phoenix, AZ; Tucson, AZ; and Yuma, AZ. Mercury-Desert Rock in NV was used in the previous Palmdale Hybrid Power Plant permit analysis, but the station no longer collects upper air data so data from this site were not used for the PEP analysis. The closest potentially representative sites are Edwards AFB and Yuma, but these are military sites and upper air soundings are not taken every day. Miramar and Vandenberg were eliminated because their data are not representative of the Project site, as both of these upper air stations are close to the ocean and have upper air profiles representative of a coastal air mass. In this case, the Applicant used a blend of upper air data collected primarily at Las Vegas, NV (2011-2014) and additionally at Tucson, AZ (2010) as being the most representative sites available that had data complete enough to use. The data collected from Tucson in 2010 were missing some data. To create the best data set for evaluating impacts, the Applicant supplemented the missing 2010 data from Tucson with data from Phoenix, AZ, Edwards Air Force Base, CA and the Yuma Proving Ground in Yuma, AZ, which are also mostly representative of high altitude desert climates. The EPA reviewed the available information and concurred with the Applicant's chosen data sets as being adequately representative for the area around the PEP.

It is Not Evident Whether Humidity Concentration Was Included in Dispersion Modeling

Comment 24:

Commenter: Jack Ehernberger (0018)

The commenter stated that evidence that the air quality emissions modeling included humidity concentration within the dispersing plume is not evident. Thus, the application is not complete with respect to humidity impact on plume chemistry (including ozone) and visibility effects as the plume interacts with Antelope Valley aerosols and Plant 42 aircraft carbon emissions.

Commenter: Jack Ehernberger (0019)
The commenter also stated, with respect to the air quality modeling, that he saw no statement of water vapor. If you consume fuel, you're going to produce water vapor. Water vapor is kind of strange to our way of life in the desert. So, if it is not immediately dispersed, it will change the way of life for people in the nearby neighborhoods. It will also influence any photochemistry reactions to the dispersed pollutants. So, the commenter thinks it's a necessary constituent for modeling the plume effect.

Response 24:

Consideration of humidity was included in the modeling analysis for the PEP. The meteorological data, which is input into AERMOD through AERMET, includes collection of dew point data, which can be used as a measure of moisture content (i.e., humidity). Thus, humidity data is considered in the model. However, while the pollutant concentrations provided in the AERMOD output results factor in moisture content, AERMOD does not provide output information on changes to local humidity. Consideration of humidity impacts is not a required analysis under the PSD program. We also note that visible vapor plumes from combined-cycle power plants are typically associated with cooling towers; however, the PEP will have a dry cooling system and visible vapor plumes are not expected.

Visibility Assessment – Humidity Conditions Limited to Less than 70% Relative Humidity

Comment 25:

Commenter: Jack Ehernberger (0019)

The commenter stated that the visibility assessment appears to be limited to humidity conditions less than 70% relative humidity. Adverse air quality impacts on visibility are much more significant for relative humidity values greater than 70% - thus the PEP PSD study is again incomplete in this regard too. I was glad to see some treatment added on visibility.

Response 25:

It is unclear what the commenter is referring to with respect to 70% relative humidity impacts on visibility. The commenter may be referring to an analysis conducted by the CEC as part of the State's licensing process. However, for the EPA's visibility analysis, the EPA has established models, such as VISCREEN, to determine visibility impacts, and they are not dependent on relative humidity.

Air Quality Modeling – Climatological Assessment Period Needs to be Longer than 5 Years

Comment 26:

(Commenter: Jack Ehernberger)

(Jack Ehernberger (0018))
The commenter stated: The regulatory modeling protocol, using a 5-year period of record, is very likely to be inadequate as a tool to specify the "worst case." Moreover, the Antelope Valley residents' wellness statistics indicate some adverse aspect already exists affecting residential developments and schools in the plume air shed zone near the PEP.

(Jack Ehernberger (0019), public hearing testimony)
The commenter stated:

I'd like this opportunity to kind of recap what impressed me as being pertinent issues raised at the summer meeting. The public expression here was that we want to go forward. The target of success is not just a power plant with a plume that adds material to the air quality; but our target should come from the cities of Palmdale and Lancaster and the Economic Development Commission in the Antelope Valley. The target is to, perhaps, double or triple our population and our local employment. The Federal criteria, which sums the project effect with last year's background or the data application background, is not really our future target. Rather, our future target would sum the power plant with the growing community that is our city target in the future. Antelope Valley is part of Los Angeles County that has an unexplained anomaly in wellness; that is, higher rates of diseases, illness and death at a younger age. And not knowing how that is explained in terms of health, we are not attaining what would probably be accepted as a national standard already. I think that captures what I remember of that meeting. In terms of the initial assessment of air quality, as I remember, it was a five-year period of record. A five-year period of record, when you grab it here or there over the calendar of decades is quite likely to miss some adverse anomalies in atmospheric behavior. So as a rule, we think of an adequate series of weather records as being more like 20 years, if not 15 more. And, also, you would think in terms of financing and business operation, they would want the picture of their risk that goes beyond just any random five-year slice of previous weather.

Response 26:

The commenter appears to suggest that an insufficient amount of meteorological data was used in the modeling for the Project, and that such data should have covered a greater number of years. We disagree with the commenter, as we have determined that enough meteorological data were utilized to ensure that worst-case meteorological conditions were adequately represented in the model results for the PEP, and that the data used were adequately representative and otherwise consistent with the GAQM.

The meteorological data used as an input to AERMOD for this analysis was selected based on spatial and climatological (temporal) representativeness as well as the ability of the individual parameters selected to characterize the transport and dispersion conditions in the area of concern. The representativeness of the measured data is dependent on numerous factors, including, but not limited to, the proximity of the meteorological monitoring site to the area under consideration, complexity of the terrain, the exposure of the meteorological site, and the period of time during which data are collected. The meteorological data should be adequately representative, and may be site-specific data or data from a nearby National Weather Service (NWS) or comparable station. Section 8.4 of the GAQM states that the model user should acquire enough meteorological data to ensure that worst-case meteorological conditions are adequately represented in the model results. The GAQM also states that the use of 5 years of meteorological data is adequate. We note that one study cited in the 2005 GAQM[41] compared various periods from a 17-year data set to determine the minimum number of years of data needed to approximate the concentrations modeled with a 17-year period of meteorological data from one station. This study indicated that the variability of model estimates due to the meteorological data input was adequately reduced if a 5-year period of record of meteorological input was used, consistent with the GAQM provision stating that the use of 5 years of meteorological data is adequate.

The commenter also suggests that our modeling analysis should consider the impacts of the PEP with the growing community, and is concerned with health problems in the area that may be related to air pollution. It is unclear which types of impacts concern the commenter, but the commenter generally appears concerned with long term planning for emission increases from other unspecified sources that may be developed within the community in the future, separate from the PEP. Such an analysis of unrelated emissions growth is generally outside the scope of this individual PSD permit action. Except for ozone, the Antelope Valley is currently attaining all of the EPA's health-based air standards (NAAQS), which provide public health protection, including for sensitive populations such as asthmatics, children, and the elderly. For those NAAQS which the Antelope Valley is already attaining, the PSD program requires that the PEP will not cause or contribute to a violation of those standards. The EPA has determined that the PEP will meet this requirement. Regarding the ozone NAAQS for which the area has been designated nonattainment, please see Response 2 for a discussion of actions intended to ensure that the Antelope Valley attains the ozone standards and health concerns in the Antelope Valley related to air pollution. Finally, we note that the Applicant also met the additional impact analysis requirements in the PSD regulations at 40 CFR 52.21, which require an analysis of general commercial, residential, industrial and other growth associated with the source or modification. See Fact Sheet at 79-80.

EPA Improperly Failed to Conduct a Cumulative CO and Annual NO_2 Impact Analysis by Using Significant Impact Levels

Comment 27:

(Commenters: Conservation Groups (0016))

As detailed in the comment summary below, the commenters asserted that the EPA should have required a cumulative impact analysis for the Project's impacts on the 1-hr and 8-hr CO NAAQS and the annual NO_2 NAAQS and increment, citing various exhibits in support of their argument.

[41] Burton, C.S., T.E. Stoeckenius and J.P. Nordin, 1983. Final Report: The Temporal Representativeness of Short-Term Meteorological Data Sets: Implications for Air Quality Impact Assessments. Systems Applications, Inc., San Rafael, CA. (Docket No. A-80-46, II-G11)).

The EPA claims that if a source by itself does not exceed a significant impact level (SIL) which the EPA has decided to use, the EPA may allow the permittee to avoid doing a cumulative impact analysis if the EPA feels like that is appropriate, on a case by case basis, based on the record. The EPA is incorrect. The statute and regulations require that sources demonstrate that they will not cause or contribute to a violation of the NAAQS and increments. This demonstration requires consideration of nearby sources as well as the permittee's source. For the PEP, the EPA proposes that because the Project itself has impacts below the CO 1-hr and 8-hr SIL, a cumulative impact analysis is not required for CO. The EPA cites to 40 CFR 51.165(b)(2) as authority for these SILs. But 40 CFR 51.165 does not apply to this permit. Rather, 40 CFR 51.165 prescribes what must be in state permitting programs. The statute and regulation prohibit PEP from contributing to violations of the CO NAAQS. The statute and regulation do not use the term "significantly" contribute. Rather, they say contribute. Thus, if the existing sources are causing CO NAAQS violations and PEP contributes to these violations at all, the EPA must deny the permit. Therefore, the EPA must require a cumulative impact analysis for CO.

The EPA's decision to not require the source to demonstrate that it will not cause or contribute to violations of the annual NO_2 NAAQS or increment is also flawed. As to the annual NO_X increment, without the EPA figuring out how much of the NO_X increment is currently consumed, the EPA is simply guessing that PEP will not cause or contribute to a violation of increment. The EPA is not allowed to make this permitting decision based on guess work. Therefore, the EPA needs to require the applicant to conduct a cumulative annual NO_X analysis.

Response 27:

The EPA has required the permit applicant to demonstrate that construction of the proposed source will not cause or contribute to a violation of the 1-hr and 8-hr CO NAAQS and annual NO_2 NAAQS and Class II increment.[42] The air quality impact analysis in the record makes this showing and is not flawed or invalid in any respect. Our air quality impact analysis, as described in the Fact Sheet, used air quality modeling to assess the impact of the Project's emissions for CO and 1-hr NO_2, and considered the monitored background concentrations for these pollutants and averaging times, which fully supported our determination that emissions from the proposed Project would not cause or contribute to a violation of the CO NAAQS or the annual NO_2 NAAQS or increment. As explained in the Fact Sheet and in further detail below, the air quality analyses also appropriately used significant impact levels (SILs) to help demonstrate that the impact of the proposed source on the CO and annual NO_2 concentrations will not cause or contribute to a violation of the relevant NAAQS or PSD increments.

Under section 165(a)(3) of the Act, an applicant for a PSD permit must "demonstrate … that emissions from construction or operation of such facility will not cause, or contribute to, air pollution in excess of any" NAAQS or PSD increment. The EPA has reflected this requirement in its PSD regulations.[43] The law is clear that such a demonstration must be made to obtain a PSD permit. *Sierra Club v. EPA*, 705 F.3d 458, 465 (D.C. Cir. 2013). However, the Act does not specify *how* a PSD permit applicant or permitting authority is to determine whether a proposed new or modified source will (or will not) cause or contribute to a violation of a NAAQS or applicable PSD increment. *Id*. CAA section 165(e) directs the EPA to define the nature of the analysis that is necessary to make this demonstration, by specifying "each air quality model or models to be used under specified sets of conditions." In accordance with this authority, the EPA has promulgated the GAQM that identifies such models and the conditions under which they may be used in the PSD program to make the demonstration required under the Act.[44] Under the GAQM, the EPA's recommended procedure for conducting a NAAQS or PSD increment assessment for PSD permitting is a multi-stage approach. The first stage is a preliminary analysis of the project-

[42] There are no PSD increments for CO. The commenters appear to refer to the NO_2 increment and the "NO_X" increment interchangeably, since the only NOx increment is specifically for NO_2 (annual).
[43] See 40 CFR 52.21(k).
[44] The PSD regulations at 40 CFR 52.21(l) provide for the use of "applicable models, data bases, and other requirements" specified in 40 CFR part 51, Appendix W.

only impacts, which is composed of a screening model and, if necessary, a refined model; the second stage is a cumulative impact analysis. GAQM § 9.2.3(a); see also NSR Manual at C.24. A cumulative impact analysis is a more comprehensive modeling exercise that generally includes both modeled and monitored air quality impacts. Cumulative impact modeling uses the proposed source's emissions and emissions from any nearby sources with air quality impacts that are not adequately represented by the background monitoring data.

With respect to the PEP, the air quality analyses included a preliminary analysis that used Project-only modeling (screening and refined modeling) and, where necessary, a cumulative impact analysis, depending on the impacts for a particular NAAQS or increment. In general, the Project-only modeling that was conducted was conservative, as compared to the cumulative impact modeling, in that the former used worst-case impacts, whereas the latter took into account the particular form of each NAAQS. Fact Sheet at 58. For example, for CO, in the preliminary impact analysis, the highest first high impact from the Project's emissions was used for our analysis, whereas, in a cumulative impact analysis, the highest second high modeled impact from the Project would have been used to demonstrate compliance.[45]

In Table 1 below, we summarize our preliminary analyses for the CO NAAQS and the annual NO_2 NAAQS and increment. These analyses are also discussed in Section 7.3.3.1 and Table 24 of the Fact Sheet. Importantly, for the CO NAAQS and the annual NO_2 NAAQS, we supplemented our preliminary Project-only modeling analysis with additional analysis in which we considered both Project-only impacts and background monitoring data.[46] In this way, we exercised our authority under CAA sections 165(a)(3) and (e) to use an air quality analysis to ensure NAAQS compliance that was composed not only of "project-only" modeling as described in the GAQM, but also of background monitoring data, an element of the "cumulative impact" analysis as described in the GAQM. We believe that our approach for assessing the air quality impacts of the Project for the CO NAAQS and the annual NO_2 NAAQS and increment was fully consistent with the Act.

Table 1 Summary of Preliminary Project-Only Analysis for 1-hr CO, 8-hr CO, and Annual NO_2

NAAQS Pollutant & Averaging Time[a]	Maximum Project-Only Modeled Impact, μg/m³	SIL, μg/m³	Background Concentration, μg/m³	Maximum Project-Only Impact + Background Concentration μg/m³	NAAQS μg/m³	PSD Class II Increment, μg/m³
CO, 1-hr	575	2000	2,176	2,751	40,000	N/A
CO, 8-hr	89	500	1,603	1,692	10,000	N/A
NO_2, annual	0.98	1.0	15.1	16.1	100	25

[a] For the 1-hr CO and 8-hr CO NAAQS, the Applicant modeled two scenarios – one during normal conditions and one during startup conditions. For each of these standards, the startup scenario had the higher maximum impact as compared to the normal condition scenario. For ease of reference, we are showing in this Table only the startup scenarios and their maximum impacts. The results of the normal operation scenarios are provided in Table 24 of the Fact Sheet.

For 1-hr CO, 8-hr CO, and annual NO_2, as seen in Table 1, the modeled Project-only impacts were *very* low compared to the applicable NAAQS and increment – each less than 4% of the applicable values. Further, as shown in the Table above, when background concentrations are considered by adding them to the maximum Project-

[45] For both the 1-hr and 8-hr NAAQS, the NAAQS value is not to be exceeded "more than once per year." As such, the second highest impact is used to determine compliance.

[46] We discuss the representativeness of the background monitoring data in Response 32.

only impacts and comparing the summed values to the applicable NAAQS, the projected impacts from the proposed Project are still well below these NAAQS – less than 17% of each NAAQS. See also Fact Sheet at Section 7.3.3.1 and Table 24. Based on this information, we were able to determine that the proposed Project would not cause or contribute to a violation of the CO NAAQS and annual NO_2 NAAQS and increment. *Ibid*. Thus, a more comprehensive air quality analysis was not needed to make this demonstration.

After review of the comments received, we continue to find that this is the appropriate conclusion. We note that, as discussed in detail in Response 32, the representativeness of the background monitoring data that was used in this case and the nature of the few emissions sources in the area near the PEP further support our conclusion that additional modeling is unnecessary to demonstrate compliance with the CO NAAQS and the annual NO_2 NAAQS and increment. As shown above, this conclusion is justified and appropriate even without any consideration of or comparison to the SILs. The commenters fail to demonstrate that any error was made in the air quality analyses, that any additional modeling is necessary, or that there is reason to believe that the Project would cause or contribute to a violation of the CO NAAQS or the annual NO_2 NAAQS or increment.

Although our air quality analyses and conclusions concerning the proposed Project are valid without any reliance on SILs, we also believe that the use of SILs in assessing the impacts of the Project was appropriate and the commenters have not shown otherwise. The EPA has issued a Legal Memorandum that shows how the CAA may be read to allow the use of SILs as part of air quality demonstrations required for PSD permit applications under CAA section 165(a)(3)).[47] Among other things, the Legal Memorandum explains that in the past, the EPA has cited *de minimis* exemption authority to justify the use of SILs, but such reliance was unnecessary. A more accurate description is that SILs have been used as a means of making the air quality impact demonstration required by CAA 165(a)(3), rather than as an exemption from the statutory requirement. As discussed in the Legal Memorandum, where air quality modeling demonstrates that the projected air quality impact of the proposed source will not exceed a properly-supported SIL, the PSD permitting authority has discretion to determine, on a case-by-case basis, that the proposed source's emissions will not "cause or contribute to" a violation of the applicable NAAQS or PSD increment, without the need for additional air quality analysis.[48]

The commenters specifically disagree with the use of SILs for the CO NAAQS and annual NO_2 NAAQS and increment.[49] As discussed above, the EPA has long used the CO and annual NO_2 values in 40 CFR 51.165(b)(2) as a

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[47] "Legal Memorandum, Application of Significant Impact Levels in the Air Quality Demonstration for Prevention of Significant Deterioration Permitting under the Clean Air Act" (2018). The Legal Memorandum accompanied an EPA policy guidance "Guidance on Significant Impact Levels for Ozone and Fine Particles in the Prevention of Significant Deterioration Permitting Program" (2018). Draft versions of the legal memorandum and policy guidance were made available to the public in August 2016 and were referenced in Table 24 of the Fact Sheet. For more information on the draft and final versions of this legal memorandum and guidance and accompanying documents, see https://www.epa.gov/nsr/draft-guidance-comment-significant-impact-levels-ozone-and-fine-particle-prevention-significant and https://www.epa.gov/nsr/significant-impact-levels-ozone-and-fine-particles. Although written specifically in support of the ozone and $PM_{2.5}$ SILs policy guidance, the legal analysis in the memorandum also applies to the use of SILs for other NAAQS and increments in the PSD program.

[48] We note, however, that upon considering the permit record in an individual case, a permitting authority also has discretion to consider additional information or analysis, such as background monitoring data and the potential impact of nearby sources, to make the required air quality impact demonstration. For the CO and annual NO_2 air quality analyses for this permit, the EPA expressly considered both modeled Project-only impacts and background monitoring data, in addition to comparing the modeled Project-only impacts to SILs, as shown in the Fact Sheet and discussed above. And, in considering these comments, the EPA has provided a detailed explanation concerning the potential impacts of nearby sources and its determination that, given the nature of the few nearby emissions sources, additional modeling is unnecessary to demonstrate compliance with the CO NAAQS and annual NO_2 NAAQS and increment.

[49] We note that the commenters did not challenge the use of the SILs in the modeling that was conducted to demonstrate the PEP's compliance with the NAAQS and Class II increments for PM_{10} and $PM_{2.5}$ and the NAAQS for 1-hr NO_2, presumably

compliance demonstration tool on a case-by-case basis in the context of PSD air quality analysis. See NSR Manual at C.26-28, 52.[50] The EPA has used these values to identify the degree of air quality impact that would "cause or contribute to" a violation of a NAAQS or PSD increment, and has often concluded on a case-by-case basis in permitting decisions that a demonstration that a source does not have an impact above these values in the ambient air is sufficient to show that a source will not cause or contribute to a violation of the NAAQS. This approach has helped to reduce the burden on permitting authorities and permit applicants to conduct often time-consuming and resource-intensive air dispersion modeling where such modeling was unnecessary to demonstrate that a permit applicant meets the requirements of section 165(a)(3), consistent with the procedures in the GAQM and EPA's authority under CAA 165(e)(3).[51]

The commenters' specific concerns related to emissions from sources within the nearby United States Air Force Plant 42 with respect to the CO NAAQS and the annual NO_2 NAAQS and Class II increment are addressed separately in Responses 31-32.

The EPA Impermissibly Relied on SILs for its Class I Increments Analysis

Comment 28:

(Commenters: Conservation Groups (0016))

The commenters asserted: "[The] Fact Sheet at 63 shows that EPA impermissibly relied on SILs in its Class I impact analysis. Even if this is harmless error for $PM_{2.5}$ because PEP established the minor source baseline date and is the

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because the modeled Project-only impacts were above those SILs and cumulative impact analyses were conducted for these pollutants. The commenters also did not comment on the numerical levels of the CO and NO_2 SILs used in the analyses for the PEP.

[50] The commenters assert that it was improper to use the CO values from 40 CFR 51.165(b), arguing that this regulation does not apply to the permit in this case and instead addresses the requirements for State permitting programs. The commenter misapprehends the purpose of the cited reference. We did not assert that the values in 40 CFR 51.165(b)(2) are legally binding SILs for use in air quality analyses for EPA-issued PSD permits. Instead, for each value listed in Table 24 of the Fact Sheet, we identified reference material to show the source of the values used in the analysis. One of the references was to 40 CFR 51.165(b)(2), for the CO NAAQS and annual NO_2 NAAQS and increment. The values reflected in this regulation were initially developed by EPA in 1978. See 43 Fed. Reg. 26380, 26398 (June 19, 1978). This notice and supporting record explain how the EPA developed these values, which represent a level of change in concentration at which the impact of the source is considered to cause or contribute to a violation of the relevant NAAQS. Based on this information, the EPA believes it also reasonable to conclude in most permitting situations that an impact below the values in 40 CFR 51.165(b) would not cause or contribute to a violation. We are not reading 40 CFR 51.165(b)(2) to require this conclusion, but rather drawing an inference from the EPA's rationale supporting the values. Other references in Table 24 are to EPA memos from 2010 and 2011 and the draft EPA ozone and $PM_{2.5}$ SILs guidance from 2016, which likewise provide a justification to show why it is reasonable for a permitting authority to conclude that a showing that a source does not have an impact above the EPA recommended values is sufficient to conclude that the source will not cause or contribute to a violation of the relevant NAAQS or increment.

[51] The commenters also assert, "The statute and regulation do not use the term 'significantly' contribute. Rather, they say contribute. Thus, if the existing sources are causing CO NAAQS violations and PEP contributes to these violations at all, the EPA must deny the permit." We agree with these comments. Specifically, if emissions from the proposed Project were determined to contribute to a CO NAAQS violation, even where existing sources are already causing CO NAAQS violations, the EPA would not issue the PSD permit, i.e., not without reductions in emissions from the Project or existing sources or another remedy so that the Project would no longer contribute to a NAAQS violation. We also agree that CAA 165(a)(3) does not say "significantly contribute" and, as discussed in the Legal Memorandum referenced in Response 27, we do not interpret the term "contribute" in CAA 165(a)(3) to mean "contribute significantly." We also note that, in the particular case of CO emissions, violations of the NAAQS are extremely uncommon. Nationwide CO levels have dramatically declined since stricter standards for motor vehicles required the use of the catalytic converter beginning in the 1970s. See, for example, https://www.epa.gov/air-trends/carbon-monoxide-trends, showing nationwide trends decreasing since 1980. Currently, there no areas in the U.S. violating the CO NAAQS. https://www3.epa.gov/airquality/greenbook/cbtc.html.

only increment consuming source at this time, that is not true for NO_X.[52] As explained above, SILs are not permissible. Furthermore, using SILs from a proposed rule is contrary to the Clean Air Act and is a due process violation."

Response 28:

We disagree with the commenters' assertion that SILs are not permissible. See Response 27 for our response to the commenters' contentions regarding the permissibility of the use of SILs. We also note the commenters' view that the use of $PM_{2.5}$ SILs in this case was, in the commenters' words, harmless error.

In this case, as detailed in Fact Sheet Section 7.3.5, the EPA analyzed Project-only impacts on Class I increments for Class I areas within 300 kilometers (km) of the Project. We determined that the modeled Project-only impacts for the relevant pollutants for which there are Class I increments were considerably lower than the corresponding Class I SILs, which themselves represent a small portion of the applicable increment, and we further noted that there are few sources in the vicinity of the relevant Class I areas that potentially would consume increment. For $PM_{2.5}$, we also noted that the Project is the source that establishes the minor source baseline date and baseline concentration in the area, and is the only increment-consuming source at this time. Based on this analysis, we determined that the Project would not cause or contribute to a violation of the applicable PSD Class I increments. We continue to believe that the analysis that was conducted based on the facts in this case was appropriate and sufficient. The commenters have not provided any information demonstrating that our analysis or conclusion was erroneous or that further analysis would lead to a different result.

The commenters also assert that "using [Class I] SILs from a proposed rule is contrary to the Clean Air Act and is a due process violation." We disagree. Although the commenters did not specify which SILs this particular assertion addresses, the only Class I SILs that reference a proposed rule are those for annual NO_2 and 24-hr PM_{10}. The Fact Sheet identifies these Class I SILs used in the PSD increment analysis and provides a reference to a 1996 EPA proposed rule to provide more information about them. The Fact Sheet did not indicate that these SILs in the Class I increments analysis, or elsewhere in the air quality analysis, were binding regulatory provisions. Instead, the 1996 proposed rule was cited as a nonbinding reference. While the rule was not completed, the record for this proposed rule supports using the proposed NO_2 and 24-hr PM_{10} Class I increment SILs from the proposed rule in this instance as a compliance demonstration tool in the Class I increments analysis. See footnote 50 in Response 27. Although the commenters asserted that "SILs are not permissible" and referenced their other comments addressed above, the commenters did not comment about the references in the Fact Sheet (concerning the $PM_{2.5}$ SILs) to the EPA's 2016 draft guidance on SILs for ozone and fine particles.[53] The 1996 proposed rule was referenced for the same purpose as the reference to the 2016 draft guidance, to incorporate the rationale reflected there to support the application of SILs to this permit application. The use of SILs in the Class I increments analysis, as well as in the rest of the air quality analysis, including the specific numerical levels of the SILs, was subject to public notice and the opportunity to comment in this proceeding pursuant to PSD permitting requirements, as exemplified by the commenters' comments and our responses herein. The EPA believes that this process satisfies the requirements of due process.

Hours of Operation Limits for Emergency Engines Must Reflect Modeling

Comment 29:

Commenters: Conservation Groups (0016)

[52] The commenters refer to the "NO_X" increment, but we assume they are referring to the annual NO_2 increment as it is the only NO_X-related increment.

[53] As noted in footnote 47 above, this 2016 draft guidance was recently issued in final form. https://www.epa.gov/nsr/significant-impact-levels-ozone-and-fine-particles.

The commenters asserted, as detailed in the following excerpt, that using calendar year limits for emergency engines D2 and D3 allows the engines to operate for significantly more hours than what is represented in the modeling. The commenters recommended that the PSD permit be changed to use monthly limits that more closely reflect the modeling or that the modeling be revised to reflect the permit limits.

The emergency generator engine and emergency fire pump engine have restrictions on their hours of operations but the limit is based on a calendar year. In contrast, the fuel usage limit for the auxiliary boiler is based on a 12-month rolling total. All three of these limits should have been used in the modeling to support the conclusion that the source does not cause or contribute to increment or NAAQS violations although it is not clear if the EPA actually did this. In any event, using calendar year limits for the engines, D2 and D3, allows the engines to operate for significantly more hours than represented in the modeling. This is particularly true during the first year of operations if the facility does not commence operations during January. The permit must be changed to use monthly limits of 2 hours per month for the emergency generator engine and 1 hour per month for the emergency fire pump engine to more closely reflect the modeling. In the alternative, if the EPA wishes to leave the emission limits as calendar year, the modeling must be revised to reflect that these sources operate more than 1 and 2 hours per month.

Response 29:
The EPA agrees with the commenters that the emission limits in the permit for the emergency engines need to reflect how the modeling was conducted. In response to this comment, we have added an additional limit for each of the emergency engines, units D2 and D3, to reflect how the units were modeled. For NAAQS with shorter averaging periods, those less than annual, the engines were modeled to assume fire pump testing occurs up to 60 minutes per day and emergency generator testing occurs up to 30 minutes per day. October 2015 Application at 7.2-2. We have added limits to the final PSD permit for the PEP for each engine that reflect the daily allowance for maintenance testing. In response to the commenters' concern related to the annual hours of operation, we revised the limit to a 12-month rolling total. See Conditions 24 and 25 of the Final Permit. The modeling did not consider the engines to only operate a certain number of hours each month; therefore, such a limit has not been demonstrated to be warranted. The changes to the permit are shown in the redline-strikeout version of the final permit.

We also confirm that the modeling for the auxiliary included the fuel use limit in the permit. See Fact Sheet at 74 and the October 2015 Application at 7.2-2.

The EPA Failed to Consider Startup and Shutdown Scenarios for All NAAQS and Increment Analyses

Comment 30:
Commenters: Conservation Groups (0016)

The commenters asserted that the EPA evaluated a startup scenario for NO_2 but not for PM_{10} or $PM_{2.5}$, but provided no justification for doing so, nor is there one. PM_{10} and $PM_{2.5}$ impacts are often highest for sources like the auxiliary boiler which has a relatively low stack height and exit velocity and temperature.

The EPA needs to set practically enforceable $PM/PM_{10}/PM_{2.5}$ emission limits during startup and shutdown of the CTs and model this emission rate to determine if the source will cause or contribute to NAAQS or increment violations. During this modeling, the EPA must use stack parameters, such as exit temperature and velocity, which reflect actual parameters during startup and shutdown. This is critical as low exit temperature and velocity tend to result in higher ambient concentrations. The EPA also needs to ensure that all of the stacks are modeled at the exact location where they actually will be.

Similarly, the EPA needs to set startup and shutdown limits for the auxiliary boiler, emergency generator engine and emergency fire pump engine, and then the EPA must model these emission rates using stack parameters which reflect actual conditions during startup and shutdown of this equipment. Emissions during startup and shutdown of these types of units can be exponentially higher than during the stack test and with their relatively low stacks and almost always operating in startup and shutdown mode, they can easily cause or contribute to violations of increments or NAAQS.

Response 30:

The EPA disagrees that we failed to properly model PM_{10} and $PM_{2.5}$ impacts and that additional modeling is required to address emissions from the CTs during startup and shutdown. We also disagree that further modeling needs to be conducted to address emissions during the startup and shutdown of the auxiliary boiler and emergency engines. Our reasoning is detailed below. We separately addressed the commenters' arguments about the need to set BACT limits during startup and shutdown of the CTs, auxiliary boiler, and emergency engines in Response 22.

As the commenters acknowledge, and was explained in the Fact Sheet, the choice of "worst case" may be different for each pollutant, since different pollutants' emissions respond differently to exhaust temperature and flowrate. The Applicant conducted a screening analysis to determine which operational conditions (including load level and ambient temperature) would result in the highest impacts for each pollutant, and then modeled the Project accordingly. Fact Sheet at 74. As explained in the Application, the Applicant specifically considered 24-hour impacts of PM_{10} and $PM_{2.5}$ under low load conditions. While the Applicant included this scenario in its modeling, the Application also noted that this was an unrealistic scenario since the Permittee would not likely operate both turbines at a very low load for a continuous 24-hours, and would more likely operate one turbine at high load. See the October 2015 Application at 7.1-1. Because PM_{10} and $PM_{2.5}$ emissions from the CTs were modeled using the worst-case conditions, including consideration of various loads and operational conditions, further modeling is not necessary to demonstrate compliance with the NAAQS or increments for PM_{10} and $PM_{2.5}$ emissions from the CTs.

We also disagree that any changes need to be made to the modeling for the boiler or emergency engines. Section 7.2 of the October 2015 application contains a detailed description of the modeled scenarios, including stack parameters. The commenters appear to be concerned that the startup or shutdown emissions (of PM_{10}, $PM_{2.5}$, NO_X and CO) from the auxiliary boiler and engines will be higher than at maximum load under normal operation and will cause NAAQS and increment violations. However, we do not expect the maximum hourly mass emissions, which is the rate used in modeling (typically lb/hr values are converted to grams/second), of this equipment during startup or shutdown to be significantly different as compared to normal operation at maximum load.

As explained in Response 22 for $PM/PM_{10}/PM_{2.5}$ emissions from the CTs, we expect less emissions during lower load, and conclude this is the case for the auxiliary boilers and emergency engines, as these units will each also be burning a clean, low particulate fuel. The requirement to use clean, low particulate fuel is in Condition 17 of the Final Permit for the boiler (use of natural gas) and Conditions 24 and 25 of the Final Permit for the emergency engines (use of nonroad diesel). As such, there is no reason to believe that emissions during a startup or shutdown event would be higher, on a lb/hr basis, than normal operation at maximum load, and the commenters have not provided any information that refutes this determination.

For NO_X emissions from the boiler and engines, we expect less NO_X formation during startup and shutdown as NO_X emissions increase with temperature, and startup and shutdown are expected to cause the lowest temperatures. For example, a study in Denmark specifically looked at the effect of startup and shutdown emissions on natural gas-fired engines and found that the emission factor used during full load was still appropriate when considering startup and shutdown NO_X emissions.[54]

For CO emissions from the boiler and engines, we expect a very short startup period when emissions are higher on a lb/hr basis, but then stabilize when a normal operating temperature is reached. For shutdown, we expect a similar, but shorter period, where emissions may be higher until the unit is shut off. For this particular equipment, which is relatively small and "off the shelf," and uses a uniform fuel, we expect the startup and shutdown periods with increased CO emissions to be short, lasting only a couple of minutes per event. As such, we do not expect a significant change in emissions on an hourly basis during startup or shutdown of the equipment as compared to full load operation. The study in Denmark referenced above that looked at startup and shutdown emissions revised the full load emissions factor upward by approximately 5% to account for startup and shutdown CO emissions.[55] In this case, the potential for a slight difference in the emission rate for CO emissions from this smaller equipment would not be determinative in whether the Project would cause or contribute to a CO NAAQS or increment violation. There are no PSD increments for CO, and the modeling for the 1-hr CO NAAQS did not include the emergency engines, as worst-case CO emissions will occur during CT startup and shutdown, when the emergency engines are not permitted to operate. Additionally, for the 1-hr CO standard, the auxiliary boiler will be in normal operation during the startup of the CTs and will be turned off during normal operation and shutdown of the CTs. Moreover, the auxiliary boiler is only used to start the CTs and is not permitted to operate thereafter. As such, modeling of the boilers and engines was appropriate for the 1-hr CO standard and considered the worst-case permitted emissions.

For the modeling analysis against the 8-hr CO standard, the auxiliary boiler was assumed to operate during two hours, and the engines were each assumed to undergo readiness testing once. In this scenario, CO emissions from the auxiliary boiler and emergency engines represent 0.1% of the emissions modeled (modeled at a rate of 1.34 lb/hr). Even if the CO emissions from the auxiliary boiler and emergency engines were off by 5% or even 25 to 50% when accounting for startup or shutdown, these emissions would not be determinative in whether the Project will cause or contribute to a NAAQS violation. The CO impacts will clearly be driven by the CTs, as startup and shutdown emissions were included in the modeling for the 8-hr CO NAAQS, and the CTs account for 99% of emissions during this scenario (modeled at a rate of 126.5 lb/hr). The modeled maximum impact from the Project was 89 $\mu g/m^3$, while the monitored background concentration is 1,603 $\mu g/m^3$, and the 8-hr CO NAAQS is 10,000 $\mu g/m^3$. Given the minor impact this source will have compared to the NAAQS and monitored background concentrations, a slight increase in the modeled CO emissions from the auxiliary boiler and emergency engines would not affect our determination that the Project will not cause or contribute to a violation of the 8-hr CO NAAQS.

The commenters also seem to be concerned that the stack parameters during a startup and shutdown event need to be considered and modeled for the auxiliary boiler and emergency engines. However, the startup and shutdown periods for this equipment last only a couple of minutes, as it is very different from starting up a combustion turbine with add-on pollution controls that need time to reach normal operating conditions. As such, there is no reason to believe, and the commenters have not shown, that the startup and shutdown stack parameters for this equipment should have been modeled differently to account for these very short periods of time. As explained, for short-term 1-hr standards the worst-case impacts are caused during startup and shutdown of the CTs, when the emergency engines are not permitted to operate and the auxiliary boiler is already in normal

[54] *The Influence of Engine Start and Stop on Total Emission from Natural Gas Fired CHP Engines*, Torben Kvist Jensen, Danish Gas Technology Center, Denmark, 2008, Table 2. http://www.dgc.eu/sites/default/files/filarkiv/documents/C0802_engine_start_stop.pdf.
[55] *Ibid*.

operation. And during other modeling scenarios, 8-hr, 24-hr and annual, this equipment will clearly not spend the majority of this time in startup or shutdown mode.

Thus, regarding the modeling for the auxiliary boiler and engines, the commenter has not shown that startup and shutdown emissions of PM_{10}, $PM_{2.5}$, NO_X and CO from the auxiliary boiler and engines are "exponentially" higher than the maximum load emission rates that were modeled and we do not find that that is the case. Similarly, there is no reason to believe that the stack parameters that were used were in error, as we expect startup and shutdown to occur only briefly. The modeling conducted by the Applicant is sufficient to demonstrate that the Project will not cause or contribute to a NAAQS or increment violation.

Last, in response to the commenters' assertion that the EPA also needs to ensure that all of the stacks are modeled at their actual point of placement, the location of the stacks was modeled according to the coordinates specified in the Application. See Figure 6-1 of the October 2015 Application. The Permittee is obligated to construct the PEP consistent with the representations in the Application, per Permit Condition 8 of the Final Permit and 40 CFR 52.21(r)(1).

Modeling Did Not Include Receptors within Plant 42

Comment 31:

Commenters: Conservation Groups (0016)

The commenters asserted that Figures 8, 9, and 10 in the Fact Sheet appear to demonstrate that those modeling exercises failed to include modeling receptors within the Plant 42 border. Figure 11, however, indicates receptors inside of Plant 42's borders.

The Fact Sheet does not provide a basis for the decision to exclude receptors inside Plant 42 for some of the modeling. Nor does it provide a reference to the administrative record in support of this decision. PEP does not own Plant 42 and therefore Plant 42 is ambient air which must have receptors in it for all of the modeling. Therefore, EPA must redo the modeling and issue a new Fact Sheet and hold a new public comment period. This is especially concerning because Figure 8 seems to indicate the maximum impact was on the border of Plant 42. Thus, it appears that violations were modeled and then receptors removed to "erase" the violation.

In addition, EPA admits that the cumulative impact analysis for PM_{10} and $PM_{2.5}$ excluded Plant 42 sources' impacts inside Plant 42's fence line. (Fact Sheet at 74.) There is no justification for this because as explained above, PEP does not own Plant 42. In other words, EPA's long-standing interpretation of ambient air allows a company to poison its own workers but not someone else's workers on an adjacent property. Therefore, EPA needs to rerun the cumulative impact analysis for PM_{10} and $PM_{2.5}$ considering all sources impacts on all receptors outside of PEP's fence line.

Response 31:

We disagree with the commenters that the treatment of receptors within United States Air Force Plant 42 (Plant 42) in the modeling analyses for the Project was in error and that we must conduct further modeling, issue a new Fact Sheet, and offer an additional public comment period.

Plant 42 is a government-owned, contractor-operated facility for the development, manufacturing and testing of high performance aircraft.[56] The PEP boundary is adjacent to a portion of the northwest boundary of Plant 42. See Figure 1 of the Fact Sheet. Plant 42 is substantially larger in area than the PEP (6,600 acres compared to 50 acres),

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[56] See Air Installation Compatible Use Zone (AICUZ) Study for Plant 42 at 2-7 to 2-9.

extending approximately 5 km to the east of the PEP and about 4 km to the south of the PEP. Fact Sheet at 67. When we refer to Plant 42 we are including the Palmdale Regional Airport, which is within the Plant 42 complex.[57] The Plant 42 installation consists of eight separate production sites that share a common airfield infrastructure. The primary mission at Plant 42 is to provide and maintain facilities for the following activities: the final assembly of jet-powered, high performance aircraft, production engineering and flight test programs, and Air Force acceptance flight tests of jet aircraft.[58] Currently, Plant 42 supports the major aircraft manufacturers Boeing, Lockheed, and Northrop Grumman.[59]

With regard to the modeling receptors used in the air quality analyses, the Fact Sheet at Section 7.5.3 – *Model receptors* – both refers to the October 2015 Application and describes in detail the receptor locations used in the Project-only and cumulative impact modeling analyses for the PEP. Specifically:

> The Applicant used receptors every 10 [meter (m)] along the Project fence line, together with an expanding in distance Cartesian grid (rectangular array) of receptors, starting with 20 m spacing out to 500 m distant from the Project. [October 2015 Application p.6.4-1.] This set of receptors was called the downwash receptor grid. An intermediate receptor grid with a 100 m resolution was modeled that was extended outwards from the edge of the downwash receptor grid to one kilometer from the Project. The first coarse receptor grid with 200 m spacing extended outwards from the edge of the intermediate grid to 5 km from the project, while the second coarse grid with 500 m receptor spacing extended to 10 km from the project. In addition, the 500 m spaced coarse grid was extended to 20 [k]m[60] from the project in order to delineate the extent of the NO_2 significant impact area . . . Concentrations within the PEP fence line were not calculated as it is not considered ambient air. Similarly, impacts from USAF Plant 42 sources were not calculated for locations inside the Plant 42 fence line in the NO_2 and PM_{10}/$PM_{2.5}$ cumulative impact analyses. However, PEP's predicted impacts on all areas outside the PEP fence line, including within the Plant 42 fence line, were modeled by the Applicant. [footnote omitted]

Fact Sheet at 73-74.

As described in the Fact Sheet, modeling receptors were included in all areas outside the PEP fenceline out to 10 or 20 km, and specifically included modeling of the PEP's impacts for all NAAQS and Class II increments reviewed (1-hr CO, 8-hr CO, 1-hr NO_2, annual NO_2, 24-hr PM_{10}, 24-hr $PM_{2.5}$, and annual $PM_{2.5}$) within the Plant 42 fenceline.[61] However, as further explained in the Fact Sheet, the additional cumulative modeling conducted for 1-hr NO_2, 24-hr PM_{10}, 24-hr $PM_{2.5}$, and annual $PM_{2.5}$ did not include Plant 42 receptors because: (1) the Applicant did not need to model Plant 42's impacts within Plant 42's own fenceline, (2) there were no additional nearby sources outside Plant 42 that required modeling, and (3) the PEP's impacts within the Plant 42 fenceline had already been modeled in the Project-only analysis.

Thus, the cumulative impact analyses for 1-hr NO_2, 24-hr PM_{10}, 24-hr $PM_{2.5}$, and annual $PM_{2.5}$ included consideration of both the cumulative impact modeling conducted for areas outside of the Plant 42 boundaries (with results shown in Fact Sheet Table 25), as well as the preliminary analysis as it pertained to the PEP's impacts within Plant 42, which did not show a NAAQS or increment violation at any Plant 42 receptors (as shown in Fact Sheet Table 24). We note that as with the NAAQS analyses for CO and annual $NO_{2,}$ our preliminary analyses for 1-

[57] The Palmdale Regional Airport has not had commercial operations since 2008. https://en.wikipedia.org/wiki/Palmdale_Regional_Airport
[58] AICUZ at 2-7 to 2-9.
[59] *Ibid*.
[60] "20 m" in the Fact Sheet was a typographical error.
[61] See also Figures 6-2 and 6-3 of the October 2015 Application at p. 6.5-10, which shows the extent of the receptor grids used.

hr NO_2, 24-hr PM_{10}, 24-hr $PM_{2.5}$, and annual $PM_{2.5}$ also considered the background monitoring concentrations for determining compliance with the NAAQS; the modeled Project-only impacts for these pollutants added to the relevant background concentrations were below the NAAQS, as shown in Table 24 of the Fact Sheet.

The commenters have not shown that our analysis was in error, or that we did not explain the basis for the approach used. Our treatment of modeling receptors within Plant 42 relates to the fact that Plant 42 is closed to public access and is described in more detail below. Further, the Application included all modeling input and output files with the specific location of each receptor and modeled impact at each receptor. All of the Applicant's modeling data was made available through the EPA's website during the public comment period, and also included the EPA's data files used to create Figures 4 through 11 of the Fact Sheet.

In determining how the sources within Plant 42 should be treated in our air quality impact analyses, we considered the EPA policy that modeling for a PSD permit need only include the air quality impacts of emissions where the impacts are projected to occur in the "ambient air." Fact Sheet at 74. "Ambient air" is defined as "that portion of the atmosphere, external to buildings, to which the general public has access." 40 CFR 50.1(e). The EPA's general policy is that the atmosphere over land owned or controlled by a source and to which public access is precluded by a fence or other physical barriers is not considered "ambient air" for PSD modeling purposes for that source.[62] Thus, based on the regulatory definition of "ambient air," and the EPA's policy, we consider the air outside the PEP's boundaries[63], including within Plant 42, to be ambient air with respect to the PEP and its emissions sources. Similarly, we consider the air outside the Plant 42 boundaries to be ambient air with respect to emissions sources located within Plant 42. But we consider the air within Plant 42 not to be ambient air with respect to Plant 42 emissions sources because Plant 42 is also closed to public access.[64] Our air quality impact determination for the PEP is based on both the preliminary analyses and cumulative analyses, which together demonstrate that the Project will not cause or contribute to a violation of a NAAQS or PSD increment. We consider this approach consistent with applicable CAA requirements, and note that there was no "erasing" of any violations within the Plant 42 boundaries.

In response to the commenters' concerns regarding Figures 8-11, we note that Figures 8-10 in the Fact Sheet displayed a visual representation of the results of the additional cumulative impacts modeling, which did not include Plant 42 receptors, as discussed above. The PEP's impacts within Plant 42 were included in the preliminary modeling, as discussed above. We had initially planned to provide a visual representation of the complete set of air quality modeling conducted for our cumulative analyses that would include both the Plant 42 portion of the Project-only modeling results with the cumulative modeling results outside the Plant 42 boundaries. However, it became evident, particularly with respect to 1-hr NO_2 where a much more conservative modeling analysis was performed for Project-only impacts, that combining the two sets of modeling results in one visual representation would have been difficult and made the representation of impacts more confusing to understand. As included in

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[62] Memo from G.T. Helms, Chief, Control Programs Operations Branch, Office of Air Quality Planning and Standards, to Steve Rothblatt, Chief, Air Branch, Region V, April 30, 1987; EPA memo from Robert D. Bauman, Chief, SO_2/Particulate Matter Programs Branch, Office of Air Quality Planning and Standards, to Gerald Fontenot, Chief, Air Programs Branch, Region VI, October 17, 1989; Letter from Douglas M. Costle, EPA Administrator, to Senator Jennings Randolph, Chairman, Committee on Environment and Public Works, United States Senate, December 19, 1980.

[63] The PEP will be closed to public access through a fenceline. See, for example, Section 6.4 of the October 2015 Application.

[64] See March 8, 2018 email exchange between G. Darvin, Atmospheric Dynamics, C. Anderson, Mojave Desert Air Quality Management District, and L. Beckham, EPA, Re: Confirmation of Plant 42 Fenceline/Receptors for PEP Modeling. As noted by Mr. Darvin in the email exchange, the strip of ambient air in the southern portion of Plant 42 leading to the Palmdale Regional Airport terminal now appears to be closed to public access (as represented in EPA's figures in the Fact Sheet). However, receptors were still included in this area to be conservative. See PEP boundary in Figure 7.6 of the October 2015 Application.

the Fact Sheet, our intent in Figures 8-11 was to show consistent information in each figure by including only modeled impacts outside of Plant 42. The figures were not intended to represent all of the modeling results. The text of the Fact Sheet described the complete set of preliminary and cumulative modeling conducted, and Tables 24 and 25 presented the maximum values from the modeling. We now recognize the figures could have been explained more clearly in the Fact Sheet. And, as the commenters highlight, Figure 11 inadvertently included the Plant 42 portion of the Project-only modeling results along with the results of the cumulative impacts analysis for the area outside of Plant 42. In further response to the commenters, the basis for excluding Plant 42 receptors in the additional cumulative modeling (while including them in the preliminary modeling) was stated in the Fact Sheet at p. 74, as discussed above. Nonetheless, our air quality impact determination is based on the *maximum* modeled impacts which were included in Tables 24 and 25 of the Fact Sheet. And, as stated above, all of the Applicant's modeling data were made available during the public comment period, which identified each receptor modeled and the resulting impacts for each modeling analysis.

Emissions from Plant 42, Including Aircraft Emissions, Need to Be Included in the Modeling Analysis

Comment 32:

Commenters: Conservation Groups (0016)

The commenters asserted (as detailed in the comment summary below) that the EPA should include emissions from aircraft using the Plant 42 runway in its cumulative impact analyses for the Project. The commenters also argued that because of these emissions, the preliminary analyses for the 1-hr and 8-hr CO NAAQS and annual NO_2 NAAQS and increment were in error.

The commenters further asserted that Air Force Plant 42 and the Palmdale Regional Airport share a common runway. Part of its mission is maintenance and modification of the B-2 Spirit bomber. While we do not have access to emission data for this particular plane, the B-2 bomber is not subject to a NO_X, CO or $PM/PM_{10}/PM_{2.5}$ emission limit and uses a jet design from the 1980s, which does not bode well for low emissions. All of the modeling did not include emissions from airplanes at the airport. Yet, 1-hr NO_X concentrations from the PEP physically overlap with the runways and manufacturing facilities at Plant 42. Current modeling showed values very close to the NAAQS right next to the runway. As explained above in other comments, while Palmdale may have less flights than O'Hare, it has 175 operations on average per day. Therefore, EPA must include the aircraft emissions in all its cumulative NAAQS modeling exercises.

The commenters also asserted that the EPA's CO analysis, as explained in the Fact Sheet, ignores the fact that the PEP is right next to airport runways which are mainly used by military aircraft. Military jets, such as the B-2 bomber which uses this runway, are unregulated for CO, NO_X and $PM/PM_{10}/PM_{2.5}$ emissions, which can be massive. There are also major industrial facilities right next to the PEP which again can have substantial CO emissions. The statute and regulation prohibit PEP from contributing to violations of the CO NAAQS. Thus, if the existing sources such as the jet engines and the manufacturing facilities at Plant 42 are causing CO NAAQS violations and PEP contributes to these violations at all, EPA must deny the permit. Therefore, EPA must require a cumulative impact analysis for CO.

The commenters next asserted that jet engine NO_X emissions during takeoff can be substantial. For example, NO_X emissions from a B777, which is subject to regulation unlike the military jets at Plant 42, is approximately 18 kg or approximately 40 lbs. This compares to the startup emission limit for the Project's CTs of 51.48 lb. The difference is that the startup emissions for the CTs are spread out over up to 39 minutes. In comparison, the 40 lbs. of NO_X from a commercial jet is spread out over only less than a minute. Thus, on an annual basis, many more takeoffs are possible than startups and thus, the jet engines' NO_X may swamp those of the PEP. The Palmdale airport has an average of 175 operations per day with 141 of those being military. If half the military flights are large planes and half those actions are take takeoffs, that is 35 takeoffs per day. That equals 255 tons per year of NO_X being emitted at close to ground level and very near where the EPA's modeling predicted the maximum impact from the stationary sources. This is not meant to be a substitute for a modeling analysis. It is just meant to show that it is arbitrary for the EPA to leave the aircraft emissions out of the modeling analysis. Furthermore, because the monitor the EPA is using for background is miles away and in an urban area, it may not be picking up any of the NO_X from the jet engines which again are released very close to ground height with almost no vertical exit velocity.

Response 32:

We disagree that the EPA should include emissions from aircraft using the Plant 42 runway in its cumulative impact analyses for the Project. We also disagree with the commenters' assertions that because of these emissions and other emissions from sources within Plant 42, the preliminary analyses for the 1-hr and 8-hr CO NAAQS and annual NO_2 NAAQS and increment that were conducted were erroneous and that additional cumulative impact analyses considering these emissions were required.

As discussed in detail in Response 31, the air quality impacts of sources within Plant 42, which would include aircraft emissions, were not analyzed within the Plant 42 fenceline because the air above the Plant 42 property is not considered ambient air for modeling of Plant 42 emission sources. Further, as described below, we expect impacts outside the Plant 42 fenceline from Plant 42 aircraft emissions to be similar to impacts caused by other mobile sources outside the Plant 42 fenceline, and we do not expect nearby stationary sources such as those within Plant 42 that were not individually modeled in our preliminary Project-only modeling to affect the accuracy or validity of our air quality analyses or our conclusion that the Project will not cause or contribute to a violation of the applicable NAAQS or PSD increments.

Nearby Stationary Sources for the CO and Annual NO_2 Analyses

The commenters refer to manufacturing/industrial sources that are adjacent to the PEP in arguing that the analyses for the 1-hr and 8-hr CO and annual NO_2 NAAQS and increment were insufficient, but do not clearly identify the sources to which they refer. We assume the commenters are referring to the stationary sources located at Plant 42, as these are the only other sources that are near the PEP boundaries. As such, the aircraft and manufacturing/industrial sources identified by the commenters are all located within the Plant 42 boundaries and as stated above, the air quality analysis for the Project did not analyze impacts from Plant 42 sources within the Plant 42 boundaries.

Regarding the potential CO and annual NO_2 impacts from stationary sources located within Plant 42 on modeling receptors outside Plant 42, we do not believe that such impacts create a concern for a potential violation of the 1-hr or 8-hr CO NAAQS or the annual NO_2 NAAQS or increment. Our analysis for these impacts included a comparison of how far below the NAAQS and increment the Project's impacts are, consideration of background concentrations, and the fact that we considered that analysis to use very conservative assumptions. See Response 27. The representativeness of the background monitoring data used as part of that analysis is discussed further below.

In addition, other available information confirms that it is very unlikely that consideration of nearby stationary sources would have affected our conclusions for CO and annual NO_2 impacts. As explained in the Fact Sheet:

> In general, for both the PSD increment and NAAQS analyses, there may be a large number of sources that could potentially be included in the nearby source emission inventory, so judgment must be applied in determining whether to exclude small and/or distant sources that have only a negligible contribution to total concentrations. Generally, only sources with a significant concentration gradient in the vicinity of the source need be included; the number of such sources is expected to be small except in unusual situations.

Fact Sheet at 67.[65]

Further, the GAQM explains:

> Concentration gradients associated with a particular source will generally be largest between that source's location and the distance to the maximum ground-level concentrations from that source. Beyond the maximum impact distance, concentration gradients will generally be much smaller and more spatially uniform. Thus, the magnitude of a concentration gradient will be greatest in the proximity of the source and will generally not be significant at distances greater than 10 times the height of the stack(s) at that source without consideration of terrain influences.

GAQM § 8.3.3(b)(ii).

Tables 7.5 and 7.7 of the October 2015 Application provide information on the stationary sources at Plant 42, including stack locations, stack heights, tpy emission rates for NO_X, and the Plant 42 stack distances from the PEP. Based on this information, the concentration gradients associated with Plant 42 stationary sources are not expected to be significant in the vicinity of the PEP. We reviewed the stack heights and their distances from the PEP at the Boeing, Lockheed and Northrup facilities at Plant 42 and found that none of them is expected to have significant concentration gradients outside Plant 42 near the PEP. For example, the stack nearest the PEP, at the Boeing facility, is a 2.0 m stack. As such, we can expect any significant concentration gradient to occur within 20 m from this Boeing stack, whereas the PEP is 690 meters from the Boeing stack. The highest stack within Plant 42, at the Lockheed facility, is 16.42 m in height. Accordingly, we can expect any significant concentration gradient to occur within 165 m from this Lockheed stack, while the PEP is more than 1500 meters from the Lockheed stack. We also note that the stationary sources at Plant 42 are significantly smaller in terms of magnitude of annual emissions than the PEP. Total NO_X emissions from the Plant 42 stationary sources are approximately 40 tpy, compared to 139 tpy from the PEP. And total CO emissions from Plant 42 stationary sources are approximately 17 tpy[66], compared to 351 tpy from the PEP.[67]

Thus, while there are stationary sources at Plant 42, their emissions are much lower compared to the proposed PEP and sufficiently far away so that they would not have a significant concentration gradient outside the Plant 42 boundary near the maximum modeled impacts of the PEP, the latter of which are very low compared to the applicable NAAQS and increment, as discussed above. For example, Figure 3 below shows the point of maximum impact for 1-hr CO, 8-hr CO, and annual NO_2 emissions from the PEP. The maximum impact for 1-hr CO and annual NO_2 is immediately adjacent to the PEP fenceline, and the maximum impact for 8-hr CO is to the northwest of the PEP, even further away from the Plant 42 stationary sources. In addition, as discussed below, we conclude that any potential impacts from nearby sources were adequately accounted for by the background monitoring data, which is considered very conservative for representing background levels near the PEP.

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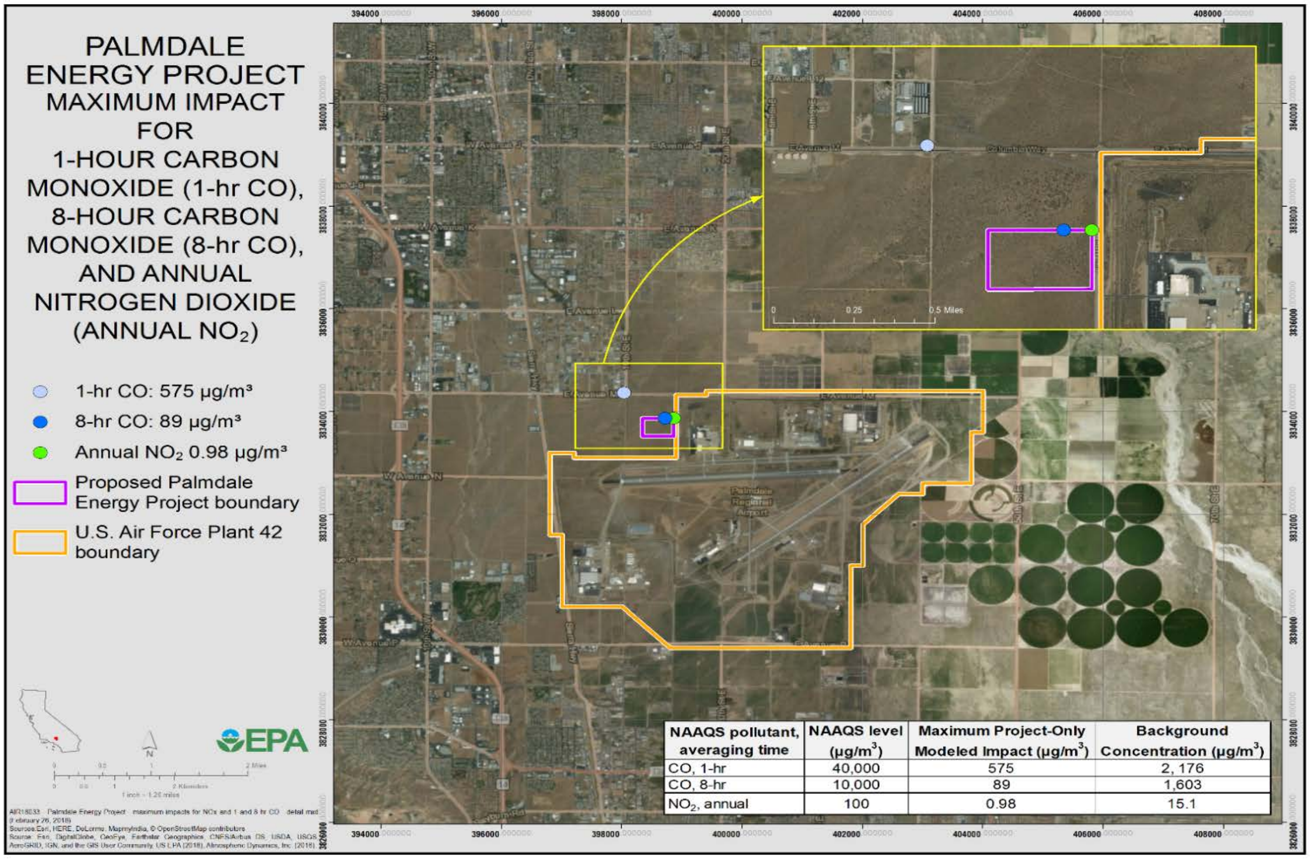
[65] See also section 8.3.3 of the GAQM, which explains, "A key point here is the interconnectedness of each component in that the question of which nearby sources to include in the cumulative modeling is inextricably linked to the question of what the ambient monitoring data represents within the project area."

[66] See January 30, 2018 email from Vickie Rausch, Air Quality Engineer, AVAQMD to Lisa Beckham, EPA Region 9, re: CO Emissions from Plant 42 sources.

[67] As a further example of the limited impacts expected from the stationary sources at Plant 42 on receptors outside Plant 42, the modeling for the cumulative impact analyses for PM_{10}, $PM_{2.5}$ and 1-hr NO_2, which included modeled impacts for these Plant 42 stationary sources, shows nearly the same results compared to our preliminary analysis for those pollutants, which did not include such impacts. See Tables 24 and 25 of the Fact Sheet. This indicates that these nearby sources, based on their magnitude of emissions and distance from the PEP, do not have a high concentration gradient near the maximum impacts of the PEP and that the preliminary analyses were conservative.

Figure 3 Maximum Project-Only Impacts for 1-hr CO, 8-hr CO, and Annual NO_2



Background Concentrations

The Lancaster-Division Street monitor that was chosen for our modeling analyses (PM_{10}, $PM_{2.5}$, CO and NO_2) is just 2.5 miles from the PEP Project, and is near the Sierra Highway (110 m), commute traffic on Division Street (50 m), and the Southern Pacific Railway (80 m). Thus, this monitor is considered highly impacted by mobile source emissions, as these roadways and this railway are all within 150 meters of the monitor, and impacts from mobile source emissions are known to be highest immediately adjacent to the roadway, that is within 150 to 180 meters from a roadway.[68] As the commenters alluded, mobile source emissions occur near ground level, as compared to stationary sources that have stacks that are higher off the ground, and they result in higher impacts on ground level ambient concentrations. In contrast, the PEP is not located near any major roadways and there are no stationary emissions sources within 150-180 meters of the PEP boundary. Thus, the Lancaster-Division Street monitor is considered to very conservatively represent background concentrations near the PEP. Therefore, the mobile source emissions that impact the Lancaster-Division Street monitor can be assumed to conservatively represent background levels and the potential impacts from sources near the PEP, including, as discussed below, aircraft emissions.

Aircraft Emissions

In the context of assessing the air quality impacts of a proposed PSD project and considering whether monitored background levels adequately represent the potential effects of existing nearby sources, we consider that, in

[68] See *Near Roadway Air Pollution and Health: Frequently Asked Questions*, Office of Transportation and Air Quality, EPA-420-F-14-044, August 2014 at 2. https://nepis.epa.gov/Exe/ZyPDF.cgi/P100NFFD.PDF?Dockey=P100NFFD.PDF

general, emissions from aircraft using an airport runway predominantly occur during landing and takeoff operations. And, the concentration gradients resulting from these emissions are fairly steep; that is, within short distances from the emission source (approximately 500 meters or less from the edge of the runway) resulting impacts decline rapidly.[69] Additionally, the location of most aircraft activity is predictable based on prevailing wind direction (planes take off and land into the wind), and this location can then be assumed to be the area of maximum impact from the aircraft activity. In this case, with respect to aircraft at Plant 42, the wind rose indicates[70] that winds are primarily from the southwest, with the result that most aircraft activity would involve planes taking off starting in the northeast of runway #22 or possibly the eastern part of runway #25.[71] Emissions resulting from the aircraft engines during takeoff and landing would then occur in the opposite direction of the plane's trajectory, that is, towards the northeast. This means that the majority of emissions from aircraft activity are occurring in the northeastern portion of the Plant 42 boundary, and the fenceline in that area is between 1,000 to 2,500 meters from the edge of the runways.

Therefore, given that we expect the highest concentration gradient from aircraft emissions to be well within the Plant 42 boundary, and that the Plant 42 runways are not particularly busy compared to commercial airports,[72] we can determine that the Plant 42 aircraft emissions will not have a significant concentration gradient in the area of modeled impacts from the PEP outside the PEP and Plant 42 boundaries. Further, we expect contributions from Plant 42 aircraft emissions to the 24-hr PM_{10}, 24-hr $PM_{2.5}$, annual $PM_{2.5}$, 1-hr CO, 8-hr CO, 1-hr NO_2, and annual NO_2 concentrations in any area outside the Plant 42 boundary to be similar to or less than the contributions from vehicle traffic.[73] In addition, we can conclude that the highest impacts would not coincide with the maximum impacts from the PEP, which, as discussed above, are closer to the PEP boundary and far to the west of the area where takeoffs and landings occur.[74] As such, we believe that any aircraft emissions impacts outside the Plant 42 boundary were adequately and appropriately accounted for in our consideration of monitored background

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[69] For example, a study conducted at Los Angeles International Airport (LAX) on ultrafine particulate matter (UFP) found that the concentrations of UFP decreased rapidly with distance (by ~90% within 500 meters from the takeoff/landing location). This study was based on minute-by-minute readings of UFB concentrations. (*See* Hsiao-Hsien Hsu et al., Contributions of aircraft arrivals and departures to ultrafine particle counts near Los Angeles International Airport. *Science of the Total Environment*, 444 (2013), pp 347-355.)

[70] See Figure 6.5 of the October 2015 Application.

[71] See also AICUZ p. 2-15 indicating that northwest takeoffs and landings rarely occur. We also note that the evidence for this is clear in satellite images, where the majority of the rubber skid marks are at the northeast and eastern portion each of the runways.

[72] The commenters cited to material on FlightAware.com to show that there are 175 operations at Plant 42 per day. As such, it is clear that Plant 42 is significantly less busy than large international commercial airports (e.g., LAX has approximately 1700 operations per day. https://flightaware.com/resources/airport/KLAX/summary). We also note that the Air Force estimates that there are only about 15 operations per day from Plant 42 aircraft and other transient aircraft that may use the runways. AICUZ at 2-13.

[73] For example, a study at Venice International Airport on hourly NO_X concentrations found that the airport contribution to the NOx atmospheric concentrations is relatively limited compared to the other sources (e.g., compared to impacts from rush-hour roadway traffic). This study was based on a monitor that was located within 450 and 650 meters of two runways and away from roadway traffic. (*See* Gabrio Valotto and Critiano Varin, Characterization of hourly NOx atmospheric concentrations near the Venice International Airport with additive semi-parametric statistical models. *Atmospheric Research*, 167 (2016), 216-223.) Another study at Logan International Airport (Boston, MA) that focused on UFB also found that concentrations of other pollutants (CO, black carbon (BC), NO, NO_2, NO_x, SO_2, and $PM_{2.5}$) decreased with increasing wind speed when winds were from the direction of the airport, indicating a different dominant source (likely roadway traffic emissions). See N. Hudda et al., Aviation Emissions Impact Ambient Ultrafine Particle Concentrations in the Greater Boston Area, *Environ. Sci. Technol.*, 2016, 50 (2016), pp 8514–8521.

[74] Other areas of the runway where fewer aircraft emissions are expected, but that are closer to the PEP, are at least 1,000 meters away from the maximum impacts of the PEP.

concentrations that relied on a monitor heavily impacted by mobile source emissions. We do not find that the emissions from the aircraft at Plant 42 raise a concern about compliance with the applicable NAAQS or increments for the Project. Available information indicates the highest concentrations of aircraft emissions will not occur outside the Plant 42 boundary, as the boundary of Plant 42 is sufficiently far away from where the emissions are generated.[75]

Summary

In sum, our preliminary analysis that relied on the Lancaster-Division Street monitor for background concentrations for the 1-hr and 8-hr CO NAAQS and annual NO_2 NAAQS was very conservative and sufficiently accounted for potential impacts outside the Plant 42 boundary caused by aircraft emissions and stationary sources within Plant 42. As explained in Response 27, the Project's impacts were *very* low compared to these NAAQS and increments – each less than 4% of the applicable values. As also explained in Response 27, when the sum of maximum Project-only impacts and background concentrations are compared to the applicable NAAQS it is evident that the projected impacts from the proposed Project are still well below the NAAQS. The cumulative impact analyses for receptors outside the Plant 42 boundary for the applicable 24-hr PM_{10}, 24-hr $PM_{2.5}$, annual $PM_{2.5}$, and 1-hr NO_2 NAAQS and increments, which modeled the air quality impact of stationary sources within Plant 42 on areas outside Plant 42, were even more conservative, particularly as they included background concentrations from the Lancaster-Division Street monitor in addition to modeled impacts from the Plant 42 stationary sources for the NAAQS analyses. These analyses support our determination that the Project will not cause or contribute to a violation for these pollutants and averaging times. Having considered the issues raised by the commenters related to emissions sources within Plant 42, specifically including their concerns about the potential impacts from aircraft at Plant 42, we continue to determine that the Project will not cause or contribute to a NAAQS or increment violation for any of the pollutants covered by the PSD permit for the Project.[76]

The EPA Must Include Duct Burning in the Annual Modeling Analysis

Comment 33:

Commenters: Conservation Groups (0016)

The commenters requested that the modeling be redone to include duct burning in the annual NO_X and $PM_{2.5}$ analyses, stating that it appears that the EPA did not include emissions from the duct burners in the annual NO_X and $PM_{2.5}$ analyses. The commenters stated there is no basis for excluding these emissions so the modeling must be redone to include them.

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[75] Additionally, while the commenters have attempted to estimate NO_X emissions from aircraft activity at Plant 42, we do not find it necessary, in this case, to specifically quantify aircraft emissions, given that the impact of such emissions outside the Plant 42 boundary were accounted for in our consideration of monitored background concentrations, as explained above.

[76] Additionally, the commenters appear to refer to an EPA modeling analysis included in Appendix 6 of the Fact Sheet for 1-hr NO_2 impacts to indicate that the maximum impacts of the PEP will occur "right next to the runway" where aircraft emissions are occurring. The EPA conducted additional cumulative modeling for 1-hr NO_2 that included impacts from Plant 42 sources on receptors both within and outside Plant 42 for informational purposes to confirm that a spike in the modeled concentrations just outside the northwest corner of Plant 42 was caused by sources within Plant 42 and not by the PEP. The EPA included the modeling results as an Appendix to the Fact Sheet. Those impacts were not seen in the Project-only analysis and had appeared to be an anomaly. As described in Response 31, it was not necessary to model the impact of Plant 42 sources on receptors within Plant 42 as part of our determination that the Project will not cause or contribute to a NAAQS or increment violation. The maximum impacts for the 1-hr NO_2 NAAQS for our cumulative analysis are available in Table 25 of the Fact Sheet (the Project's impacts on receptors within Plant 42 were considered in our preliminary analysis as reflected in Table 24 of the Fact Sheet).

Response 33:
The EPA disagrees with the commenters that the modeling analyses for annual NO_2[77] and $PM_{2.5}$ should be redone to appropriately reflect duct burning, as we believe that the analyses were conducted appropriately to reflect the worst-case modeling scenario for each pollutant. Due to a typographical error, the Fact Sheet erroneously stated that no duct burning was the worst case for $PM_{2.5}$. Fact Sheet at 74. As seen in Table 29 on page 74 of the Fact Sheet, however, $PM_{2.5}$ emissions were the highest with duct burning, and this is the scenario that was in fact modeled, as stated in the October 2015 Application at 7.2-2.

The EPA Must Model the Emergency Engines

Comment 34:
Commenters: Conservation Groups (0016)

The commenters stated that they agree that it is appropriate to not include emergency engines in startup and shutdown scenarios because there is a permit condition which prohibits that. However, the emissions from the emergency engines must be included in other scenarios.

Response 34:
The EPA agrees with the commenters, and recognizes that the Fact Sheet was unclear on this issue. However, in fact, the engines were appropriately modeled in all scenarios. See Responses 22 and 30, and the October 2015 Application at 7.2-2-3.

The EPA Did Not Provide a Basis for Certain Data Substitution and Bias Adjustments in the Permit

Comment 35:
Commenters: Conservation Groups (0016)

The commenters stated:

Condition 28 provides: "Data reported to meet the requirements of Condition 51 shall not include data substituted using the missing data procedures in subpart D of 40 CFR part 75, nor shall the data have been bias adjusted according to the procedures of 40 CFR part 75."

Condition 29.b contains a similar provision. The Fact Sheet does not provide an explanation of the basis for these provisions or any reference to the administrative record supporting these provisions.

Response 35:
Conditions 28 and 29.b of the proposed PSD permit for the Project (now Conditions 29 and 30.b of the Final Permit, respectively) are necessary to allow the Permittee to use the same CEMS for compliance with PSD permit conditions, NSPS limits, and the Acid Rain Program. For the data from a CEMS to be considered valid, it is important that each CEMS be certified, operated, maintained, and the resulting data used in a uniform fashion. To do this, the EPA generally requires CEMS in PSD permits to follow the requirements and procedures specified in 40 CFR 60.13 and the applicable performance specification in Appendix B of 40 CFR part 60. These are the same procedures and requirements used for CEMS that are required by an NSPS standard in 40 CFR part 60. However, these particular units – the two CTs – are also subject to the Acid Rain Program that has a similar but slightly different set of procedures and requirements that must be followed for CEMS. Those differences specifically relate to missing data procedures and bias adjustments. 40 CFR 60.13 and Appendix B of 40 CFR part 60 do not

[77] Although the commenter referenced "NO_X" emissions, the ambient air quality analysis is based on predictions of ambient NO_2 concentrations, as NO_2 is the applicable NAAQS pollutant.

have provisions that allow for missing data to be substituted or for the data to be bias adjusted. As such, by including the provisions referenced by the commenter, we otherwise consider a CEMS meeting the requirements of the Acid Rain Program (in 40 CFR part 75) to be equivalent to meeting the requirements of 40 CFR part 60.13 and Appendix B to 40 CFR part 60, and the same CEMS can be used for meeting the monitoring requirements for the three different programs.

Further, to the extent the commenters were suggesting that 40 CFR 124.8(b)(4) requires the EPA to detail the basis for each and every individual permit condition, including those that the commenters are asking about, we disagree. As stated above, 40 CFR 124.8(b)(4) requires that the Fact Sheet contain a "brief summary of the basis for the draft permit conditions." The Fact Sheet contained our detailed analysis providing the basis for our determination that the Project will meet the PSD permit program requirements and the basis for the associated emission limits in our PSD permit, which satisfied this regulatory requirement. Considering the detailed analysis provided in the Fact Sheet, and the fact that the Fact Sheet was over 90 pages, we believe the Fact Sheet appropriately met the requirements of 40 CFR 124.8(b)(4) although the particular permit conditions raised by the commenter were not specifically discussed. The notice and comment process for our proposed permit provided the commenters with sufficient information and opportunity to raise their questions related to the permit conditions at issue, and to obtain our specific reasoning for the conditions.

The Shakedown Period is Not Long Enough

Comment 36:

Commenter: Gregory S. Darvin, Senior Meteorologist, Atmospheric Dynamics, Inc. (on behalf of the Applicant) (0015)

The commenter proposed to revise the commissioning/shakedown period from 90 to 180 days from first fire, which would make it consistent with the Antelope Valley AQMD Final Determination of Compliance (FDOC), stating that the proposed 90 days is insufficient time to fully commission a combined-cycle power plant and is more typical of a simple cycle plant. As summarized in the application, the commissioning/shakedown period would not exceed 180 days from first fire.

Response 36:

The EPA has revised the permit as requested by the commenter because the 90 days listed in Condition 13 was an inadvertent error. As stated in Condition 13, shakedown is a period that begins with initial startup and ends not later than initial performance testing. The permit requires initial performance testing to be complete within 180 days of initial startup. Final Permit Condition 41. As such, the shakedown period shall be no longer than 180 days. See Condition 13 of the Final Permit. This change is shown in the redline-strikeout version of the final permit.

CO BACT Emission Limit is Not Achievable at Less Than Full Load and Should Be Revised

Comment 37:

Commenter: Gregory S. Darvin, Senior Meteorologist, Atmospheric Dynamics, Inc. (on behalf of the Applicant) (0015)

The commenter stated that:

The proposed BACT concentration limit of 1.5 ppm of CO at 15% O_2 without the duct burner being operational will not be guaranteed by Siemens, the turbine manufacturer at output lower than base (100%) GT load. As part of the design of the plant, the turbines and the combined-cycle portion of the plant is designed to provide flexible capacity to the California Independent Systems Operator (CAISO). Flexible capacity natural gas fired generation resources will operate to meet the ramping and peak load requirements in the morning and late afternoon, helping to integrate the ramp up and ramp down of solar generation provided by other facilities.

The turbines and combined-cycle portion of the plant are designed and permitted to operate down to 40% load which could reflect the operational profile during the peak solar generation time of day. The turbines (and plant) could then be ramped up as the sun sets and peak loads increase in the late afternoon/early evening hours.

As such, we would propose to revise the language in the draft permit to reflect that the 1.5 ppm limit (and corresponding lb/hr limits) only apply at 100% load, and to apply 2 ppm (and corresponding lb/hr limits) at other loads.

Response 37:

The EPA agrees with the commenter's concerns related to meeting a 1.5 ppm CO BACT limit without duct burning at lower load levels. As discussed in more detail below, we have determined there is sufficient evidence that 1.5 ppm may not be achievable at lower loads for the PEP's CTs and thus we are instead including the 1.5 ppm limit in the final permit as a demonstration limit. We note, however, that we disagree that a BACT limit should be revised solely because the vendor will only provide a guarantee at 100% load. If a limit has been determined to be demonstrated in practice, the lack of a vendor guarantee is not a sufficient basis for setting a higher BACT limit.

To evaluate the concerns raised by the commenter, we reviewed recent, actual emissions and operating data for a CT in California that is the same model that will be used at the PEP – the Siemens SGT6-5000F. The data demonstrated that CO emissions during normal operations are often below 1 ppm. However, we must ensure BACT is achievable over various operating conditions, particularly in this case where the PEP is expected to operate its CTs at varying loads during normal operation. As such, we looked at how the existing CT specifically responded to those instances of fluctuating load conditions. We looked at a particular period of data between March 7 – April 6, 2016, when it appeared the CT was operating at less than full load and the load level was fluctuating frequently. We then compared this to data for the period between July 11 – August 18, 2016, when it appeared the CT was operating mostly at or near full load. These two scenarios are presented in Figures 4 and 5 below.

As seen in Figure 4, during fluctuating load conditions, CO emissions appeared to be erratic, routinely spiked above 1 ppm, and in a few instances, were at or above the unit's 2.0 ppm limit. Further, the CO emissions did not appear to become less erratic as load increased, indicating that CO emissions in this particular range are not solely a function of the load level. As seen in Figure 5, during near full load, steady conditions, emissions were almost always below 1 ppm. Emissions only spiked above 1 ppm and became erratic during those few instances when the unit operated below 160 MW, at which point the emissions became similar to those seen in Figure 4.

This data provides uncertainty as to whether 1.5 ppm CO can be consistently achieved under all normal operating conditions, and, as a result, we are finalizing the 1.5 ppm limit without duct burning as a demonstration limit. While we recognize that the unit we analyzed is designed to meet a 2.0 ppm limit, it exceeded this limit occasionally during fluctuating load conditions. As such, it is not clear that simply designing the PEP to achieve 1.5 ppm (through more frequent catalyst changes or using additional catalyst) would ensure that 1.5 ppm would be met.

When we say we are finalizing 1.5 ppm as a demonstration limit, we mean that the initial CO BACT limit will be 2.0 ppm (and 10.4 lb/hr[78]) without duct burning, but after a 5-year demonstration period[79] the limit will become 1.5

[78] It is necessary to also change the lb/hr emission limit as it reflects the highest emission rate at full load when meeting the applicable ppm limit (either 1.5 ppm or 2.0 ppm).

[79] We note that this is a longer demonstration period than we have used in the past for demonstration limits for other PSD permit. However, it is warranted given that the PEP is a load following unit that we expect to operate less often that the baseload units for which we have typically set a demonstration limit.

ppm (and 7.8 lb/hr), unless the Permittee can demonstrate that 1.5 ppm is unachievable. Additionally, the Final Permit contains criteria for how the Permittee would make such a demonstration and requires that the Permittee apply for a permit revision to include the achievable limit, which would be subject to public notice and comment (see Condition 18.c of the Final Permit). We note that, if appropriate based on information gleaned during the demonstration period, the Permittee could alternatively request that the 1.5 ppm limit apply only at higher loads, based on a showing that the 1.5 ppm limit can only be achieved above a particular load level.[80] We note that the EPA's air quality impact analysis was based on a 2.0 ppm limit during normal operating conditions, and this change to the Final Permit does not affect the startup and shutdown conditions that were modeled. As such, no update to the modeling analysis is warranted for this change to the Final Permit. This change is shown in the redline-strikeout version of the final permit.

Summary of Data Reviewed

The data reviewed for this analysis is available as part of the record for our final PSD permit decision for the PEP. We obtained the CO emissions data from the San Joaquin Valley Air Pollution Control District, and the load data from the EPA's publicly available Air Program Markets Data. For the 2017 CO emissions data, we did not have data for October through December, as it was not yet available. Our analysis only included data associated with normal operating conditions. We excluded data associated with startup and shutdown events, CEMS calibration checks, and CEMS monitor downtimes. In addition to the figures presented here, the information in the record also shows the CO emissions and load over all of the 2016 and 2017 data, and shows the load level chronologically, which is how we found the fluctuating load conditions and full load conditions used above. We note that there were other fluctuating load conditions that showed spikes in CO emissions, but we chose the particular sets of dates that we utilized because they were of longer duration than others.

[80] It is unlikely that such a demonstration could be made that a 1.5 ppm limit should apply only at 100% load, as the data reviewed indicates that this limit is likely achievable down to 75 or 80% load. However, we do not have enough information at this time to conclusively determine that a particular load level should be applied for a 1.5 ppm limit, as the unit reviewed was designed for 2.0 ppm.

Figure 4 CO Emissions During Fluctuating Load Conditions

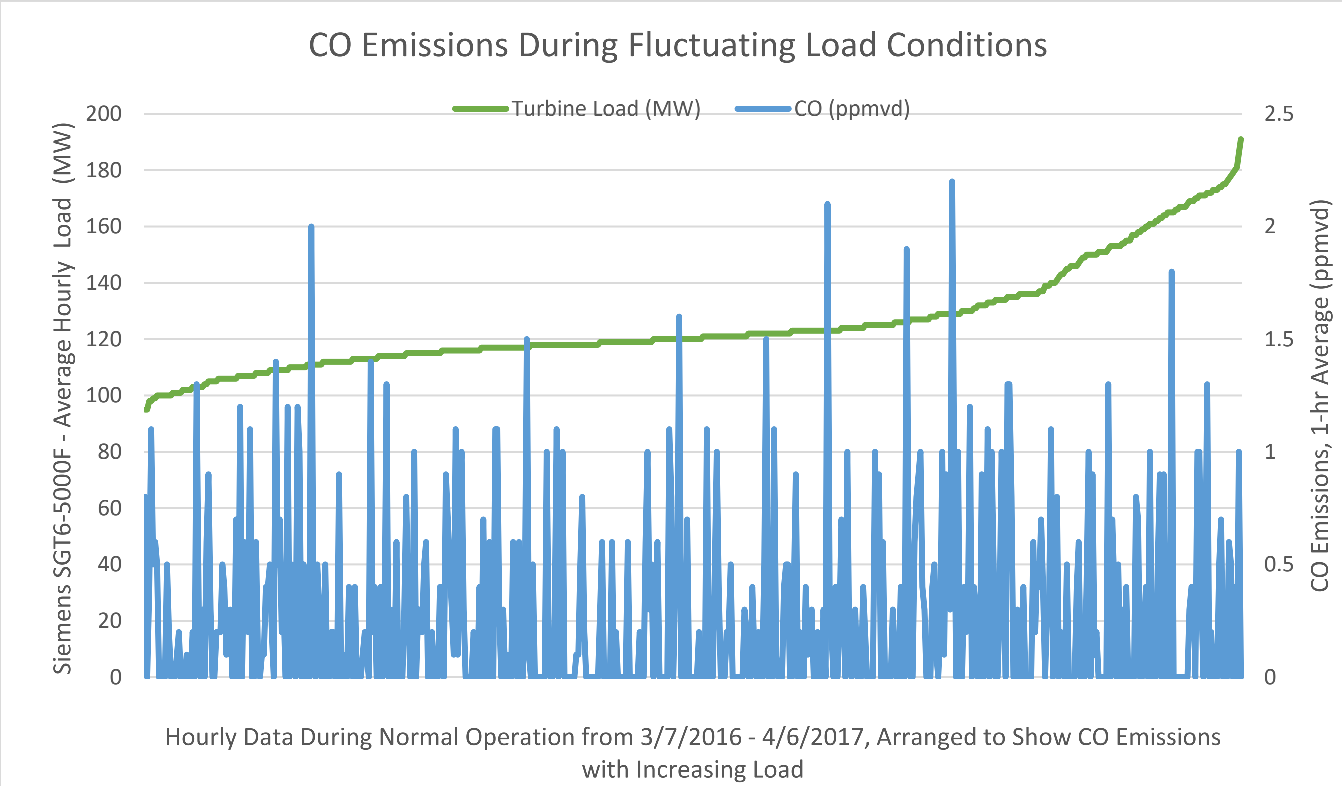
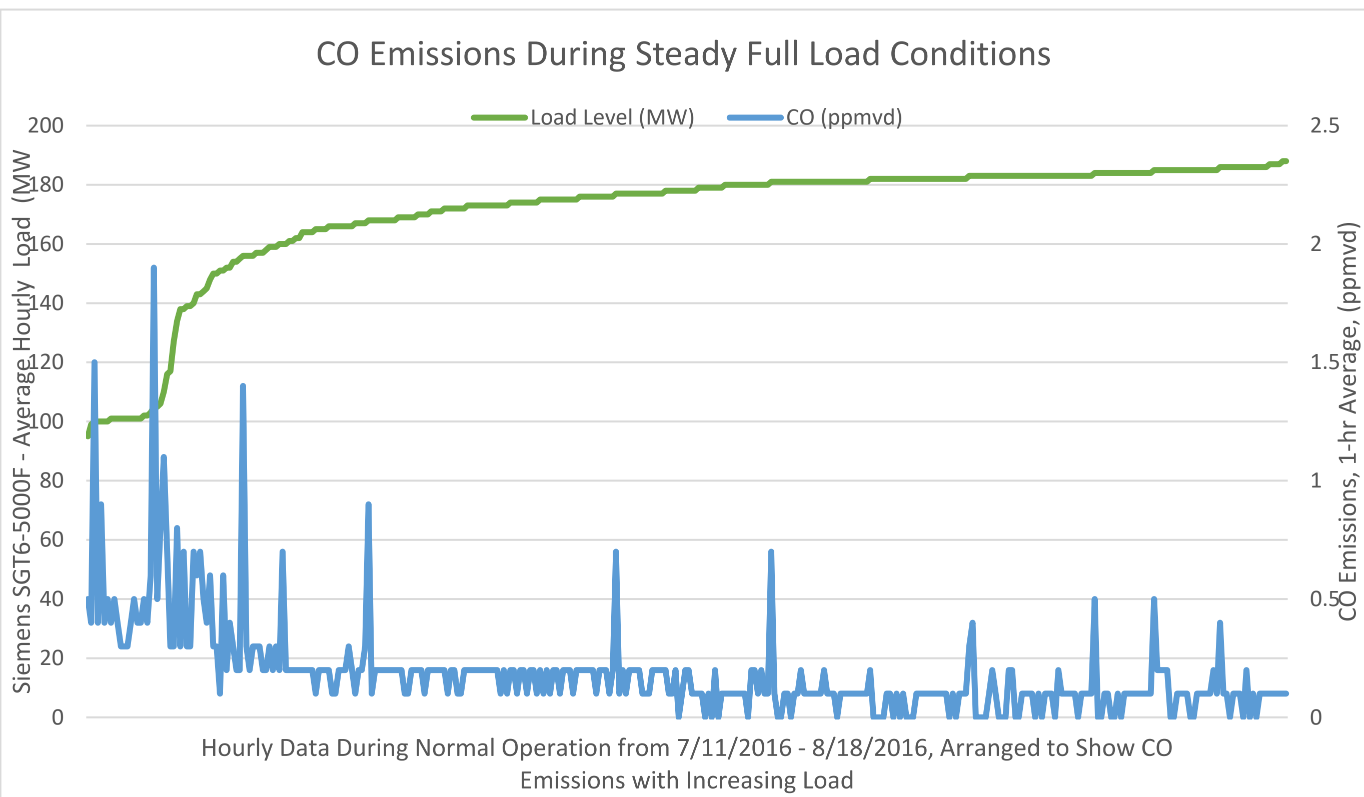


Figure 5 CO Emissions During Steady Full Load Conditions



The Definitions for Cold, Warm and Hot Startup Should be Revised

Comment 38:

Commenter: Gregory S. Darvin, Senior Meteorologist, Atmospheric Dynamics, Inc. (on behalf of the Applicant) (0015)

The commenter suggested changes to the definitions and startup and shutdown limits for cold, warm, and hot startup to be consistent with the FDOC, as follows:

> a. We note that the definitions of the cold, warm, and hot startup scenarios are not applicable for plant configurations that incorporate an auxiliary boiler as part of the fast start design. As such, we propose the following language which would match the FDOC.
>
> i. *Cold Startup-A gas turbine (GT) startup that occurs when the steam turbine (ST) rotor temperature is less than 485°F after a GT shutdown (SD).*
>
> ii. *Warm Startup-A GT SU that occurs when the ST rotor temperature is greater than or equal to 485°F but less than 685°F after a GT SD.*
>
> *iii. Hot Startup-A GT SU that occurs when the ST rotor temperature is greater than 685°F after a GT SD.*
>
> …
>
> c. For consistency with the FDOC startup and shutdown limits, we would propose the following emissions limits which remove some of the precision associated with the numbers used in the application:

	NO_X	CO	Duration
Cold Startup	52 lb/event	416 lb/event	39 minutes
Warm Startup	47 lb/event	378 lb/event	35 minutes
Hot Startup	43 lb/event	305 lb/event	30 minutes
Shutdown	33 lb/event	76 lb/event	25 minutes

Response 38:

The EPA has revised the definitions and limits in the final PSD permit for the PEP in response to this comment.

We agree that defining cold, warm, and hot startup using temperature ranges is more appropriate than the time limits that were included in our proposed permit. The limits in the proposed permit reflect the traditional time periods associated with cold, warm and hot startups. However, the use of an auxiliary boiler changes the timeframes because it allows the CTs to reach their operating temperatures in less time. As such, timing the periods to specific operating temperatures more accurately reflects the various startup conditions.

We disagree with the commenter's proposal that we revise the lb/event emission limits to remove some of the precision associated with the numbers used in the application, in order to ensure consistency with the FDOC's startup and shutdown limits. Upon further review of these limits, however, we noted that some of the lb/event limits in the proposed permit required a higher level of precision -- by having more significant figures -- than the other limits in this section of the permit. Accordingly, we revised the lb/event limits in Condition 19.c to provide consistent significant figures (3 significant figures for the NOx and CO limits), and for the same reason, also revised the lb/hr limit in Condition 19.e. The revision of these limits does not change the modeling analysis, as correction for the appropriate significant figures occurs last, not at the beginning of the analysis. See Condition 19 of the Final Permit. These changes are shown in the redline-strikeout version of the final permit.

Fuel Use Limit for CTs Should Be Revised

Comment 39:

Commenter: Gregory S. Darvin, Senior Meteorologist, Atmospheric Dynamics, Inc. (on behalf of the Applicant) (0015)

The commenter stated:

> The total annual fuel use of natural gas for each turbine appears to be in error. From the PSD application, the annual fuel use on the turbines should reflect up to 8,000 hours per year but the limit appears to be for 6,500 hours. The correct limit should be 1.820 x 10^{10} standard cubic feet (scf) for each turbine.

Response 39:

The EPA agrees with the commenter that an incorrect fuel use limit was included in the permit for the CTs (representing 6,500 hours instead of 8,000 hours). The Fact Sheet clearly documented our intent for the fuel use limit to reflect an equivalent of 8,000 hours of operation, consistent with the PSD permit application and the modeling analysis. Fact Sheet at 7 and 14. However, upon review, the value is actually 1.735 x 10^{10} scf per year (scf/yr). [81] The final permit has been revised to reflect a limit of 1.735 x 10^{10} scf/yr. Also, in reviewing this comment we discovered that the equipment list on page 2 of the permit should be clarified. The proposed permit listed the heat input of each CT as 2,410 MMBtu/hr; however, this included the potential heat input from the duct burners. We revised the Final Permit to reflect the maximum heat input from only the CTs, without the duct burners, which is 2,217 MMBtu/hr. See Fact Sheet at 5, Table 1. The heat input from the duct burners remains separately identified in the equipment list. See Condition 20 of the Final Permit. These changes are shown in the redline-strikeout version of the final permit.

Duct Burner Fuel Use Limit for the CTs Should Be Revised

Comment 40:

Commenter: Gregory S. Darvin, Senior Meteorologist, Atmospheric Dynamics, Inc. (on behalf of the Applicant) (0015)

The commenter stated:

Similar to the issue identified in Comment 40, the duct burner fuel use limit appears to incorporate the turbine fuel use for 1,500 hours per year, instead of only the duct burners. The correct fuel limit should be 2.97 x 10^{8} scf per year.

Response 40:

The EPA agrees with the commenter that an incorrect fuel use limit was included in the proposed permit for duct burning (representing 1,500 hours of operation of the duct burners and 1,500 hours of operation of the turbines, instead of only operation of the duct burners). However, upon review, the value is actually 2.75 x 10^{8}scf/yr.[82] The Fact Sheet clearly documented our intent for the fuel use limit to reflect an equivalent of 1,500 hours of duct burner operation, consistent with the PSD permit applicant and the modeling analysis. Fact Sheet at 7 and 14. The final permit has been revised to reflect a limit of 2.75 x 10^{8} scf/yr. See Condition 21 of the Final Permit. This change is also shown in the redline-strikeout version of the final permit.

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[81] The maximum hourly fuel flow of each CT is 2,169,356.70 scf/hr (at ISO conditions). See Table A-10 in Appendix A to the October 2015 Application. Calculation: (2.169 x 10^{6} scf/hr) x (8000 hrs/yr) = 1.735 x 10^{10} scf/yr.

[82] The maximum hourly mass flowrate for each duct burner is 8,074 lb/hr and the density of natural gas is 22.743 scf/lb. See Table A-10 and Attachment A-1 to Appendix A of the October 2015 Application. Calculation: (8074 lb/hr) x (22.745 scf/lb) x (1500 hrs/yr) = 2.75 x 10^{8} scf/yr.

The EPA Cannot Enforce Condition Based on Information It Does Not Have

Comment 41:

Commenters: Conservation Groups (0016)

The commenters stated that Condition 4 says that determination of compliance with Condition 4 will be based on "information available to EPA". The commenters assert that this violates the Credible Evidence Rule and renders this condition not enforceable as a practical matter because members of the public or the state and local air agencies would need to determine what information the EPA has and would not be able to enforce this condition based on information they have which the EPA does not have. Therefore, this condition must be changed to delete the entire last sentence of the condition so that any credible evidence can be used to enforce this condition.

Response 41:

We disagree with the commenter's assertions that the reference in Condition 4 of the Proposed Permit (also Condition 4 of the Final Permit) to "information available to EPA" violates the credible evidence rule and renders the condition not enforceable as a practical matter.

Condition 4 of the Proposed Permit reads as follows:

> 4. *Source Operation*
> At all times, including periods of startup, shutdown, shakedown, and malfunction, the Permittee shall, to the extent practicable, maintain and operate the Source, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the EPA which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the Source.

The language in Condition 4 is a standard requirement that is based largely on the language in 40 CFR 60.11(d). See also 40 CFR 52.12(c); see generally Final Rule, Credible Evidence Revisions, 62 Fed. Reg. 8314 (Feb. 24, 1997). The second sentence of this permit condition simply makes clear that the EPA may consider a wide variety of information in determining whether acceptable operating and maintenance procedures are being used. This provision in no way limits the EPA's or other parties' discretion or ability to enforce the first condition of Condition 4 or any other portion of the permit, nor does it conflict with the credible evidence rule. In fact, the Proposed Permit included a credible evidence provision at Condition 12 (also Condition 12 of the Final Permit), which largely mirrors the language found in 40 CFR 60.11(g). Last, we note that emissions data on which the EPA might rely in making any compliance determination is available to the public pursuant to Clean Air Act section 114(c).

Permit Conditions Allowing for a Shakedown Period and for CEMS to Not Be Certified Until After Shakedown Should Be Removed

Comment 42:

Commenters: Conservation Groups (0016)

Th commenters stated that Condition 13 must be deleted and Condition 27's allowance of CEMS to not be certified by the end of shakedown must also be deleted, as NAAQS and increments apply at all times. The commenters assert that this is especially important with NAAQS with short averaging times. PSD regulations require that permit applicants establish that they will not cause or contribute to a violation of a NAAQS or increment. However, the applicant has not demonstrated that it will not cause or contribute to a violation of a NAAQS or increment during "shakedown" when the emission limits of Condition 18, 19, and 22 do not apply and the NO_X and CO CEMS are not certified. Therefore, the commenters state that Condition 13 must be deleted or the EPA must deny the permit.

Response 42:

The PSD regulations allow for the exclusion of temporary emissions (e.g., emissions occurring during the construction phase of a project) from the demonstration of compliance with the NAAQS and PSD increments and the related source impact analysis, air quality analysis and additional impact analysis requirements in 40 CFR 52.21(k), (m), and (o), if the allowable emissions from the major source do not impact a Class I area or an area where a PSD increment is known to be violated. 40 CFR 52.21(i)(3). As stated in Condition 13 of the Proposed Permit (also Condition 13 of the Final Permit), the shakedown period is the period beginning with initial startup, and ending no later than initial performance testing, during which the permittee conducts contractual and operational testing and tuning to ensure the safe, efficient and reliable operation of the equipment. Condition 13 of the Final Permit limits the shakedown period to 180 consecutive days, and therefore the emissions occurring during shakedown are a "once in a lifetime event" of limited duration for the equipment. We consider these emissions to be temporary within the meaning of 40 CFR 52.21(i)(3). The Applicant properly excluded these temporary emissions when evaluating the Project for compliance with the applicable NAAQS and increments, as the Applicant demonstrated that the Project will not impact a Class I area or an area where a PSD increment is known to be violated. See Fact Sheet Section 7.3, including Tables 24, 25, and 27. Thus, the Permittee need not demonstrate compliance with the NAAQS and increments for these temporary emissions, and we disagree that Condition 13, related to the temporary emissions that occur during shakedown, must be deleted or requires permit denial.

We also disagree that Condition 28 of the Final Permit (Condition 27 of the Proposed Permit), requiring the CEMS to be certified prior to the end of shakedown, or upon the commencement of commercial operations, whichever comes first, requires revision. In light of the exemption stated above, the Permittee does not need to demonstrate that the temporary emissions occurring during shakedown are in compliance with the emission rates in the Permit in order to ensure compliance with the NAAQS or increments, and thus the CEMS need not be certified until the end of the shakedown period. Further, the certification process for the CEMS will require the CTs to be in operation, and as such it is not feasible to ensure the CEMS are certified prior to their "first fire."

Define "Regular, Seasonal Closures" in Permit Condition 14

Comment 43:

Commenters: Conservation Groups (0016)

The commenters stated that Condition 14 should define "regular, seasonal closures" because the restarting of a facility can constitute a major modification triggering PSD review.

Response 43:

The EPA disagrees that a definition for the term "regular, seasonal closures" is necessary or appropriate for Condition 14 of the Final Permit (also Condition 14 of the Proposed Permit). Condition 14 of the permit, in which this term is used, requires that the Permittee submit a written report to the EPA of any permanent or indefinite closure within 90 days of the cessation of any operations at the permitted source, and clarifies that no notification is necessary for regular, seasonal closures. We believe this language is of adequate specificity while remaining general enough to encompass various types of regular or seasonal closures that are not of a permanent or indefinite nature. What constitutes regular or seasonal closure for a particular source may vary, thus defining this term is not warranted and would likely create unnecessary confusion. The commenters appear to be referencing an existing EPA policy related to reactivation of PSD sources, where a source that is shut down for at least two years is presumed to be permanently shut down and reactivation may trigger PSD review unless that presumption is rebutted based on the specific facts concerning the particular source. This policy applies to sources that are permanently or indefinitely closed with no continuing intent to restart. This policy does not apply to the temporary idling of a facility, for instance because seasonal weather conditions limit the need for the facility, so long as the facility intends to resume operations. We do not believe that defining the term “regular, seasonal closures” in the PEP permit is necessary to ensure compliance with Condition 14 or to ensure that EPA’s current reactivation policy to which the commenters appear to refer will not apply upon resuming normal operations.

Permit Limits for PM_{10} and $PM_{2.5}$ Must Include Both Filterable and Condensable PM

Comment 44:

Commenters: Conservation Groups (0016)

The commenters stated that Conditions 18.a.iv, 18.b.v and 22.c of the Proposed Permit need to specify that these limits include both filterable and condensable PM_{10} and $PM_{2.5}$. BACT applies to both types of PM_{10} and $PM_{2.5}$ regardless of whether the new source performance standard and/or national emission standard for hazardous air pollutions apply to both.

Response 44:

The EPA agrees with the commenters that both filterable and condensable PM_{10} and $PM_{2.5}$ must be accounted for in determining compliance with the emission limits in Conditions 18.a.ii, 18.b.iii and 22.c of the Final Permit. We disagree, however, that these permit conditions need to specify that the limits include both filterable and condensable PM_{10} and $PM_{2.5}$. The compliance demonstration method for these limits, i.e., performance testing in Condition 41.c.iv of the Final Permit, clearly specifies that testing for PM_{10} and $PM_{2.5}$ must include both filterable and condensable PM_{10} and $PM_{2.5.}$ This provision is adequate and appropriate to ensure that both filterable and condensable PM_{10} and $PM_{2.5}$ are accounted for in determining compliance with these permit limits.

The Permit Should Specify the Methodology for Determining Compliance for Duct Burners

Comment 45:

Commenters: Conservation Groups (0016)

The commenters stated that Conditions 18.b.i and ii need to specify the methodology for determining compliance when the duct burners are used for part of an hour. It should specify that the emission limit should be pro-rated in relationship to the amount of time the duct burners were used.

Response 45:

The EPA disagrees with the commenters’ assertions that (1) it is necessary for the permit to specify how to treat hours with partial duct burning for purposes of determining compliance with the permit’s mass-based emission limits for the CTs in Conditions 18.b.i and ii of the Final Permit, and (2) these mass-based emission limits for NO_X should be prorated based on the duration of time the duct burner is used within an hour. First, we interpret the duct burning limit in these permit conditions to apply to any hour that duct burning is used. Compliance with these limits is already based on a stringent 1-hr average, and prorating these emission limits would add unnecessary complexity to the permit. Additionally, these limits are BACT limits and not the NO_X limit set to ensure the worst-case modeled conditions are not exceeded. Condition 19.d of the Permit was set to ensure protection of the 1-hr NO_2 NAAQS. Fact Sheet at 74, footnote 102. The particular limits referenced by the commenter are both significantly lower than the limit set to protect the NAAQS.

The Permit Must Define “Normal Operating Mode”

Comment 46:

Commenters: Conservation Groups (0016)

The commenters stated that Condition 19.b needs to define "normal operating mode" to be enforceable as a practical matter.

Response 46:

We do not believe that a definition of the term "normal operating mode" in Condition 19.b. is necessary or appropriate to ensure that the condition is enforceable as a practical matter.

In general, the EPA regards any period of operation that does not meet the definition of a shakedown, startup, shutdown, or malfunction period, as defined in the permit, to be normal operation. We believe that the term "normal operating mode" may be construed broadly, and attempting to narrow it through a definition could have unintended consequences.

In addition, the specific context in which the term "normal operating mode" is used in Condition 19.b of the Final Permit makes clear that it is unnecessary to define the term to ensure enforceability of the condition. Condition 19.b states: "Shutdown is defined as the period beginning with reducing fuel flow below normal operating mode and lasting until fuel flow is completely shut off and combustion has ceased." By defining the period of shutdown to include the complete shutoff of fuel flow and the cessation of combustion, it is clear that this provision, by definition, may only be used to address periods of actual and complete shutdown, which are limited by the permit to a duration of 25 minutes. See Condition 19.c of the Final Permit. Therefore, any potential misinterpretation of the term "normal operating mode" in Condition 19.b could not be used to improperly lengthen the shutdown period in order to allow for higher emissions for an extended period of time.

The Permit Must Require Monitoring, Testing and Reporting for Emission Limits for the Auxiliary Boiler, Emergency Generator Engine and Emergency Fire Pump Engine During Normal Operations

Comment 47:

(Commenters: Conservation Groups)

The commenters stated that the permit must also have monitoring, testing and reporting for the emission limits for the auxiliary boiler, emergency generator engine and emergency fire pump engine during normal operations. In the draft permit, there is no testing to ensure compliance with any of the emission limits in Condition 22.

Response 47:

The EPA agrees that the Project's auxiliary boiler, emergency generator engine, and emergency fire pump engine need adequate monitoring, testing and reporting to demonstrate compliance. However, no change to the permit is required to address these issues, as the proposed permit already contained these requirements. Monitoring and testing requirements for these units are in Final Permit Conditions 40, 41, and 44; recordkeeping requirements are in Final Permit Conditions 46, 47, 49, and 50; and reporting requirements are in Final Permit Conditions 51, 53, and 54.

The Permit Must Include Fuel Sulfur Limits for the Diesel Engines

Comment 48:

Commenters: Conservation Groups (0016)

Conditions 24.e and 25.e of the Proposed Permit must specify that the engines shall only burn diesel fuel with 15 parts per million sulfur (ppm S) or less. Without this condition, the determination of potential to emit and resultant determination of which pollutants are above the significant emission rate are not valid. For the same reason, Conditions 24 and 25 must also require testing of the sulfur content of the diesel fuel to ensure compliance with this 15 ppm S requirement. It is not true that diesel with more than 15 ppm S is not available.

The EPA's regulations allow the use of 500 ppm sulfur fuel in a certain type of diesel which is referred to as diesel transmix, as shown in an attached exhibit. Furthermore, the 15 ppm S standard does not apply downstream of the refinery for nonroad, locomotive and marine fuel. (40 CFR 80.524.) That means that nonroad diesel has to average 15 ppm S when it leaves the refinery or importer but that average does not guarantee that the diesel burned at PEP will be 15 ppm S or below. In addition, there are numerous exceptions to the 15 ppm S standard. For example, motor vehicle diesel fuel can be downgraded to 15 ppm S. (40 CFR 80.527) Refiners can use credits rather than actually producing 15 ppm S nonroad diesel. (40 CFR 80.536) Small refiners can also get exemptions from the 15 ppm S standard. (40 CFR 80.550 – 80.555.)

Response 48:

We agree with the commenters that additional specificity is needed in the permit regarding the type of diesel fuel that may be used by the Project, but do not agree with all of the commenters' statements and recommendations. The commenters cite to several regulatory provisions for motor vehicles that are not applicable in this case. The engines for the PEP are subject to the NSPS standards in 40 CFR part 60, subpart IIII and must burn nonroad diesel fuel that is compliant with 40 CFR 80.510(b), which limits the sulfur content to 15 ppm. 40 CFR 60.4207(b). This requirement became applicable to refiners of nonroad diesel on June 1, 2010 (40 CFR 80.510(b)) and to retailers and wholesale distributers on December 1, 2010 (40 CFR 80.511(b)(2)). We disagree that there is a potential issue with transmix fuel, because, as stated in the information provided by the commenters, such fuel is only for locomotive and marine diesel applications. We have clarified the permit to require use of "nonroad diesel" instead of "diesel," including documentation that the diesel purchased is nonroad diesel. Condition 47.o of the Final Permit. This change is also shown in the redline-strikeout version of the final permit.

We disagree with the commenters that a specific limit on sulfur content is needed in this case given the clear regulatory requirements for nonroad diesel to meet 15 ppm on a per gallon basis beyond the refiner or importer. For the same reason, we do not believe that permit conditions requiring testing of the sulfur content of the diesel fuel to ensure compliance with the 15 ppm sulfur content requirement are warranted.

The EPA Should Prohibit CEMS Repairs, Calibration Checks, and Zero and Span Adjustments During Periods of Startup, Shutdown and Malfunction of the CTs

Comment 49:

Commenters: Conservation Groups (0016)

The commenters stated that Condition 27.b of the Proposed Permit should prohibit CEMS repairs, calibration checks, and zero and span adjustments during periods of startup, shutdown and malfunction of the CTs. This will ensure that periods when emissions from the CTs may be highest are not unmonitored.

Response 49:

We understand the commenter's desire to ensure that the CEMS are monitoring emissions during periods when emissions may be the highest. However, the commenter's suggestion would not be feasible or practical. The occurrence of startup, shutdown, and malfunctions is unpredictable and ensuring the proper operation of the CEMS should be independent of how the equipment it is monitoring is operated. Further, it would be overly burdensome to have these procedures delayed or moved depending on how the equipment it is monitoring is operating at a given moment. Typically, the CEMS is operated completely independent of the equipment it is monitoring and many procedures take place at predetermined intervals.

The Span Value for the CO CEMS Should Be Higher

Comment 50:

Commenters: Conservation Groups (0016)

The commenters stated that Condition 32.d should require a span value of significantly higher than 125 percent of the maximum estimated hourly potential CO emissions of the CTs. As mentioned before, CO emissions can be exponentially higher during startup, shutdown and malfunction. See below sample chart. Limiting span to 125 percent makes the CO BACT limit not practically enforceable because the CEMS will not be capturing high values.

Response 50:

We agree with the commenter that a different span value should be required for the CO CEMS. In response to this comment, we revised Condition 33.a of the Final Permit to require the CO CEMS to comply with Performance Specification (PS) 4A instead of PS 4. PS 4A is for sources with low emission standards (below 100 ppm) that may also have short term spikes (e.g., during startup). Additionally, we removed the span value specification that was listed in proposed Condition 32 (now Final Permit Condition 33). Since the span value is no longer specified, the Permittee will follow the span value requirements of PS 4A, which references PS 2. PS 2 requires the span value, when it is not otherwise specified, to be twice the emission standard. See Section 3.11 of PS 2 in Appendix B of 40 CFR part 60. The Permittee will need a low-range span for the emission standard during normal operation and a high-level span when the startup/shutdown limits apply. These changes are also shown in the redline-strikeout version of the final permit.

The Permit Needs to Require a Watt Meter for the Steam Turbine Generator

Comment 51:

Commenters: Conservation Groups (0016)

The commenters stated that Condition 18.a.v of the Proposed Permit includes the MWh contribution from the steam turbine generator in the GHG BACT limit. Therefore, in order for this condition to be enforceable as a practical matter, Condition 35 of the Proposed Permit needs to require a watt meter for the steam turbine generator in addition to for each CTG.

Response 51:

The EPA agrees with the commenters, and we have revised Condition 36 of the Final Permit accordingly. This change is shown in the redline-strikeout version of the final permit.

The Monitoring Plan Must be Consistent with Requirements in the Permit

Comment 52:

Commenters: Conservation Groups (0016)

The commenters stated that Condition 33 of the Proposed Permit must specify that nothing in the monitoring plan can be inconsistent with requirements in the permit. For example, the performance evaluation procedures and acceptance criteria cannot be less stringent than the applicable performance standards and other requirements in the permit. The commenters assert that without this clarification, not only is Condition 33 not enforceable as a practical matter, it also violated the PSD public participation requirements because the public will not have an opportunity to review and comment on the monitoring plans. The monitoring plan could also constitute a modification of the PSD permit without obtaining approval for the modification.

Response 52:

In response to this comment, the EPA has added language to Condition 34 of the Final Permit to specify that the monitoring plan must be consistent with the required monitoring in the permit and may not be used to alter how compliance with the applicable emission limits is determined. This change is shown in the redline-strikeout version of the final permit.

Permit Condition Allowing for Performance Test Waivers are Not Enforceable as a Practical Matter

Comment 53:

Commenters: Conservation Groups (0016)

The commenters stated that Condition 40.e of the Proposed Permit must be removed, and assert this provision makes the emission limits not subject to CEMS not enforceable as a practical matter and also violates the public participation provisions.

Response 53:

The EPA disagrees with the commenter that proposed Condition 40.e (now Final Permit Condition 41.e) must be removed to ensure the permit is enforceable as a practical matter. This condition allows the Permittee to request approval from the EPA, with adequate justification, for waiver of a particular annual performance test or for a performance test to be performed at less than full load. There are circumstances where it is appropriate to waive a performance test, such as when a source will not be operating during the period when the annual performance test is required. In such cases, to prevent unnecessary air pollution, the EPA may waive the testing requirement until the source is operating again. Similarly, a piece of equipment may have difficulty reaching full load if other portions of the operation that cannot be controlled prevent operating at full capacity. Nonetheless, we recognize the commenter's concern that this condition may be too broad and therefore have revised the permit to clarify that this condition may be used only in limited circumstances and to provide more specificity concerning the nature of the justification that is required. We have also added language to Final Permit Condition 41.e to make clear that any such waiver or allowance that is issued by the EPA shall be in writing and that the Permittee must adhere to any specifications or requirements concerning such waiver or allowance that the EPA imposes therein. These changes are shown in the redline-strikeout version of the final permit.

We also disagree that this narrow permit condition allowing limited changes to testing protocols on a case-by-case basis with adequate justification and with the EPA's approval violates public participation requirements. Our proposal to allow for such limited changes was subject to public notice and the opportunity to comment in this proceeding pursuant to PSD permitting requirements, as exemplified by the commenters' comment and our response. The EPA believes that this process satisfies the applicable public participation requirements.

Comments Previously Submitted on the Palmdale Hybrid Power Project

Comment 54:

Commenter: Jack Ehernberger (0017)

The commenter submitted a copy of comments that had been prepared in 2011 for the CEC's licensing process for the Palmdale Hybrid Power Project (PHPP). The comments relate to the locations of meteorological data used, the number of years of meteorological data used, and concerns related to low altitude wind, temperature, and humidity.

Response 54:

The commenter's comments were developed in the context of the California state licensing process for the PHPP from 2011. The PHPP was a project somewhat similar to the PEP that had been previously proposed at the site of the proposed PEP. On September 25, 2012, the EPA issued a final PSD permit for the PHPP to the City of Palmdale. However, the PHPP was never constructed and the PSD permit authorizing its construction eventually expired. Since that time, Palmdale Energy, LLC has obtained ownership of a portion of the site that was associated with the PHPP, developed its own power plant project – the PEP – and is now seeking authorization to construct the PEP.

As discussed in our Fact Sheet, our PSD permit decision for the PEP is based on Palmdale Energy, LLC's PSD permit application for the PEP and a new review and analysis by the EPA of the PSD requirements as they relate to the PEP. As such, the commenter's comments from 2011 concerning the analysis before the CEC for the PHPP were drafted prior to our issuance of, and are not directed at, our proposed decision for the PEP or the underlying analysis for our proposed decision as discussed in our Fact Sheet and supported by our administrative record. Nor did the commenter explain with any specificity the comments' relevance to the EPA's proposed PSD permit decision or analysis for the PEP. Therefore, we cannot provide a more detailed response to these comments. We note that this commenter also separately provided oral comments during the public hearing and later written comments that were specific to our proposed permit decision and analysis for the PEP. We have considered and responded to those comments. See Comments and Responses 3, 23, 24, 25, and 26.

Public Comments on the Draft Cultural Resources Report

The National Historic Preservation Act Analysis is Inadequate

Comment 55:

Commenter: Conservation Groups (0016)

The commenters stated concerns regarding what they believe are inadequacies in the EPA's National Historic Preservation Act (NHPA) analysis, as reflected in the comment summary and excerpts below.

The commenters alleged that the EPA's NHPA analysis is inadequate because the EPA considered only impacts within the physical footprint of PEP and supporting structures and only impacts caused by land disturbance activities. The commenters asserted that the EPA failed to address the issue of air pollution from the proposed PEP impacting historical properties, and that the destructive effect of air pollution on our built heritage has long been apparent, and the links between environment, its pollution and culture are obvious. The commenters further stated that damage done by air pollution is real, measurable, and in many cases obvious, and materials may be more sensitive than plants and animals since they have no healing capacity. The commenters cited several sources that allegedly support these assertions and the assertions below.

The commenters presented a brief description of the different forms of deterioration associated with atmospheric pollution with respect to various types of materials including stone, metals, timber, and glass, among other materials, and provided a detailed explanation of the manner in which various air pollutants can cause harm to historic properties. The commenters asserted that historic materials are deteriorated by means of three mechanisms, which in many cases interact together, simultaneously or in a time sequence, specifically, physical damage, chemical and biological damage, and soiling.

The commenters further asserted that the primary and secondary PM/PM_{10} and $PM_{2.5}$, as well as the NO_X, SO_2, ground level ozone, carbon dioxide, nitrous oxide, hydrochloric acid and possibly other pollutants that PEP will cause in the ambient air, will adversely impact historical properties.

The commenters also referenced tools that, in their view, are available to consider air pollution impacts on historic properties, citing the MULTI-ASSESS study and the CULTSTRAT study.

The commenters stated that non-zero air pollution impacts, including acidifying NO_X and soiling $PM_{2.5}$ impacts, were modeled by the EPA for up to 127 miles away from PEP. Within that distance, the commenters assert there are many historic properties that are susceptible to adverse impacts from PEP's air pollution. The commenters provided references to properties in the area. The commenters further stated that the EPA must obtain a complete list of relevant historical properties to conduct a proper NHPA analysis.

Response 55:

We appreciate the commenters' concerns related to potential air pollution impacts on historic properties. However, as discussed below, we do not agree that the air emissions associated with the PEP have the potential to affect any historic properties, nor have the commenters provided information that demonstrates that our determination in this regard is incorrect.

The commenters cite certain studies indicating that certain forms of air pollution can, as a general matter, cause adverse effects to cultural resources. However, the information cited does not demonstrate that the air emissions from the PEP, a natural-gas fired power plant with relatively low emissions, have the potential to affect historic properties. The information presented by the commenters mainly focuses on a general link between air pollution and potential effects to historic properties. That is, areas with higher air pollution are more likely to experience pollution-related effects to historic properties. The information focuses on large scale regional effects and does not identify ways to attribute specific emission increases to specific effects on historic properties. Instead, the information appears to be intended as a tool for demonstrating the relevance of regional quantification of pollutant emissions to help assess where potential effects may occur, and then to use this information to inform local policy for protecting historic properties. The information presented by the commenters does not show that air pollution from natural gas-fired power plants is linked to effects on historic properties or indicate that the magnitude of the emissions from the PEP is of the kind that would lead to effects to historic properties in general or to any specific cultural resources. Nor are we aware of any such information. As indicated in numerous places in the literature referenced by the commenters, the types of stationary sources generally associated with high levels of pollutants that could affect historic properties are coal and oil-fired power plants. The literature does not identify natural gas power plants as such a source type. For example, a coal-fired power plant generally emits thousands to tens of thousands of tons per year of NO_X compared to the PEP's 139 tpy. Also, the magnitude of the PEP's emissions within the area can be ascertained by considering the NO_X emissions inventory for the area. In 2012, mobile source emissions in the Antelope Valley accounted for 69.6 tons per day of NO_X, while stationary sources accounted for 28.3 tons per day. The PEP is expected to emit up to 0.57 tons per day of $NO_{X,}$ representing about 0.6% of NO_X emissions in the Antelope Valley.[83]

We note that although the commenters mention two studies, CULTSTRAT and MULTI-ASSESS, that they believe should inform the EPA's determination on the effects of air pollution, no citations were provided for these studies, and the general material referenced by the commenters refers to these studies but also does not provide citations to them. Further, it is unclear how the commenters expected the EPA to use these studies to inform our decision. Based on the referenced material, the CULTSTRAT study appears to be related to estimating the cost-benefit of renovation activities for historic properties exposed to air pollution, and the MULTI-ASSESS study appears to be related to determining acceptable background levels of air pollution that can be used to balance air pollution impacts and reasonable maintenance intervals of historic properties. These studies do not appear to provide information that would further inform the EPA concerning the potential effects of the air emissions from the PEP on historic properties or otherwise call into question the EPA's conclusion in this regard.

We also note that as part of the PSD permit review for the PEP, the emissions of the pollutants regulated under our PSD permit are subject to BACT and are therefore minimized in accordance with CAA requirements, and were demonstrated to comply with the NAAQS and PSD increments. In addition, although outside the scope of our PSD permit, the local AVAQMD permitting process requires that the Applicant obtain offsets to address certain other pollutants to be emitted by the PEP. In sum, we have no basis for concluding that the relatively small magnitude of air emissions associated with this well-controlled source has the potential to result in effects to historic

[83] CARB Review of the Mojave Desert AQMD and Antelope Valley AQMD Federal 75 ppb Ozone Attainment Plans for the Western Mojave Desert Nonattainment Area at Table 3 and AVAQMD's Final Determination of Compliance at 5.

properties, and the general information provided by the commenters concerning air pollution and historic properties does not change our conclusion in this regard.

After consideration of the information provided by the commenters, we concluded that it did not change our determination that we considered all potential effects of the Project on historic properties as part of the Section 106 consultation process. The general information provided by the commenters does not demonstrate that air pollutant emissions from the PEP are of the magnitude that would result in direct or indirect effects to historic properties. Accordingly, our determination of the Area of Potential Effects was not changed by the information presented by the commenters.

We also note that as part of the Section 106 consultation process, in addition to seeking public input, we also obtained input from nearby Tribes, and on December 21, 2017, we provided our proposed determination of no adverse effect to the California State Historic Preservation Officer (SHPO) for consulting party review, which included the concerns raised by the commenters that are addressed in this comment response. In a letter dated February 22, 2018, the SHPO stated that the EPA's proposed Area of Potential Effects appeared to be sufficient to take direct and indirect effects into account and stated that she had no objection to our proposed finding of no adverse effects to historic properties.

Additional Conditions Requested by the San Manuel Band of Mission Indians

Comment 56

(Commenter: San Manuel Band of Mission Indians (0020))

The commenter provided the following comments related to cultural resources:

The San Manuel Band of Mission Indians (SMBMI) appreciates the opportunity to review the project documentation, as the proposed project exists within Serrano ancestral territory. That said, due to the results of the cultural resources investigation and the thorough Cultural Conditions of Certification generated by the CEC, as well as the Cultural Resource Management (CRM) Department's present state of knowledge regarding cultural resources of concern within the project APE, SMBMI can now register its lack of cultural resources-based concerns with the project's permitting and implementation, as planned and conditioned, at this time. However, should the CEC's Cultural Conditions of Certification be altered or should a decision be made to not include these conditions in their entirety, SMBMI requests to re-open Section 106 consultation at that time.

Additionally, SMBMI requests the following:

1. That the Cultural Resources Mitigation Management Plan (CRMMP) detailed in the CEC's third Cultural Conditions of Certification (CUL-3) be written in such a way as to require collaboration with consulting Tribes in the event Native American resources are discovered. This collaboration will need to include the Tribes' review and comment upon the nature, boundaries, and significance of any find and its treatment, including collection strategies and curation. This document will also need to include provisions for consulting Tribes to collaborate with the Cultural Resources Specialist (CRS) and Compliance Project Manager (CPM) with regard to Native American monitoring post-discovery;

2. To be contacted should, as outlined in CUL-6, a Native American monitor need to be obtained to monitor areas of the project where Native American artifacts are discovered;

3. In the event a SMBMI Tribal Monitor participates in the project, to be supplied with all relevant monitoring reports and associated documentation and;

4. To contact SMBMI's CRM Department should there be a discovery of interest to Native Americans, as described and prescribed in CUL-6 and CUL-7.

This communication concludes SMBMI's Section 106-based input on this undertaking, at this time, and no additional consultation pursuant to NHPA is required unless the Cultural Conditions of Certification are not implemented as currently written or there is an unanticipated discovery of Native American cultural resources during project implementation.

Response 56

We appreciate the input of the SMBMI in the Section 106 process. On November 1, 2017, the Applicant submitted an addendum to its PSD permit application agreeing to adhere to the conditions requested by the SMBMI. The requested conditions are included in our Final Cultural Resources Report for the Project. We note that the EPA does not have the authority to revise the CEC's conditions of certification, but the Applicant's update of its PSD permit application, which it is obligated to follow under Condition 8 of the PSD permit and 40 CFR 52.21(r)(1), is a sufficient basis for ensuring that the requested actions will be taken.

3. Final PSD Permit No. SD 17-01

After careful review of the comments submitted and consideration of the views expressed by the commenters, the pertinent Federal statutes and regulations, and additional material relevant to the application and contained in our administrative record, Region 9 is issuing a decision pursuant to 40 CFR 52.21 to issue a final PSD permit to Palmdale Energy, LLC for the PEP. As described in this document, Region 9's consideration of the comments received during the public comment period resulted in a number of changes to the Final Permit as compared with the proposed permit. For the purpose of clarity, we have created an unofficial redline-strikeout version of the Final Permit that shows the changes made to the permit since proposal. However, the signed, clean version of the Final Permit is the official permit, and it controls in the event of any unintended discrepancies between the underline/strikeout version of the Final Permit and the signed, clean version of the Final Permit. In addition to the changes described in our responses above we also made several other minor changes, which can be seen in the unofficial redline-strikeout version, as follows:

- Cover page: Correction of signature to reflect the current Acting Air Division Director for Region 9, revisions to make clear when the permit will become effective, and a grammatical correction
- Page 2 and Condition 2: Revision to the abbreviation for the Antelope Valley Air Quality Management District
- Attachment A: Corrections to the list of abbreviations and acronyms for consistency with the terms used in the Final Permit
- Throughout the document: Revisions to permit condition numbering to reflect revised and additional permit conditions; removal of the word "draft"