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

Fact Sheet

Palmdale Energy Project
PSD Permit: SE 17-01

August 2017

Fact Sheet

Proposed Prevention of Significant Deterioration Permit

Palmdale Energy Project
Palmdale, California

PSD Permit No. SE 17-01

Contents

List of Tables

List of Figures

Fact Sheet

Proposed Prevention of Significant Deterioration Permit
Palmdale Energy Project

Section 1.0: Executive Summary

Palmdale Energy, LLC (PE or Applicant) applied to the U.S. Environmental Protection Agency (EPA) Region 9 for authorization under the Clean Air Act (CAA) Prevention of Significant Deterioration (PSD) program to construct and operate a new power plant that will generate 645 megawatts (MW, nominal output at average annual conditions) of electricity using natural gas. The power plant, known as the Palmdale Energy Project (PEP or Project) is to be located in the city of Palmdale, in Los Angeles County, California, within the Antelope Valley Air Quality Management District (Antelope Valley AQMD or District).

The EPA is proposing to issue a PSD permit to allow construction of the Project because it satisfies the requirements of the PSD program, including the following:

- The proposed PSD permit requires the best available control technology (BACT) to limit emissions of nitrogen oxides (NO_X), carbon monoxide (CO), total particulate matter (PM), particulate matter less than or equal to 10 micrometers (µm) in diameter (PM_{10}), particulate matter less than or equal to 2.5 µm in diameter ($PM_{2.5}$), and greenhouse gases (GHG).

- The proposed emission limits will protect the National Ambient Air Quality Standards (NAAQS) for nitrogen dioxide (NO_2), CO, PM_{10}, and $PM_{2.5,}$ and will not cause emission increases above the applicable PSD increments. There are no NAAQS for PM or GHGs.

- The Project will not adversely impact air quality or visibility in parks or wilderness areas that are given special protection under the CAA (referred to as Class I areas).

- An analysis of impacts on soils, vegetation, visibility and growth associated with the Project has been performed.

Section 2.0: Overview and Purpose

The PSD program is a preconstruction review and permitting program applicable to certain new major stationary sources and major modifications at existing major stationary sources. The specific requirements under the PSD program applicable to stationary sources located within the Antelope Valley AQMD are in the EPA's Federal Implementation Plan for the PSD program at 40 CFR 52.21. See 40 CFR 52.270(a). The PSD program applies to any regulated NSR pollutant (as defined in 40 CFR 52.21(b)(23)(i)), except for pollutants designated nonattainment for a NAAQS. The PEP is a new major stationary source that is in an area that has been designated as attainment or unclassifiable for all NAAQS pollutants except ozone.

The applicability of PSD to a particular source must be determined in advance of construction or modification, and is pollutant-specific. The primary criterion is whether the proposed project is sufficiently large (in terms of its emissions) to be a major stationary source or major modification of an existing major stationary source.

If the emissions from a project are greater than the applicability levels specified in the definitions for a major stationary source or major modification, a PSD permit must be issued before construction of the project. The requirements that must be satisfied to issue a PSD permit by the reviewing authority include:

- Conduct a control technology review (40 CFR 52.21(j));
- Conduct a source impact analysis (40 CFR 52.21(k));
- Conduct an additional impacts analysis (40 CFR 52.21(o));
- For sources impacting Class I areas, notify the Federal land managers of the PSD application and evaluation of the impacts on air quality related values (including visibility) in Class I areas (40 CFR 52.21(p)); and
- Follow the applicable public participation requirements (40 CFR 52.21(q) and 40 CFR Part 124).

This document describes the legal and factual basis for the proposed PSD permit for the PEP, including requirements under section 165 of the CAA and the PSD regulations at 40 CFR 52.21. This document serves as a Fact Sheet for the proposed PSD permit per 40 CFR 124.8.

Section 3.0: Source Description and Project Summary

The EPA initially received an application from the Applicant for the Project on October 14, 2015. The EPA requested and received supplemental application information from the Applicant during the application review process. The application materials for the proposed PSD permit for the Project (hereinafter referred to as "the Application") are included in the EPA's administrative record for the proposed PSD permit. The EPA determined the PSD permit application for the Project to be complete on August 16, 2017.

Section 3.1: Source Location and Address

Description of Location

The Project will be located on an approximately 50-acre parcel west of the northwest corner of U.S. Air Force Plant 42, and east of the intersection of Sierra Highway and East Avenue M, Palmdale, California.

Source Address

The address for the proposed Project is 950 East Avenue M, Palmdale, California 93440.

Figure 1 Palmdale Energy Project: Project Boundary and U.S. Air Force Plant 42

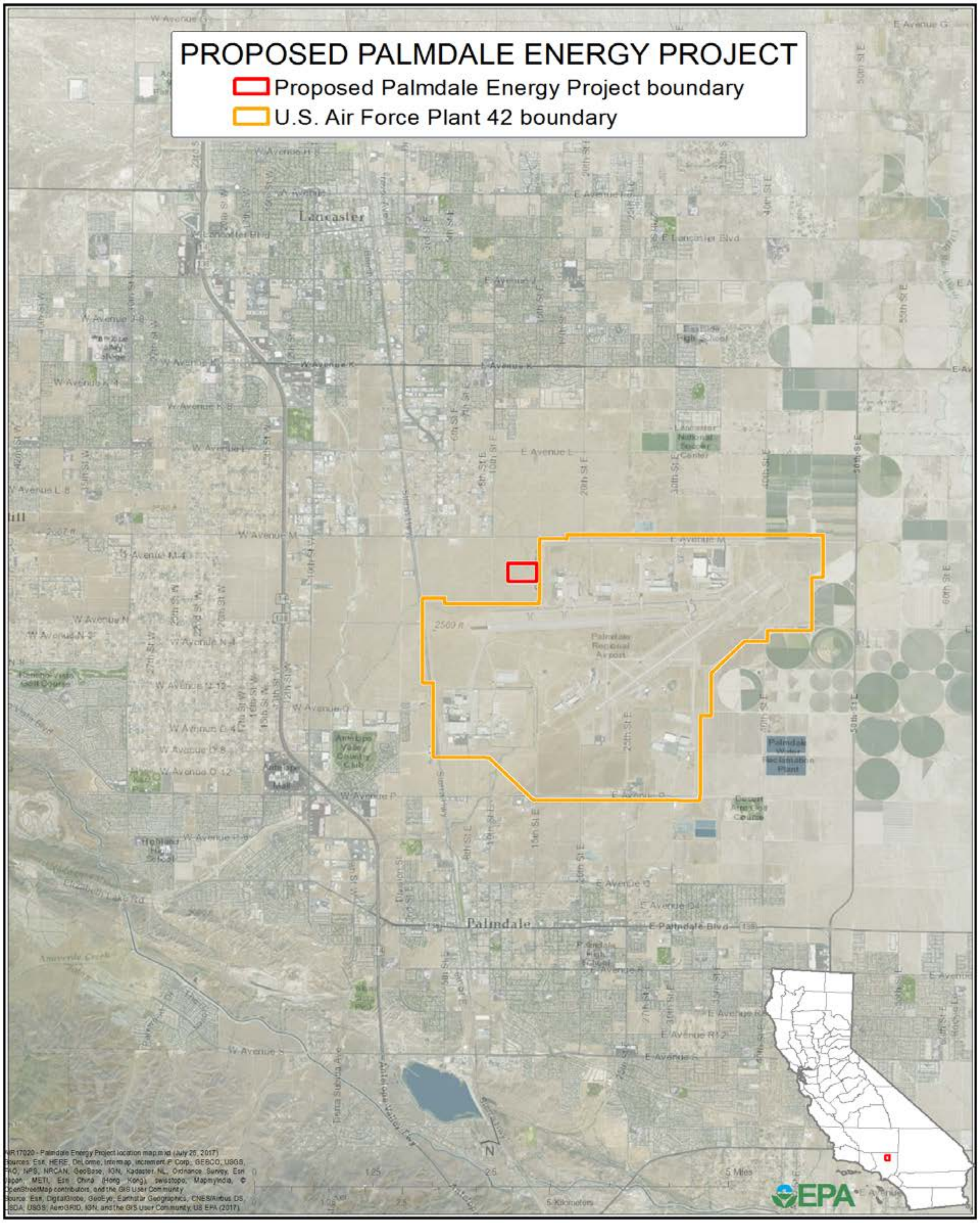
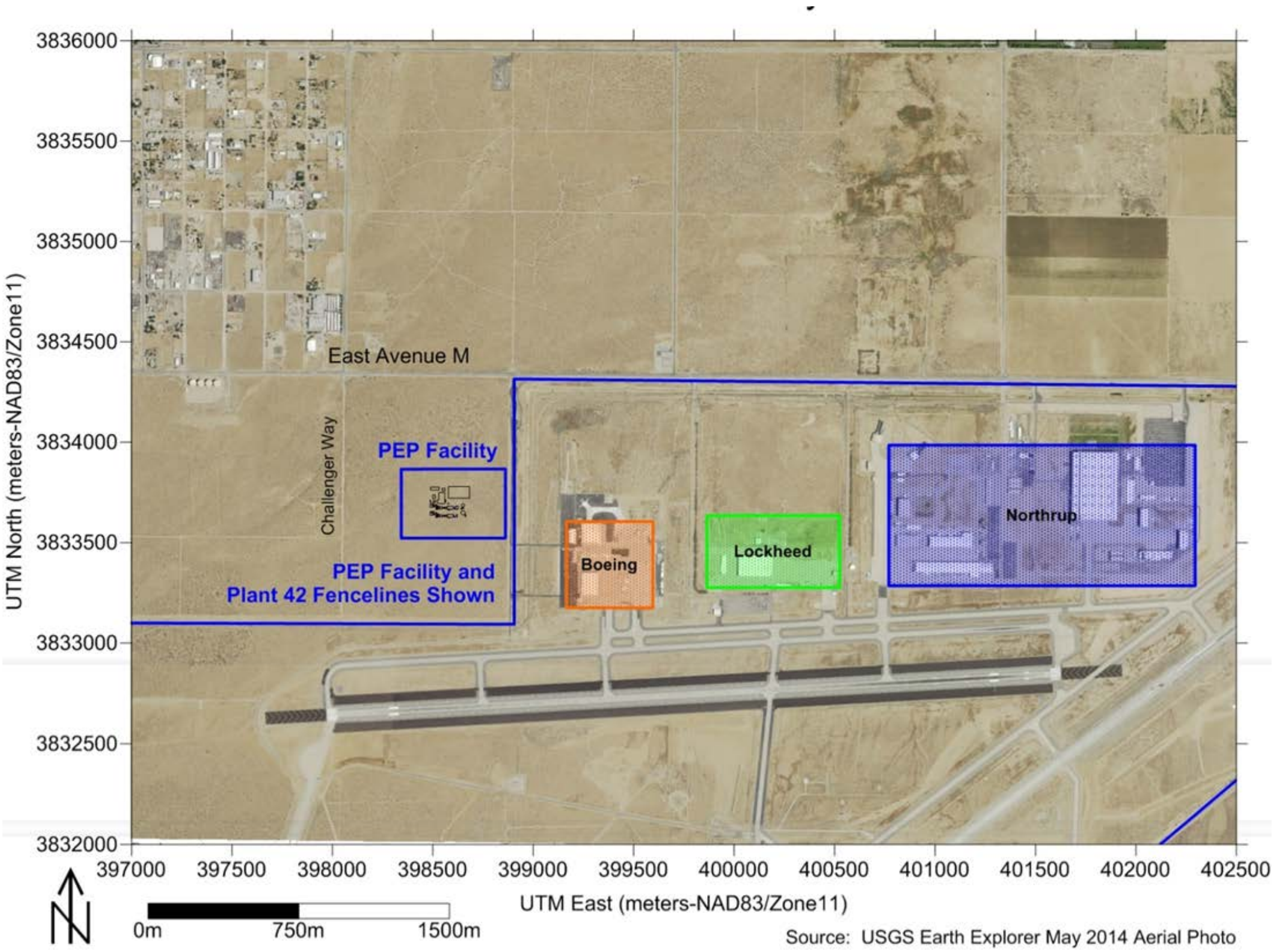


Figure 2 Location of Project and Nearby U.S. Air Force Plant 42 Sources



Section 3.2: Project Description

The Applicant, Palmdale Energy, LLC, a solely owned subsidiary of Summit Power Holdings, LLC, proposes to construct, own, and operate the PEP. This section of the Fact Sheet describes the Project as proposed by the Applicant.

The Project would consist of a natural gas-fired, fast start combined-cycle generating system (standard 2 X 1 configuration) to be developed on an approximately 50-acre site in the northern portion of the City of Palmdale. 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.[1]

The Project's combined-cycle equipment would utilize two Siemens SGT6-5000F natural gas-fired combustion turbine generators (CTs), two heat recovery steam generators (HRSG), and one steam turbine generator. The

[1] See page 2-1 of the October 2015 Application.

facility will utilize an auxiliary boiler to facilitate the fast start cycle for the CTs. In addition, the facility will have an emergency fire-pump system and an emergency electrical generator onsite. Process cooling for the combined-cycle system will be achieved by dry cooling technology. The electrical switching yard for the facility will include six circuit breakers, each containing 360 pounds of sulfur hexafluoride (SF_6). Table 1 lists the equipment that comprises the Project.

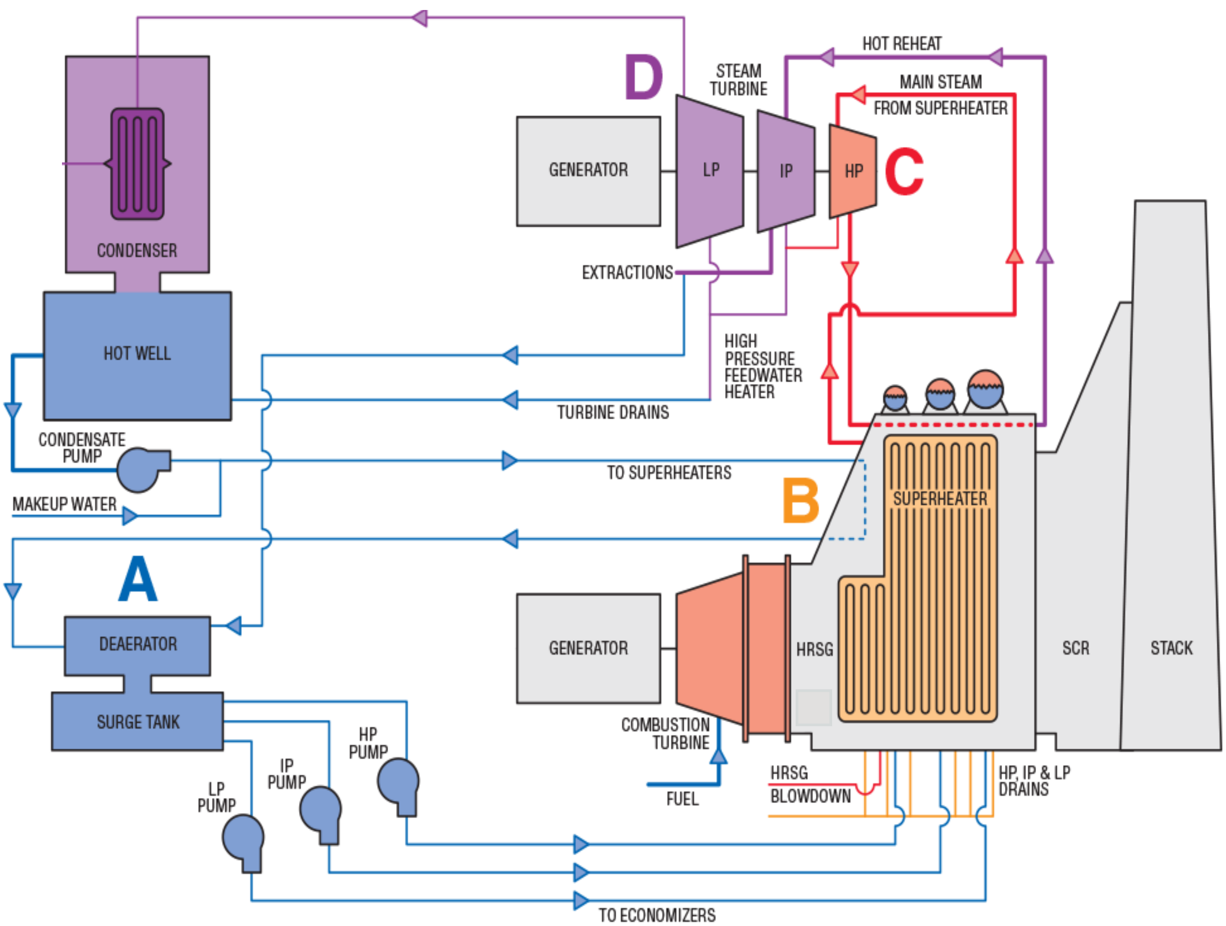
Table 1 Equipment List for the Palmdale Energy Project

Equipment	Description
Two natural gas-fired Siemens SGT6-5000F combustion turbines (CTs)	• Each 214 MW (nominal, average annual) CT, with a maximum heat input rate of 2,217 MMBtu/hr (ISO) • Equipped with natural gas duct burners, rated at 193.1 MMBtu/hr (HHV) for each turbine system • Each CT vented to a dedicated HRSG and a shared 276 MW Steam Turbine Generator
Auxiliary Boiler	• 110 MMBtu/hr (HHV) with ultra-low-NO_X burner, fired on natural gas
Emergency Diesel-Fired Internal Combustion (IC) Engine	• 1,500 kW (2,011 hp)
Emergency Diesel-Fired IC Fire Pump Engine	• 140 hp (104 kW)
Dry Cooling System	• Air-cooled condenser (ACC) consisting of modules containing several finned tube bundles with an axial fan.
Circuit Breakers	• Enclosed-pressure SF_6 Circuit Breakers

Electricity will be generated by the combustion turbine generators when the combustion of natural gas turns the turbine blades. The spinning blades will drive an electric generator with the potential to generate up to 214 MW of electricity from each turbine.

The facility will generally be operated in combined-cycle mode because each turbine will be equipped with a dedicated HRSG, where hot combustion exhaust gas will flow through a heat exchanger to generate steam. The facility will be equipped with duct burners firing natural gas to increase steam output from the HRSG during periods of peak energy demand. The steam generated from each of the HRSGs will drive a 276 MW steam turbine. Power plant output will be 645 MW (nominal output at average annual conditions). Exhaust gas exiting the steam turbine will enter an air-cooled condenser. Figure 1 shows the typical setup of a combined-cycle combustion turbine with a HRSG.

Figure 3 Basic Flow Diagram for Gas-fired Turbine and Steam Generator



Section 3.3: Construction and Operating Schedule

Construction of the Project is scheduled to begin as soon as financing closes and after the completion of all final project permits and approvals. Construction is anticipated to take approximately 23 months, with commissioning and operations commencing as early as the summer of 2019.

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.[2] Our analysis must consider these operational variations and be based on the worst-case operating conditions from an emissions perspective.

Consistent with the Application, operation of the facility will be limited as follows:

[2] See page 2-6 of the October 2015 PSD Application.

- The fuel use for the CTs will be limited to an amount equivalent to 8,000 hours per year, each, and the fuel use for the associated duct burner for each CT will be limited to an amount equivalent to 1,500 hours per year.
- The fuel use for the auxiliary boiler will be limited to an amount equivalent to 4,884 hours per year.
- The emergency fire pump engine may operate during emergencies and up to 52 hours per year for maintenance and readiness testing.
- The emergency generator engine may operate during emergencies and up to 26 hours per year for maintenance and readiness testing.

Section 3.4: Previous Project – Palmdale Hybrid Power Plant

On September 25, 2012, the EPA issued a final PSD permit decision authorizing the construction of a somewhat similar project – that had been previously proposed at the site of the proposed PEP – known as the Palmdale Hybrid Power Plant (PHPP).[3] The PSD permit for the PHPP was issued to the City of Palmdale, but the power plant was never constructed and the PSD permit 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, and is now proposing to construct the PEP. Our proposed PSD permit for the PEP is based only on the PSD permit application submitted by Palmdale Energy, LLC for the PEP. PSD permits are issued on a case-by-case basis; thus, our current proposed permit action is the results of a new review and analysis of the regulatory requirements for obtaining a PSD permit. We expect that there will be differences between our previous analysis for the PHPP, which was conducted in 2011. Several factors contribute to these differences, including:

- The proposed PEP is a larger power plant than the PHPP – 645 MW versus 570 MW, respectively.
- The proposed PEP is considered a load-following power plant, whereas the PHPP was considered a baseload power plant.
- The applicant for the PHPP proposed in its PSD permit application to include a solar thermal component as a key part of the PHPP, whereas Palmdale Energy, LLC has not proposed to include such a component as part of the proposed PEP.
- Our current analysis for the PEP considers any changes that have been made to the PSD permitting program since the PHPP permit was issued.
- Our current analysis for the PEP includes our most recent review and analysis of available control technologies. In some instances, we did not consider our previous BACT determination for the PHPP because numerous, more recent determinations were more relevant.
- Our current analysis for the PEP considers the current ambient air quality data and currently applicable NAAQS and increments.

Section 4.0: Public Comment Period, Procedures for Final Decision, and EPA Contact

The EPA is issuing a public notice that provides notice of, and requests public comment on, our proposal to issue a PSD permit to Palmdale Energy, LLC authorizing the construction of the Project.

The public comment period will commence on August 17, 2017. All written comments must be received by the

[3] See September 25, 2012 letter from Deborah Jordan, Air Division Director, EPA Region 9 to Steve Williams, City Manager, City of Palmdale, "RE: PSD Appeal No. 11-07, City of Palmdale, PSD Permit No. SE 09-01 Final Permit Decision"

EPA or postmarked by **October 6, 2017.** Comments must be sent or delivered in writing to Lisa Beckham at one of the following addresses:

E-mail:	R9AirPermits@epa.gov
Online docket:	Docket ID No. EPA-R09-OAR-2017-0473, at http://www.regulations.gov. Enter the Docket ID No. into the search box and follow the online instructions for submitting comments.
U.S. Mail:	Lisa Beckham (AIR-3) Air Permits Office U.S. EPA Region 9 75 Hawthorne Street San Francisco, CA 94105-3901

Comments should address the proposed PSD permit and the Project, including such matters as:

1. The best available control technology (BACT) determination for the Project;
2. The effect of the Project on ambient air quality; and
3. The effects of the Project, if any, on Class I areas.

The EPA will hold a public hearing**,** pursuant to 40 CFR 124.12, to provide the public with further opportunity to comment on the proposed PSD permit for the Project. At the public hearing, any interested person may provide written comments or oral comments, in English or Spanish, and relevant data pertaining to our proposed PSD permit. Reasonable limits may be set upon the time allowed for oral statements at the hearing. The EPA will also make a transcript of the public hearing proceedings available to the public.

The date, time, and location of the public hearing is as follows:

Date:	September 21, 2017
Time:	7:00 p.m. – 8:30 p.m.
Location:	Sgt. Steven Owen Memorial Park Stanley Kleiner Activity Center 43011 10th Street W Lancaster, CA

Simultaneous English-Spanish translation services will be provided at the public hearing. If you require a reasonable accommodation, please contact Philip Kum, EPA Region 9 Reasonable Accommodations Coordinator, by **September 7, 2017** at (415) 947-3566, or kum.philip@epa.gov.

All data submitted by the Applicant as part of the Application is available as part of the administrative record for this proposed permit. The administrative record, including the proposed PSD permit, our analysis (a Fact Sheet, per 40 CFR 124.8), the Application, and other supporting information are available through the EPA Region 9 website at: https://www.epa.gov/caa-permitting/prevention-significant-deterioration-psd-permits-issued-region-9#pending.

The EPA's proposed PSD permit for the Project and our Fact Sheet are also available for review in hardcopy at the following locations: Antelope Valley Air Quality Management District, 43301 Division Street, Suite 206, Lancaster, CA 93535, (661) 723-8070; Palmdale City Library, 700 East Palmdale Boulevard, Palmdale, CA 93550-4742, (661) 267-5600; Lancaster Regional Library, 601 W. Lancaster Boulevard, Lancaster, CA 93534-3398,(661) 948-5029; and Quartz Hill Library, 42018 N. 50th Street West, Quartz Hill, CA 93536-3590, (661) 943-2454.

All comments that are received will be included in the public docket without change and will be available to the public, including any personal information provided, unless the comment includes Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Information that is considered to be CBI or otherwise protected should be clearly identified as such and should not be submitted through the electronic docket or e-mail. If a commenter sends e-mail directly to the EPA, the e-mail address will be automatically captured and included as part of the public comment. Please note that an e-mail or postal address must be provided with comments if the commenter wishes to receive direct notification of the EPA's final decision regarding the Application and proposed PSD permit.

Before taking final action on the Application, the EPA will consider all comments submitted in writing during the public comment period, and written and oral comments submitted at the public hearing described above.

The EPA will send notice of our final PSD permit decision for the Project to each person who submitted comments and contact information during the public comment period or requested notice of the final permit decision. The EPA will provide written responses to comments in a document accompanying the EPA's final permit decision.

The EPA's final permit decision will become effective 30 days after the service of notice of the decision unless:

1. A later effective date is specified in the decision; or
2. The decision is appealed to the EPA's Environmental Appeals Board pursuant to 40 CFR 124.19; or
3. There are no comments requesting a change to the proposed permit decision, in which case the final decision shall become effective immediately upon issuance.

If you have questions, or if you wish to obtain further information, please contact Lisa Beckham at (415) 972-3811, via email at R9airpermits@epa.gov, or at the mailing address above. If you would like to be added to our mailing list to receive future information about this proposed permit decision or other permit decisions issued by EPA Region 9, please contact Lisa Beckham at (415) 972-3811 or visit EPA Region 9's website at https://www.epa.gov/caa-permitting/forms/public-notice-distribution-list-caa-permits-pacific-southwest-region-9. Lisa Beckham can also be reached through EPA Region 9's toll-free general information line at (866) 372-9378.

Section 5.0: Applicability of the Prevention of Significant Deterioration Regulations

This section describes the general requirements of the PSD regulations, our analysis to determine applicability of the requirements of the PSD program to the Project, and our analysis supporting our determination that the Project's emissions of NO_X, CO, PM, PM_{10}, $PM_{2.5}$, and GHG trigger the requirement for a PSD permit.

Section 5.1: PSD Applicability – Project Emissions

The PEP is a new stationary source being built at a site where no stationary source currently exists. The regulations provide that the PSD program is only triggered for a new stationary source if it is a *major* stationary source. See 40 CFR 52.21(a)(2)(i). As a fossil fuel-fired steam electric plant of more than 250 MMBtu/hr of heat input, the PEP is defined as a major stationary source if it emits, or has the potential to emit, 100 tons per year (TPY) or more of any regulated NSR pollutant other than greenhouse gases (GHGs)[4]. See 40 CFR 52.21(b)(1).

Once it is determined that a new source is a major source, certain PSD requirements are triggered for any regulated NSR pollutant that the facility would emit, or have the potential to emit, in *significant* amounts. The PSD regulations define the significant level for the regulated NSR pollutants, which varies by pollutant. Table 2 presents, for each relevant regulated NSR pollutant, the PEP's estimated potential emissions, the major source threshold, the significant emissions rate (SER), and whether PSD applies. See 40 CFR 52.21(b)(23)(i) and 52.21(b)(49)(iii)-(iv).

Table 2 shows that the PEP will be a major source for NO_X and CO, and will also have significant emissions of PM, PM_{10}, $PM_{2.5}$, and GHGs. Thus, the facility is subject to PSD and must meet certain PSD requirements for NO_X, CO, PM, PM_{10}, $PM_{2.5}$ and GHGs. The pollutants reviewed in this analysis did not include the nonattainment pollutant ozone and its precursor pollutants - NO_X and volatile organic carbons (VOC). Emissions of nonattainment pollutants from new or modified major stationary sources triggering new source review are regulated under the Act's nonattainment NSR permit program (CAA section 173) rather than the PSD program (CAA section 165).[5] However, we still reviewed NO_X for PSD applicability because the area is designated unclassifiable/attainment for the NO_2 NAAQS, and NO_X is also a precursor to $PM_{2.5}$, for which the area is designated unclassifiable/attainment.

Table 3 presents the estimated emissions of the PSD-regulated pollutants by emission unit for the Applicant's worst-case operating scenario as described above in Section 3.3. This includes operation of the CTs up to 8,000 hours per year and emissions from expected start-up and shutdown cycles.

This Fact Sheet describes the basis for our proposal to issue a PSD permit authorizing construction of the PEP, consistent with the requirements of the PSD program. As described below in Sections 6 through 9, we evaluated BACT for the Project and reached a BACT determination for the subject pollutants, and evaluated the potential air quality impacts of the Project to ensure the Project's consistency with other PSD requirements.

Table 2 Potential to Emit and PSD Applicability

Pollutant	Potential to Emit[6] (TPY)	Major Source Threshold (TPY)	SER (TPY)	Significant?
CO	351	100	100	**Yes**
NO_X (also a $PM_{2.5}$ precursor)	139	100	40	**Yes**
PM	81	100	25	**Yes**
PM_{10}	81	100	15	**Yes**

[4] Emissions of greenhouse gases alone do not trigger PSD applicability. See 40 CFR 52.21(b)(49)(iii)-(iv).
[5] The PEP obtained a CAA nonattainment NSR permit from the Antelope Valley AQMD authorizing its emissions of ozone precursors VOCs and NO_X. See the District's Final Determination of Compliance (FDOC) issued on August 22, 2016.
[6] Potential to emit for CO, NO_X, $PM/PM_{10}/PM_{2.5}$, and SO_2 based on limits in the Final Determination of Compliance (FDOC) issued by the Antelope Valley AQMD. Those limits are generally consistent with the limits in EPA's proposed PSD permit for the Project. Emissions of lead and H_2SO_4 are based on maximum emission rates. Emissions for GHGs are based on the proposed PSD permit conditions.

Pollutant	Potential to Emit[6] (TPY)	Major Source Threshold (TPY)	SER (TPY)	Significant?
$PM_{2.5}$[7]	81	100	10	**Yes**
SO_2 (also a $PM_{2.5}$ precursor)	11	100	40	No
Lead	0	100	0.6	No
Sulfuric acid mist (H_2SO_4)	4.8	100	7	No
GHG[8] (as CO_2e)	2,117,888	--	75,000	**Yes**
Hydrogen sulfide(H_2S)	<1	100	10	**No**
Total reduced sulfur	<1	100	10	**No**
Reduced sulfur compounds	<1	100	10	**No**

Table 3 Estimated Emissions of PSD-Regulated Pollutants by Emission Unit for the Worst-Case Operational Scenario

Emission Unit	CO	NO_X	$PM/PM_{10}/PM_{2.5}$	GHG (as CO_2e)
Two 214 MW (nominal) Combustion Turbines w/ 193.1 MMBtu/hr duct burners	341.08	138.24	80.67	2,112,350
110 MMBtu/hr Auxiliary Boiler	9.94	0.51	0.32	5,380
2,011 BHP Emergency Diesel Engine	0.3	1.7	0.1	233
140 BHP Emergency Diesel Fire Pump	0.1	0.08	0.04	20.4
Circuit Breakers	n/a	n/a	n/a	123
Total Facility[9]	**351 tpy**	**141 tpy**	**81.1 tpy**	**2,118,106**

[7] NO_X and SO_2 are precursors to the formation of $PM_{2.5}$, and emissions of 40 TPY or more of NO_X or SO_2 are also considered significant for purposes of $PM_{2.5}$ under PSD. See 40 CFR 52.21(b)(23)(i). Thus, PEP's projected emissions of NO_X, which exceed 40 TPY, are significant for $PM_{2.5}$ as well as for NO_X itself.

[8] Currently, there is not a significant emission rate for GHGs. The PSD program is triggered for GHGs when GHGs meet the definition of a pollutant subject to regulation. For a new major stationary source, GHGs become subject to regulation when a source is a new major stationary source for a regulated NSR pollutant that is not GHGs, and will emit or will have the potential to emit 75,000 or more TPY of CO_2e. For convenience, we are listing this 75,000 TPY threshold for GHGs as a SER because the Project triggers PSD for a regulated NSR pollutant other than GHGs and thus the 75,000 TPY threshold is relevant. See also memo from Janet McCabe, "Next Steps and Preliminary Views on the Application of Clean Air Act Permitting Programs to Greenhouse Gases Following the Supreme Court's Decision in Utility Air Regulatory Group v. Environmental Protection Agency," July 24, 2014 (available at https://www.epa.gov/sites/production/files/2015-12/documents/20140724memo.pdf). In addition, the EPA has proposed a SER for GHGs of 75,000 TPY of CO_2e. See 81 FR 68110 (Oct. 3, 2016).

[9] These values are slightly higher than the values in Table 2, because of minor differences in estimating emissions from emergency engines between this analysis and the Antelope Valley AQMD's FDOC. The FDOC contains federally enforceable limits consistent with the values in Table 2 for CO, NO_X and $PM/PM_{10}/PM_{2.5}$.

Section 6.0: Determination of Best Available Control Technology

Section 6.1: Overview of Top-Down BACT Analysis

This section describes the EPA's BACT analysis for the control of NO_X, CO, PM, PM_{10}, $PM_{2.5}$, and GHG emissions from emission units at the proposed Project. Section 169(3) of the Clean Air Act defines BACT as follows:

> "The term 'best available control technology' means an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under the Clean Air Act emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable through application of production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of 'best available control technology' result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 [New Source Performance Standards or NSPS] or 112 [National Emission Standards for Hazardous Air Pollutants or NESHAP] of the Clean Air Act."

See also 40 CFR 52.21(b)(12). In accordance with 40 CFR 52.21(j), a new major stationary source is required to apply BACT for each regulated NSR pollutant that it would have the potential to emit in significant amounts.

The EPA generally follows a long-established process for conducting its case-by-case BACT analysis – referred to as a "top-down" BACT analysis – to ensure that adequate consideration is given to the statutory and regulatory criteria for determining BACT.

In brief, under the top-down process, all available control technologies are ranked in descending order of control effectiveness. The applicant and reviewing agency first examine the most stringent (i.e., most effective) emission control technology. That technology with the emissions limit that it can consistently achieve is established as BACT unless it is demonstrated that technical considerations, or energy, environmental, or economic impacts, justify a conclusion that the most stringent technology is not achievable for the particular project under review. If the most stringent technology is eliminated, then the next most stringent option is evaluated until BACT is determined. The top-down BACT analysis is a case-by-case exercise for the particular source under evaluation. In summary, the five steps involved in a top-down BACT evaluation are:

1. Identify all available control options with practical potential for application to the specific emission unit for the regulated pollutant under evaluation;
2. Eliminate technically infeasible technology options;
3. Rank remaining control technologies by control effectiveness;
4. Evaluate the most effective control alternative and document results, considering energy, environmental, and economic impacts as appropriate; if top option is not selected as BACT, evaluate next most effective control option; and
5. Select BACT, which will be the most stringent technology not rejected based on technical, energy, environmental, and economic considerations, and establish the emissions limit that can be consistently achieved with that technology.

Section 6.2: Summary of BACT Determinations

Table 4 below provides a summary of our BACT determinations for the emission units and pollutants regulated under the proposed PSD permit for the PEP. A detailed discussion of our BACT analysis for these units and pollutants follows in Sections 6.3-6.6 below.

Table 4 Summary of BACT Determination for the Palmdale Energy Project

<table>
<tr><th>Equipment</th><th>NO_X</th><th>CO</th><th>$PM/PM_{10}/PM_{2.5}$</th><th>GHGs</th></tr>
<tr><td>Two 214 MW Combustion Turbines w/ 193.1 MMBtu/hr duct burners (DB), & shared HRSG with a 276 MW steam generator;

-Limits applicable to each unit</td><td>• 2.0 ppm NO_X, 15% O_2, 1-hr average
• 17.1 lb/hr w/o DB and 18.5 lb/hr w DB, 1-hr average
• During startup and shutdown events, separate lb/event and minutes/event limits apply. See Section 6.3.5</td><td>• 1.5 ppm CO w/o DB and 2.0 ppm CO w DB, 15% O_2, 1-hr average
• 7.8 lb/hr w/o DB and 11.3 lb/hr, w/ DB, 1-hr average
• During startup and shutdown events, separate lb/event and minutes/event limits apply. See Section 6.3.5</td><td>• PUC-quality natural gas
• 11.8 lb/hr PM
• 0.0048 lb/MMBtu PM
• Based on test average</td><td>• 928 lb CO_2/MWh_{net} (12-month rolling average) – includes CO_2 contribution from the HRSG natural gas-fired DBs and MWh contribution from the steam turbine.</td></tr>
<tr><td rowspan="2">110 MMBtu/hr Auxiliary Boiler</td><td>• 9.0 ppm NO_X, 3% O_2, 3-hr average</td><td>• 50 ppm CO, 3% O_2, 3-hr average</td><td>• 0.007 lb/MMBtu PM
• PUC-quality natural gas
• Based on test average</td><td>• Biennial tune-up</td></tr>
<tr><td colspan="4">• Fuel use limit (12-month rolling total) – equivalent to 4,884 hours of operation per year</td></tr>
<tr><td>2,011 BHP Emergency Diesel Engine</td><td colspan="4">• Model year 2011 or later engine certified by the EPA to the emission standards for non-methane hydrocarbons (NMHC)+NO_X, CO, and PM for emergency engines in 40 CFR part 60, subpart IIII
• Limited to emergency use and 26 hours per year for readiness and maintenance testing</td></tr>
<tr><td>140 BHP Emergency Diesel Fire Pump</td><td colspan="4">• Model year 2011 or later engine certified by the EPA to the emission standards for NMHC+NO_X, CO, and PM for emergency fire pump engines in 40 CFR part 60, subpart IIII
• Limited to emergency use and 52 hours per year for readiness and maintenance testing</td></tr>
<tr><td>Circuit Breakers</td><td>Not applicable</td><td>Not applicable</td><td>Not applicable</td><td>• Enclosed-pressure SF_6 circuit breakers with 0.5% (by weight) annual leakage rate and 10% leak detection systems</td></tr>
</table>

Section 6.3: BACT for Natural Gas Combustion Turbine Generators

The PEP will have two combined-cycle, natural gas-fired CTs. Each CT has a maximum heat input capacity of 2,217 MMBtu/hr (at ISO conditions) and will have a dedicated HRSG with a 193.1 MMBtu/hr duct burner. Each CT will be limited to a fuel use limit equivalent to 8,000 hours of operation per year, and each duct burner will be limited to a fuel use limit equivalent to 1,500 hours of operation per year. The CTs are subject to BACT for NO_X, CO, PM, PM_{10}, $PM_{2.5}$, and GHGs. A BACT analysis for each pollutant has been performed and is detailed below.

Section 6.3.1: Nitrogen Oxide Emissions for CTs

Step 1 - Identify All Control Technologies

The inherently lower-emitting control options for NO_X emissions include:

- Low NO_X burner design (e.g., dry low NO_X (DLN) combustors)
- Water or steam injection
- Inlet air coolers
- Catalytic combustion (K-LEAN™ or XONON™)

The available add-on NO_X control technologies include:

- Selective Catalytic Reduction (SCR) system
- EMx™ system (formerly SCONOX)
- Selective non-catalytic reduction (SNCR)

Step 2 – Eliminate Technically Infeasible Control Options

The available control options identified in Step 1 are considered technically feasible, except for catalytic combustion, EMx™, and SNCR.

Catalytic Combustion and EMx™

There is not sufficient evidence that catalytic combustion (as K-LEAN™ or XONON™) or EMx™ have been commercially applied to large-scale combustion turbines.

We could find only one fairly recent reference to the use of catalytic combustion technology and it was for a 1.4 MW combustion turbine.[10] In addition, we did not find any examples of this technology being used to comply with BACT. It appears this technology was being developed in the late 1990s and early 2000s, but has never shown progress as being commercially available for large-scale combustion turbines. Further, even if it were determined to be commercially available large-scale CTs such as those to be employed by the PEP, the technology ikely could not meet current BACT as reported emissions associated with this control option are 3 ppm of NO_X.[11]

Similarly, we are eliminating EMx™ technology (formerly SCONOX) from further consideration as it has yet to be demonstrated in practice on CTs larger than 50 MW. The manufacturer has stated that it is a scalable technology and that NO_X guarantees of <1.5 ppm are available.[12] However, we found only one BACT analysis that determined that EMx™/SCONOX was BACT for a large CT. The accompanying permit for the facility, Elk Hills Power in California, allowed

---

[10] http://www.kawasakigasturbines.com/index.php/press_releases/read/kawasaki_gas_turbines_cogeneration_system_helps_bridgewater_correctional_fa

[11] http://www.modernpowersystems.com/features/featurexonon-goes-commercial/

[12] Information available at http://www.rjmann.com/pdf%20files/emerachem/EMx_technical.pdf.

the use of either SCR or SCONOX (the former name of EMx™) to meet a permit limit of 2.5 ppm, and the control technology that was actually installed for that source was SCR, not SCONOX/EMx™.[13] The Redding Power Plant in California, a 43 MW gas-fired CT, was permitted with a 2.0 ppm demonstration limit using SCONOX. However, it was determined that the unit could not meet the demonstration limit and, as a result, the limit was revised to 2.5 ppm.[14] Based on these two examples, it appears that EMx™ has been demonstrated to achieve only 2.5 ppm, but has never been demonstrated on large CTs. Similar to catalytic combustion, EMx™ appears to be a technology that was being developed in the late 1990s and early 2000s, but has never shown progress in commercial applications for large CTs.

SNCR

Suitable applications for SNCR are units with furnace exit temperatures of 1550°F to 1950°F, residence times greater than one second, and high levels of uncontrolled NO_X.[15] SNCR is unsuitable for the PEP because the CTs for this project do not have high levels of uncontrolled NO_X and combustion exit temperatures before the HRSG would be around 900-1100°F. Further, we are not aware of any instances where this technology has been applied to combustion turbines.

Step 3 – Rank Control Technologies

A summary of recent BACT limits for similar combined-cycle, natural gas-fired CTs is provided in Table 6 at the end of this section. All recently issued permits indicate that a limit of 2.0 ppm based on a 1-hr average represents the greatest level of NO_X control. The available control technologies are ranked according to control effectiveness in Table 5, as determined by reviewing other BACT determinations[16] and the limits proposed by the Applicant.

Table 5 NO_X Control Technologies Ranked by Control Effectiveness

NO_X Control Technology	Emission Rate (ppmvd @ 15% O_2, 1-hr average)
SCR with dry low NO_X combustors and inlet air coolers	2.0
Dry low NO_X combustors and inlet air coolers	9
Water or steam injection	>9

Step 4 – Economic, Energy and Environmental Impacts

The Applicant has proposed SCR, the top-ranked technology, as BACT. In Step 4 of the BACT analysis it is appropriate to consider the collateral environmental impacts associated with SCR.

The SCR system requires onsite ammonia storage and will result in relatively small amounts of ammonia slip from the CTs' exhaust gases. Ammonia has the potential to be a toxic substance with harmful side effects, if exposed through inhalation, ingestion, skin contact, or eye contact.[17] Ammonia has not been identified as a carcinogen. It is noted that the Applicant will use aqueous ammonia, which is considered the safer storage method. Additionally, we note that the

[13] See current title V operating permit for the facility – S-1152677 issued on August 12, 2016.

[14] See letter dated June 23, 2005 from the Shasta County Air Quality Management District to the Redding Electric Utility.

[15] See EPA's Air Pollution Control Technology Fact Sheet for SNCR at page 3 – "Certain application[s] are more suitable for SNCR due to combustion unit design. Units with furnace exit temperatures of 1550°F to 1950°F, residence times greater than one second, and high levels of uncontrolled NO_X are good candidates."

[16] EPA Region 9 generally relies on the EPA's RACT-BACT-LAER Clearinghouse (RBLC) to evaluate past BACT determinations. The RBLC provides case-specific information on air pollution technologies, as provided by the EPA, State, and local permitting agencies. Additionally, EPA Region 9 also reviews other recent permitting decisions we are aware of that have not been entered in to the RBLC. https://cfpub.epa.gov/rblc/index.cfm?action=Home.Home

[17] Information is available from the Agency for Toxics Substances and Disease Registry at http://www.atsdr.cdc.gov/phs/phs.asp?id=9&tid=2.

California Energy Commission's Final Staff Assessment for the Project includes Conditions of Certification to ensure the safe receipt and storage of aqueous ammonia at the PEP.[18]

Ammonia slip emissions for the Project are limited to 5 ppm by the Final Determination of Compliance (FDOC) issued by the Antelope Valley AQMD for the Project. The District conducted a Health Risk Assessment (HRA) that included ammonia slip emissions. The results of the assessment showed that the maximum non-cancer chronic and acute hazard indices were both less than the significance level of 1.0 (0.0154 and 0.0271, respectively).[19]

Disposal of spent SCR catalyst can also create environmental impacts, as the spent catalyst can contain heavy metals such as vanadium pentoxide. Vanadium pentoxide is an acute hazardous waste under the Resource Conservation and Recovery Act (RCRA).[20] This potential impact is mitigated through recycling the spent catalyst with the manufacturer.

Considering the above factors, the possible risks associated with onsite storage and use of ammonia and SCR catalyst do not appear to outweigh the benefits associated with the significant NO_X reductions that would result from the application of this technology.

Step 5 – Select BACT

Based on a review of the available control technologies for NO_X emissions from natural gas-fired combustion turbines, we have concluded that BACT for the Project's CTs is dry-low NO_X combustors, inlet air coolers, and SCR and an emissions limit of 2.0 ppm at 15% O_2 based on a 1-hr average. Additionally, we are setting a mass emission limit for each CT of 17.1 lb/hr without duct firing and 18.5 lb/hr duct firing, based on a 1-hr average. The lb/hr limits represent the highest expected emissions, on a mass basis with and without duct firing, at the maximum operating rate and 2.0 ppm of NO_X.

Section 111 and 112 standards: The Project's CTs are subject to the Standards of Performance for Stationary Combustion Turbines at 40 CFR part 60, subpart KKKK. Each unit must meet a limit of 15 ppm of NO_X at 15% O_2 or 150 ng/J of useful output, as specified in Table 1 to 40 CFR 60 subpart KKKK. There are no applicable standards under section 112 of the Act for the CTs. Our proposed BACT limit of 2.0 ppm of NO_X at 15% O_2 ensures that BACT is at least as stringent as the applicable standard under sections 111 of the Act.

---

[18] This information is available at http://docketpublic.energy.ca.gov/PublicDocuments/08-AFC-09C/TN213623_20160912T162711_Final_Staff_Assessment.pdf, conditions HAZ-1 through HAZ-6 on pages 7.2-182 through 187.

[19] See Final Determination of Compliance for Palmdale Energy Project issued by the District on August 22, 2016 at 34 for the ammonia slip limits and at 14-15 for the HRA.

[20] See 40 CFR part 261, subpart D.

Table 6 Summary of Recent NO_X BACT Limits for Similar Combined-Cycle, Natural Gas-fired CTs

Facility	Location	NO_X Limit	Averaging Period	Control	Permit Issuance	Source
AES Huntington Beach	California	2.0 ppm LAER	1-hr	SCR	4/18/2017	Final Permit
AES Alamitos	California	2.0 ppm LAER	1-hr	SCR	4/18/2017	Final Permit
Middlesex Energy Center, LLC	New Jersey	2.0 ppm LAER	1-hr	SCR	7/19/2016	RBLC # NJ-0085
St. Charles Power Station	Louisiana	2.0 ppm	24-hr	SCR	8/31/2016	RBLC # LA-0313
Virginia Electric and Power Company	Virginia	2.0 ppm	1-hr	SCR	6/17/2016	RBLC # VA-0325
TVA Johnsonville Cogeneration	Tennessee	2.0 ppm	30-day	SCR	4/19/2016	RBLC # TN-0162
APEX Texas Power	Texas	2.0 ppm	--	SCR	3/24/2016	RBLC # TX-0788
Okeechobee Clean Energy Center	Florida	2.0 ppm	24-hr	SCR	3/9/2016	RBLC # FL-0356
Decordova Steam Electric Station	Texas	2.0 ppm	--	SCR	3/8/2016	RBLC # TX-0789
Brunswick County Power Station	Virginia	2.0 ppm	1-hr	SCR/LNB	1/28/2015	PSD Permit
FGE Eagle Pines Project	Texas	2.0 ppm	24-hr	SCR	11/4/2015	RBLC # TX-0773
Mattawoman Energy Center	Maryland	2.0 ppm	3-hr	SCR/DLN	11/13/2015	RBLC # MD-0045
Salem Harbor Station Redevelopment	Massachusetts	2.0 ppm LAER	1-hr	SCR/DLN	1/30/2014	RBLC # MA-0039
West Deptford Energy Station	New Jersey	2.0 ppm LAER	3-hr	SCR	7/18/2014	RBLC # NJ-0082
Keys Energy Center	Maryland	2.0 ppm	3-hr	SCR/DLN	10/31/2014	RBLC # MD-0046
Moundsville Combined Cycle Power Plant	West Virginia	2.0 ppm	--	SCR/DLN	11/24/2014	RBLC # WV-0025
Garrison Energy Center	Delaware	2.0 ppm LAER	1-hr	SCR/LNB	January 2013	RBLC # DE-0024

Section 6.3.2: Carbon Monoxide Emissions for CTs

Step 1 – Identify All Control Technologies

The inherently lower-emitting control options for CO emissions include:

- Good combustion practices
- Catalytic combustion (K-LEAN™ or XONON™)

The available add-on CO control technologies include:

- Oxidation catalyst
- EMx™

Step 2 – Eliminate Technically Infeasible Options

The available control options identified in Step 1 are considered technically feasible, except for:

Catalytic combustion

There is not sufficient evidence that catalytic combustion, K-LEAN or XONON, has been commercially applied to large-scale combustion turbines. We could find only one fairly recent reference to the use of this technology and it was for a 1.4 MW combustion turbine.[21] In addition, we did not find any examples of this technology being used to comply with BACT. It appears this technology was being developed in the late 1990s and early 2000s, but has never shown progress as being commercially available for large-scale combustion turbines. Further, even if it were determined to be commercially available for large-scale CTs such as those to be employed by the PEP, it likely could not meet current BACT, as reported CO emissions for this technology are 5 ppm.[22]

EMx™

As discussed in the NO_X BACT analysis, it is clear that EMx™ is an available control technology for CO emissions from CTs. However, it has yet to be demonstrated in practice on CTs larger than 50 MW. While the manufacturer claims that the technology is scalable and that emission rates below 1 ppm are achievable for CO, we could not find any information that demonstrates this on large CTs. And, the only large CT that has been permitted to use EMx™ for BACT ultimately installed a different other technology and did not install EM_x™. As stated previously, EMx™ appears to be a technology that was being developed in the late 1990s and early 2000s, but has never shown progress in commercial applications for large CTs.

Step 3 – Rank Remaining Control Technologies

A summary of recent BACT limits for similar combined-cycle, natural-gas fired CTs is provided in Table 8 at the end of this section. All of the most recent BACT determinations use oxidation catalyst to achieve BACT. However, recently, there have been varying BACT emission limits that have been established. For this analysis, we will be considering two sets of emission limits: (1) 2.0 ppm with and without duct burners firing and (2) 1.5 ppm without duct burners firing and 2.0 ppm with duct burners firing. Our review of the other BACT determinations with lower limits indicates that either these limits have not been demonstrated to be achieved in practice (because the facility was never constructed and/or has not started operating) or the limit is not applicable during all operating loads outside the startup and shutdown periods (which is how EPA Region 9 typically establishes BACT limits for CO from CTs). Additionally, we have concerns that the CO CEMS used for monitoring compliance with this limit cannot accurately measure compliance with limits in the 1.0 ppm or less range.[23] See also Table 8 and its footnotes for additional information. The remaining available

[21] http://www.kawasakigasturbines.com/index.php/press_releases/read/kawasaki_gas_turbines_cogeneration_system_helps_bridgewater_correctional_fa

[22] http://www.modernpowersystems.com/features/featurexonon-goes-commercial/

[23] See July 11, 2017 email regarding "Measuring CO from Gas-Fired Turbines – Using CEMS," from Kim Garnett in EPA's Office of Air Quality Planning and Standards, Measurement Technology Group to Lisa Beckham, EPA Region 9, Air Permits Office.

control technologies are ranked according to control effectiveness in Table 7, as determined by reviewing other BACT determinations and the limits proposed by the Applicant.

Table 7 CO Control Technologies Ranked by Control Effectiveness

CO Control Technology	Emissions Rate (ppmvd @ 15% O_2, 1-hr average, without duct firing)	Emissions Rate (ppmvd @ 15% O2, 1-hr average, with duct firing)
Oxidation catalyst and good combustion practices	1.5 ppm	2.0 ppm
Oxidation catalyst and good combustion practices	2.0 ppm	2.0 ppm
Good combustion practices	9.0 ppm	9.0 ppm

Step 4 – Economic, Energy and Environmental Impacts

In considering the collateral environmental impacts associated with the use of an oxidation catalyst, we note that there are potential environmental impacts associated with disposal of spent catalyst, which could contain hazardous material. However, this is mitigated through returning the catalyst to the manufacturer for recovery and reuse. We are not aware of any significant or unusual adverse environmental impacts associated with good combustion practices and an oxidation catalyst.

<u>CO Cost Analysis</u>

The Applicant provided cost analyses evaluating its proposed limit of 2.0 ppm CO versus a potential limit of 1.0 ppm CO.[24] The applicant estimated the average cost to reduce CO to 2.0 ppm to be $3,600/ton, and the average cost to reduce CO to 1.0 ppm to be $4,100/ton. We evaluated the Applicant's analyses, the EPA's Cost Control Manual, and adjusted the 1.0 ppm analysis to consider the limit under consideration – 1.5 ppm. We arrived at costs of $3400/ton at a limit of 2.0 ppm and $3700/ton at a limit of 1.5 ppm. See Appendix 1– Cost Analysis for Oxidation Catalyst on the CTs. Both cost values are considered cost-effective, and we are not eliminating a limit of 1.5 ppm CO (without duct firing) in this step.

Step 5 – Select BACT

Based on the review of the available control technologies, we have concluded that BACT for each of CO for the Project's CTs is good combustion practices and an oxidation catalyst with a limit of 1.5 ppm at 15% O_2 based on a 1-hr average without duct firing, and 2.0 ppm with duct firing. Additionally, we are setting mass emission limits of 11.3 lb/hr with duct burning and 7.8 lb/hr without duct burning, based on a 1-hr average. These mass emission limits represent the highest expected emissions, on a mass basis, at the maximum operating rate and 2.0 ppm CO.

Section 111 and 112 standards: While these units are subject to the Standards of Performance for Stationary Combustion Turbines at 40 CFR part 60, subpart KKKK, this regulation does not include standards for CO. There are no section 112 standards for CO emissions from combustion turbines.

[24] See May 12, 2017 letter from Gregory Darvin, Atmospheric Dynamics to Lisa Beckham, EPA Region 9, Air Permits Office, Re: Palmdale Energy Project Prevention of Significant Deterioration Permit Response to Comments (May 2017 Response Letter).

Table 8 Summary of Recent CO BACT Limits for Similar Combined-Cycle, Natural Gas-Fired

Facility	Location	CO Limit (CO Limit with duct firing)	Averaging Period	Control	Permit Issuance	Source
AES Huntington Beach	California	1.5 ppm	1-hr	Oxidation catalyst/GCP	4/18/2017	Final Permit
AES Alamitos	California	1.5 ppm	1-hr	Oxidation catalyst/GCP	4/18/2017	Final Permit
St. Charles Power Station	Louisiana	2.0ppm	24-hr rolling	Oxidation catalyst/GCP	8/31/2016	RBLC # 0313
Middlesex Energy Center, LLC	New Jersey	2.0 ppm	3-hr rolling	Oxidation catalyst/GCP	7/19/2016	RBLC # NJ-0085
Greensville Power Station[25]	Virginia	1.0 ppm (1.6 ppm)	3-hr	Oxidation catalyst	6/17/2016	RBLC # VA-0325
TVA - Johnsonville Cogeneration	Tennessee	2.0 ppm	30-day	Oxidation catalyst/GCP	4/19/2016	RBLC # TN-0162
Mattawoman Energy Center	Maryland	2.0 ppm	3-hr	Oxidation catalyst/GCP	11/13/2015	RBLC # MD-0045
CPV Towantic, LLC[26]	Connecticut	0.9 ppm (1.7 ppm)	1-hr	Oxidation catalyst	11/30/2015	RBLC # CT-0157
Eagle Mountain Steam Electric Station	Texas	2.0 ppm	24-hr rolling	Oxidation catalyst	6/18/2015	RBLC # TX-0751
SR Bertron Electric Generating Station	Texas	4.0 ppm (also 2.0 ppm)	1-hr (12-mo rolling)	Oxidation catalyst	12/19/2014	RBLC # TX-0714
Colorado Bend Energy Center	Texas	4.0 ppm	3-hr	Oxidation catalyst	4/1/2015	RBLC # TX-0730
Wildcat Point Generation Facility	Maryland	1.5 ppm	3-hr	Oxidation catalyst	4/8/2014	RBLC # MD-0042
FGE Texas Power I and II	Texas	2.0 ppm	3-hr rolling	Oxidation catalyst	3/24/2014	RBLC # TX-0660
Salem Harbor Station Redevelopment	Massachusetts	2.0 ppm	1-hr	Oxidation catalyst	1/30/2014	RBLC # MA-0039
Sand Hill Energy Center	Texas	2.0 ppm	1-hr	Oxidation catalyst	9/13/2013	RBLC # TX-0709
Palmdale Hybrid Power Plant	California	1.5 ppm[27] (2.0 ppm)	1-hr	Oxidation catalyst	9/25/2012	Final Permit (expired)
Warren County Power Station	Virginia	1.5 ppm (2.4 ppm)	1-hr	Oxidation catalyst/GCP	12/17/2010	RBLC # VA-0315

[25] Construction is projected to be completed in December 2018. http://www.fluor.com/projects/engineering-construction-dominion-greensville-power
[26] Projected to begin operations in 2018. http://www.cpvtowantic.com/
[27] Limit applicable after a 3-year demonstration period. The Permittee could have applied for a permit revision if the limit was not achievable.

Facility	Location	CO Limit (CO Limit with duct firing)	Averaging Period	Control	Permit Issuance	Source
Kleen Energy Systems[28]	Connecticut	0.9 ppm (1.7 ppm)	1-hr	Oxidation catalyst	2/25/2008	RBLC # CT-0151

[28] Limit not applicable during "transient operations," which includes startup, shutdown, shifts between load, fuel switch and equipment cleaning, and operation below 60% load. See pages 252-253 of South Coast Air Quality Management District's Final Determination of Compliance for the Huntington Beach Energy Project – November 2016.

Section 6.3.3: PM, PM_{10} and $PM_{2.5}$ Emissions for CTs

All particulate emissions from gas-fired turbines are expected to be in the range of $PM_{2.5}$. As such, we have combined the BACT analyses for PM, PM_{10} and $PM_{2.5}$. Additionally, the analysis includes total particulate emissions – condensable and filterable.

Step 1 – Identify All Control Technologies

The following inherently lower-emitting control options for PM, PM_{10}, and $PM_{2.5}$ emissions from the CTs include:

- Low particulate fuels, low sulfur fuels, and/or pipeline quality natural gas (also referred to as "clean fuel")
- Good combustion practices (including air inlet filter)

The available add-on PM, PM_{10}, $PM_{2.5}$ control technologies include:

- Cyclones (including multiclones)
- Wet scrubber
- Dry electrostatic precipitator (ESP)
- Wet ESP
- Baghouse/fabric filter

Step 2 – Eliminate Technically Infeasible Control Options

All of the inherently lower-emitting control options identified in Step 1 are technically feasible. All of the identified add-on control technologies are considered infeasible and have never been demonstrated on combustion turbines.

Add-on PM control technologies are designed for high particulate exhausts or exhausts with both fine and coarse particulate matter. Natural gas-fired combustion turbines will only emit fine particulate matter. While many add-on PM technologies can have high control efficiencies – greater than 99% - these control efficiencies are not applicable to this particular project. A review of the EPA's Air Pollution Control Technology Fact Sheets[29] for add-on particulate matter technologies indicates that the lowest particulate inlet concentration[30] that would allow these control devices to work effectively is 0.1 grains per cubic feet. The exhaust gas concentration for the PEP is approximately 0.001 grains per cubic feet, significantly below the operating range of add-on PM technologies. Also, as part of the requirement to use clean fuel, the permit will contain a sulfur-based grain loading limit for natural gas used at the facility. As such, we have eliminated the add-on technologies from further consideration.

Step 3 – Rank Remaining Control Technologies

A summary of recent PM BACT determinations is provided in Table 9. Our review of these BACT limits indicates that the use of clean fuel and good combustion practices represents BACT for combined-cycle combustion turbines. Permitting authorities have set PM BACT limits in a variety of manners, including setting pound per hour PM limits, pound per MMBtu PM limits, grain loading PM limits, and fuel type limits. For a variety of reasons, it is difficult to evaluate the PM BACT limits achieved by other combustion turbines, including:

- 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

[29] https://www.epa.gov/catc/clean-air-technology-center-products

[30] By "inlet particulate concentration" we mean the concentration of particulate matter in the exhaust gas that would enter an add-on particulate matter control device.

requirements.[31]

- 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.

Given these factors, it is not reasonable to assume that an individual existing lb/hr or lb/MMBtu BACT limit is necessarily achievable or feasible to meet on an ongoing basis for the CTs for the PEP.

Step 4 – Economic, Energy and Environmental Impacts

The Applicant has chosen the highest ranked control option, good combustion practices and use of clean fuels, and we are not aware of any significant or unusual environmental impacts associated with the chosen technology.

Step 5 – Select BACT

We have determined that BACT is clean fuel and good combustion practices. By "clean fuel" we mean California Public Utilities Commission (PUC)-quality natural gas. PUC-quality natural gas shall not exceed a sulfur content of 0.20 grains per 100 dry standard cubic feet on a 12-month rolling average and shall not exceed a sulfur content of 1.0 grains per 100 dry standard cubic feet, at any time.

Further, we are setting PM/PM_{10}/$PM_{2.5}$ emission limits of 11.8 lb/hr and 0.0048 lb/MMBtu for each of the CTs with compliance to be based on the average of three stack test runs. Compliance tests will be conducted annually using EPA Methods 5 and 202 for filterable and condensable PM, PM_{10}, and $PM_{2.5}$, respectively, collecting a minimum of 120 dry standard cubic feet per test run. 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. Appendix 2 contains an analysis of available PM emission data for reference.

Section 111 and 112 standards: There are no applicable PM limits under sections 111 or 112 of the Act for the CTs.

[31] Aside from the BACT determination, we believe PM emissions limits are warranted in the permit to ensure compliance with the NAAQS and PSD increments – a required element of our PSD permit approval.

Table 9 Summary of Recent PM BACT Limits for Similar Combined-Cycle, Natural gas-fired CTs

Facility	Location	PM Limit (PM Limit w/Duct Firing)	Type of PM - Filterable(F), Total(T)	Averaging Period	Control	Permit Issuance	Source
AES Huntington Beach Energy	California	--	--	--	Natural Gas	4/18/2017	Final Permit
AES Alamitos Energy	California	--	--	--	Natural Gas	4/18/2017	Final Permit
CPV Towantic, LLC	Connecticut	9.73 lb/hr (20.4 lb/hr)	$TPM_{2.5}$	--	--	11/30/2015	RBLC # CT-0157
Entergy Louisiana, LLC	Louisiana	0.0082 lb/MMBtu	FPM_{10}	3-hr average	GCP/Pipeline NG	8/31/2016	RBLC # LA-0313
Middlesex Energy Center, LLC	New Jersey	18.3 lb/hr	TPM_{10}	Stack testing	GCP/Pipeline NG	7/19/2016	RBLC # NJ-0085
Greensville Power Station	Virginia	0.0039 lb/MMBtu	TPM_{10}	3 stack tests	GCP/Pipeline NG	6/17/2016	RBLC # VA-0325
Johnsonville Cogeneration	Tennessee	0.0050 lb/MMBtu	TPM	--	GCP	4/19/2016	RBLC # TN-0162
Neches Station	Texas	19.35 lb/hr	TPM_{10}, $TPM_{2.5}$	--	GCP/Low Sulfur Fuel	3/24/2016	RBLC # TX-0788
Okeechobee Clean Energy Center	Florida	2 gr/100 scf	TPM, TPM_{10}, TPM2.5	--	Clean Fuel	3/9/2016	RBLC # FL-0356
Decordova Steam Electric Station	Texas	35.41 lb/hr	TPM, TPM_{10}, $TPM_{2.5}$	--	GCP/Low Sulfur Fuel	3/8/2016	RBLC # TX-0789
Mattawoman Energy Center	Maryland	17.9 lb/hr (27.7 lb/hr)	$TPM_{2.5}$	3 stack test runs	--	11/13/2015	RBLC # MD-0045
Lon C. Hill Power Station	Texas	16.0 lb/hr	TPM_{10}, $TPM_{2.5}$	--	GCP/Pipeline NG	10/2/2015	RBLC # TX-0767
Moundsville Combined Cycle Power Plant	West Virginia	8.9 lb/hr 0.0037 lb/MMBtu	$TPM_{2.5}$	--	GCP/NG/Inlet Air Filtration	11/21/2014	RBLC # WV-0025
Keys Energy Center	Maryland	11.0 lb/hr (15.0 lb/hr)	TPM_{10}	3 stack test runs	GCP/Pipeline NG	10/31/2014	RBLC # MD-0046
West Deptford Energy Station	New Jersey	10.0 lb/hr (21.55 lb/hr; 0.0069 lb/MMBtu)	TPM_{10}, $TPM_{2.5}$	3 stack test runs	Natural Gas Fuel	7/18/2014	RBLC # NJ-0082

Section 6.3.4: GHG Emissions for CTs

Step 1 – Identify All Control Technologies

The inherently lower-emitting control options for GHG emissions include:

- *New thermally efficient combined cycle gas turbine design* – A combined-cycle gas turbine design recovers the waste heat from the gas turbine using a heat recovery steam generator (HRSG). The HRSG allows more energy to be produced using a downstream steam turbine without additional fuel use.
- *Hybrid battery design* - Hybrid battery storage designs that increase the efficiency of the gas turbine and/or reduce fuel use.

The add-on control options for GHG emissions include:

- *Carbon capture and sequestration (CCS)* – CCS is a technology that involves capture and storage of carbon dioxide (CO_2) emissions to prevent their release to the atmosphere. For a gas turbine, this includes removal of CO_2 emissions from the exhaust stream, transportation of the CO_2 to an injection site, and injection of the CO_2 into available sequestration sites. Potential CO_2 sequestration sites include geological formations (such as deep saline formations) and depleted oil and gas fields (for enhanced recovery).

Hybrid solar thermal design – In general, this technology could be considered a lower-emitting control option for GHGs.

As noted above, the PSD permit applicant for the Palmdale Hybrid Power Project (PHPP), the previously permitted project at the location where the PEP would be sited, proposed a hybrid solar thermal power plant design for the PHPP. Specifically, the PHPP design provided for 50 MW of solar thermal heat that would be integrated into the power produced by the combined cycle plant by sharing a steam turbine generator. As part of the City of Palmdale's design for the PHPP, the solar component was included by the EPA as part of the BACT determination for the PHPP.[32] As noted previously, the PHPP was never constructed, and the PSD permit for the PHPP expired.

In addition to the PHPP, we have identified a number of other natural gas combined-cycle turbine projects employing a solar thermal design. We are aware of two such projects in the U.S. – Victorville 2 in California, and the Martin Next Generation Solar Energy Center (Martin facility)[33] in Florida. The Martin facility, which is operational, is described in more detail in the discussion below. However, the Victorville 2 project was never built and the associated PSD permit for the project expired.[34] We are also aware of five similar international projects, located in Italy, Egypt, Iran, Algeria, and Morocco.[35] All of the hybrid solar projects in operation started construction between 2007 and 2009, and, at this time, we are not aware of any other projects proposing to utilize a similar design.

---

[32] The only project that we are aware of that required a hybrid solar thermal design as BACT was the PHPP. See comment and response 40 in the Responses to Public Comments on the Proposed Prevention of Significant Deterioration Permit for the Palmdale Hybrid Power Plant, pages 39-40. https://www.regulations.gov/document?D=EPA-R09-OAR-2011-0560-0058. https://www.regulations.gov/document?D=EPA-R09-OAR-2011-0560-0058. We note that in the BACT analysis for the PHPP, we did not consider the solar thermal portion of the power plant in setting the GHG BACT numerical emissions limit.

[33] http://www.renewableenergyworld.com/articles/2009/03/75-mw-csp-plant-to-be-built-in-florida.html

[34] At the time the Victorville 2 project was issued a PSD permit in 2010, a GHG BACT analysis was not required under the PSD program. Such analyses were not required until January 2, 2011. 40 CFR 52.21(b)(49)(iv). Information regarding the Victorville 2 permit is available here: https://www.epa.gov/caa-permitting/prevention-significant-deterioration-psd-permits-issued-region-9#issued.

[35] https://en.wikipedia.org/wiki/Combined_cycle#Integrated_solar_combined_cycle_.28ISCC.29

For our review of the PEP, we are not including hybrid solar thermal design as an available technology because we have determined that it would redefine the fundamental business purpose of the Project, as explained below. A permitting authority does not have to consider in its BACT analysis a control option that would fundamentally redefine the source.

In our examination of whether a control option would redefine the fundamental business purpose of the source, the EPA employs a two-step process. First, "the permit applicant initiates the process and . . . defines the proposed facility's end, object, aim or purpose – that is the facility's basic design." *Helping Hand Tools v. U.S. EPA*, 848 F.3d 1185, 1194 (9th Cir. 2016) (*quoting In re Prairie State Generating Co.*, 13 E.A.D. 1, 22 (E.A.B. 2006), *aff'd sub nom Sierra Club v. U.S. EPA*, 499 F.3d 653 (7th Cir. 2007)). We must ensure that the proposed facility design was derived for reasons independent of air quality. *See id.* at 1193; *accord In re Prairie State Generating Company*, 13 E.A.D. 1, 25–26 (E.A.B. 2006). Next, the EPA considers the facility's basic design and "takes a 'hard look' . . . to determine which design elements are inherent to the applicant's purpose and which elements can be changed to reduce pollutant emissions without disrupting the applicant's basic business purpose." *Helping Hand Tools v. U.S. EPA*, 848 F.3d at 1194.

PEP Basic Design Elements

With respect to the source under consideration in this case, 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.[36, 37] 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.

In conducting this evaluation, we have also determined that the proposed facility design for the PEP was derived for reasons independent of air quality. The fundamental business purpose of the PEP, to operate as an intermediate load-following facility, is completely consistent with the current designs of other combined-cycle natural gas-fired facilities recently permitted in California. The two mostly recently permitted projects – the AES Huntington Beach Energy Project and the AES Alamitos Energy Center – both have combined-cycle CTs designed as intermediate, load-following units.[38,39] Currently, renewable energy makes up about 30% of installed capacity

[36] See page 2-7 of the October 2015 Application, "…which would allow for a flexible response to changing power market conditions, which is the fundamental business purpose of the proposed facility."

[37] See page 10 of the May 2017 response letter, '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."

[38] See Huntington Beach FDOC at 10, 265, and footnote 1. AES expects the Huntington Beach plant, which includes peaking units and combined-cycle units, to be dispatched at peaking and intermediate loads on a regular basis, and the expected actual capacity factor is anticipated to be between 45-75%. The combined-cycle units are expected to operate 6,100 hours/yr. An identified benefit of the Huntington Beach project is that it provides fast starts and ramp-up/ramp-down capability that allow the turbines to shut down when not needed, in contrast to the existing steam utility boilers which need to be maintained on stand-by load.

[39] See Alamitos FDOC at 268. "A primary objective is to provide fast starting and stopping, flexible, controllable generation with the ability to ramp up and down through a wide range of electrical output to allow the integration of renewable

within the electrical power grid system operated by the California Independent System Operator (CAISO), which the PEP would serve. As California continues its plans to reduce statewide GHG emissions and increase renewable generation, the electric grid served by the CAISO will need more and more flexibility to adjust to rapid changes in renewable energy availability. Going forward, it is expected that there will be less need for fossil-fueled baseload power plants in California, creating a demand for natural gas-fired units to be able to provide flexible capacity.[40,41] 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.

Compatibility with Hybrid Solar Thermal Design

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.

As explained in Application for the PEP:

> *Since the original PHPP was licensed by the California Energy Commission, the California energy market has drastically changed. In recent years, the State enacted mandates that 50% of the energy needs by 2030 be generated by renewable energy resources, the cost of photovoltaic solar has dropped significantly and the Federal Incentives have been extended for solar projects coming on line prior to the end of 2023. As a result, the operating profiles of natural gas fired combined cycle projects in California have changed with the majority of base loaded plants now operating with daily startups and shutdowns. As more photovoltaic (PV) solar energy is brought on line in the coming years, the need for natural gas fired resources during daytime hours will be even further reduced. Thus, the use of a [concentrated solar power (CSP)] solar trough design to supplement/replace the duct firing needs in the HRSG during daytime hours is not practical given the current and future energy markets.*[42]

---

energy into the electrical grid to satisfy California's Renewable Portfolio Standard."

[40] The End of the Era of Baseload Power Plants, *Green Tech Media*, June 29, 2016. https://www.greentechmedia.com/articles/read/the-end-of-the-era-of-baseload-power-plants

[41] As Solar Pushes Electricity Prices Negative, 3 Solutions for California's Power Grid*, Inside Climate News*, June 14, 2017. https://insideclimatenews.org/news/14062017/solar-renewable-energy-negative-prices-california-power-grid-solutions.

[42] See July 27, 2017 letter from Gregory Darvin, Atmospheric Dynamics to Lisa Beckham, EPA Region 9 at 2.

The Application further provides that:

> *Integration of a CSP steam producing system with a natural gas fired combined cycle project will not meet the project objectives since in all likelihood, most of the gas fired resources serving California's load will not be producing energy at their full capability during daytime "solar" hours.*[43]

The only example in the U.S. of an operating hybrid solar thermal design is the Martin facility, which is a 1,150 MW combined-cycle power plant located in Florida. Serving as an intermediate load-following unit does not appear to be part of the Martin facility's fundamental design purpose.[44] The CTs at the Martin facility were permitted in 2003, well before fast-start combined-cycle plants were available. For example, a cold startup period for the CTs at the Martin facility is limited to between 4 and 6 hours, whereas the PEP's cold startup will be limited to 39 minutes. These operating parameters indicate that the Martin facility was likely designed as a baseload facility, like most other combined cycle plants at that time, and cannot respond quickly to changing market conditions, such as ramping in the morning and evening, in contrast to the PEP.

Requiring the PEP to add a solar thermal component to the project design, to obtain reductions in fuel use or increase the efficiency of the power plant, would require the PEP to operate in a way that is outside its fundamental business purpose, by operating as a baseload facility.[45]

In sum, we are not considering a hybrid solar thermal design as part of the BACT analysis because it would fundamentally redefine the business purpose of the PEP.

Step 2 – Eliminate Technically Infeasible Control Options

Carbon Capture and Sequestration – CCS involves three main components: capturing the CO_2 emissions from the exhaust stream, transporting the captured CO_2 to the sequestration site, and injection of the CO_2 into a geologic reservoir for long-term sequestration. All three of these aspects are relevant when determining whether CCS is technically feasible for a particular project.

For this analysis, we are relying upon the EPA's Literature Survey of Carbon Capture Technology (Literature Survey) used to support the EPA's Carbon Pollution Standards for Electric Generating Units (EGUs).[46] This document provides a detailed overview of CCS technology for fossil-fuel fired EGUs and a list of sources utilizing CCS technology. Table 2 of the Literature Survey identifies a CCS project in Bellingham, Massachusetts that captured a 40 MW slip stream from a 320 MW natural gas-fired combined cycle power plant. The project operated from 1991 to 2005 and captured approximately 100,000 metric tons of CO_2 per year.[47] The captured CO_2 was used as food-grade CO_2 by the beverage industry. As such, CCS is technically feasible for the type of equipment associated with the PEP. However, as detailed below, when considering source-specific factors,[48] there are technical difficulties that would preclude the successful use of CCS for the PEP.

---

[43] *Id*. at 3.
[44] See page 4 of Final BACT Determinations, FPL Martin Power Plant, Unit 8 Combined Cycle Project, Florida Department of Environmental Protection, April 10, 2003.
[45] While the Applicant acknowledges that part of its business design may require, at times, that the PEP respond to market conditions in a baseload capacity, this operational mode is not a guaranteed mode of operation.
[46] See Technical Support Document for Docket EPA-HQ-OAR-2013-0495, Literature Survey of Carbon Capture Technology, July 10, 2015.
[47] Ibid., at 38, 39.
[48] See discussion on technical infeasibility determinations in the EPA's NSR Workshop Manual, October 1990 DRAFT at B.7.

At this time, there is not enough information to show that a load-following natural gas combined-cycle power plant (NGCC), like the PEP, could successfully employ CCS. In responding to comments on the use of CCS on NGCC EGUs for the Carbon Pollution Standards for EGUs, the EPA specifically raised concerns about being able to use CCS on units that do not operate at steady state conditions (as baseload units):

> *"While the commenters make a strong case that the existing and planned NGCC-with-CCS projects demonstrate the feasibility of CCS for NGCC units operating at steady state conditions, many NGCC units do not operate this way. For example, the Bellingham, MA and Sumitomo NGCC units cited by the commenters operated at steady load conditions with a limited number of starts and stops, similar to the operation of coal-fired boilers. In contrast, our base load natural gas-fired combustion turbine subcategory includes not only true base load units, but also some intermediate units that cycle more frequently, including fast-start NGCC units that sell more than 50 percent of their potential output to the grid. Fast-start NGCC units are designed to be able to start and stop multiple times in a single day and can ramp to full load in less than an hour. In contrast, coal-fired EGUs take multiple hours to start and ramp relatively slowly. These differences are important because we are not aware of any pilot-scale CCS projects that have demonstrated how fast and frequent starts, stops, and cycling will impact the efficiency and reliability of CCS. Furthermore, for those periods in which a NGCC unit is operating infrequently, the CCS system might not have sufficient time to startup. During these periods, no CO2 control would occur. Thus, if the NGCC unit is intended to operate for relatively short intervals for at least a portion of the year, the owner or operator could have to oversize the CCS to increase control during periods of steady-state operation to make up for those periods when no control is achieved by the CCS, leading to increased costs and energy penalties. While we are optimistic that these hurdles are surmountable, it is simply premature at this point to make a finding that CCS is technically feasible for the universe of combustion turbines that are covered by this rule."* (footnotes excluded) 80 Fed. Reg. 64510, 64614; Oct. 23, 2015.

As previously described, this Project is designed as an intermediate load-following NGCC facility that is intended to ramp up and down multiple times in a day with fast startup times. While the obstacles to using CCS on load-following combined-cycle CTs may one day be addressed, we have not been able to find an example of such a unit using or planning to use CCS. CCS has not been adequately demonstrated for the type of project under consideration in this action and thus we do not consider it to be a technically feasible control option for the PEP. We are eliminating it from further BACT review for the Project due to technical infeasibility.

Hybrid battery storage – By hybrid battery storage, we mean battery storage options that will directly reduce emissions from fossil fueled CTs or increase the efficiency of the CTs.[49] Appendix 3 provides a list of the literature reviewed as part of this analysis to determine the current state of hybrid battery storage technology.

We are aware of one project with two small gas-fired simple-cycle CTs that is in the process of utilizing battery storage to increase the efficiency of the CTs. For each CT, the project by GE uses the 50 MW LM6000 Hybrid EGT which:

---

[49] Our analysis does not include battery storage projects that provide electricity to the grid independently (as their own power source), even if such projects are located adjacent to gas-fired CTs. Such independent power projects are outside the scope of this analysis as they would redefine the fundamental business purpose and design of the project, in that they would require the use of battery storage to generate power when the Project is clearly designed to generate power from natural gas-fired combined cycle units.

"integrates a 10 MW battery energy storage system from Current and an existing GE LM6000 aeroderivative gas turbine with control system upgrades provided by GE's Power Services. The system will allow the turbine to operate in standby mode without using fuel and enable immediate response to changing energy dispatch needs. By eliminating the need to constantly run the turbines at minimum loads to maintain spinning reserves, the LM6000 Hybrid EGT will save fuel, reduce maintenance costs and cut down on greenhouse gas (GHG) emissions.[50]

This is a brand-new technology that is in the early stages of development, with this first application having coming online in April 2017. GE and Siemens both claim to be able to apply this type of hybrid battery design to a wide range of turbines.[51] However, to date, we are only aware of this initial project involving small (50 MW) simple cycle gas-fired turbines, and neither GE or Siemens has identified specific emission reductions that can be achieved through the use of this technology. This is a very new and rapidly growing technology that may have enormous potential to change how peaking and load following units operate to reduce fuel use and increase efficiency. But thus far there has only been the example of the one project described above using the technology for about 4 months, and the technology has not been demonstrated in practice on any combined-cycle facilities. The Applicant also provided several concerns related to the use of a hybrid battery design, including: (1) the Applicant is not aware of any plans to integrate this technology on large frame gas turbines or combined-cycle projects, (2) there is no industry feedback or long-term experience achieved in practice regarding long term operation and maintenance of this technology, and (3) vendors have indicated it is not their intent to utilize this technology on large combined-cycle projects.[52] Given the available information, we are determining that a hybrid battery design is not technically feasible for the Project.

Step 3 – Rank Remaining Control Technologies

The remaining control option for GHG emissions from the PEP's CTs is new thermally efficient combined cycle gas turbine design.

GHG BACT limits for CTs

A summary of some recent BACT emission limits for similar combined-cycle, natural-gas fired CTs is provided in Table 11. The BACT limits that have been established in recent years vary considerably in the pollutant regulated (CO_2 or CO_2e) and the conditions that have been specified for evaluating the limit (see the Notes column). Overall, the limits vary from 792 to 1,000 lb/MWh and from 7,220 to 7,605 Btu/kWh. All recent BACT determinations rely on a thermally efficient combined cycle turbine.

Similar to our analysis for PM emissions, it is difficult to evaluate BACT limits for GHGs achieved by other combustion turbines using a thermally efficient unit as potentially appropriate for the PEP, because there are no reasonable methods, beyond good combustion practices, that the permittee could employ to adjust its operations to comply with the emissions limits that will be selected. Further, without add-on controls, GHG emissions will be highly dependent on the size and model of the combustion turbine. In light of this, we need to be particularly careful to ensure that the BACT limit that is selected is technically feasible to meet on an ongoing basis for the life of the facility.

---

[50] http://hub.currentbyge.com/h/i/292529148-ge-unveils-world-s-first-battery-storage-gas-turbine-hybrid-with-southern-california-edison

[51] See GE information here: http://www.gereports.com/taking-charge-ge-bundles-batteries-largest-steam-gas-turbines/, and Siemens information here: http://w3.siemens.com/powerdistribution/global/SiteCollectionDocuments/en/mv/power-supply-solutions/siestorage/SIESTART_SIESTORAGE.pdf.

[52] See July 27, 2017 letter from Gregory Darvin, Atmospheric Dynamics to Lisa Beckham, EPA Region 9 at 4 and 5.

We are not able to determine that an individual BACT limit for a different facility is achievable or comparable for the combustion turbines for the PEP. Therefore, we are not evaluating a specific emission rate in ranking the control options by effectiveness. We view any large frame turbine emitting less than 1,000 lb CO_2/MWh(net) as falling into the single category of highly efficient CTs.[53]

The available control technology is listed along with its control effectiveness in Table 10, as determined by reviewing other BACT determinations and the limits proposed by the Applicant.

Table 10 GHG Technologies Ranked According to Control Effectiveness

GHG Control Technology	CO_2 Emissions Rate (lb/MWh)
Thermally efficient combined-cycle turbine design	<1,000 lb/MWh

Step 4 – Economic, Energy, and Environmental Impacts

The Applicant has chosen the remaining control technology – thermally efficient combined cycle turbine design. We are not aware of any significant or unusual adverse environmental, economic or energy impacts associated with the chosen technology.

Step 5 – Select BACT

Based on a review of the available control technologies for GHG emissions from natural gas-fired combustion turbines, we have concluded that BACT for this source is thermally efficient combined-cycle CT design. We are setting a BACT limit of 928 lb CO_2/MWh_{net} based on a 12-month rolling average, including periods of startup and shutdown. As discussed further below, the emission limit is are based on the worst-case operating scenario where the PEP would occasionally operate in a peaking mode. When operating at full plant load, the PEP CTs will likely perform at a much higher thermal efficiency and a much lower GHG emission rate. We note that this proposed limit is consistent with, and actually lower than, the BACT emission limits for the AES Huntington Beach Energy Center and AES Alamitos Energy Center, the two recently permitted similar intermittent load-following projects.

<u>Basis for lb/MWh GHG Limit</u>

The PEP will be a load-following power plant and will need the flexibility to operate under various conditions, as determined by the demands of the electric grid. The GHG BACT limit must take these varying operating scenarios into account and set a limit that is achievable under all operating conditions. The Applicant provided performance data for the Siemens SGT6-5000F CTs under various operating scenarios,[54] and assessed a combination of full plant loads, reduced plant loads, and rapid plant cycling where the steam turbine may not be utilized. We agree with the Applicant's approach, as it is stated in the application that the proposed facility is intended to be able to provide flexible response to changing power market conditions. As such, it represents a fundamental business purpose of the Project.[55] The performance data for these three scenarios is reproduced in Appendix 4 for reference. In addition to performance data from the manufacturer, the Applicant also considered anticipated degradation of the equipment over time. The Applicant assumed a rate of 6% degradation based

[53] See the EAB's March 14, 2014 decision for the La Paloma Energy Center, LLC (PSD Appeal No. 13-10) upholding EPA Region 6's decision to set varying CO_2 emission limits for 3 different turbine models, as each was determined to be comparably efficient on a performance basis.
[54] See information from Siemens provided in the October 2015 Application, Appendix A, Attachment A-1.
[55] See pages 2-1 and 2-7 in the October 2015 Application and page 10 of the May 2017 Response Letter.

upon a 48,000-hour maintenance interval recommended by the manufacturer. This degradation rate is consistent with the rate used previously by the EPA for the Pio Pico Energy Center and is less than the rate for the recently permitted AES Huntington Beach Energy Project and AES Alamitos Energy Center, which used 8%. Based on our detailed review of the available data, the worst-case operating scenario is the rapid plant cycling scenario where occasionally the steam turbine may not be utilized. This resulted in an average CO_2 emission rate of 928 lb/MWh(net), including 6% degradation over 30 years.

Use of CO_2 instead of CO_2e

For this limit, the pollutant that is subject to regulation under the CAA for PSD permitting purposes is a group of six gases: carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. As a general matter, it may thus be appropriate to establish BACT limits on a CO_2e basis. However, for consistency with the applicable NSPS GHG standards in 40 CFR part 60, subpart TTTT and the continuous monitoring requirements therein, we are establishing the BACT on a CO_2 basis. CO_2 emissions are expected to account for over 99.5% of CO_2e emissions from natural gas-fired power plants.

Section 111 and 112 standards: These units are subject to the Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units at 40 CFR part 60, subpart TTTT. These units are subject to the limits in Table 2 to subpart TTTT and must meet a limit of either (1) 1,000 lb CO_2/MWh_{gross} or 1,030 lb CO_2/MW_{net} based on a 12-operating month rolling average or (2) 120 lb CO_2/MMBtu based on purchase records of permitted fuels (natural gas). Our proposed lb/MWh_{net} limit is more stringent than the comparable limit in subpart TTTT Table 2, and the only permitted fuel is natural gas, ensuring that the subpart TTTT Table 2 limit of 120 lb CO_2/MMBtu will also be met. There are no applicable GHG section 112 standards for the CTs.

Table 11 Summary of Recent GHG BACT Limits for Similar Combined-Cycle, Natural gas-fired CTs

Facility	Location	GHG Limit lb/MWh	GHG Limit Btu/kWh	Notes	Permit Issuance	Source
AES Huntington Beach	California	967.6 lb CO2/MWh (calendar annual average)	--	Net output	4/18/2017	Final Permit
AES Alamitos	California	937.88 lb CO2/MWh (calendar annual average)	--	Gross output, including degradation	4/18/2017	Final Permit
Decordova Station	Texas	966 lbCO2e/MWh	--		10/4/2016	RBLC # TX-0810
St. Charles Power Station	Louisiana	1000 lb CO2e/MWh	--		8/31/2016	RBLC # LA-0313
Middlesex Energy Center	New Jersey	888 lb CO2e/MWh	--	Gross w/duct firing	7/19/2016	RBLC # NJ-0085
Eagle Mountain Steam Electric	Texas	917 lb CO2e/MWh	--		7/19/2016	RBLC # TX-0805
Greensville Power Station	Virginia	890 lb CO2e/MWh (after 30 yr operation)	--	Net output	6/17/2016	RBLC # VA-0325
Apex Power – Neches Station	Texas	925 lb CO2e/MWh	--	--	3/24/2016	RBLC # TX-0788
Rockwood Energy Center	Texas	865-965 lb CO2e/MWh	--	Multiple models permitted	3/18/2016	RBLC # TX-0791
Okeechobee Clean Energy Center	Florida	850 lb CO2e/MWh (12-month rolling)	--	-Excludes startup and shutdown	3/9/2016	RBLC # FL-0356
Trinidad Generating Station	Texas	937 lb CO2e/MWh	--	--	3/1/2016	RBLC # TX-0787
CPV Towantic, LLC	Connecticut	809 lb CO_2/MWh initial demo	7,220 Btu/kWh 12-mo rolling	HHV, w/o duct firing, net plant	11/30/2015	RBLC # CT-0157
Mattawoman Energy Center	Maryland	865 lb CO_2e/MWh 12-mo rolling	--	w/ and w/o duct firing	11/13/2015	RBLC # MD-0045
FGE Eagle Pines	Texas	886 lb CO_2e/MWh 816 lb CO_2e/MWh	--	w/o duct firing w/ duct firing	11/4/2015	RBLC # TX-0773
SR Bertron Electric Generating Station	Texas	825 lb CO_2/MWh	--	citing 40 CFR Part 60, Subpart TTTT	9/15/2015	RBLC # TX-0761
Cedar Bayou Electric Generating Station	Texas	825 lb CO_2/MWh	--	citing 40 CFR Part 60, Subpart TTTT	9/15/2015	RBLC # TX-0762
Colorado Bend Energy Center	Texas	879 lb CO_2/MWh	7,395 Btu/kWh	HHV, gross MW, w/o SU/SD	4/1/2015	RBLC # TX-0730
Moundsville Combined Cycle Power Plant	West Virginia	792 lb CO_2e/MWh	--	w/ and w/o duct firing	11/21/2014	RBLC # WV-0025

Facility	Location	GHG Limit lb/MWh	GHG Limit Btu/kWh	Notes	Permit Issuance	Source
Keyes Energy Center	Maryland	869 lb CO2/MWh (12-month rolling)	--	Gross w/ and w/o duct firing	10/31/2014	RBLC # MD-0046
Lon C. Hill Power Station	Texas	920 lb CO2/MWh (12-month rolling)	--	--	10/28/2014	RBLC # TX-1380
CPV St. Charles	Maryland	--	7,605 Btu/kWh	@ ISO conditions	4/23/ 2014	RBLC # MD-0041
Marshalltown Generating Station	Iowa	851 lb CO_2/MWh 12-mo rolling	--	gross	4/14/2014	RBLC # IA-0107
Sewaren Generating Station	New Jersey	925 lb CO_2/MWh 12-mo rolling	--	gross output for 2 turbines and duct burners w/ associated steam turbine	3/7/2014	RBLC # NJ-0081
Brunswick County Power Station	Virginia	--	7,500 Btu/kWh		3/12/ 2013	RBLC # VA-0321

Section 6.3.5: BACT for NO_X and CO During Startup and Shutdown for CTs

This section evaluates BACT for NO_X and CO emissions from the CTs during startup and shutdown. It is not technically feasible to use SCR and an oxidation catalyst to control NO_X and CO emissions, respectively, from the CTs when the equipment is outside of the manufacturer's recommended operating temperature ranges. For SCR and an oxidation catalyst, this occurs during turbine startup or shutdown. Therefore, BACT is achieved for NO_X and CO during these periods by minimizing the duration of startup and shutdown.[56]

Historically, combined-cycle gas turbine power plants were limited in how fast the steam turbine could be started because components of the steam cycle cannot withstand rapid temperature changes. The "rapid start" design of the PEP and other modern combined-cycle plants reduces the time required for the steam cycle to start up. The 110 MMBtu/hr auxiliary boiler is primarily designed to produce steam to shorten the duration of startups, thus minimizing emissions during CT startup.

Our evaluation of startup and shutdown emission limits found limited information regarding limits during startup and shutdown. Some facilities that have BACT limits with longer averaging periods (such as 24-hours) may not need to set separate startup and shutdown emission limits. Because the PEP has short 1-hour averaging periods, it is appropriate to set limits on a mass basis and limit the duration of startup and shutdown events.

As presented in Table 12, we have determined that the emission rate limits and fast startup and shutdown times for the CTs provided by the Applicant represent BACT for NO_X and CO during startup and shutdown. These limits are based on manufacturer's data, including a margin of error.[57]

Table 12 Summary of NO_X and CO BACT Limits During Startup and Shutdown

Event	NO_X	CO	Duration
Cold Startup	51.48 lb/event	415.8 lb/event	39 minutes
Warm Startup	46.8 lb/event	378 lb/event	35 minutes
Hot Startup	43.2 lb/event	304.8 lb/event	30 minutes
Shutdown	33.0 lb/event	75.9 lb/event	25 minutes

Cold, warm, and hot startup definition – A cold startup is a startup that occurs more than 48 hours since the CT was shutdown. A hot startup is a startup that occurs less than 9 hours since the CT was shutdown. A warm startup is a startup that occurs between 9 and 48 hours since the CT was shutdown.

Section 111 and 112 standards: These units are subject to NO_X and GHG limits in Standards of Performance for Stationary Combustion Turbines at 40 CFR part 60, subpart KKKK and Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units at 40 CFR part 60, subpart TTTT, respectively. However, neither regulation has limits specific to startup and shutdown periods, as they do not contain short-term averaging periods for the otherwise applicable limits. There are not section 112 standards applicable to NO_X and GHGs for CTs.

[56] It is not necessary to set separate startup and shutdown limits for PM, PM_{10}, and $PM_{2.5}$ or for GHGs. We expect the PM, PM_{10}, and $PM_{2.5}$ emission limits that we have selected as BACT to be met during startup and shutdown, as less PM emissions are expected at lower loads. For GHGs, the applicable BACT limit is averaged over 12 months, and applies at all times, including startup and shutdown.

[57] See Table 5-6, Startup and Shutdown Emissions Per Turbine in the October 2015 Application.

Section 6.4: BACT for Auxiliary Boiler

The Project includes a 110 MMBtu/hr boiler that will be used to start up the CTs. The unit will be fired with natural gas and fuel use will be limited to an amount equivalent to 4,884 hours of operation per year. The boiler is subject to BACT for NO_X, CO, PM, PM_{10}, $PM_{2.5}$, and GHGs. A top-down BACT analysis for each pollutant has been performed and is summarized below.

Section 6.4.1: Nitrogen Oxide Emissions for Auxiliary Boiler

Step 1 – Identify All Control Options

The following inherently lower-emitting control options for NO_X emissions include:

- Low NO_X burner design Ultra-low NO_X burner design (ULNB)

The available add-on NO_X control technologies include:

- Selective Catalytic Reduction (SCR) system
- Selective non-catalytic reduction (SNCR)

Step 2 – Eliminate Technically Infeasible Control Options

All of the available control options are considered technically feasible except SNCR. Suitable applications for SNCR are units with furnace exit temperatures of 1550°F to 1950°F, residence times greater than one second, and high levels of uncontrolled NO_X.[58] SNCR is unsuitable for this application because the auxiliary boiler for this project does not have high levels of uncontrolled NO_X and it has combustion exits temperatures around 300°F. Further, we are not aware of any applications for which SNCR has been applied to similar natural gas-fired boilers in this size range. Based on these factors, we are eliminating SNCR as technically infeasible.

Step 3 – Rank Remaining Control Technologies

Table 13 ranks by effectiveness the remaining control technologies for the auxiliary boiler, as determined by reviewing other BACT determinations and the limits proposed by the Applicant. Table 15 below (at the end of Section 6.4.4) summarizes our review of recent BACT determinations for similar equipment. We found one BACT determination that imposed a limit of 5 ppm NO_X using ULNB – the Freeport LNG Pretreatment Facility in Texas. However, this project is currently under construction, and thus this limit has not yet been demonstrated in practice.[59] Since the Freeport LNG project was permitted there have not been any other determinations of 5 ppm NO_X for similar boilers using ULNB. Based on this, we are only considering ULNB at 9 ppm NO_X.

Table 13 NO_X Control Technologies Ranked by Control Effectiveness

NO_X Control Technologies	Emission Rate (ppmvd @ 3% O_2)
SCR	5
Ultra-Low NO_X burners	9
Low NO_X burners	30

Step 4 – Economic, Energy, and Environmental Impacts

---

[58] See EPA's Air Pollution Control Technology Fact Sheet for SNCR at page 3 – "Certain application[s] are more suitable for SNCR due to combustion unit design. Units with furnace exit temperatures of 1550°F to 1950°F, residence times greater than one second, and high levels of uncontrolled NO_X are good candidates."

[59] See memo to file from Lisa Beckham, EPA Region 9 Regarding the Freeport LNG Pretreatment Facility in Texas.

The Applicant submitted a cost analysis demonstrating that SCR is not cost-effective for the PEP's auxiliary boiler. The Applicant estimated the cost effectiveness at $58,100/ton of NO_X removed. However, in conducting this analysis, the Applicant looked at the cost of reducing NO_X from the incremental cost of going from 9 ppm using ultra-low NO_X burners instead of the total cost effectiveness from the base case. We agree that when calculating the cost effectiveness of adding post process emissions controls to certain inherently lower polluting processes, in this case ULNB, baseline emissions may be assumed to be the emissions from the lower polluting process itself.[60]

The Applicant's SCR cost analysis for the boiler also included two assumptions that we modified for purposes of our own cost analysis. First, we determined that it would be appropriate to assume a longer catalyst life than that assumed by the Applicant in its analysis, i.e., 5 years instead of 3.[61] Second, we assumed that SCR could achieve 5ppm NO_X, whereas the assumed that it could achieve 1.8 ppm NO_X. We are not aware of any BACT determinations less than 5 ppm when using SCR on this type of equipment. Based on these modifications, we adjusted the Applicant's analysis, reviewed EPA's updated Cost Control Manual data sheet for SCR, and arrived at an average cost effectiveness of $88,000/ton. Both the Applicant's and our cost analysis indicated that the use of SCR for the auxiliary boiler would be considered outside the range of what is typically considered cost-effective.

The Applicant has chosen the highest remaining ranked control option for NO_X from the auxiliary boiler – ultra-low NO_X burners, and we are not aware of any significant or unusual adverse environmental impacts associated with the chosen technology.

Step 5 – Select BACT

Based on the review of the available control technologies, we have concluded BACT is the limited hours of operation, ultra-low NO_X burners and an emission rate of 9.0 ppm at 3% O_2 based on a 3-hr average.

Section 111 and 112 standards: The auxiliary boiler is subject to the requirements of 40 CFR part 60, subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units. Specifically, this unit must comply with the NO_X emission limit in 40 CFR 60.44b depending on the heat release rate of the unit – 0.10 lb/MMBtu for a low heat release rate or 0.20 lb/MMBtu for a high heat release rate. The proposed BACT limit of 9 ppm is approximately equal to 0.011 lb/MMBtu, and well below the NO_X limits in Subpart Db. Our proposed BACT limit is at least as stringent as the applicable standards under sections 111 of the Act. There are no applicable section 112 standards to this equipment.

Section 6.4.2: Carbon Monoxide Emissions for Auxiliary Boiler

Step 1 – Identify All Control Technologies

The following inherently lower-emitting control options for CO emissions from this emission unit include:

- Good combustion practices

The available add-on CO control technologies for this emission unit include:

- Oxidation catalyst

Step 2 – Eliminate Technically Infeasible Control Options

[60] See EPA's Draft NSR Workshop Manual at B.37 (October 1990).

[61] The EPA's updated Cost Control Manual assumes a catalyst life of 24,000 hours. The auxiliary boiler is expected to operate up to 4884 hours per year. 24,000 divided by 4,884 hours is 4.9 years between catalyst replacements.

An oxidation catalyst is being eliminated in this step because it is not technically feasible. Typically, the lowest operation range for oxidation catalyst is around 400-500°F (200-300°C)[62], and the auxiliary boiler exhaust for this Project will be at approximately 300°F. While there may be developing technologies for low temperature oxidation catalysts[63], we are not aware of any such available application for natural gas boilers of this type.

Step 3 – Rank Remaining Control Technologies

Table 14 lists the remaining control technologies and shows their effectiveness –only good combustion practices and limited use remain – as determined by reviewing other BACT determinations and the limits proposed by the Applicant. A review of recent BACT determinations is in Table 15. We found one determination that required 25 ppm CO for a similar boiler using good combustion practices – the Freeport LNG Pretreatment Facility in Texas. This project is currently under construction, and therefore this limit has not yet been demonstrated in practice. We note that since the Freeport LNG project was permitted, there have been no further CO BACT determinations at 25 ppm using good combustion practices. Based on this, we are only considering ULNB at 50 ppm CO.

Table 14 CO Control Technologies Ranked by Control Effectiveness

CO Control Technologies	Emission Rate (ppmvd @ 3% O_2)
Good combustion practices and limited use	50

Step 4 – Economic, Energy and Environmental Impacts

The Applicant has chosen the highest ranked control option for the boiler, and we are not aware of any significant or unusual adverse environmental impacts associated with the chosen technology.

Step 5 – Select BACT

Based on the review of the available control technologies, we have concluded that BACT is the limited hours of operation, good combustion practices and an emission rate of 50.0 ppm at 3% O_2 based on a 3-hr average.

Section 111 and 112 standards: The auxiliary boiler is subject to the requirements of 40 CFR part 60, subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units. However, there are no CO limits in Subpart Db. There are no applicable section 112 standards to this equipment.

Section 6.4.3: PM, PM_{10} and $PM_{2.5}$ Emissions for Auxiliary Boiler

All particulate emissions from the auxiliary boiler and process heater are expected to be $PM_{2.5}$. As a result, the BACT analyses for PM, PM_{10} and $PM_{2.5}$ have been combined. Additionally, the analysis evaluates total particulate matter – filterable and condensable.

Step 1 – Identify All Control Technologies

The following inherently lower-emitting control options for PM, PM_{10}, and $PM_{2.5}$ emissions include:

- Low particulate fuels, low sulfur fuels, and/or pipeline-quality natural gas (also referred to as "clean fuel")
- Good combustion practices (including air inlet filter)
- Limited use (limits on the hours of operation)

The available add-on PM, PM_{10}, $PM_{2.5}$ control technologies include:

- Cyclones (including multiclones)

[62] https://www.nettinc.com/information/emissions-faq/how-does-an-oxidation-catalyst-work
[63] https://technology.nasa.gov/patent/LAR-TOPS-124

- Wet scrubber
- Dry electrostatic precipitator (ESP)
- Wet ESP
- Baghouse/fabric filter.

Step 2 – Eliminate Technically Infeasible Control Options

All of the inherently lower-emitting control options identified in Step 1 are technically feasible. All of the identified add-on control technologies are considered infeasible because of the high exhaust flow rates and low particulate matter loading associated with natural gas-fired boiler exhaust. See our detailed discussion related to PM BACT for the CTs in Section 6.3.3: PM, PM_{10} and $PM_{2.5}$ Emissions for CTs. Our analysis of the feasibility of add-on PM controls in that section applies equally to the auxiliary boiler.

Step 3 – Rank Remaining Control Technologies

The only remaining control technology is the use of clean fuel, good combustion practices, and limited hours of operation. A review of recent BACT determinations for similar boilers is summarized in Table 15.

Step 4 – Economic, Energy and Environmental Impacts

The Applicant has chosen the highest ranked control option for the boiler, and we are not aware of any significant or unusual adverse environmental impacts associated with the chosen technology.

Step 5 – Select BACT

Based on the review of the available control technologies, we have concluded BACT is the limited hours of operation, good combustion practices, clean fuel, and an emission rate of 0.007 lb/MMBtu, based on annual PM stack testing. As seen in Table 15, this limit is consistent with other recent BACT determinations for similar units. By "clean fuel" we mean California PUC-quality natural gas. PUC-quality natural gas shall not exceed a sulfur content of 0.20 grains per 100 dry standard cubic feet on a 12-month rolling average and shall not exceed a sulfur content of 1.0 grains per 100 dry standard cubic feet at any time.

Section 111 and 112 standards: The auxiliary boiler is subject to the requirements of 40 CFR part 60, subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units. However, there are no PM limits in Subpart Db for natural gas boilers. Because the auxiliary boiler uses natural gas as fuel there are no applicable section 112 standards.

Section 6.4.4: GHG Emissions for Auxiliary Boiler

Step 1 – Identify All Control Technologies

The Applicant generally assumed that the auxiliary boiler would incorporate the newest designs that increase thermal efficiency, such as electronic ignition, new burner technologies, modern optimized instrumentation and controls, and a non-condensing economizer.

The inherently lower-emitting control options for GHG emissions include:

- *Conducting boiler tune-ups* – this would ensure that optimal thermal efficiency is maintained. Maintaining higher thermal efficiency reduces the amount of fuel combusted, which helps to minimize GHG emissions.

The add-on control options for GHG emissions include:

- *CCS* – CCS is a technology that involves capture and storage of CO_2 emissions to prevent their release to the atmosphere. For a boiler, this includes removal of CO_2 emissions from the exhaust stream, transportation of the

CO_2 to an injection site, and injection of the CO_2 into available sequestration sites. Potential CO_2 sequestration sites include geological formations (including oil and gas fields for enhanced recovery).

Step 2 – Eliminate Technically Infeasible Control Options

Please see our discussion above in Section 6.3.4: GHG Emissions for CTs related to CCS in the GHG BACT analysis for the CTs. While CCS is an available control option, it would not be technically feasible for the auxiliary boilers. The boiler unit is designed for intermittent operation, for which CCS technology has not yet been demonstrated in practice. Therefore, CCS is not technically feasible for the auxiliary boiler and will not be considered further in the BACT analysis.

Step 3 – Rank Remaining Control Technologies

After elimination of CCS as a potential control technology, the purchase of a thermally efficient unit conducting boiler tune-ups are the remaining technologies.

Step 4 – Economic, Energy, and Environmental Impacts

The Applicant has chosen the highest ranked control option for the auxiliary boiler, and we are not aware of any significant or unusual adverse environmental impacts associated with the chosen technology.

Step 5 – Select BACT

Based on a review of the available control technologies for GHG emissions from natural gas-fired boilers, we have concluded that BACT for this source is the purchase of thermally efficient unit, conducting boiler tune-ups, and limiting the auxiliary boiler to 4,884 hours of operation per year (based on an equivalent amount of fuel use). Our review of other BACT determinations shows similar BACT determinations for such units. Some BACT limits have set lb/MMBtu limits, but such limits are merely the standard emission factor for CO_2 emissions and not based on the efficiency of the particular boiler. Given limited practical value, we have decided to not set such a limit, as we have determined that biennial boiler tune-ups would more effectively ensure the boiler is operating efficiently.

Section 111 and 112 standards: There are no applicable section 111 or 112 standards for GHGs for this unit. Therefore, our proposed BACT limit is at least as stringent as the applicable standards under sections 111 and 112 of the Act.

Table 15 Summary of Recent BACT Limits for Boilers Rated between 100 and 250 MMBtu/hr

Facility	Location	NO_X	CO	$PM/PM_{10}/PM_{2.5}$	GHGs	Permit Issuance	Source
AES Huntington Beach Energy Center	California	5 ppm, SCR	50 ppm	Natural gas	Natural gas, good combustion	4/18/2017	Final Permit
AES Alamitos Energy Center	California	5 ppm, SCR	50 ppm	Natural gas	Natural gas, good combustion	4/18/2017	Final Permit
Ineos Oligomers USA LLC – Linear Alpha Olefins Plant	Texas	0.0060 lb/MMBtu, LNB and SCR	--	--	--	11/3/2016	RBLC # TX-0811
Indorama Ventures Olefins, LLC – Indorama Lake Charles Facility	Louisiana	0.06 lb/MMBtu, ULNB	0.082 lb/MMBtu	0.007 lb/MMBtu	--	8/3/2016	RBLC # LA-0314
Virginia Electric and Power Company – Greensville Power	Virginia	0.011 lb/MMBtu	0.035 lb/MMBtu	0.007 lb/MMBtu	117.1 lb/MMBtu	6/17/2016	RBLC # VA-0325
TVA – Johnsonville Cogen	Tennessee	0.013 lb/MMBtu	0.084 lb/MMBtu	0.008 lb/MMBtu	117 lb/MMBtu	4/19/2016	RBLC #TN-0162
Magellan Processing LP – Corpus Christi Terminal Condensate Splitter	Texas	0.006 lb/MMBtu, SCR	50 ppm	--	--	4/10/2015	RBLC # TX-0731
Agrium U.S. Inc – Kenai Nitrogen Operations	Arkansas	0.01 lb/MMBtu, ULNB	50 ppm	0.0074 lb/MMBtu	59.61 tons/MMcf	1/6/2015	RBLC # AK-0083
Southern Power Company – Trinidad Generating Facility	Texas	9 ppm, ULNB	--	--	--	11/20/2014	RBLC # TX-0712
Cronus Chemicals, LLC	Illinois	0.08 lb/MMBtu	0.037 lb/MMBtu	0.0075 lb/MMBtu	871 tpy	9/5/2014	RBLC # IL-0114
Freeport LNG Development LP – Pretreatment Facility	Texas	5.0 ppm, ULNB	25 ppm	0.91 lb/hr	--	7/16/2014	RBLC # TX-0678

Section 6.5: BACT for Emergency Internal Combustion Engines

The PEP includes a 2,011 HP (1,500 kW) diesel-fired emergency generator and a 140 HP (104 kW) diesel-fired emergency fire pump engine. The emergency generator will be limited to 26 hours of non-emergency operation each year for maintenance and readiness testing, and the fire pump engine similarly will be limited to 52 hours of non-emergency operation each year for maintenance and readiness testing. There is no limit on the use of the emergency engines during an actual emergency. This equipment is subject to BACT for NO_X, CO, PM, PM_{10}, $PM_{2.5,}$ and GHGs. A top-down BACT analysis has been performed and is summarized below.

Step 1 – Identify All Control Technologies

The control options for NO_X emissions from engines include SCR, NO_X reducing catalyst, NO_X adsorber, catalyzed diesel particulate filter, catalytic converter, and oxidation catalyst. A catalytic converter and oxidation catalyst are also control options for CO emissions. For PM, PM_{10}, and $PM_{2.5}$ emissions, a diesel particulate filter/trap can be added on. There are no known add-on controls for GHGs.

Step 2 – Eliminate Technically Infeasible Control Options

All of the control technologies identified are assumed to be technically feasible.

Step 3 – Rank Remaining Control Technologies

The available control technologies are ranked according to control effectiveness in Tables 16 and 17, as determined by reviewing other BACT determinations and the limits proposed by the Applicant, and a summary of recent BACT determinations is provided in Table 18.

Unlike other combustion equipment (e.g., CTs and boilers), new diesel engines are required to be certified in compliance with EPA's NSPS requirements, including emission limits, upon purchase. Different types of engines have different emission requirements based on the type of engine being purchased (emergency engine, emergency fire pump engine, or non-emergency engine). Depending on the type of engine and the applicable NSPS emission limits, engine manufacturers may need to employ add-on control technologies to comply with such limits.

We considered the baseline to be the emission levels required by the NSPS standards for emergency generator engines and emergency fire pump engines, as applicable. Then we considered the use of available add-on controls for each pollutant – NO_X, CO, and PM. In the case of the emergency generator engine, we evaluated the level of control that would be achieved by the application of the NO_X and PM NSPS emission standards for non-emergency engines, which would entail the use of add-on controls. This option assumes the Applicant's purchase of a certified non-emergency engine rather than the addition of controls after purchase.

Table 16 104 kW Emergency Engine Control Technologies Ranked by Control Effectiveness

Engine Type	$NMHC+NO_X$ (g/kWh)	PM (g/kWh)	CO (g/kWh)
NSPS-Fire Pump Engine + NO_X, CO, PM Controls[64]	0.4	0.03	0.5
NSPS-Fire Pump Engine	4.0	0.30	5.0

[64] We are assuming each control for NO_X, CO and PM can achieve 90% reduction. This is typical for the available controls, such as SCR, oxidation catalyst, and diesel particulate filter.

Table 17 1500 kW Emergency Engine Control Technologies Ranked by Control Effectiveness

Engine Type	NMHC+NO_X (g/kWh)	PM (g/kWh)	CO (g/kWh)
NSPS-Non-emergency (includes NO_X and PM controls) + CO controls	0.86[65]	0.03	0.35
NSPS-Non-emergency (includes NO_X and PM controls)	0.86[66]	0.03	3.5
NSPS-Emergency + CO Controls	6.4	0.20	0.35
NSPS-Emergency Engine	6.4	0.20	3.5

Step 4 – Economic, Energy and Environmental Impacts

Due to economic impacts, the Applicant eliminated add-on controls for the engines. As explained below, we agree that the top-ranked control technologies would be economically impractical in this case.

First, NO_X controls required to meet the standards for non-emergency engines would likely not provide measurable reductions when the engines are usually operated, which is for readiness and maintenance testing. It takes time for the NO_X controls to be operational and emergency engines typically only operate 30 minutes to an hour for readiness and maintenance testing.

Second, the EPA previously estimated that the cost effectiveness of adding NO_X controls to stationary diesel engines in a report entitled "Alternative Control Techniques Document: Stationary Diesel Engines," dated March 5, 2010. In this analysis, we estimated that the cost of adding NO_X controls to a Tier 2 engine rated above 750 hp, which is equivalent to the NSPS standards that the emergency generator must meet, would be $9,833/ton (2010 dollars), assuming 1000 hours of operation.[67] EPA similarly estimated that adding CO controls would cost $9,837/ton, and adding PM controls to cost $99,724/ton.[68]

The limited use of th engines for the Project is an important consideration in determining what is cost-effective. The PEP's engines are expected to operate far less than typical equipment (such as CTs and boilers) and less than in the analysis EPA previously performed as described in the March 5,2010 report. See the potential to emit values in Table 19.[69] Finally, the cost-effectiveness values would be even higher for smaller engines like the emergency fire pump engine as they emit even less pollutants than larger engines evaluated in the report.

Considering the very limited use of these engines and the estimated cost of add-on controls (including the use of NSPS certified non-emergency engines) we are eliminating the use these controls as BACT for these engines as not cost-effective.

---

[65] The actual applicable NSPS limits are 0.67 g/kWh for NO_X and 0.19 g/kWh for NMHC. The two limits were added together in order to compare them to the other types of engines.

[66] Ibid.

[67] See EPA's Alternative Control Techniques Document: Stationary Diesel Engines, Table 5-2, March 5, 2010. https://www.epa.gov/sites/production/files/2014-02/documents/3_2010_diesel_eng_alternativecontrol.pdf

[68] Ibid, Table 5-3 and 5-4.

[69] The worst-case maximum hours of operation for emergency engines in California is estimated to be 200 hours per year including readiness and maintenance testing and emergency use.

Table 18 Summary of Recent BACT Limits for Emergency Engines

Facility	Location	NO_X	CO	$PM/PM_{10}/PM_{2.5}$	GHGs	Permit Issuance	Source
Cameron LNG Facility	Louisiana	NSPS	NSPS	NSPS	NSPS	2/17/2017	RBLC # LA-0316
Methanex – Geismar Methanol Plant	Louisiana	NSPS/NESHAP	NSPS/NESHAP	NSPS/NESHAP	NSPS/NESHAP	12/22/2016	RBLC # LA-0317
Entergy Louisana – St. Charles Power Station	Texas	27.34 lb/hr	14.81 lb/hr	0.86 lb/hr	--	8/31/2016	RBLC # LA-0313
Lake Charles Methanol Facility	Louisiana	NSPS	NSPS	NSPS	NSPS	6/30/2016	RBLC # LA-0305
Virginia Electric and Power Company – Greensville Power	Virginia	6.4 g/kW-hr	3.5 g/kW-hr	0.4 g/kW-hr	163.6 lb/MMBtu	6/17/2016	RBLC # VA-0325
Magnolia LNG Facility	Louisiana	NSPS	NSPS	NSPS	NSPS	3/21/2016	RBLC #LA-0307
PSEG Fossil, Sewaren Generating Station	New Jersey	42.3 lb/hr	3.5 lb/hr	0.26 lb/hr	--	3/10/2016	RBLC # NJ-0084
Florida Power & Light, Okeechobee Clean Energy Center	Florida	--	3.5 g/kW-hr	0.2 g/kW-hr	--	3/9/2016	RBLC # FL-0356
Cameron Interstate Pipeline LLC – Holbrook Compressor Station	Louisiana	14.16 lb/hr	--	0.44 lb/hr	77 tpy	1/22/2016	RBLC # LA-0292
Flopam Facility	Louisiana	NSPS	NSPS	NSPS	--	1/7/2016	RBLC # LA-0318
Benteler Steel Tube Facility	Louisiana	6.4 k/kW-hr	--	0.2 g/kW-hr	--	6/4/2015	RBLC # LA-0309

Table 19 Emergency Engine Emissions, Potential to Emit

Pollutant	Emergency Generator (TPY)	Emergency Fire Pump Engine (TPY)
NO_X	1.7	0.08
CO	0.3	0.1
PM, PM_{10}, $PM_{2.5}$	0.1	0.04
CO_2e	233	20.4

Step 5 – Select BACT

Based on the review of the available control technologies, we have concluded that BACT for the PEP's diesel emergency fire-pump engine and diesel emergency generator is EPA-certified NSPS emergency engines. This means that these engines will be certified to the applicable emission standards for NMHC+NO_X, CO, and PM for the same size and model year provided in the applicable NSPS – 40 CFR part 60 subpart IIII. The NSPS for engines does not currently regulate GHG emissions, but a separate GHG limit is not being proposed. It is assumed that newly purchased engines would be the most energy efficient available and that operating in compliance with NSPS requirements will ensure that each engine is properly maintained and as efficient as possible. Given the limited use of these engines, regularly measuring the efficiency of the engines through a permit limit provides no practical benefit.

Section 111 and 112 standards: The engines will be certified to the NSPS standards in 40 CFR part 60, subpart IIII. The engines are also subject to the standards in 40 CFR part 63, subpart ZZZZ, which only requires that the engines comply with the applicable requirement in 40 CFR part 60, subpart IIII. Therefore, our proposed BACT limits are at least as stringent as the applicable standards under sections 111 and 112 of the Act.

Section 6.6: BACT for Circuit Breakers

There will be an electrical switchyard within the PEP boundary. The switchyard will include six circuit breakers, each containing 360 pounds of sulfur hexafluoride (SF_6), a potent GHG. Thus, the circuit breakers are subject to BACT for GHG emissions. The only GHG emitted from the circuit breakers is SF_6.

Step 1 – Identify All control Technologies

The inherently lower-emitting control options for GHG emissions include:

- *Use of dielectric oil, compressed air, or vacuum circuit breakers* – these types of circuit breakers do not contain any GHG pollutants.
- *Totally enclosed SF_6 circuit breakers with leak detection systems* – these types of circuit breakers have a maximum leak rate of 0.5% per year by weight and have an alarm warning when 10% of the SF_6 has escaped. The use of an alarm identifies potential leak problems before the bulk of SF_6 has escaped.

No add-on control options for GHG emissions were identified.

Step 2 – Eliminate technically infeasible control options

We are eliminating the use of *dielectric oil, compressed air, or vacuum circuit breakers* as discussed below:

In 1999 the EPA established the *SF_6 Emission Reduction Partnership for Electric Power Systems* as a collaborative effort between the EPA and the electric power industry to identify, recommend, and implement cost-effective solutions to reduce sulfur hexafluoride (SF_6) emissions.[70] Under the partnership, the EPA shares information on best management practices and technical issues to help reduce SF_6 emissions. Most recently, in January 2017, the EPA hosted the 2017 Workshop for SF_6 Emission Reduction Strategies.[71] The EPA's partnership has predominately focused on solutions for reducing SF_6 leak rates, with dielectric oil, compressed air, and vacuum circuit breakers not being included in the potential mitigation options. We are not aware that these technologies have been demonstrated recently to be used in high voltage applications like the utility industry. The 2017 Workshop included a presentation by 3M™ Novec™ on dielectric fluids as alternatives to SF_6 for power utilities[72], and a presentation by PG&E on pilot applications of SF_6-free installations[73]. However, the available information does not indicate that these alternatives are currently commercially available.

Based on available information about this sector of the power industry, we are eliminating dielectric oil, compressed air, and vacuum circuit breakers as technically infeasible. We are not aware of any commercially available options using these technologies at this time that meet the needs of the power sector. As such, we are only further considering the use of totally enclosed SF_6 circuit breakers with leak detection systems.

Step 3 – Rank remaining control technologies

The remaining technology is the use of enclosed-pressure SF_6 circuit breakers with an annual leakage rate of 0.5% by weight, a 10% by weight leak detection system. See Table 21 for a review of recent BACT limits for SF_6 circuit breakers. Nearly all are based on the same leak detection system as that proposed for the PEP.

Table 20 Circuit Breaker Control Technologies Ranked by Control Effectiveness

GHG Control Technologies	CO_2e Emission Rate (TPY)
Enclosed-pressure SF_6 circuit breakers with 0.5% (by weight) annual leakage rate and 10% by weight leak detection systems	123

Step 4 – Economic, Energy, and Environmental Impacts

The applicant has proposed the remaining control technology and we are not aware of any significant or unusual environmental impacts associated with the chosen technology.

Step 5 – Select BACT

Based on a review of the available control technologies for GHG emissions from circuit breakers, we have concluded that the Applicant's proposed requirements are BACT for this source: the use of enclosed-pressure SF_6 circuit breakers with an annual leakage rate of 0.5% by weight and a 10% by weight leak detection system.

Section 111 and 112 standards: The are no section 111 or 112 standards applicable to this equipment.

[70] https://www.epa.gov/f-gas-partnership-programs/electric-power-systems-partnership
[71] https://www.epa.gov/f-gas-partnership-programs/2017-workshop-sf6-emission-reduction-strategies
[72] https://www.epa.gov/f-gas-partnership-programs/sf6-alternatives-power
[73] https://www.epa.gov/f-gas-partnership-programs/sf6-free-hv-gis-and-breakers

Table 21 Summary of Recent BACT Limits SF6 Circuit Breakers

Facility	Location	Sulfur Hexafluoride	Permit Issuance	Source
Florida Power & Light Okeechobee Clean Energy Center	Florida	0.5% annual leak release rate. Leak detection and alarm system	3/9/2016	RBLC # FL-0356
Mattawoman Energy Center	Maryland	Meet ANSI C37.013 or equivalent. Leak detection and repair	11/13/2015	RBLC # MD-0045
Florida Power & Light – Fort Myers Plant	Florida	0.5% annual leak release rate. Leak detection and alarm system	9/10/2015	RBLC # FL-0355
Keys Energy Center	Maryland	Meet ANSI C37.013 or equivalent. Leak detection and repair	8/25/2015	RBLC # MD-0046
CPV Maryland – St. Charles	Maryland	Meet ANSI C37.013 or equivalent. Leak detection and repair	4/23/2014	RBLC # MD-0041
Interstate Power and Light Marshalltown Generating Station	Iowa	0.5% annual leak release rate.	11/7/2013	RBLC #IA-0108
St. Joseph Energy Center	Indiana	0.5% annual leak release rate. Leak detection and alarm system, 0.009 tpy of SF_6	12/3/2012	RBLC # IN-0158

Section 7: Ambient Air Quality Impact Report

Clean Air Act section 165 and the EPA's PSD regulations at 40 CFR 52.21(k) require an examination of the impacts of the proposed PEP on ambient air quality. The Applicant must demonstrate, using air quality models, that the facility's emissions of the PSD-regulated air pollutants would not cause or contribute to a violation of (1) the applicable National Ambient Air Quality Standards (NAAQS), or (2) the applicable PSD increments. This section includes a discussion of the relevant background data and air quality modeling, and our conclusion that the Project will not cause or contribute to a violation of the applicable NAAQS or PSD increments and is otherwise consistent with PSD requirements concerning air quality.

7.1: Overview of PSD Program Ambient Air Quality Analysis

The main purpose of the air quality analysis is to demonstrate that emissions from a proposed new major stationary source or major modification will not cause or contribute to a violation of any applicable NAAQS or PSD increment.

Generally, the analysis will involve (1) predictions, using dispersion modeling, of ambient concentrations that will result from the applicant's proposed project and, as necessary, (2) a more detailed assessment of the impact of the project's emissions on existing air quality, typically involving the analysis of ambient monitoring data and air quality dispersion modeling results.

These requirements and the ambient air quality analysis that was conducted for the PEP are discussed in detail below.

7.1.1 National Ambient Air Quality Standards (NAAQS)

The NAAQS consist of *primary standards* that provide public health protection, including protecting the health of "sensitive" subpopulations such as asthmatics, children, and the elderly, and *secondary standards* that provide public welfare protection, including protection against decreased visibility and damage to animals, crops, vegetation, and buildings.

7.1.2 PSD Increment

PSD increments are intended to prevent the air quality in clean areas from deteriorating to the level set by the NAAQS. The NAAQS is a maximum allowable concentration "ceiling." A PSD increment, on the other hand, is the maximum allowable increase in concentration that is allowed to occur above a baseline concentration for certain pollutants. The baseline concentration is defined for each such pollutant for which there is a PSD increment and, in general, is the ambient concentration existing at the time that the first complete PSD permit application affecting the area is submitted. Significant deterioration is said to occur when the amount of new pollution would violate the applicable PSD increment. It is important to note, however, that the air quality cannot deteriorate beyond the concentration allowed by the applicable NAAQS, even if not all of the PSD increment is consumed.

7.1.3 Class I, II and III Areas

Class I areas are areas of special national or regional natural, scenic, recreational, or historic value for which the PSD regulations provide special protection.

All other areas not defined as Class I areas, are, by default, considered Class II areas, unless redesignated as Class I or III by the EPA Administrator as provided in 40 CFR 52.21(e) and (g) (or through a PSD program approved by the EPA under

40 CFR 51.166). Class I areas have more stringent PSD increment values than Class II areas.[74] Class I areas are also subject to additional review and protection as discussed in detail below in section 8.

7.2 Application Requirements

A PSD permit applicant for a new major stationary source must provide separate modeling analyses for each criteria pollutant (other than nonattainment pollutants, which are not subject to PSD review)[75] with potential emissions at or above the applicable PSD significant emission rate (SER).[76] Modeling is performed in accordance with the EPA's Guideline on Air Quality Modeling, in Appendix W to 40 CFR Part 51 (Appendix W). AERMOD with its default settings is the standard model choice. A cumulative impact analysis under 40 CFR 52.21(m) is required for each such criteria pollutant unless a preliminary project-only analysis is conducted that the permitting authority determines is sufficient to demonstrate that the project will not cause or contribute to a violation of the applicable NAAQS and PSD increments. Where a preliminary analysis shows that the project by itself will not have a significant impact on ambient air quality for that pollutant in any location, the permitting authority may determine, as warranted on a case-by-case basis, that additional analysis is not required in order to demonstrate that the project will not cause or contribute to a violation of the applicable NAAQS and PSD increments.

When a cumulative impact analysis is conducted for a pollutant, the analysis must demonstrate that the Project under consideration will not cause or contribute to a NAAQS or increment violation. A cumulative impact analysis includes appropriate nearby pollution sources in the modeling, and adds a monitored background concentration to account for sources not explicitly included in the model. Required model inputs characterize the various emitting units, meteorology, and the land surface, and define a set of receptors.[77]

The modeling protocol for the PEP was submitted to the EPA on August 19, 2015, and generally based on the 2005 version of Appendix W. On May 22, 2017, revisions to Appendix W became effective.[78] While these revisions to Appendix W are now in effect, the final rule revising Appendix W allows permitting authorities the discretion to approve modeling protocols that were submitted in a timely manner to be based on the 2005 version of Appendix W, through a transition period that ends January 17, 2018.[79] We find it appropriate in this case to allow the use of the Applicant's modeling protocol based on the 2005 version of Appendix W, referred to hereafter as the "2005 Appendix W," because the modeling protocol was submitted in a timely manner and based on the requirements in effect at that time. In addition, we note that, in general, we would not consider the 2005 Appendix W to be less stringent than the 2017 version of Appendix W. Finally, we note the Applicant incorporated one of the proposed changes to Appendix W into its modeling protocol related to modeling Class I impacts greater than 50 km from the Project. This proposed change was eventually finalized in the 2017 Appendix W revisions.

[74] Class III areas, which are not relevant for purposes of this analysis, are subject to less stringent PSD increment values than Class II areas.
[75] As noted above, the proposed PEP would be located in a federal ozone nonattainment area, thus ozone and its precursors (NO_X and VOC) are not subject to PSD review in this case. However, NO_X is still potentially subject to PSD review because of the separate NO_2 NAAQS.
[76] Pollutants that are precursors to a criteria pollutant also trigger PSD review based on the applicable SER for the precursor pollutant.
[77] Receptors are spatial locations at which to estimate pollutant concentrations, typically out to 50 km from the facility at issue.
[78] See the Final Rule at 82 Fed. Reg. 5182 (Jan. 17, 2017) and the delays of the effective date at 82 FR 8499 (Jan. 26, 2017) and 82 FR 14324 (Mar. 20, 2017).
[79] See the "Dates" section of the January 17, 2017 final rule.

7.2.1 Good Engineering Practice Stack Height

Consistent with 40 CFR 52.21(h), consideration of Good Engineering Practice (GEP) stack height prior to conducting modeling is needed, to ensure:

(1) that downwash is properly considered in the modeling for stacks less than GEP height, and
(2) that stack heights used as inputs to the modeling are no greater than GEP height.

GEP does not limit the actual height of any stack, but prevents artificial dispersion from the use of overly tall stacks.

7.3 Summary of Modeling Results for NAAQS and Increments

This section (7.3) provides a summary of the modeling results showing the PEP's compliance with applicable NAAQS and PSD increments. The following two sections (7.4 and 7.5) discuss the modeling approach and modeling inputs used to conduct the modeling for the PEP.

7.3.1 Pollutants Subject to NAAQS and Increment Review

The Applicant submitted an air quality impact analysis for the applicable criteria pollutants with potential Project emissions at or above the relevant SER, including for emissions related to precursor pollutants. Potential emissions from the PEP and the applicable SERs for these pollutants are shown in Table 22, derived from Table 2 above. The proposed PEP has the potential to emit CO, NO_X, PM_{10}, and $PM_{2.5}$ above the applicable SERs, including NO_X as a precursor to $PM_{2.5}$, so air quality impact analyses were required for these pollutants.

Table 22 NAAQS Pollutants Emitted in Significant Amounts

Pollutant	Potential to Emit (TPY)	Significant Emission Rate (SER) (TPY)	Greater Than or Equal to SER?
CO	351	100	**Yes**
NO_X (also a $PM_{2.5}$ precursor)	139	40	**Yes**
PM_{10}	81	15	**Yes**
$PM_{2.5}$[80]	81	10	**Yes**
SO_2 (also a $PM_{2.5}$ precursor)	11	40	No
Lead	0	0.6	No

7.3.2: Background Ambient Air Quality

The PSD regulations generally require the air quality analysis to contain air quality monitoring data as needed to assess ambient air quality in the area for the PSD-regulated pollutants for which there are NAAQS that may be affected by the source. 40 CFR 52.21(m). In addition, as part of a cumulative air quality impact analysis for demonstrating compliance

[80] NO_X and SO_2 are precursors to the formation of $PM_{2.5}$, and emissions of 40 TPY or more of NO_X or SO_2 are also considered significant for purposes of $PM_{2.5}$ under PSD. See 40 CFR 52.21(b)(23)(i). Thus, PEP's projected emissions of NO_X, which exceed 40 TPY, are significant for $PM_{2.5}$ as well as for NO_X itself.

with the NAAQS, a background concentration is added to represent those sources not explicitly included in the modeling.

For background concentrations, the Applicant chose the Lancaster Division Street monitoring station, which is the nearest station available. This monitoring station collects NO_2, CO, PM_{10}, $PM_{2.5}$ and O_3 data. The most recent three years of data available at the time of the application were 2012-2014 (October 2015 Application p.4.4-3). [81] While the Lancaster Division Street monitoring station is just 2.5 miles from the PEP power block, it is also within the city of Lancaster, which has a population of some 160,000 and is near several roads and a railway. This location is more urbanized than the PEP site. The monitors are thus considered conservative for representing background concentration data for these pollutants.

Table 23 below shows the background concentrations of the PSD-regulated pollutants for which there are NAAQS subject to review for this Project. Also shown are the corresponding NAAQS.

Table 23 Background Concentrations and NAAQS

NAAQS pollutant & averaging time	Background Concentration, μg/m³	Primary NAAQS, μg/m³	Secondary NAAQS, μg/m³
CO, 1-hr	2,176	40,000 (35 ppm)	N/A
CO, 8-hr	1,603	10,000 (9 ppm)	N/A
NO_2, 1-hr	81	188 (100 ppb)	N/A
NO_2, annual	15.1	100 (53 ppb)	100 (53 ppb)
PM_{10}, 24-hr	80	150	150
$PM_{2.5}$, 24-hr	18	35	35
$PM_{2.5}$, annual	6.1	12.0	15.0

Note: Form of the NAAQS used throughout this analysis:
-CO 8-hr and 1-hr values are not to be exceeded more than once per year
-NO_2 annual value is the annual mean
-NO_2 1-hr value is 98th percentile averaged over three years
-PM_{10} 24-hr value is not to be exceeded more than once per year on average over 3 years
-$PM_{2.5}$ annual value is the annual mean, averaged over 3 years
-$PM_{2.5}$ 24-hour value is 98th percentile averaged over three years
Source: https://www.epa.gov/criteria-air-pollutants/naaqs-table .

7.3.3: Preliminary Analysis: Project-Only Impacts

The EPA has developed significant impact level (SIL) values as a compliance demonstration tool for characterizing air quality impacts from proposed PSD sources. A SIL is a level of ambient air impact that may be projected to result from a proposed PSD project's emissions, for a given NAAQS or PSD increment, below which the source may be determined to have an insignificant impact in the permitting authority's determination of whether the proposed PSD source will cause or contribute to a NAAQS or PSD increment violation. When maximum modeled concentrations[82] resulting from the project's emissions are below the SIL value, further air quality analysis may not be necessary. This determination is made by the permitting authority on a case-by-case basis, based on the record. As described in further detail in Section 7.3.4,

[81] October 2015 PSD Application PEP p.4.4-3 and Table 4-5 p 4.44. See also PEP PSD Modeling Protocol p.13.
[82] Maximum modeled concentrations are the highest impact that are expected to occur based on the form of the applicable standard. Because meteorology varies over the course of a year, the maximum modeled concentration is often higher for short-term standards (1-hr or 24-hr) as compared to long-term standards (annual). The NAAQS do not represent single "not to exceed" exposure limits, but are instead based on exposure averaged over a particular timeframe for the particular standard.

for maximum modeled concentrations that equal or exceed the SIL value, the EPA as the PSD permitting authority generally requires a cumulative air quality impact analysis.

7.3.3.1 Results of Preliminary Analysis

For the PEP, the results of the preliminary (Project-only) air quality modeling analysis are shown in Table 24. PEP impacts are above the SILs for 1-hour NO_2, 24-hour PM_{10}, 24-hour $PM_{2.5}$, and annual $PM_{2.5}$, so cumulative impact analyses were conducted for these NAAQS.

For the other NAAQS pollutants/averaging times and increments that are subject to PSD review for the PEP, Project impacts are below the SILs as shown in Table 24, and we have determined that in this case, further air quality analysis is unnecessary to demonstrate compliance with the pertinent NAAQS and increments for these pollutants. For CO, Project-only impacts are well below the SILs, and Project-only impacts and background concentrations are very small in comparison with the relevant NAAQS. With respect to annual NO_2, the Project-only impact is close to the relevant SIL. However, given the relatively minor impacts from the Project (0.98 $\mu g/m^3$) as compared to the annual NO_2 NAAQS (100 $\mu g/m^3$) as well as the low background level (15.1 $\mu g/m^3$) compared to the annual NO_2 NAAQS and annual NO_2 PSD Class II increment (25 $\mu g/m^3$), as shown in Table 23 above and Table 24 below, we do not believe that further air quality analysis is needed to determine that the Project will not cause or contribute to a violation of the annual NO_2 NAAQS or Class II PSD increment.

Below are maps of the modeled significant impact areas (SIA) for NO_2, PM_{10}, and $PM_{2.5}$. We note that while the prevailing winds near the Project site are from the southwest to the northeast, the maximum impact areas are generally to the north and/or south of the Project. This is because building downwash (that is, turbulence created by the nearby buildings) and conditions related to stagnant air play a greater role than the prevailing winds when evaluating the maximum impacts.

Figure 4 PEP Significant Impact Area for NO_2 Emissions

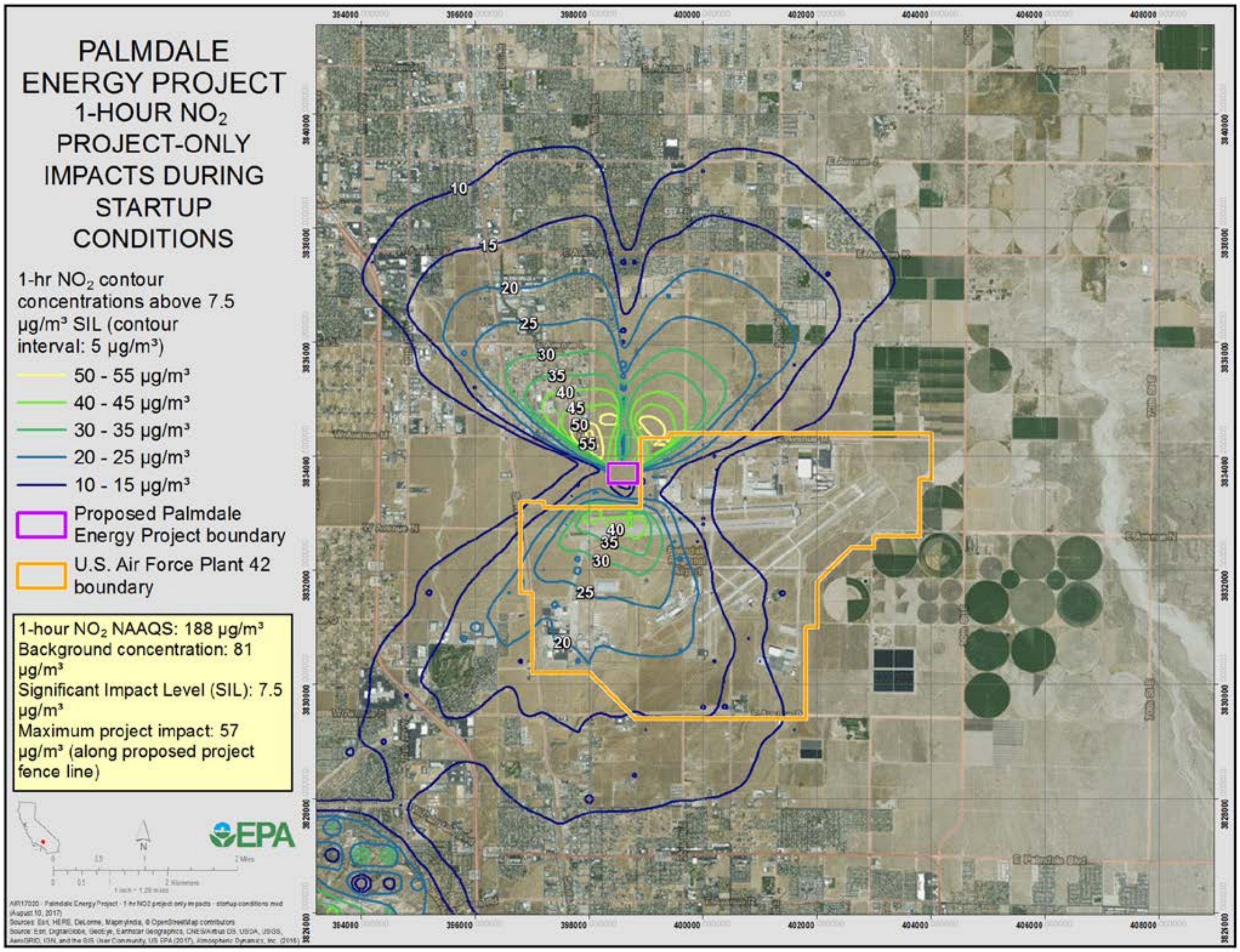


Figure 5 PEP Significant Impact Area for Annual PM_{10}

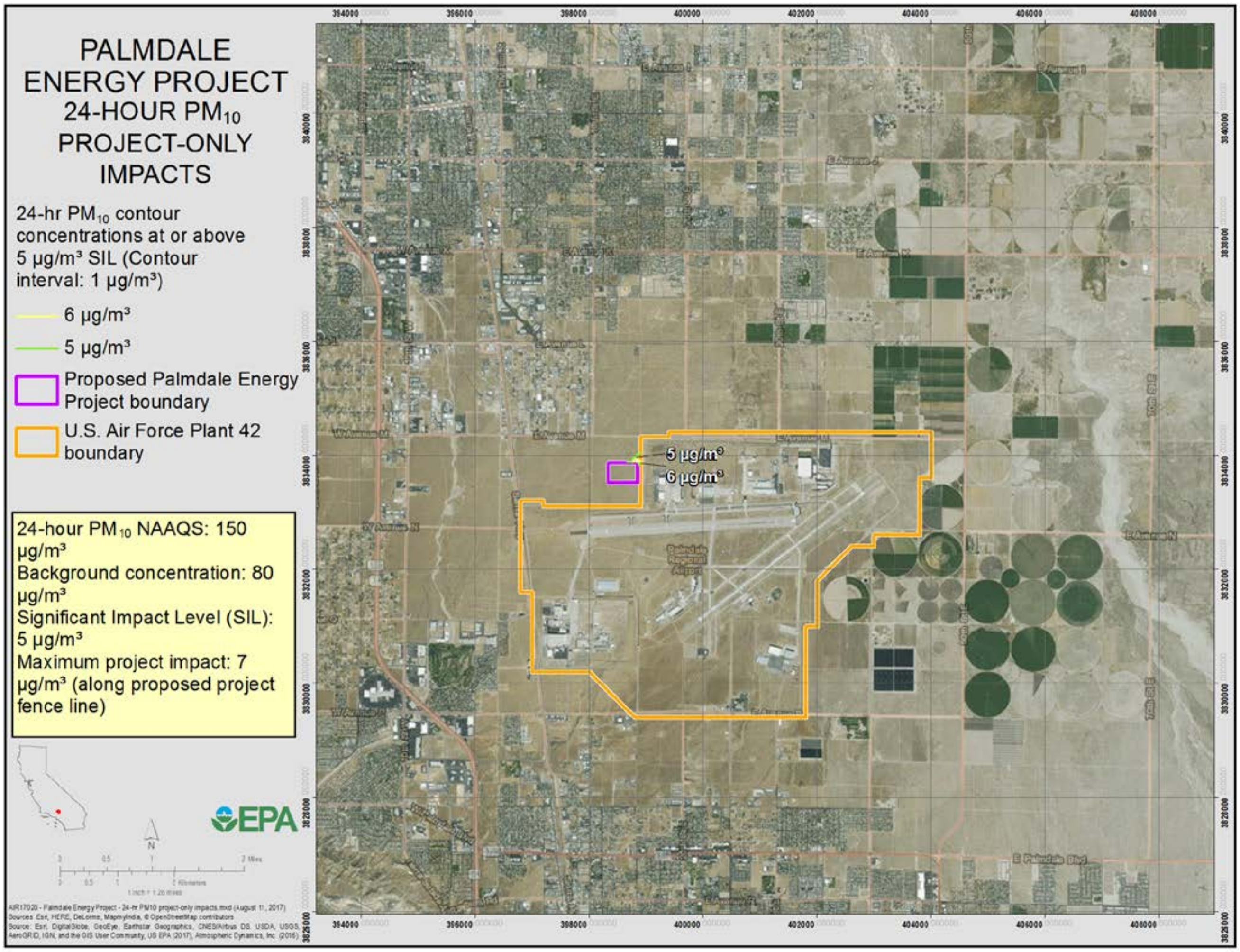


Figure 6 PEP Significant Impact Area for Annual $PM_{2.5}$

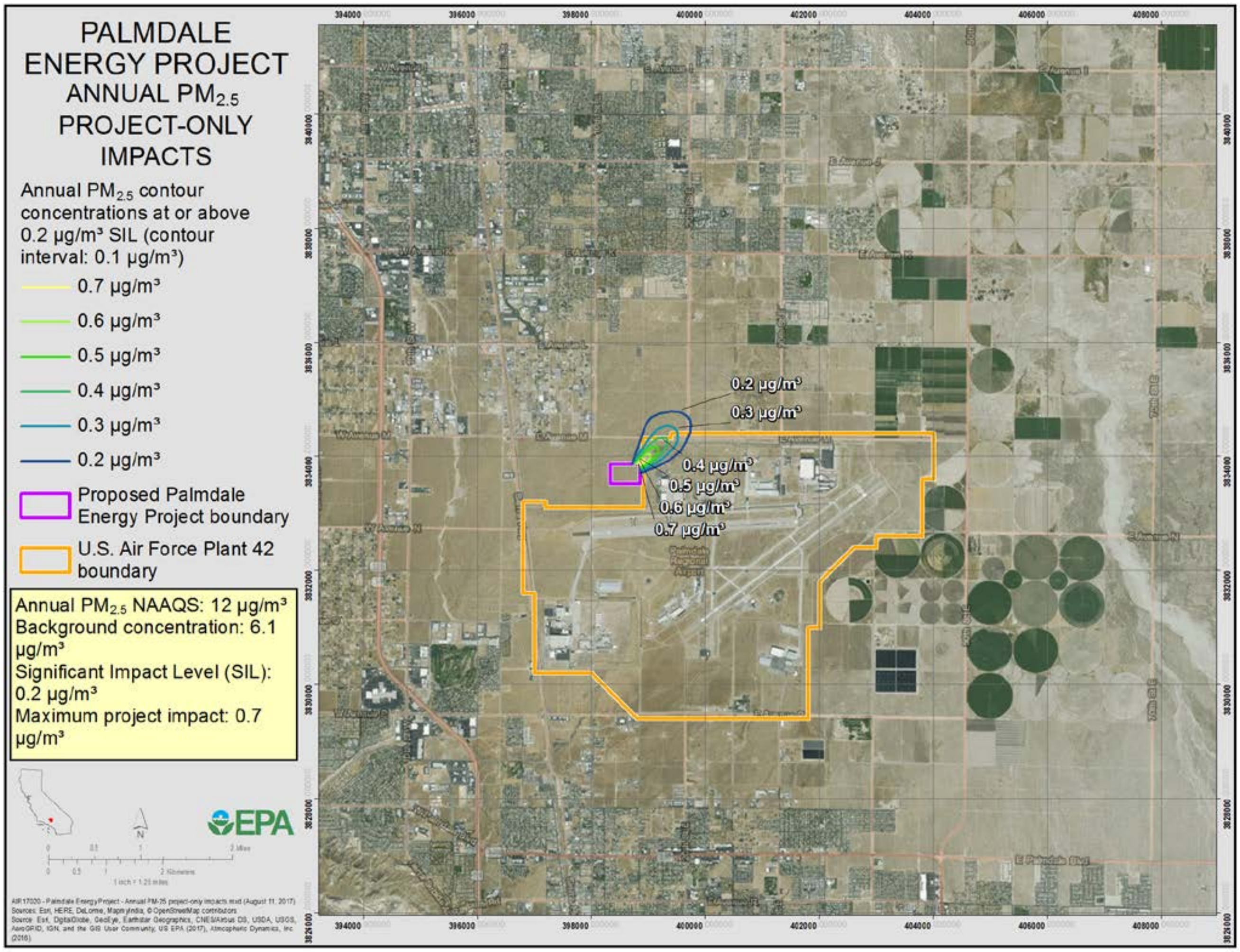


Figure 7 PEP Significant Impact Area for 24-Hour PM2.5

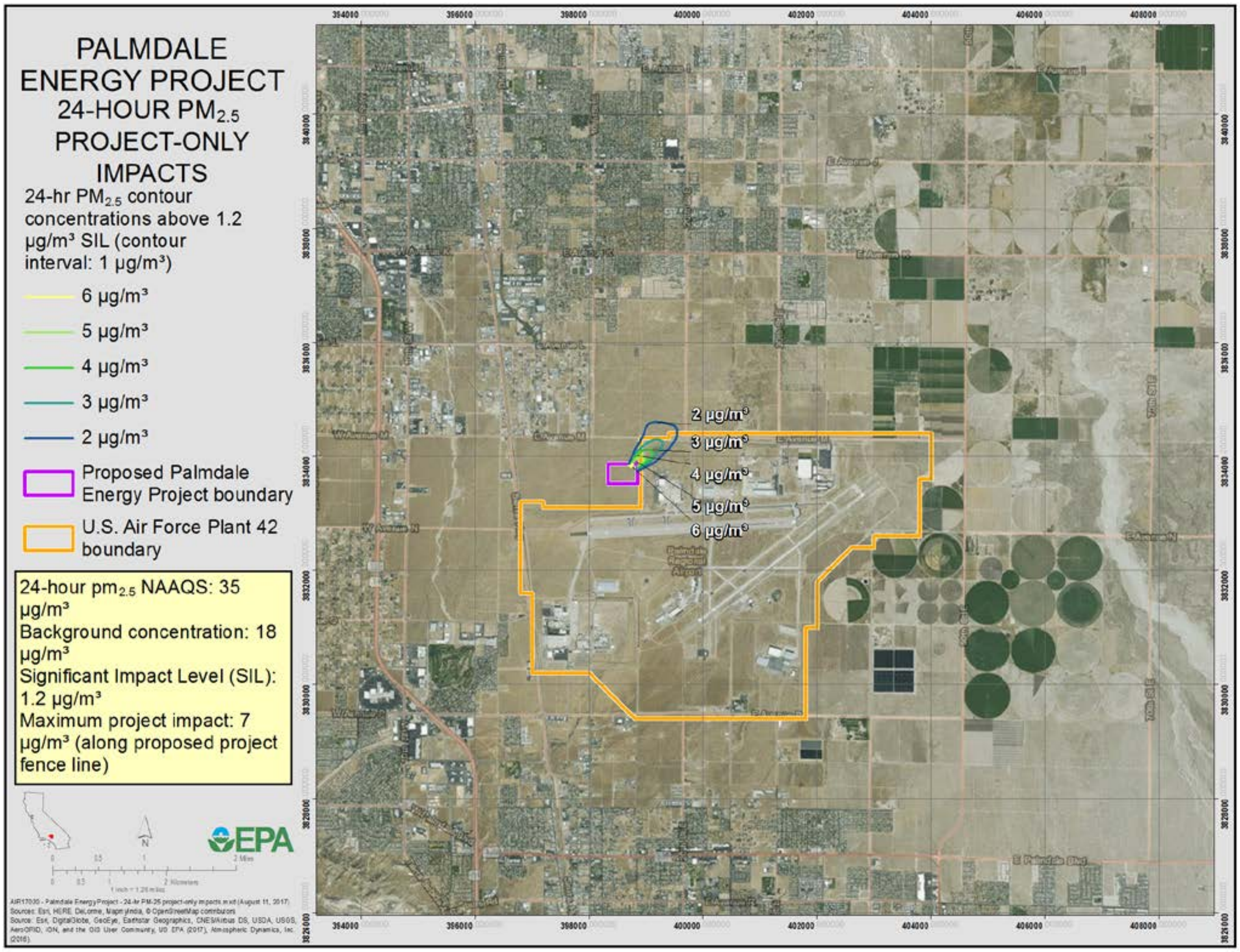


Table 24 Summary of Maximum Project Impacts, SILs, Background Concentrations, NAAQS, and PSD Class II Increments

NAAQS pollutant & averaging time	Maximum Project-Only Modeled Impact, μg/m³	SIL, μg/m³	Background Concentration, μg/m³	NAAQS μg/m³	PSD Class II Increment, μg/m³	Project Impact at or above SIL?
CO, 1-hr	124	2000	2,176	Primary: 40,000 (35 ppm)	N/A	No
CO, 1-hr (Startup/shutdown)	575	2000	2, 176	Primary: 40,000 (35 ppm)	N/A	No
CO, 8-hr	29	500	1,603	Primary: 10,000 (9 ppm)	N/A	No
CO, 8-hr (Startup)	89	500	1,603	Primary: 10,000 (9 ppm)	N/A	No
NO_2, 1-hr	14	7.5 (4 ppb)	81	Primary: 188 (100 ppb)	N/A	**Yes**
NO_2, 1-hr (Startup)	57	7.5 (4 ppb)	81	Primary: 188 (100 ppb)	N/A	**Yes**
NO_2, annual	0.98	1.0	15.1	Primary and Secondary: 100 (53 ppb)	25 (13 ppb)	No
PM_{10}, 24-hr	7	5	80	Primary and Secondary: 150	30	**Yes**
$PM_{2.5}$, 24-hr	7	1.2	18	Primary and Secondary: 35	9	**Yes**
$PM_{2.5}$, annual	0.7	0.2	6.1	Primary: 12 Secondary:15	4	**Yes**

Source: See Section 7.3 and Tables 7-2 and 7-4 of the October 2015 Application
SIL Values: The 1-hr NO_2 SIL is provided in the EPA's June 28, 2010 and March 1, 2011 memos entitled "Applicability of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard" and "Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO2 National Ambient Air Quality Standard," respectively.[83] The 24-hr and annual $PM_{2.5}$ SIL values are provided in the EPA's August 18, 2016 draft $PM_{2.5}$ guidance entitled "Guidance on Significant Impact Levels for Ozone and Fine Particles in the Prevention of Significant Deterioration Permitting Program" as well as the supporting "Technical Basis for the EPA's Development of Significant Impact Thresholds for PM2.5 and Ozone" and the supporting "Legal Support Memorandum: Application of Significant Impact Levels in the Air Quality Demonstration for Prevention of Significant Deterioration Permitting under the Clean Air Act," both dated August 1, 2016. [84] For the 1-hr and 8-hr CO, annual NO_2, and 24-hr PM_{10} SILs, see 40 CFR 51.165(b)(2).

[83] https://www3.epa.gov/scram001/guidance/clarification/ClarificationMemo_AppendixW_Hourly-NO2-NAAQS_FINAL_06-28-2010.pdf and https://www.epa.gov/sites/production/files/2015-07/documents/appwno2_2.pdf
[84] https://www.epa.gov/nsr/draft-guidance-comment-significant-impact-levels-ozone-and-fine-particle-prevention-significant

7.3.4: Results of the Cumulative Impacts Analysis

The results of the PSD cumulative impacts modeling analysis for PEP's normal operations and startup and shutdown periods are shown in Table 25. The analysis demonstrates that emissions from PEP during normal operations and startup and shutdown will not cause or contribute to a violation of the NAAQS for 1-hour NO_2, 24-hour PM_{10}, 24-hour $PM_{2.5}$, or annual $PM_{2.5}$ or the applicable PSD increments for these pollutants and averaging periods. For cumulative impacts, as compared to the NAAQS, the modeled impacts of the Project and appropriate nearby sources were added to the background concentration. The modeled impacts of the Project and appropriate nearby sources may vary from the Project-only impacts provided above in Table 24 because the cumulative analysis considers the form of the NAAQS, and the Project-only analysis considered a more conservative worst-case impact. As described further in Section 7.4.2.2, for Class II PSD increments, the modeled impacts of the Project and appropriate nearby sources may be compared to the applicable increment.

Table 25 Summary of Project and Nearby Sources Impacts, PSD Class II Increments, Background Concentrations, Cumulative Impacts with Background, and NAAQS

NAAQS pollutant & averaging time	Project and Nearby Sources Modeled Impact (μg/m³)	PSD Increment, Class II (μg/m³)	Background Concentration (μg/m³)	Cumulative Impact (μg/m³)	NAAQS (μg/m³)
NO_2, 1-hr	See note	N/A	See note	111	Primary: 188 (100 ppb)
NO_2, 1-hr (startup/shut down)	See note	N/A	See note	126	Primary: 188 (100 ppb)
PM_{10}, 24-hr	7	30	80	87	Primary & Secondary: 150
$PM_{2.5}$, 24-hr	5	9	18	23	Primary & Secondary: 35
$PM_{2.5}$, annual	0.77	4	6.1	6.9	Primary: 12 Secondary: 15

Sources: October 2015 PSD Application Table 7-8 and 7-9, p.7.4-7 and 7.4-8.
Note: NO_2 impacts were evaluated using the Tier 3 Ozone Limiting Method (OLM), with hourly seasonal background values added consistent with EPA modeling guidelines, and as a result, separate modeled and background values not available. There are no PSD increments for 1-hour NO_2. See Section 7.4.6.

Figure 8 PEP Cumulative Impacts for 1-Hour NO_2 Emissions

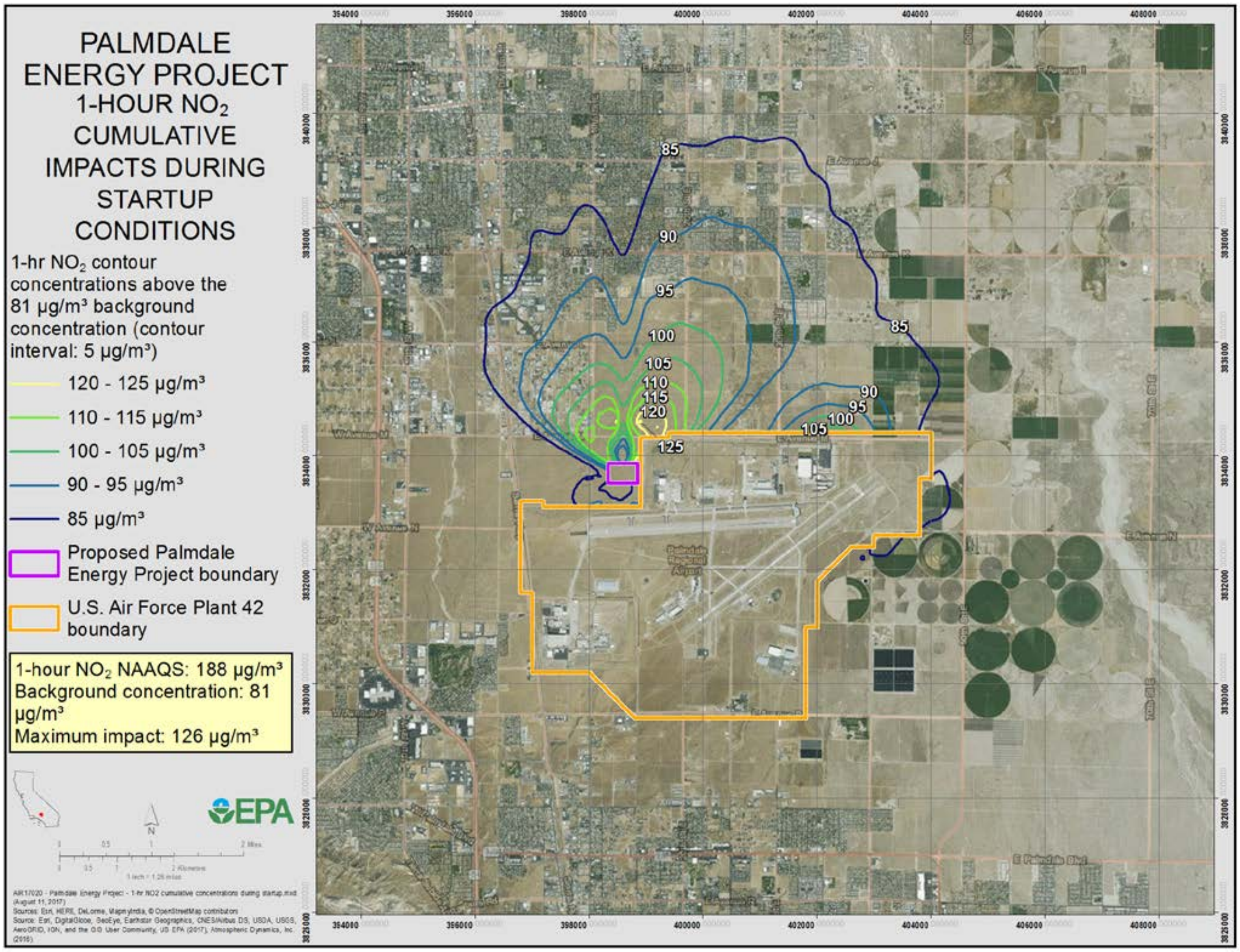


Figure 9 PEP Cumulative Impacts for 24-Hour PM_{10} Emissions

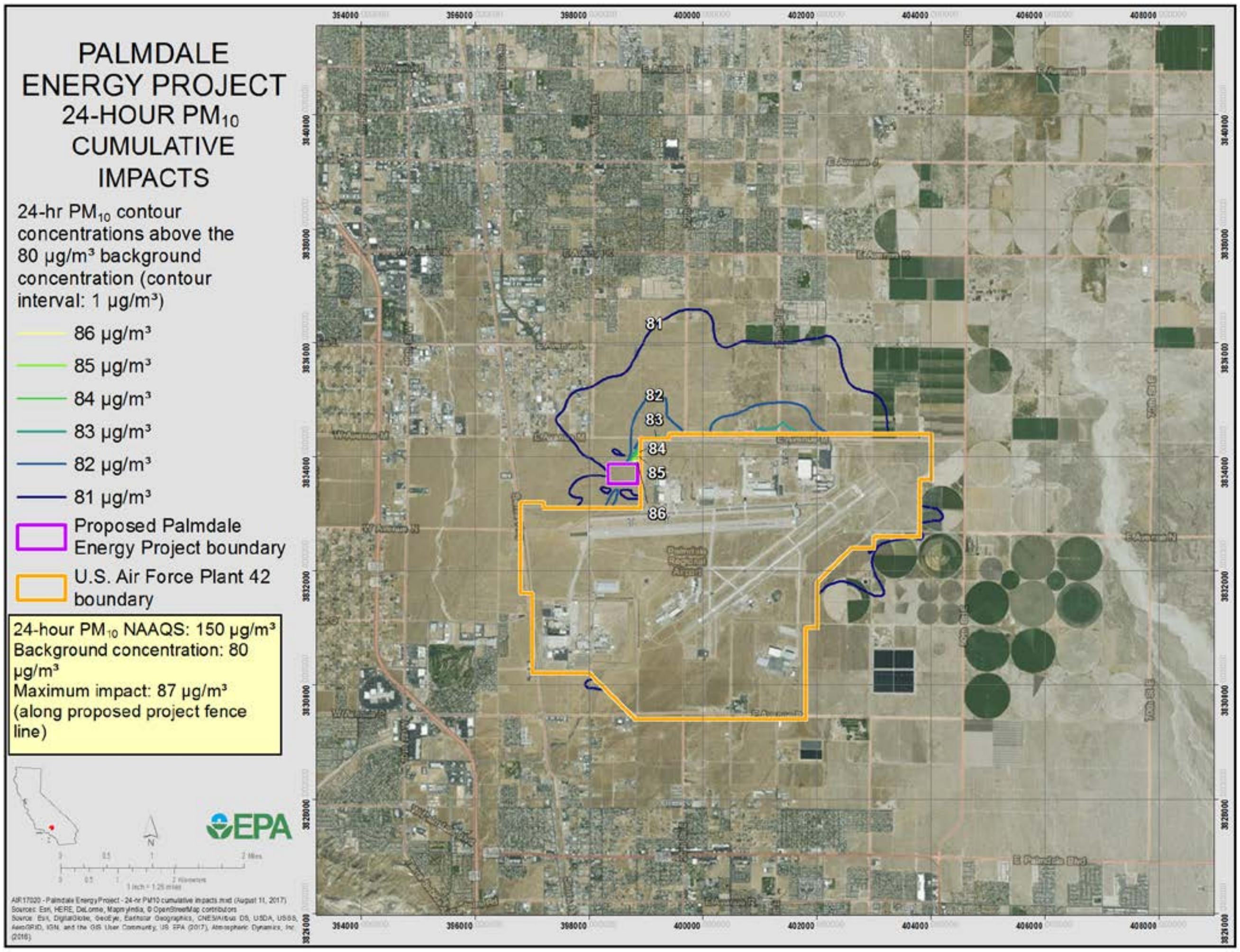


Figure 10 PEP Cumulative Impacts for Annual $PM_{2.5}$ Emissions

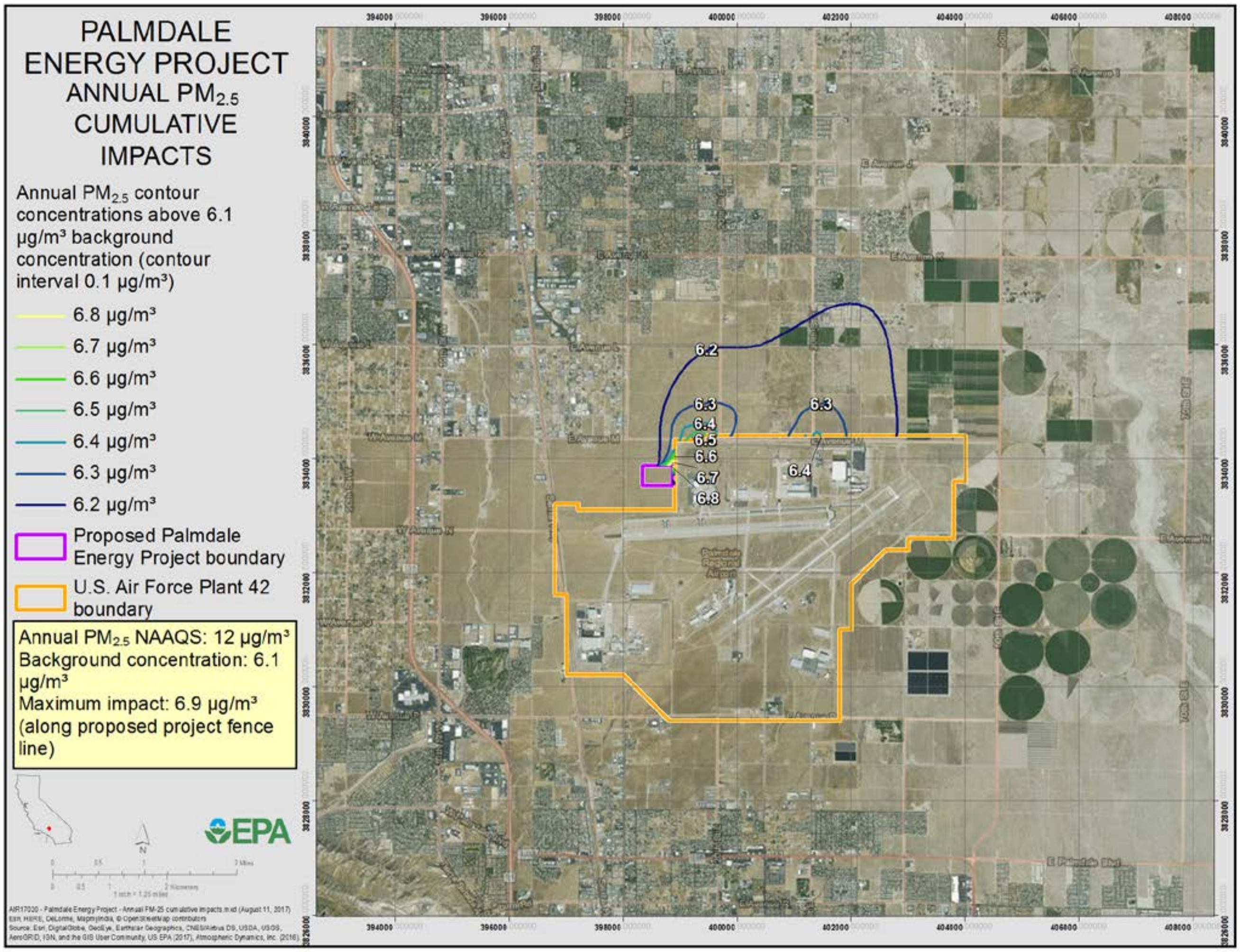
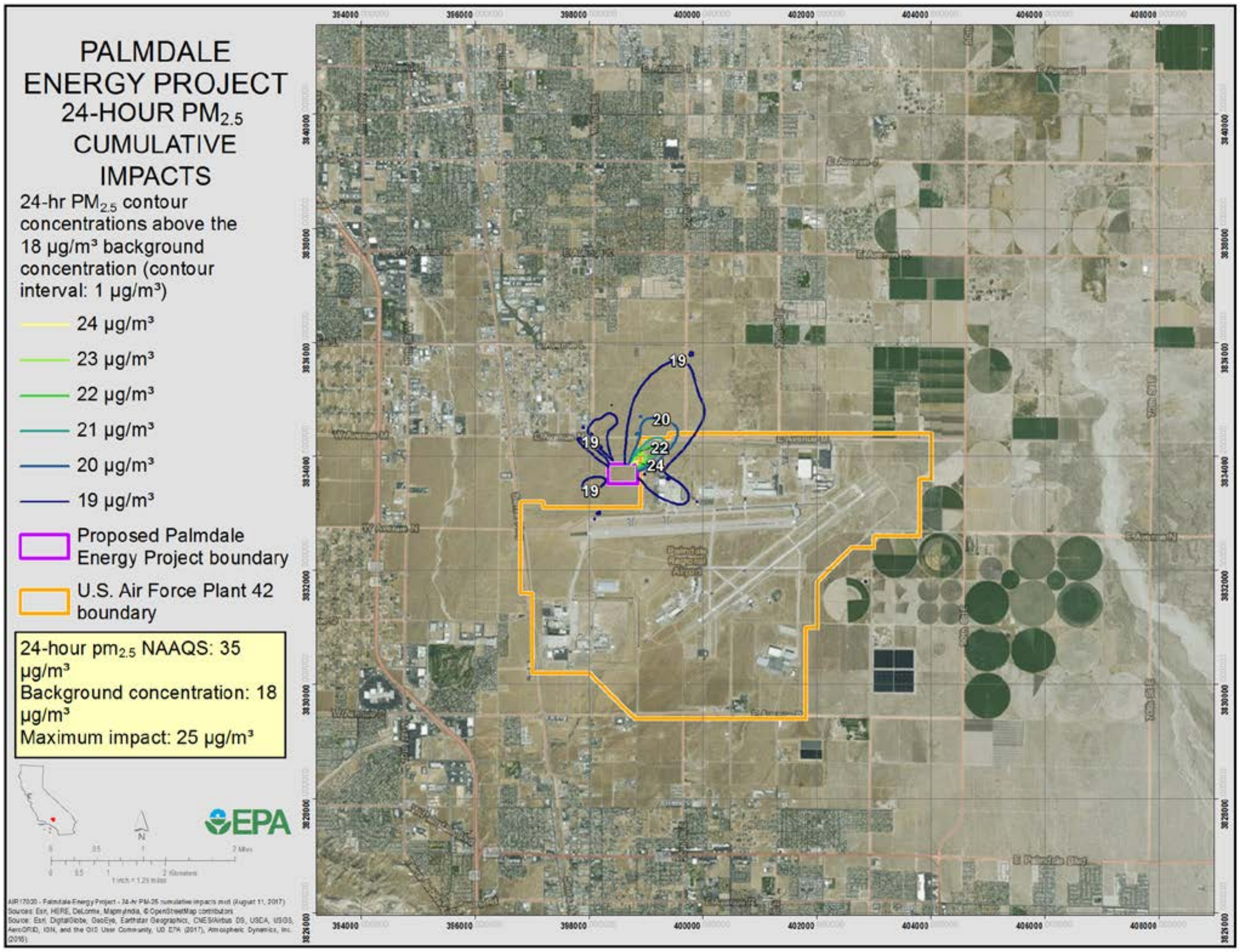


Figure 11 PEP Cumulative Impacts for 24-Hour $PM_{2.5}$ Emissions



7.3.5: Class I Increment Analysis

We conducted an analysis of impacts from the Project on the Class I increments. There are no Class I increments for CO or 1-hr NO_2. As part of the Class I analysis, the applicant first models the Project's impacts at the nearest Class I areas. The EPA has developed a different set of SIL values for use as compliance demonstration tools for characterizing air quality impacts in Class I increment analyses. If modeled impacts are below the applicable Class I increment SIL, then the permitting authority may determine, on a case-by case basis, that impacts for purposes of the Class I increment analysis are insignificant and no further analysis is required to conclude that emissions from the proposed PSD source will not cause or contribute to a violation of applicable Class I increments. Figure 12 below provides a map of the Class I areas within 300 km of the Project that were evaluated as part of the Class I analysis for the PEP. Table 26 below lists the Class I areas shown on the map in Figure 12.

Table 26 Class I areas within 300 km of project

Class I Areas within 300 km	Approx. Distance from Project
San Gabriel Wilderness Area	35 km (22 mi)
Cucamonga Wilderness Area	61 km (38 mi)
San Gorgonio Wilderness Area	118 km (73 mi)
Domeland Wilderness Area	119 km (74 mi)
San Rafael Wilderness Area	140 km (87 mi)
San Jacinto Wilderness Area	149 km (93 mi)
Aqua Tibia Wilderness Area	165 km (103 mi)
Joshua Tree National Park	165 km (103 mi)
Sequoia National Park	188 km (117 mi)
John Muir Wilderness Area	204 km (127 mi)
Kings Canyon National Park	220 km (137 mi)

As seen in Table 27, the results of the Class I increment analysis demonstrate that all modeled impacts for NO_2, PM_{10} and $PM_{2.5}$ will be considerably lower than the corresponding Class I SILs. There are few sources in the vicinity of these Class I areas that potentially would consume increment, and the values in the table are well below the respective SILs. Further, for $PM_{2.5}$, PEP 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. We have determined for purposes of the Class I increment analysis that projected impacts from PEP emissions are insignificant, no further analysis is required, and emissions from PEP will not cause or contribute to a violation of the applicable Class I PSD increments.

Figure 12 Class I Areas within 300 km of the PEP

Table 27 PEP Project Predicted Impacts Compared to Class I Increment Significant Impact Levels

	NO_2, annual ($\mu g/m^3$)	PM_{10}, 24-hr ($\mu g/m^3$)	PM_{10}, annual ($\mu g/m^3$)	$PM_{2.5}$, 24-hr ($\mu g/m^3$)	$PM_{2.5}$, annual ($\mu g/m^3$)
Significant Impact Level	0.1	0.3	0.2	0.27	0.05
Class I Increment	2.5	8	4	2	1
	Project Impacts				
San Gabriel Wilderness Area	0.005	0.17	0.004	0.17	0.004
Cucamonga Wilderness Area	0.001	0.01	0.000	0.01	0.001
San Gorgonio Wilderness Area	0.002	0.03	0.002	0.03	0.002
Domeland Wilderness Area	0.007	0.13	0.005	0.14	0.006
San Rafael Wilderness Area	0.003	0.01	0.002	0.10	0.002
San Jacinto Wilderness Area	0.004	0.13	0.003	0.13	0.003
Aqua Tibia Wilderness Area	0.004	0.09	0.003	0.09	0.003
Sequoia National Park	0.006	0.14	0.005	0.14	0.005
Joshua Tree National Park	0.007	0.15	0.006	0.15	0.006
John Muir Wilderness Area	0.005	0.01	0.004	0.01	0.001
Kings Canyon National Park	0.001	0.01	0.000	0.01	0.001

Source: October 2015 Application, Table 7-11, page 7.5-3

SIL Values: The 24-hr and annual $PM_{2.5}$ SIL values are provided in the EPA's August 18, 2016 draft $PM_{2.5}$ guidance entitled "Guidance on Significant Impact Levels for Ozone and Fine Particles in the Prevention of Significant Deterioration Permitting Program;" as well as, the supporting "Technical Basis for the EPA's Development of Significant Impact Thresholds for PM2.5 and Ozone," and the supporting "Legal Support Memorandum: Application of Significant Impact Levels in the Air Quality Demonstration for Prevention of Significant Deterioration Permitting under the Clean Air Act," both dated August 1, 2016.[85] The annual NO_2 and 24-hr PM_{10} SIL values see the EPA's proposed rulemaking "Prevention of Significant Deteriorations (PSD) and Nonattainment New Source Review (NSR)" at 61 Fed. Reg. 38250, 38291 on July 23, 1996.[86]

7.4 Modeling Approach

7.4.1 Modeling Data and Information Reviewed

The modeling analysis for the Project comprises the five documents listed in Table 28 below. The PSD Air Quality Modeling Protocol for the Palmdale Energy Project (August 2015) describes the methods used for the air quality impact analyses, including choice of model and the preparation of model inputs such as meteorological data.

85 https://www.epa.gov/nsr/draft-guidance-comment-significant-impact-levels-ozone-and-fine-particle-prevention-significant

86 https://www.gpo.gov/fdsys/pkg/FR-1996-07-23/pdf/96-17544.pdf

Table 28 Modeling Documentation for Palmdale Energy Project PSD Application

Short name	Citation
Modeling Protocol	"PSD Air Quality Modeling Protocol for the Palmdale Energy Project", Atmospheric Dynamics, Incorporated (August 2015)
PSD Application	"PSD Permit Application for the Palmdale Energy Project" (October 2015)
Completeness Review Letter	"Receipt and Preliminary Review of PSD Permit Application for Palmdale Energy Project" (December 2015)
Response to Completeness Review Letter	"Palmdale Energy Project Prevention of Significant Deterioration Permit Application Completeness Review" (April 2016)
Response to Comment	"FLM Concurrence That No Other AQRV Analyses are Required in Class I Areas" (January 2016)

7.4.2 Approach for NAAQS and Class II Increments

The Applicant modeled the impact of the Project on the NAAQS and PSD Class II increments using AERMOD in accordance with Appendix W. The modeling analyses included predicting maximum air quality impacts during startups and shut-downs, as well as a variety of conditions to determine worst-case short-term air impacts.

7.4.2.1 Startup and Shutdown Analyses

Combustion turbine NO_X and CO emissions during startup and shutdown (SU/SD) are estimated to be substantially higher than during normal operations, and thus the Applicant also considered startup/shutdown NO_X and CO emissions for the CTs. Emissions from emergency engine readiness and maintenance testing were not included in the modeling, as these are considered intermittent emission sources, and the permit limits the testing of these engines to time periods when the CTs are not in startup or shutdown mode.[87] The model results are shown in Table 24 for the preliminary or Project-only impact analysis, and in Table 25 for the cumulative impact analysis. The results demonstrate that emissions from PEP will comply with the 1-hour NO_2 NAAQS and both the 1-hour and 8-hour CO NAAQS under startup/shutdown conditions.

7.4.2.2 Cumulative Impact Analysis for NAAQS and PSD Increments

A cumulative impact analysis for comparison to the NAAQS includes nearby sources in addition to the project undergoing PSD review. For demonstrating compliance with the PSD increment, only increment-consuming sources need to be included, since the increment concerns only changes occurring since the applicable major or minor source baseline date. But, a conservative and sometimes easier approach is to model the impacts of the Project and all appropriate nearby sources. This was the approach taken for the PEP. For demonstrating compliance with the NAAQS, a background concentration is added to represent those sources not explicitly included in the modeling, so that the total predicted impact accounts for all contributions to current air quality. However, for an increment analysis, no background is added because the amount of increment consumed only includes the emissions increases above the baseline concentration. The increment consumed above the baseline concentration includes: (1) the Project and (2) nearby sources that were constructed *after* the applicable major and minor source baseline dates. For this analysis, all appropriate nearby sources were included in the

[87] See the EPA's March 1, 2011 memo "Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard", Memorandum from Tyler Fox, EPA Air Quality Modeling Group to EPA Regional Air Division Directors, March 1, 2011." at 8.

increment analysis; that is, sources that were constructed *prior* to the applicable major source and minor source baseline dates were not excluded. The nearby sources used for this analysis are discussed below.

Nearby source emission inventory

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. See 2005 Appendix W, Section 8.2.3.

The emission inventory data provided by the Antelope Valley AQMD for nearby sources included both maximum short-term hourly emissions and annual emissions. For the short-term averaging periods, the maximum hourly emissions as provided were assumed to occur for 1-hour and 24-hour time periods. The list of sources provided in the inventory, which includes sources with $PM_{2.5}$ and NO_X emissions, is included in Table 7-5 of the October 2015 Application. The closest sources in the inventory include Lockheed-Martin, Northup-Grumman and Boeing Defense sources. These are all United States Air Force (USAF) Plant 42 sources.

The EPA's NO_2 guidance clarification states that the nearby source inventory "should focus on the area within about 10 kilometers of the project location." The PEP nearby source inventory is consistent with this recommendation for NO_2 analyses.[88]

For the emission inventory data provided by Antelope Valley AQMD, the Applicant performed a "Q/D" analysis, which provides another factor for consideration in determining whether sources with small emissions (Q) and/or at large distances (D) would be reasonable to exclude from the analysis. The Q/D screening method has been used in past PSD permit applications and was used for the PHPP previously proposed at the site where the PEP would be located. The "Q/D" analysis means that Q is the NO_X emissions, in TPY, from the potential nearby source and D is the distance, in km, the potential source is from the Project. Consistent the PHPP application, the Applicant proposed that sources with a Q/D over 20 would be included as nearby sources. The closest sources to the PEP are the sources at USAF Plant 42, which is located adjacent to the PEP facility to out to 5 km to the east and about 4 km to the south of the PEP facility. The result of the Q/D analysis for these sources was much less than 20; however, given their proximity to the PEP the Applicant nonetheless included the USAF Plant 42 sources in all four cumulative impact analyses: 24-hour PM_{10}, 24-hour $PM_{2.5}$, annual PM_{10} and 1-hour NO_2. .\ (October 2015 Application, p.7.4-2). All of the other facilities outside the Plant 42 area were located considerably further from the proposed PEP facility, and had small Q/D values, generally less than 3, that would not be expected to cause a significant concentration gradient in the Project vicinity. Therefore, all of the other non-Plant 42 facilities were excluded from further cumulative modeling analyses. The Q/D analysis provides additional evidence that the selected nearby source inventory is adequate for the cumulative impact analyses.

Based on the combination of (1) conservative background monitored concentrations that are expected to include the effect of most nearby sources, (2) EPA guidance focusing on sources within 10 km for the cumulative analyses analysis, and (3) the Q/D analysis, we have determined that the nearby source inventory used in the cumulative impact analyses is appropriate.

---

[88] p.16 of "Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard", Memorandum from Tyler Fox, EPA Air Quality Modeling Group to EPA Regional Air Division Directors, March 1, 2011.

7.4.3 Approach for Class I Increments

For the Class I increments analysis, we started with a Project-only analysis to determine whether a cumulative impact assessment was needed. the San Gabriel Wilderness Area is within 50 km of the PEP site location and was thus evaluated with AERMOD using the same meteorology and modeling options as used in the Class II increment analyses described above.

For the remaining Class I areas, the 2005 Appendix W suggests that the use of AERMOD be limited to distances of approximately 50 km. Beyond 50 km, the CALPUFF dispersion model is typically used to assess the long-range transport of pollutants. However, consistent with the recently adopted EPA revisions to Appendix W (82 Fed. Reg. 5182, January 17, 2017) an alternative modeling approach was used because CALPUFF is no longer recommended for long-range transport (distances greater than 50 km). The Applicant's alternative approach used AERMOD with an arc of receptors at 50 km distance from the PEP, with receptors placed at two (2) degree intervals in the direction of each Class I area, with receptor heights ranging from the lowest elevation to the maximum elevation for 100 meter intervals for each Class I area.

We find the Applicant's approach acceptable for the Project-only Class I impacts analysis. The modeled impacts of the Project using this method were compared to the applicable Class I increment SILs in each Class I area within 300 km of the Project. As noted above, after reviewing the result of the Project-only Class I impacts analysis, we determined that, in this case, further analysis was not needed to demonstrate the PEP's compliance with the Class I PSD increments.

7.4.4 Good Engineering Practice (GEP) Analysis

The Applicant performed a GEP stack height analysis, to ensure (a) that downwash was properly considered in the modeling for stacks less than GEP height, and (b) that stack heights used as inputs to the modeling were no greater than GEP height, so as to disallow artificial dispersion from the use of overly tall stacks. As is typical, the GEP analysis was performed with the EPA's BPIP (Building Profile Input Program) software, which uses building dimensions and stack heights. The analysis found that GEP stack height for the main combustion turbines was 99.05 m, greater than the planned actual height of 48.8 m. GEP stack height for the other equipment was similarly greater than the planned heights. So, for all emitting units, the AERMOD modeling used the planned actual stack heights, and included wind direction-specific Equivalent Building Dimensions to properly account for downwash.[89]

7.4.5 $PM_{2.5}$ Considerations

Secondary $PM_{2.5}$ is included in the analysis of NAAQS and PSD increments. Formation of secondary $PM_{2.5}$ from precursor pollutants such as NO_X and SO_2 from a source can occur at downwind distances over time periods of hours or days. The EPA has guidance on how to account for secondary $PM_{2.5}$ from the precursors NO_X and SO_2.[90]

Based on our review of the available information and the record, we have determined that it is unlikely that NO_X and SO_2 emissions from the PEP will significantly impact secondary $PM_{2.5}$ formation. While it is possible that some transformation will occur, given the time for the transformation to occur, secondary $PM_{2.5}$ impacts are expected to occur at distances much farther downwind than the modeled $PM_{2.5}$ significant impact area (SIA).

---

[89] PEP PSD Application, 6.3-1

[90] EPA Guidance for $PM_{2.5}$ Permit Modeling, March 2014, and draft "Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and PM2.5 under the PSD Permitting Program, December 2, 2016."

Nevertheless, to assess secondary $PM_{2.5}$ formation, the Applicant considered the EPA's 2014 guidance on $PM_{2.5}$ permit modeling. In the case of the PEP, with $PM_{2.5}$ and NO_X emissions over the applicable SERs, the guidance recommends modeling direct $PM_{2.5}$ emissions using dispersion modeling (AERMOD) and the use of qualitative, hybrid qualitative/quantitative, or full quantitative photochemical grid modeling to account for secondary $PM_{2.5}$ impacts. The Applicant modeled direct $PM_{2.5}$ emissions using AERMOD, and, for secondary impacts, took a hybrid qualitative/quantitative approach consistent with Appendix D of the 2014 guidance for secondary impacts.

In this approach, the formation of secondary $PM_{2.5}$ from SO_2 and NO_X was accounted for by using interpollutant offset ratios. The interpollutant offset ratios are used to predict the expected secondary $PM_{2.5}$ contribution from SO_2 and NO_X emissions. The Applicant used ratios typically associated with the western U.S. of 40 tons of SO_2 to 1 ton of $PM_{2.5}$ and 100 tons of NO_X to 1 ton of $PM_{2.5}$. As seen in the Total Equivalent $PM_{2.5}$ calculation below, the ratios were applied to the potential emissions of SO_2 and NO_X from the PEP to calculate the secondary $PM_{2.5}$ emissions and then total (primary and secondary) equivalent $PM_{2.5}$ emissions. The ratio of total equivalent emissions to primary $PM_{2.5}$ emissions – 1.02 – can then be used to determine the total PM2.5 air quality impacts, by multiplying the 1.02 ratio by the modeled impacts from primary $PM_{2.5}$ emissions.

Total Equivalent $PM_{2.5}$ =Primary $PM_{2.5}$ emissions + Secondary $PM_{2.5}$ emissions
=Primary $PM_{2.5}$ emissions + [(SO_2 emissions/40) + (NO_X emissions/100)]
=81.01 tpy + (11.39 tpy/40) + (139 tpy/100) = 82.68 tpy

Equivalent $PM_{2.5}$ Impact Ratio =Total Equivalent $PM_{2.5}$ / Primary $PM_{2.5}$
= 82.68 tpy / 81.01 tpy =1.02

Thus, all modeled emissions presented above of $PM_{2.5}$ for the PEP sources (turbines, auxiliary boiler, and emergency equipment) were increased by a factor of 1.02 to account for secondary formation for PEP sources emitting significant amounts of secondary precursor emissions. The proposed PEP's emissions of SO_2 do not equal or exceed the PSD SER for SO_2, and would not need to be included in the evaluation of secondary $PM_{2.5}$ impacts according to EPA guidance, but were conservatively included here.[91] If SO_2 were not included, the results would slightly less than 1.02.

However, consistent with the EPA's 2014 $PM_{2.5}$ guidance, there should be a qualitative analysis that demonstrates that the NO_X ratio is valid. The Applicant addressed this by considering the EPA's 2016 draft guidance for modeled emission rates for precursors (MERPs).[92] For the draft guidance, the EPA modeled hypothetical sources around the U.S. to determine the types of secondary PM $PM_{2.5}$ impacts that can be expected to occur in various regions of the country. The draft guidance included modeling a hypothetical source of 500 TPY of NO_X in Los Angeles County, California and Kern County, California, both near the proposed PEP. The results of the Applicant's analysis are summarized below[93]]:

- The Project's secondary $PM_{2.5}$ emissions from NO_X would not exceed the $PM_{2.5}$ SILs for the Western U.S. because emissions increase are below the MERPs of 1075 tpy and 3184 tpy for the 24-hour and annual $PM_{2.5}$ standards, respectively.

[91] PEP PSD Application p.7.2-4.
[92] "Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and PM2.5 under the PSD Permitting Program," December 2, 2016, Richard Wayland, Air Quality Assessment Division. https://www3.epa.gov/ttn/scram/guidance/guide/EPA454_R_16_006.pdf
[93] See August 14, 2017 email from G. Darvin to L. Beckham, "Data in EPA's Draft MERPs Guidance."

- Modeling from hypothetical 500 tpy NO_X sources in Los Angeles and Kern County also indicate that the Project would not exceed the $PM_{2.5}$ SILs. The maximum modeled secondary impacts were 0.17 μg/m^3 and 0.014 μg/m^3 for the 24-hour and annual standards, respectively.
- Adding the primary impacts of PEP and background concentration to the modeled secondary impacts from Los Angeles and Kern County demonstrate that the annual and 24-hour $PM_{2.5}$ NAAQS would not be exceeded.

In sum, the Applicant's use of the offset ratios method for estimating $PM_{2.5}$ secondary impacts is consistent with modeled secondary $PM_{2.5}$ emissions of similar sources near the PEP, and thus was sufficiently conservative for demonstrating the Project will not cause or contribute to a NAAQS violation.

7.4.6 NO_2 Considerations

The Applicant used the Ozone Limiting Method (OLM) option in AERMOD, in which ambient ozone concentrations limit the amount of emitted NO that is converted to NO_2 (after an initial 10% conversion). In addition to requiring monitored ozone values, the method requires specification of an in-stack NO_2/NO_X ratio. The EPA believes the OLM method is justified in this area because, while the area has substantial ozone, most of that is due to transport from outside the area, rather than to photochemistry operating on VOC and NO_X emissions from sources within the area. Therefore, the alternative mechanisms for conversion of NO to NO_2 by the hydroxyl and peroxyl radicals are likely to be less important than the ozone conversion mechanism, and so the conversion is ozone-limited.

In-stack NO_2/NO_X ratio
The Project-only predicted concentrations of NO_2 were computed using the Ambient Ratio Method (ARM) following the EPA's guidance. ARM uses national default values of 0.80 (80%) and 0.75 (75%) for 1-hour and annual average NO_2/NO_X ratios, respectively. For the normal and startup/shutdown cumulative impact analysis for the 1-hour NO_2 averaging time, NO_2/NO_X in-stack ratios were based on the EPA's guidance (a default of 0.5 for the PEP Project sources, for all operating cases including startup, and a default of 0.2 for background sources in the cumulative inventory). The Applicant noted that since the Project would be located in an ozone nonattainment area, ozone concentrations are generally high, so that the initial in-stack NO_2/NO_X ratio is of less importance than would otherwise be the case, since plentiful ozone is available to convert NO to NO_2.

NO_2 monitor representativeness/conservativeness
As mentioned above, the Applicant chose the Lancaster Division Street monitor for background NO_2 concentrations. This monitor is just 2.5 miles from the PEP power block, and is near the Sierra Highway (110 m), the Antelope Valley Freeway (SR-14) (4 km), commute traffic on Division Street (50 m), and the Southern Pacific Railway (80 m). The EPA agrees with the Applicant that this location is conservative for providing NO_2 background concentrations for the Project.

O_3 background monitor representativeness
The Applicant notes that since O_3 is a regionally formed pollutant, the nearness of the monitoring site to the Project is the most important criterion for representativeness. The Lancaster Division Street monitor is just 2.5 miles away from the PEP facility, and the EPA agrees that it is adequately representative.

Missing O_3 data procedure
The Applicant filled in missing ozone data using a procedure to ensure that NO to NO_2 conversion is not underestimated.

This was accomplished by interpolating O_3 concentrations for periods with one to three missing hours. When substituting ozone concentrations from periods with up to 24 consecutive missing hours, the maximum ozone concentrations from the hour before/after the missing period or the ozone concentration from the same hour for the day before/after the missing period was used. The few remaining extended periods of missing data were replaced with the maximum ozone concentrations for the same hour for the four days before/after the missing hour.

Combining modeled and monitored values

The EPA has issued guidance on combining modeled and monitored values for air quality analyses for purposes of demonstrating compliance with the 1-hour NO_2 NAAQS (EPA's March 2011 memo).[94] The Applicant's approach was consistent with the EPA's March 2011 memo, by using the 3rd highest seasonal NO_2 concentration for each hour from the Lancaster monitoring station, averaged over three years for determining the background NO_2 concentration.

In addition, the Applicant's modeling included some intermittent sources (PEP's emergency generators) that may not need to be included, per the EPA's March 2011 memo[95], further adding to the conservativeness of the analysis.

Thus, the Applicant's overall approach to the 1-hour NO_2 analysis for the PEP, including the emission inventory, background concentrations of NO_2 and O_3, and method for combining model results with monitored values, is adequately conservative.

7.5 Model Inputs

7.5.1 Model selection

As discussed in the modeling protocol submitted by the Applicant,[96] the model that the Applicant selected for analyzing air quality impacts in Class II areas is AERMOD (version 15181), along with AERMAP (version 11103) for terrain processing, AERMET (version 15181) for meteorological data processing, and AERMINUTE (version 14337) for reducing the number of calms. In addition, the modeling utilized the Building Profile Input Program for PRIME (BPIP-PRIME). This accords with the default recommendations in Appendix W, section 4.2.2 on Refined Analytical Techniques.

7.5.2 Meteorology Model Inputs

AERMOD requires representative meteorological data in order to accurately simulate air quality impacts. For surface air data, the Applicant selected 2010-2014 data from the Palmdale Regional Airport Automated Surface Observing System meteorological monitoring site (ASOS). The Project site is located 2.5 km west-northwest of this meteorological monitoring site. ASOS monitoring sites measure surface meteorological data such as wind speed and direction, temperature, pressure, cloud heights, and sky cover. ASOS surface data are generally selected for processing for AERMOD because ASOS hourly data are routinely recorded and archived, generally meet the EPA's data completeness criteria, instruments are located in unobstructed areas meeting the EPA's

---

[94] "Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard," Memorandum from Tyler Fox, EPA Air Quality Modeling Group to EPA Regional Air Division Directors, March 1, 2011. http://www.epa.gov/ttn/scram/Additional_Clarifications_AppendixW_Hourly-NO2-NAAQS_FINAL_03-01-2011.pdf.

[95] *Ibid.*, p.10.

[96] PSD Air Quality Modeling Protocol, p.4; PSD Permit Application for the Palmdale Energy Project, p.6.2-1.

siting criteria, and instrument heights and sensor sensitivities meet the EPA's instrument specifications. Also, short-term (1-minute) wind direction and speed data were available to be processed by the AERMINUTE program to eliminate excessive calm observations and give hourly averages consistent with the EPA's modeling requirements. Other nearby meteorological sites were examined, but the Palmdale Airport had better data completeness, is the closest, and has the same surface characteristics as the Project site. The Palmdale Airport data is at or above 90% completeness for every quarter. In addition, the site is within two miles, just on the other side of the airport's airstrip; and it is on flat, desert scrub land, with no intervening high ground between the Project and the meteorological tower.

The Applicant made additional comparisons of land surface characteristics of the Project and the meteorological site (Palmdale Airport), in terms of surface roughness in each radial direction, concluding that because of the site's proximity and essentially identical characteristics and closeness to the PEP, the Palmdale Airport data may be considered "site specific" (or "on-site") data. Generally, fewer years of data are required if the data are site-specific. However, up to five years of data should be used if it has been collected. Here, because five years of meteorological data were collected, five years of data were used. Based on this information, the chosen 2010-2014 Palmdale Regional Airport surface data are amply representative for the PEP analysis.

For upper air (UA) data, the Applicant selected a blend of 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;[97] 2010 data from Tucson were also supplemented by data from Phoenix, the Edwards Air Force Base (AFB) near North Edwards, and the Yuma Proving Ground in Arizona (Yuma). The Applicant stated that representative UA observations nearest to the Project site are Edwards AFB Yuma. However, data at military installations like Edwards AFB and Yuma are not collected every day.

We note that there are also UA data collected at Vandenberg AFB in Lompoc, California and the Marine Corps Air Station in Miramar, California near San Diego. These monitoring sites were eliminated because the data were not representative of the Project site, as both of the monitoring stations are close to the ocean. They have upper air profiles representative of a coastal area which is dissimilar to the high-altitude, desert climate of Palmdale.

For the previously proposed PHPP Project, UA data from Desert Rock Airport, Nevada was used. However, Desert Rock has since stopped collecting UA data

In December 2010, UA measurements at Las Vegas, Nevada began to be collected. The Applicant used four years of UA data collected there from 2011 to 2014. To complete five years of meteorology data for use in the model, UA data collected at Tucson in 2010 were also used and supplemented with the data from Phoenix and Edwards AFB/Yuma Proving Ground. All of the meteorological monitoring sites chosen for use in this analysis represent elevated desert areas like Palmdale. Based on this information, we find the UA data is sufficient and representative of Palmdale.

7.5.2.1 Land characteristics model inputs

Land characteristics are used in the AERMOD modeling system in three ways: (1) via elevation within AERMOD to assess plume interaction with the ground; (2) via a choice of rural versus urban algorithm within AERMOD; and (3) via specific values of AERMET parameters that affect turbulence and dispersion, namely surface roughness, Bowen ratio, and albedo.

---

[97] PSD Air Quality Modeling Protocol, p. 6 and PSD Permit Application for the Palmdale Energy Project p.6-5-2.

The Applicant used terrain elevations from United States Geological Survey (USGS) Digital Elevation Model (DEM) data for receptor heights for AERMOD, which uses them to assess plume distance from the ground for each receptor. The elevations were also used within the AERMAP preprocessor to determine hill height scales for each receptor used by AERMOD to determine whether the plume goes over or around the hill.

For rural versus urban algorithm within AERMOD, the Applicant classified land use within 3 km of the project using the 12-category Auer procedure, one of the methods recommended by the EPA (2005 Appendix W, Section 7.2.3(c)). Since desert scrub land is more than 50% of the area, it is classified as "rural" for choosing dispersion algorithms within AERMOD. (October 2015 Application, p 6.5-7)

The Applicant followed the EPA's "AERMOD Implementation Guide" (2008 version) in using the EPA's AERSURFACE processor with the National Land Cover Data 1992 archive to determine surface characteristics for AERMET. A 2005 satellite image shows no significant change in land use since the 1992 data was compiled, so it remains appropriate. Land use cover categories were translated by AERSURFACE into monthly parameter values used in AERMET's stage 3 input files. The AERSURFACE determination of surface roughness length used land cover in 2 radial sectors, desert scrub and the airport's airstrip, which appears reasonable. The Bowen ratio (ratio of sensible to latent heating, i.e., direct temperature change versus air heating via evaporation) and albedo (reflection coefficient) affect heat-driven turbulence and dispersion under daytime convective conditions. Seasonal Bowen ratio for the surrounding 10x10 km area was estimated by AERSURFACE using three surface moisture categories and the amount of precipitation relative to the 30-year climatological record. Seasonal albedo was also supplied by AERSURFACE for the 10x10 km area based on land cover.

The approach taken by the Applicant as described above follows the standard EPA-recommended procedures for AERMOD inputs.

7.5.3 Model receptors

Model receptors are chosen geographic locations at which the model estimates concentrations of pollutants. The receptors should have good area coverage and be closely spaced enough so that the maximum model concentrations can be found. At larger distances, spacing between receptors may be greater than it is close to the source because concentrations vary less with increasing distance. The spatial extent of the receptors is limited by the applicable range of the model (roughly 50 km for AERMOD), and in some cases by knowledge of the distance at which impacts fall to negligible levels. Receptors need be placed only in ambient air, that is, locations "external to buildings, to which the general public has access" (e.g., not inside the project fence line). In addition, to avoid overly conservative estimates when multiple sources are being modeled, separate modeling runs may be needed for different subsets of receptors, so that a given source's emissions are not counted toward concentrations within its own fence line.

The Applicant used receptors every 10 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.[98] 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 m from the project in order to delineate the extent of the NO_2 significant impact area. Finally, if necessary, refined receptor

[98] October 2015 Application p.6.4-1.

grids with 20 m resolution were modeled around any location on the coarse and intermediate grids where a maximum impact was modeled for the PEP facility modeling analyses (i.e., with a PEP impact that was above the concentrations on the downwash grid). Based on the locations of the maximum modeled concentrations, no refined receptor grids were required as all maximum PEP facility impacts occurred on the 10 m fence line or 20 m downwash receptor grids. 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.[99]

7.5.4 Load screening and stack parameter model inputs

The Applicant performed initial "load screening" modeling, in which a variety of source operating loads and ambient temperatures were modeled, to determine the worst-case stack parameter scenario for use in the rest of the modeling. It modeled 100% load, 100% with duct burners operating, 75% load, 50% load, 43% load, and 40% load. Temperatures ranged from 23°F to 108°F. For annual averages, it used 100% load with a conservatively low temperature of 64°F (lower than actual annual average).[100] The choice of "worst case" may be different for each pollutant, since different pollutants' emissions respond differently to temperature and flow rate. During normal conditions, for this screening analysis, the worst-case load and ambient temperature condition is 100 percent load with duct firing and without evaporative cooling at 23°F for all pollutants and averaging times. However, for NO_2 and CO, during startup/shutdown emissions, the worst-case conditions is 43 percent load without duct firing and 64°F.[101] The corresponding stack parameters were used in the remainder of the modeling to provide conservative estimates of PEP impacts. Startup/shutdown emissions for $PM_{2.5}$ are equal to or less than normal emissions. Annual emissions using no duct burning is the worst case (duct burning will be limited to 1500 hours).

Table 29 Load Screening and Stack Parameters

	Operating Mode		
Parameter	**Startup/Shutdown**	**Normal (Duct Burning)**	**Annual (no Duct Burning)**
UTM Coordinates	398,596.6E and 3,833,693.16m N, UTM NAD83 Zone 11		
Stack Height, ft	160		
Stack Diameter, ft	22		
% Load	43	100	100
Ambient Temp, °F	64	23	64
Stack Flowrate, acfm	786,096	1,322,717	1,334,691
Stack Velocity, ft/sec	34.3	58	58.5
Stack Temperature, °F	177	186	195
NO_X, lb/hr (g/sec)	53.6 (6.795)[102]	18.5 (2.331)	15.8 (1.988)
PM_{10}, lb/hr (g/sec)	11.8	11.8 (1.487)	9.2 (1.160)
$PM_{2.5}$, lb/hr (g/sec)	12.03	12.0 (1.517)	9.39 (1.183)

[99] We conducted an additional analysis that included impacts from USAF Plant 42 sources inside the Plant 42 fence line for the 1-hr NO2 standard. The maximum impact was 175 µg/m^3. A map of the impacts is shown in Appendix 6.
[100] October 2015 Application, Appendix C, page 1 Palmdale AERMOD Turbine Screening Results.
[101] October 2015 Application, p 7.1-1.
[102] The 53.6 lb/hr modeled emission rate is included in the permit to ensure protection of the 1-hr NO_2 NAAQS.

	Operating Mode		
Parameter	**Startup/Shutdown**	**Normal (Duct Burning)**	**Annual (no Duct Burning)**
CO, lb/hr (g/sec)	419.4 (52.85)[103]	11.3 (1.424)	N/A

8. Class I Area Impacts: Air Quality Related Values

The PSD regulations at 40 CFR 52.21(p) require that PSD permit applicants address potential impairment to air quality related values (AQRVs), including visibility degradation (i.e., regional haze, plume blight) and the deposition of nitrogen and sulfur, for Class I areas. The particular Federal Land Manager[104] (FLM) for a Class I area is responsible for defining specific AQRVs for an area and for establishing the criteria to determine an adverse impact on the AQRVs. If a FLM determines that a source will adversely impact AQRVs in a Class I area, the FLM may recommend that the permitting agency deny issuance of the PSD permit, even in cases where no applicable increments would be violated. However, the permitting authority makes the final decision to issue or deny the PSD permit. The AQRV analysis for the PEP relies on guidance provided by the FLMs – the 2010 Federal Land Managers' Air Quality Related Values Work Group (FLAG 2010).

8.1 Q/D Analysis

The FLAG 2010 guidance allows for a screening analysis to determine whether a project is expected to cause adverse effects in Class I areas that are greater than 50 km from the particular project. This analysis, called the Q/D Analysis, looks at the sum of emissions of NO_X, PM_{10}, SOx, and H_2SO_4 on an annual basis (using the 24-hour worst-case day) ("Q") and divides it by the distance a particular Class I area is from a project ("D"). If the result is less than or equal to 10, then an applicant can presumptively determine that no adverse impacts are expected. Table 31 provides the Q/D results for the Project for the ten nearby Class I areas that are greater than 50 km from the project.

For the PEP Q/D analysis, Q is 327.3 tpy based on emissions of one warm start, one hot start, two shutdowns, and 22.1 hours of operating with duct firing. This a hypothetical worst-case day, and is not expected to occur on a frequent basis.

All Q/D values for the PEP Q/D analysis are less than 10, meaning no adverse impacts to the FLMs AQRVs are expected in these Class I areas. As such, we are not requiring further AQRV analysis for the ten nearby Class I areas that are greater than 50 km from the Project. We note that further analysis of the San Gabriel Wilderness Area is warranted, as this area is less than 50 km from the Project – where the Q/D screening tool is not applicable.

Table 30 Q/D Analysis for Class I Areas >50 km from the PEP

Class I Area	Q	D	Q/D
Cucamonga Wilderness Area	327.3	61.2	5.35
San Gorgonio Wilderness Area	327.3	118.3	2.77

[103] This 419.4 lb/hr modeled emission rate is included in the permit to ensure protection of the 1-hr CO NAAQS.
[104] FLMs include, for example, the U.S. Forest Service, National Park Service, and U.S. Fish and Wildlife Service.

Domeland Wilderness Area	327.3	119.4	2.74
San Rafael Wilderness Area	327.3	140.6	2.33
San Jacinto Wilderness Area	327.3	149.1	2.20
Aqua Tibia Wilderness Area	327.3	164.8	1.99
Sequoia National Park	327.3	164.9	1.98
Joshua Tree National Park	327.3	188.2	1.74
John Muir Wilderness Area	327.3	204.2	1.60
Kings Canyon National Park	327.3	220.5	1.48

8.2 AQRVs – San Gabriel Wilderness Area

For the San Gabriel WA, which is within 50 km of the Project, the impact of the Project on visibility impairment, also known as plume blight, was assessed. The EPA VISCREEN screening model was used to estimate visibility impairment by the PEP to the San Gabriel WA. Effects of plume blight are assessed as changes in plume perceptibility (ΔE) and plume contrast (C_p) for sky and terrain backgrounds. A Level 1 analysis, using default meteorological data and no site-specific conditions, was conducted.

The results of the VISCREEN modeling runs are presented in Tables 31 and 32. The VISCREEN results are presented for the two default worst-case theta angles – theta equal to 10 degrees representing the sun being in front of an observer, and theta equal to 140 degrees representing the sun being behind the observer. A negative plume contrast means the plume has a darker contrast than the background sky.

Table 31 Class I VISCRENN Modeling Results of Changes in Plume Perceptibility (ΔE)

Background	Distance (m)	Plume Perceptibility (ΔE)		Criteria (ΔE)
		Theta 10	Theta 140	
Sky	48.1	0.231	0.575	2
Terrain	35.5	1.223	0.295	2

Table 32 Class I VISCREEN Modeling Results of Changes in Plume Contrast (Cp)

Background	Distance (m)	Plume Contrast (C_p)		Criteria (C_p)
		Theta 10	Theta 140	
Sky	48.1	0.003	-0.008	0.05
Terrain	35.5	0.009	0.003	0.05

The results from the VISCREEN model show that changes in plume perceptibility and plume contrast for sky and terrain backgrounds are below the criteria thresholds.[105] Therefore, the plume would not be perceptible against a sky or terrain background.

[105] US Forest Service, et.al. "Federal Land Manager's Air Quality Related Values Workbook (FLAG), Phase 1 report-Revised 2010", October 2010, p.18-19. https://www.nature.nps.gov/air/Pubs/pdf/flag/FLAG_2010.pdf

In an email dated January 22, 2016, the U.S. Forest Service, the FLM for the San Gabriel WA, stated that it had reviewed the Application materials and that no further analysis was needed for AQRVs.

Section 9: Additional Impacts Analysis

In addition to assessing the ambient air quality impacts expected from a proposed new source, the PSD regulations require that the Permittee evaluate potential impacts on (1) soils and vegetation; (2) growth; and (3) visibility impairment. 40 CFR 52.21(o). This visibility analysis is independent of the Class I visibility AQRV analysis discussed in section 8 above. The depth of the analysis generally depends on existing air quality, the quantity of emissions, and the sensitivity of local soils, vegetation, and visibility in the source's impact area. Below we have provided a summary of the information provided by the Applicant to address additional impacts[106]. Based on our consideration of the information and analysis provided by the Applicant, we do not believe that emissions associated with the Project will result in adverse impacts on soils or vegetation, growth, or visibility.

Section 9.1: Soils and Vegetation

For most types of soils and vegetation, ambient concentrations of criteria pollutants below the secondary NAAQS will not result in harmful effects because the secondary NAAQS are set to protect public welfare, including vegetation, crops, and animals. As provided in Section 7, this Project will not result in a violation of the primary or secondary NAAQS. In addition, the Applicant also considered the EPA's "Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals" (1980)[107] to determine if maximum modeled ground-level concentrations of NO_2 and CO could have an impact on plants, soils, and animals. As see in Table 33, the modeled impacts of NO_2 and CO emissions from the facility, individually, and in addition to the background concentrations of NO_2 and CO, are well below the minimum impact level for sensitive plants using this screening procedure.

Table 33 Project Maximum Concentrations and EPA Guidance Levels

Criteria Pollutant and Guidance Averaging Time	EPA Screening Concentration (μg/m³)	Modeled Maximum Concentrations[108] (μg/m³)	Modeling Averaging time
NO2 4-hours	3,760	126	1 hour
NO_2 8-Hours	3,760	126	1 hour
NO_2 1-Month	564	126	1 hour
NO_2 Annual	94	16.1	Annual
CO Weekly	1,800,000	1692	8 hour

[106] See Sections 4.5, 7.6, and 8 of the October 2015 Application.
[107] Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals," EPA 450/2-81-078, December 1980.
[108] Modeled maximum concentrations based on: cumulative NAAQS analysis for the 1-hr NO_2 NAAQS, Table 25; project-only annual NO_2 impacts and background annual NO_2 concentration, Table 24; project-only 8-hour CO impacts and background 8-hr CO concentration, Table 24.

Nitrogen Deposition
In addition to the ambient pollutant exposure levels, plants have the potential to be affected by intake of air pollutants that have deposited and subsequently accumulated in the soil. Nitrogen deposition in soil can have beneficial effects to vegetation if they are currently lacking these elements. At levels above plant requirements, gaseous emission impacts on soils can cause acidic conditions to develop. Soil acidification and eutrophication can occur as a result of atmospheric deposition of nitrogen.

Nitrogen deposition is a potential AQRV evaluated by the FLMs as part of a Class I impacts analysis. The PEP screened out of that analysis based on the FLMs' guidance, and no specific nitrogen deposition analysis was required. As such, nitrogen deposition associated with the Project is not expected to occur at levels that would negatively impact soils and vegetation.

Section 9.2: Visibility Impairment

Using procedures in the EPA's Workbook for Plume Visual Impact Screening and Analysis,[109] the Applicant conducted Level 1 VISCREEN assessments of visibility impairment (plume blight) for one Class I area. This Class I area was San Gabriel Wilderness Area (see Section 7.5.1 of the October 2015 Application), which is located within 50 km of the proposed PEP.

The Applicant also identified three potentially sensitive Class II areas within 50 km of the proposed PEP. These areas, with their approximate closest distances to PEP, were:

- Pleasant View Ridge Wilderness (26.5 km)
- Magic Mountain Wilderness Area (28.3 km)
- Sheep Mountain Wilderness Area (44.3 km)

The Applicant performed a Level 1 VISCREEN analysis for the Pleasant View Ridge Wilderness, the closest of the identified areas. Because a Level 1 screening analysis is the most simplified and conservative approach (where the input data, other than distances, are identical, including the use of background visual range), it is most conservative to use the closest area. The results of this analysis were below the significance criteria for the selected area. See Tables 34 and 35below.

Table 34 Class II VISCREEN Modeling Results of Changes in Plume Perceptibility (ΔE)

Distance (km)	Background	Plume Perceptibility (ΔE)		Criteria (ΔE)
Nearest Border – 26.5 Furthest Border – 42.0		**Theta 10**	**Theta 140**	
	Sky	0.542	0.967	2
	Terrain	1.726	0.402	2

[109] "Workbook for Plume Visual Impact Screening and Analysis (Revised)", EPA, EPA–454/R–92–023, 1992.

Table 35 Class II VISCREEN Modeling Results of Changes in Plume Contrast (Cp)

Distance (km)	Background	Plume Contrast (C_p)		Criteria (C_p)
Nearest Border – 26.5 Furthest Border – 42.0		Theta 10	Theta 140	
	Sky	0.001	-0.014	0.05
	Terrain	0.009	0.004	0.05

Because the VISCREEN results are below the threshold criteria, we do not expect the Project to contribute to visibility impairment.

Section 9.3: Growth

The growth component of the additional impact analysis considers an analysis of general commercial, residential, industrial and other growth associated with the PEP. 40 CFR 52.21(o). Based on the information submitted by the Applicant[110], as summarized provided below, we do not expect the Project to result in any significant growth.

Section 9.3.1: Construction Phase Growth Impacts

The proposed PEP is expected to require 339 construction workers (average day value). The proposed Project would draw from the construction work force in the region. It is assumed that few, if any, construction workers would permanently relocate to the nearby communities of Palmdale, Lancaster, Lake Los Angeles, Santa Clarita, etc. during the Project construction phase. This is because construction workers typically commute relatively long distances to their work sites. Should some construction workers choose to stay temporarily at a local area motel or hotel, there are at least 30 hotels in the vicinity (Palmdale and Lancaster). Should a portion of the workers relocate to the area for the duration of their construction assignments, impacts to available housing and population would be minor, as vacancy rates in Palmdale and Lancaster were estimated at 3.7 percent. Construction impacts of the Project to population are therefore expected to be minimal, and the Project would not result insubstantial population growth. Additionally, as the construction workforce is expected to either commute to the area or temporarily occupy the available supply of hotels or rentals in the area, the demand on the local housing supply is expected to be negligible.

Section 9.3.2: Operation Phase Growth Impacts

Recent census data shows population growth in the area (Los Angeles, San Bernardino, and Kern Counties), but these growth trends show that the Southern California region is expected to experience population growth with or without implementation of the proposed PEP. The PEP would supply energy in order to accommodate existing demand and already projected growth. New resources like PEP will help supplement the replacement of lost generation from retired once through cooling plants.[111] As water is a limited resource, with the use of dry cooling, this project will also be able to supplement the replacement of aging merchant power plants which rely on the use of wet cooling towers.

---

[110] See Section 8 of the October 2015 Application.

[111] As explained elsewhere in the Application, as a load-following facility, the PEP will also service to integrate renewable energy into the grid, as part of California's efforts to expand renewal energy.

The proposed PEP is expected to employ 23 persons. Some of the Project operations jobs may involve relocation to the area for workers with specialized technical or managerial skills. However, as the overall size of the workforce needed for Project operation is small, population impacts would be less than significant, especially as some of these workers would likely already be residents of the local area. Further, due to the small number of workers needed for operation of the plant and the availability of local housing, operation of the Project is expected to have an insignificant impact on housing.

Section 10: Environmental Justice Analysis

Executive Order 12898, entitled "Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations," states in relevant part that "each Federal agency shall make achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations and low-income populations." Section 1-101 of Exec. Order 12898, 59 Fed. Reg. 7629 (Feb. 16, 1994).

EPA determined that there may be minority or low-income populations potentially affected by its proposed action on the PEP PSD permit application, and determined that it would be appropriate to prepare an Environmental Justice Analysis for this action. EPA therefore prepared an Environmental Justice Analysis, which is included in the administrative record for EPA's proposed PSD permit for the Project. EPA's analysis concludes that the Project will not cause or contribute to air quality levels in excess of health standards for the pollutants regulated under EPA's proposed PSD permit for the Project, and that therefore the Project will not result in disproportionately high and adverse human health or environmental effects with respect to these air pollutants on minority or low-income populations residing near the proposed Project, or on the community as a whole.

Section 11: Endangered Species Act

Pursuant to section 7 of the Endangered Species Act (ESA), 16 U.S.C. 1536, and its implementing regulations at 50 CFR part 402, the EPA is required to ensure that any action authorized, funded, or carried out by the EPA is not likely to jeopardize the continued existence of any endangered or threatened species or result in the destruction or adverse modification of such species' designated critical habitat. The EPA has determined that our PSD permitting action for the PEP is subject to ESA section 7 requirements.

In a letter dated September 14, 2011, the U.S. Fish and Wildlife Service (the Service) concurred with the EPA's finding that the PHPP, the natural gas-fired power plant that was previously issued a PSD permit by the EPA at this location, may affect but is not likely to adversely affect the federally threatened desert tortoise (*Gopherus agassizii)* or endangered arroyo toad *(Bufo californica).*[112] The biological assessment used in that determination is included in our administrative record for this action.

The EPA contacted the Service to determine whether the PEP raised any potential concerns for federally-listed threatened or endangered species beyond those already considered for the PHPP that could trigger the need for further ESA section 7 consultation. In an email dated July 26, 2016, the Service stated that no additional ESA review was needed for PEP with respect to the desert tortoise and arroyo toad. That is, the previous analysis for the PHPP remains valid for the PEP. However, the Service informed the EPA of a new issue to consider since the

[112] See letter from Carl T. Benz, FWS, to Gerardo C. Rios, EPA, regarding "Proposed Palmdale Hybrid Power Plant, Los Angeles County" dated September 14, 2011.

previous ESA section 7 determination by the Service regarding the PHPP: the Southwestern willow flycatcher, a listed endangered species, has been colliding with transmission and generation tie lines. This could be a potential issue for the PEP as it has a fairly long transmission and generation tie line associated with it.

In response to this concern, the Applicant provided a Biological Assessment (December 2016) regarding the Southwestern willow flycatcher, which was subsequently provided to the Service. The Biological Assessment concluded that the proposed transmission and generation tie lines are not expected to result in impacts to the Southwestern willow flycatcher from individuals colliding with the transmission line or habitat alteration. In response, the Service raised concerns that there is information that Southwestern willow flycatchers are known to occur near the Project site and the proposed generation tie-line and recommended formal ESA section 7 consultation with the Service since the Project may adversely affect a listed species.[113] However, upon further review and analysis, the Service evaluated the likelihood of southwestern willow flycatchers striking generation tie-lines and considered it to be discountable, and as a result no longer recommended formal consultation.[114] Based on the available information we have determined that the Project may affect but is not likely to adversely affect the southwestern willow flycatcher, and the Service has concurred.

Section 12: National Historic Preservation Act

Section 106 of the National Historic Preservation Act (NHPA) requires the EPA to consider the effects of this proposed permit action on properties listed in or eligible for inclusion in the National Register of Historic Places. To make this determination, the EPA prepared a Cultural Resources Report for the PEP. A copy of the Draft Cultural Resource Report is part of administrative record for this permitting action. During the public comment period for this action, as described in Section 4 above, any interested party is welcome to bring specific concerns or information to our attention regarding this Project's potential effect on historic properties.

For purposes of our NHPA review, we are proposing the Area of Potential Effect (APE) to include the Project site footprint, defined as the 50-acre footprint of the power plant, the 20-acre temporary laydown and parking area, the 35.6 miles of proposed transmission lines, the 0.25 miles of sanitary wastewater pipeline, the one-mile extension of the reclaimed water supply pipeline, and the 8.7 miles of natural gas supply pipeline. Except with respect to archeological resources, the APE also includes one parcel deep from the Project site footprint in urban areas, but in rural areas is expanded to include a 0.5-mile buffer from the Project site footprint, and from any above-ground linear facilities (to encompass resources whose setting could be adversely affected by industrial development). For archeological resources, the APE includes a 200-ft radius from the Project site footprint and a 50-ft radius from the centerline of linear facilities.

EPA Region 9 will consult with the California State Historic Preservation Officer (California SHPO) under NHPA section 106 on the Project. In addition, EPA Region 9 sent a letter to the San Manuel Band of Mission Indians (hereinafter San Manuel Tribe) to inquire whether the Tribe has an historical interest in the Project and the APE, and to inquire whether the Tribe wished to consult with the EPA in the section 106 process. The San Manuel Tribe recently responded with a request to consult with the EPA in the section 106 process. Accordingly, the EPA intends to consult with the San Manuel Tribe as well as the SHPO as part of the NHPA section 106 process prior to issuing a final PSD permit decision for the Project. The EPA is currently proposing to determine that the PEP will not adversely affect historic properties.

---

[113] See email dated January 11, 2017 from Ray Bransfield, Fish & Wildlife Service to Lisa Beckham, EPA Region 9, re: Palmdale Energy Project - Federal Permit - Section 7 Consultation.

[114] See email dated August 3, 2017 from Ray Bransfield, U.S. Fish & Wildlife Service to Lisa Beckham, EPA Region 9, re: Palmdale Energy Project and Southwestern Willow Flycatcher.

Appendix 1 – Cost Analysis for Oxidation Catalyst on the CTs

Table 36 Oxidation Catalyst Cost Analysis for CTs - 2.0 ppm

	Costs (2017$)	Notes
	Capital Costs	
Direct Capital Costs		
Purchased Equipment:		
A. Purchased Equipment Costs	$700,000	scale up from OGS at 50.6 MMBtu/hr
B. Other Required Systems	$90,000	Internal frame cost
C. Instrumentation & Controls	$70,000	EPA OAQPS 10% of A
D. Freight	$35,000	EPA OAQPS 5% of A
E. Taxes	$74,000	8.25% Tax Rate (CA average)
Total Purchased Equipment Costs **(TEC)**	$969,000	
Installation Costs:		
F. Foundation & Supports	$97,000	EPA OAQPS 10% of TEC
G. Erection and Handling	$339,000	EPA OAQPS 35% of TEC
H. Electrical	$10,000	EPA OAQPS 1% of TEC
I. Piping	$19,000	EPA OAQPS 2% of TEC
J. Insulation	$19,000	EPA OAQPS 1% of TEC
K. Painting	$10,000	EPA OAQPS 1% of TEC
L. Site Preparation	$0	estimated by Project Engineer
Total Installation Costs **(TIC)**	$494,000	
Total Direct Capital Costs (TDCC)	$1,463,000	Sum of TEC and TIC
Indirect Capital Costs		
L. Engineering & Supervision	$145,000	EPA OAQPS 15% of TEC
M. Construction and Field Exp.	$97,000	EPA OAQPS 10% of TEC
N. Contractor Fees	$48,000	EPA OAQPS 5% of TEC
O. Startup	$10,000	EPA OAQPS 1% of TEC
P. Performance Testing	$10,000	EPA OAQPS 1% of TEC
Total Indirect Capital Costs (TICC)	$310,000	
Total Direct & Indirect Capital Costs (TDICC)	$1,773,000	Sum of TDCC and TIDCC
Contingency (@3%)	$53,190	3% of TDICC (EPA OAQPS)
Total Capital Costs (TCC):	$1,826,000	Sum of TDCC, TIDCC, and contingency
	Annual Operating Costs	
Direct Operating Costs		
Q. Operating Labor	$38,000	1 hr/day, @108.50 hr, 350 days/yr

R. Supervisory Labor	$6,000	EPA OAQPS 15% of Q
S. Maintenance Labor	$19,000	0.5 hr/day, @$108.5 hr, 350 days/yr
T. Maintenance Materials	$19,000	100% of maintenance labor costs
U. Utility Expenses (gas and electricity, fuel penalty)	$57,000	applicant estimate
V. Media replacement and disposal (catalyst, every 5 yrs)	$489,000	applicant estimate
W. Annual Media Cost	$24,000	V, divided by media life (5 yrs) x CRF (7%, 15 yrs, = 0.24389)
X. Other Penalties	$0	Already included (loss power sales, added maintenance)
Total Direct Operating Costs (TDCO)	$163,000	
Indirect Operating Costs		
Y. Overhead	$37,800.00	60% of Total Labor, EPA OAQPS (Q+R+S)
Total Indirect Operating Costs		
Capital Charges & Costs		
Z. Property Tax	$27,000	EPA OAQPS 1.48% of TCC
AA. Insurance	$18,000	EPA OAQPS 1% of TCC
BB. General Administrative	$37,000	EPA OAQPS 2% of TCC
CC. Capital Recovery Costs	$147,000	7% per OMB, 30 yr plant lief, CFR=0.0806 of TCC
Total Capital Charges Costs	$229,000	Sum of Z, AA, BB, CC
Total Annualized Operating Costs	$392,000	Sum of TDOC, TIOC, TCCC
Cost Effectiveness		
Base Case Emissions		
Base Concentration	9	ppm
Annual Emission Rate	157.80	tpy
Oxidation Catalyst Case		
CO Concentration	2	ppm
Annual Emission Rate	41.20	tpy
CO Reduction from Uncontrolled Case:	116.60	
Control Cost Effectiveness	$3,400.00	

Notes and References:
See notes and references Table R-1 and R-2 in May 2017 Response Letter

Table 36 Oxidation Catalyst Cost Analysis for CTs - 1.5 ppm

	Costs (2017$)	Notes
Capital Costs		
Direct Capital Costs		
Purchased Equipment:		
A. Purchased Equipment Costs	$850,000	scaleup from OGS at 50.6 MMBtu/hr
B. Other Required Systems	$90,000	Internal frame cost
C. Instrumentation & Controls	$85,000	EPA OAQPS 10% of A
D. Freight	$42,500	EPA OAQPS 5% of A
E. Taxes	$88,000	8.25% Tax Rate (CA average)
Total Purchased Equipment Costs **(TEC)**	$1,156,000	
Installation Costs:		
F. Foundation & Supports	$116,000	EPA OAQPS 10% of TEC
G. Erection and Handling	$405,000	EPA OAQPS 35% of TEC
H. Electrical	$12,000	EPA OAQPS 1% of TEC
I. Piping	$23,000	EPA OAQPS 2% of TEC
J. Insulation	$23,000	EPA OAQPS 1% of TEC
K. Painting	$12,000	EPA OAQPS 1% of TEC
L. Site Preparation	$0	estimated by Project Engineer
Total Installation Costs **(TIC)**	$591,000	
Total Direct Capital Costs (TDCC)	$1,747,000	Sum of TEC and TIC
Indirect Capital Costs		
L. Engineering & Supervision	$173,000	EPA OAQPS 15% of TEC
M. Construction and Field Exp.	$116,000	EPA OAQPS 10% of TEC
N. Contractor Fees	$58,000	EPA OAQPS 5% of TEC
O. Startup	$12,000	EPA OAQPS 1% of TEC
P. Performance Testing	$12,000	EPA OAQPS 1% of TEC
Total Indirect Capital Costs (TICC)	$371,000	
Total Direct & Indirect Capital Costs (TDICC)	$2,118,000	Sum of TDCC and TIDCC
Contingency (@3%)	$63,540	3% of TDICC (EPA OAQPS)
Total Capital Costs (TCC):	$2,182,000	Sum of TDCC, TIDCC, and contingency
Annual Operating Costs		
Direct Operating Costs		
Q. Operating Labor	$38,000	1 hr/day, @108.50 hr, 350 days/yr
R. Supervisory Labor	$6,000	EPA OAQPS 15% of Q
S. Maintenance Labor	$19,000	0.5 hr/day, @$108.5 hr, 350 days/yr

T. Maintenance Materials	$19,000	100% of maintenance labor costs
U. Utility Expenses (gas and electricity, fuel penalty)	$77,000	applicant estimate
V. Media replacement and disposal (catalyst, every 5 yrs)	$585,000	applicant estimate
W. Annual Media Cost	$29,000	V, divided by media life (5 yrs) x CRF (7%, 5 yrs, = 0.24389)
X. Other Penalties	$0	Already included (loss power sales, added maintenance)
Total Direct Operating Costs (TDCO)	$188,000	
Indirect Operating Costs		
Y. Overhead	$37,800.00	60% of Total Labor, EPA OAQPS (Q+R+S)
Total Indirect Operating Costs		
Captial Charges & Costs		
Z. Property Tax	$33,000	EPA OAQPS 1.48% of TCC
AA. Insurance	$22,000	EPA OAQPS 1% of TCC
BB. General Administrative	$44,000	EPA OAQPS 2% of TCC
CC. Capital Recovery Costs	$176,000	7% per OMB, 30 yr plant lief, CFR=0.0806 of TCC
Total Capital Charges Costs	$275,000	Sum of Z, AA, BB, CC
Total Annualized Operating Costs	$463,000	Sum of TDOC, TIOC, TCCC
Cost Effectiveness		
Base case Emissions		
Base Concentration	9	ppm
Annual Emission Rate	157.80	tpy
SCR Case		
CO Concentration	1.5	ppm
Annual Emission Rate	31.00	tpy
NO_X Reduction from Uncontrolled Case:	126.80	
Control Cost Effectiveness	$3,700.00	

Notes and References:
See notes and references Table R-1 and R-2 in May 2017 Response Letter

Appendix 2 – PM/PM_{10}/$PM_{2.5}$ Test Data for CTs

Available data:

- 3 source test results for the same CT model as the PEP (STG6-5000F) near Lodi, California, and
- Information from the manufacturer showing 10 test results.

There is a total of 12 data points. The data and statistics are summarized in Tables 37 and 38 below. The data demonstrates a high variability in emissions and demonstrates that the emission rate used by the applicant in the air quality impact analysis is reasonable. The emission rate is within the average plus 2 standard deviations (98% confidence level). In addition, this emission rate is in line with other emission rates for gas-fired combustion turbines – see Table 9 in Section 6.3.3: PM, PM_{10} and $PM_{2.5}$ Emissions for CTs.

Table 37 Available PM Test Data for STGF-5000F

Test Average (lb/hr)
2.73 (Lodi Energy Center)
1.88 (Lodi Energy Center)
1.64 (Lodi Energy Center)
4.84 (Manufacturer)
4.45 (Manufacturer)
5.41 (Manufacturer)
6.9 (Manufacturer)
7.9 (Manufacturer)
16 (Manufacturer)
11.7 (Manufacturer)
9.6 (Manufacturer)
5.75 (Manufacturer)
5.42 (Manufacturer)

Table 38 PM Test Data Analysis for STG5-5000F

Average Emission Rate (lb/hr)	6.48
Standard Deviation (lb/hr)	4.06
Average +2 SD, 98% confidence level (lb/hr)	14.60
Permitted Emission Rate (lb/hr)	11.8

Appendix 3 – Summary of Battery Storage Literature Review

Article	Date	Link
A look at the new battery storage facility in California built with Tesla Powerpacks	1/31/2017	https://arstechnica.com/business/2017/01/a-look-at-the-new-battery-storage-facility-in-california-built-with-tesla-powerpacks/
5 battery energy storage projects to watch in 2016	11/30/2015	http://www.utilitydive.com/news/5-battery-energy-storage-projects-to-watch-in-2016/409624/
The Texas Energy Storage Market: A Four-Part Examination	10/18/2016	http://www.lexology.com/library/detail.aspx?g=96c1507a-0c85-41e3-af04-8f5634e8ed45
NEC Energy Solutions provides first utility-scale battery energy storage project in Massachusetts	10/17/2016	http://www.energy-storage.news/news/nec-energy-solutions-provides-first-utility-scale-battery-energy-storage-pr
CAISO Battery Storage Trial	11/21/2016	http://www.tdworld.com/blog/caiso-battery-storage-trial
Battery storage technologies, applications and trend in renewable energy, 2016 IEEE International Conference on Sustainable Energy Technologies	11/14/2016	http://ieeexplore.ieee.org/abstract/document/7811821/
List of energy storage projects, Wikipedia	Accessed 4/3/2016	https://en.wikipedia.org/wiki/List_of_energy_storage_projects
A Look at the Biggest Energy Storage Projects Built Around the World in the Last Year	2/3/2016	https://www.greentechmedia.com/articles/read/a-look-at-the-biggest-energy-storage-projects-built-around-the-world-in-the
World's Largest Storage Battery Will Power Los Angeles	7/7/2016	https://www.scientificamerican.com/article/world-s-largest-storage-battery-will-power-los-angeles/
GE Unveils World's First Battery Storage & Gas Turbine Hybrid with Southern California Edison	10/4/2016	http://www.businesswire.com/news/home/20161004006177/en/GE-Unveils-World%E2%80%99s-Battery-Storage-Gas-Turbine

Appendix 4 – GHG Performance Data for the CTs

Table 39 Palmdale Energy Project Plant Performance Metrics

85 Deg. 20% RH	Plant Output (Net) MWh	CO_2 Production (lb/hr)	Notes
Base load, evap cooling on, no duct firing	657	530,016	
Base load, evap cooling on, full duct firing	704	577,928	MW & CO_2 production with duct firing
75% load, no evap cooling, no duct firing	474	394,328	
Plant minimum load, no evap cooling, no duct firing	159	143,777	317,500 MW for minimum load – 2 units. This reflects one unit at minimum load. CO_2 production is 143,777 lb/hr for a single unit in operation.
Other Relevant Performance Information			
Average annual site conditions (64°F), base load, evap cooling on, no duct firing	656	531,846	
Average annual site conditions (64°F), 75% load, evap cooling off, no duct firing	498	207,265	Part load operation
98° F, base load, evap cooling on, duct firing	677	565,112	

Source: Table R-5 in May 2017 Response Letter

Table 40 Operating Case 1 – Base Load Scenario

Case 1 Parameters	MWh	CO_2 Production (lbs)	Notes
5 cold starts, 35 warm starts, 40 shutdowns, 6560 hours no duct firing, 1500 hours with duct firing, 40 hours in SU/SD			
64 hours in startup	Not Included	Not Included[115]	
68 hours of brining combined cycle into operation	33,871	14,094,020	Using an average MW and CO_2 production (75% Point @64°F) for the startup time - 1.5 hours. Reduce operating hours w/o duct firing appropriately. 5 x 3 hours + 35 x 1.5 hours = 68 hours
Hours of part load operation - minimum	0	0	
6392 hours of operation w/o duct firing	4,195,070	3,399,559,632	6460-68=6392 hours of base load operation. Temp of 64°F - average annual temp
1500 hours of duct firing	1,015,650	847,668,000	Temp of 98°F for duct firing
Totals	**5,244,590**	**4,261,321,652**	

[115] Although emissions from startup and shutdown were not included in the Applicant's analyses for the GHG BACT limit, the limit that is set does not exclude periods of startup and shutdown.

Average Annual CO_2 Production Value (lb/MWh)	**813**		
30-year degradation @6% (lb/MWh)	**864**		

Source: Table R-6 in May 2017 Response Letter

Table 41 Operation Case 2 - Intermediate Scenario

Case 2	MWh	CO_2 Production (lbs)	Notes
5 cold starts, 360 warm starts,360 hot starts, 725 shutdowns, 2125 hours no duct firing, 1500 hours with duct firing, 695 hours in SU/SD			
695 hours in Startup	Not Included	Not Included	
1095 hours of bringing combined cycle into operation	518,811	431,789,160	Using an average MWs and CO2 production (75% Point @64°F) for the startup time - 1.5 hours. Reduce operating hours w/o duct firing appropriately. 5 x 3 hours + 720 x 1.5 hours = 1095
Hours of Part Load Operation - Minimum	0	0	4 hours per day during afternoon solar peak - 4 hours per day time 360 days. One unit in operation at minimum and one unit restart to achieve afternoon ramp
1030 hours of operation w/o duct firing	676,710	545,916,480	2970-600-1440 = 930 hours of base load operation.
1500 hours of duct firing	1,015,650	847,668,000	Use 98°F case for duct firing
Totals	**2,211,171**	**1,825,373,640**	
Average Annual CO_2 Production Value (lb/MWh)	**826**		
30-year degradation @6% (lb/MWh	**878**		

Source: Table R-7 in May 2017 Response Letter

Table 42 Operating Case 3 – Occasional Peaking Scenario

Case 3	MWh	CO_2 Production (lbs)	Notes
5 cold starts, 360 warm starts,180 hot starts, 545 shutdowns, 2970 hours no duct firing, 1500 hours with duct firing, 530 hours in SU/SD			
530 Hours in Startup	Not Included	Not Included	
600 Hours of brining combined cycle into operation	284,280	236,596,800	Using an average MWs and CO2 production (75% Point @64°F) for the startup time - 1.5 hours. Reduce operating hours w/o duct firing appropriately. 5 x 3 hours + 360 x 1.5 hours + 180 x .25 hours = 600

1440 Hours of Part Load Operation - Minimum	228,672	207,038,880	4 hours per day during afternoon solar peak - 4 hours per day time 360 days. One unit in operation at minimum and one unit restart to achieve afternoon ramp
930 hours of operation w/o duct firing	611,010	492,914,880	2970-600-1440 = 930 hours of base load operation.
500 hours of Steam Bypass Operation	223,650	265,008,000	No steam turbine power generated - 447.3 MW generated by 2 gas turbines operating - emission controls active
1000 hours of duct firing	677,100	565,112,000	Use 98°F case for duct firing
Totals	**2,024,712**	**1,766,760,560**	
Average Annual CO_2 Production Value (lb/MWh)	**873**		
30-year degradation @6% (lb/MWh)	**928**		

Source: Table R-8 in May 12 Response Letter

Appendix 5 – Cost Analysis for SCR on Auxiliary Boiler

Table 43 SCR Cost Analysis for Auxiliary Boiler

	Costs (2015$)	Notes
Capital Costs		
Direct Capital Costs		
A. Purchased Equipment Costs	$400,000	Scale up from OGS at 50.6 MMBtu/hr
B. Other Required Systems (aqueous ammonia system)	$0	included in EC costs
C. Instrumentation & Controls	$40,000	EPA OAQPS 10% of A
D. Freight	$20,000	EPA OAQPS 5% of A
E. Taxes	$33,000	8.25% Tax Rate (CA average)
Total Purchased Equipment Costs **(TEC)**	$493,000	
Installation Costs:		
F. Foundation & Supports	$39,000	EPA OAQPS 8% of TEC
G. Erection and Handling	$74,000	EPA OAQPS 15% of TEC
H. Electrical	$5,000	EPA OAQPS 1% of TEC
I. Piping	$10,000	EPA OAQPS 2% of TEC
J. Insulation	$10,000	EPA OAQPS 2% of TEC
K. Painting	$5,000	EPA OAQPS 1% of TEC
L. Site Preparation	$0	estimated by Project Engineer
Total Installation Costs **(TIC)**	$143,000	
Total Direct Capital Costs (TDCC)	$636,000	Sum of TEC and TIC
Indirect Capital Costs		
M. Engineering & Supervision	$49,000	EPA OAQPS 10% of TEC
N. Construction and Field Exp.	$49,000	EPA OAQPS 10% of TEC
O. Contractor Fees	$25,000	EPA OAQPS 5% of TEC
P. Startup	$5,000	EPA OAQPS 1% of TEC
Q. Performance Testing	$5,000	EPA OAQPS 1% of TEC
Total Indirect Capital Costs (TICC)	$133,000	
Total Direct & Indirect Capital Costs (TDICC)	$769,000	Sum of TDCC and TIDCC)
Contingency (@3%)	$23,070	
Total Capital Costs (TCC):	$792,070	Sum of TDCC, TIDCC, and contingency
Annual Operating Costs		
Direct Operating Costs		
R. Operating Labor	$2,000	0.25 hr/day, @$35 hr, 200 days/yr
S. Supervisory Labor	$0	EPA OAQPS 15% of R

T. Maintenance Labor	$2,000	0.25 hr/day, @$35 hr, 200 days/yr
U. Maintenance Materials	$2,000	100% of maintenance labor costs
V. Utility Expenses (gas and electricity, fuel penalty)	$4,000	applicant estimate
W. Process chemicals costs (ammonia)	$6,500	applicant estimate
X. Annual Media Cost	$2,000	$50K media replacement and disposal, divided by media life (5 yrs) x CRF (7%, 5 yrs, = 0.24389)
Y. Other Penalties	$0	Already included (loss power sales, added maintenance)
Total Direct Operating Costs (TDCO)	$19,000	
Indirect Operating Costs		
Z. Overhead	$2,400.00	60% of Total Labor, EPA OAQPS (R+S +T)
Total Indirect Operating Costs		
Capital Charges & Costs		
AA. Property Tax	$8,000	EPA OAQPS 1% of TCC
BB. Insurance	$8,000	EPA OAQPS 1% of TCC
CC. General Administrative	$16,000	EPA OAQPS 2% of TCC
DD. Capital Recovery Costs	$64,000	7% per OMB, 30 yr plant life, CFR=0.0806 of TCC
Total Capital Charges Costs	$96,000	Sum of AA, BB, CC, DD
Total Annualized Operating Costs	$115,000	
Cost Effectiveness		
Base case Emissions		
Base Concentration	9	ppm w/ ULNB
Annual Emission Rate	2.95	tpy
SCR Case		
NO_X Concentration	5	ppm w/SCR (LAER in South Coast AQMD)
Annual Emission Rate	1.64	tpy
NO_X Reduction from Uncontrolled Case:	1.31	
Control Cost Effectiveness	**$88,000**	$/ton to reduce NO_X w/SCR

Notes:

See notes and references in October 2015 Application, Appendix D, Table D9

Appendix 6 – Cumulative1-hr NO_2 Impacts Including Impacts on Plant 42