U.S. ENVIRONMENTAL PROTECTION AGENCY
REGION IX

FACT SHEET AND
AMBIENT AIR QUALITY IMPACT REPORT

For a Clean Air Act
Prevention of Significant Deterioration Permit

Pio Pico Energy Center
PSD Permit Number SD 11-01

June 2012

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PROPOSED PREVENTION OF SIGNIFICANT DETERIORATION PERMIT

PIO PICO ENERGY CENTER

Fact Sheet and Ambient Air Quality Impact Report (PSD Permit SD 11-01)

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Acronyms & Abbreviations

Act	Clean Air Act [42 U.S.C. Section 7401 et seq.]
AFC	Application for Certification
b_{ext}	Light extinction coefficient
BA	Biological Assessment
BACT	Best Available Control Technology
BTU	British thermal units
CAA	Clean Air Act [42 U.S.C. Section 7401 et seq.]
CARB	California Air Resources Board
CEC	California Energy Commission
CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CO2e	Carbon Dioxide Equivalent
CT	Combustion Turbine
GE	General Electric
gr/scf	Grains per Standard Cubic Feet
EAB	Environmental Appeals Board
EPA	U.S. Environmental Protection Agency
ESA	Endangered Species Act
ESP	Electrostatic Precipitator
FWS	U.S. Fish and Wildlife Service
GHG	Greenhouse Gases
HHV	Higher Heating Value
HRSG	Heat Recovery Steam Generator
ISO	International Organization for Standards
km	Kilometers
kW	Kilowatts of electrical power
$\mu g/m^3$	Microgram per Cubic Meter
MMBTU	Million British thermal units
MW	Megawatts of electrical power
NAAQS	National Ambient Air Quality Standards
NESHAPS	National Emission Standards for Hazardous Air Pollutants
NO	Nitrogen oxide or nitric oxide
NO_2	Nitrogen dioxide
NO_x	Oxides of Nitrogen ($NO + NO_2$)
NP	National Park
NSPS	New Source Performance Standards, 40 CFR Part 60
NSR	New Source Review
O_2	Oxygen
PM	Total Particulate Matter
$PM_{2.5}$	Particulate Matter less than 2.5 micrometers (μm) in diameter
PM_{10}	Particulate Matter less than 10 micrometers (μm) in diameter
PPEC	Pio Pico Energy Center
PPM	Parts per Million

PSD	Prevention of Significant Deterioration
PTE	Potential to Emit
PUC	Public Utilities Commission
RATA	Relative Accuracy Test Audit
RBLC	U.S. EPA RACT/BACT/LAER Information Clearinghouse
SDAPCD	San Diego County Air Pollution Control District
SIL	Significant Impact Level
SF_6	Sulfur Hexafluoride
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
SO_x	Oxides of Sulfur
TDS	Total Dissolved Solids
TPY	Tons per Year
VOC	Volatile Organic Compounds
WA	Wilderness Area

Proposed Prevention of Significant Deterioration (PSD) Permit Fact Sheet and Ambient Air Quality Impact Report

PIO PICO ENERGY CENTER

Executive Summary

Pio Pico Energy Center, LLC (PPLLC or applicant) has applied to EPA Region 9 (EPA) for authorization under the Clean Air Act (CAA) Prevention of Significant Deterioration (PSD) program to construct a new power plant that will generate 300 megawatts (MW) of electricity using natural gas. The plant, known as the Pio Pico Energy Center (PPEC or Project), would be located in San Diego County, California. EPA is issuing a proposed PSD permit for the PPEC, which is consistent with the requirements of the PSD program for the following reasons:

- The proposed PSD permit requires the Best Available Control Technology (BACT) to limit emissions of nitrogen oxides (NO_x), total particulate matter (PM), particulate matter 10 micrometers (µm) in diameter and smaller (PM_{10}), particulate matter 2.5 µm in diameter and smaller ($PM_{2.5}$), and greenhouse gases (GHG);

- The proposed emission limits will protect the National Ambient Air Quality Standards (NAAQS) for nitrogen dioxide (NO_2), PM_{10}, and $PM_{2.5}$. There are no NAAQS for PM or Greenhouse Gases;

- The facility will not adversely impact soils and vegetation, or air quality, visibility, and deposition in Class I areas located within 100 km, which are parks or wilderness areas given special protection under the Clean Air Act.

1. Purpose of this Document

This document serves as the Fact Sheet and Ambient Air Quality Impact Report (Fact Sheet) for the proposed PSD permit for the PPEC. This document describes the legal and factual basis for the proposed PSD permit, including requirements under the CAA, including CAA section 165 and the PSD regulations at Title 40 of the Code of Federal Regulations (CFR) section 52.21. This document also serves as a Fact Sheet for the proposed PSD permit per 40 CFR section 124.8.

2. Applicant

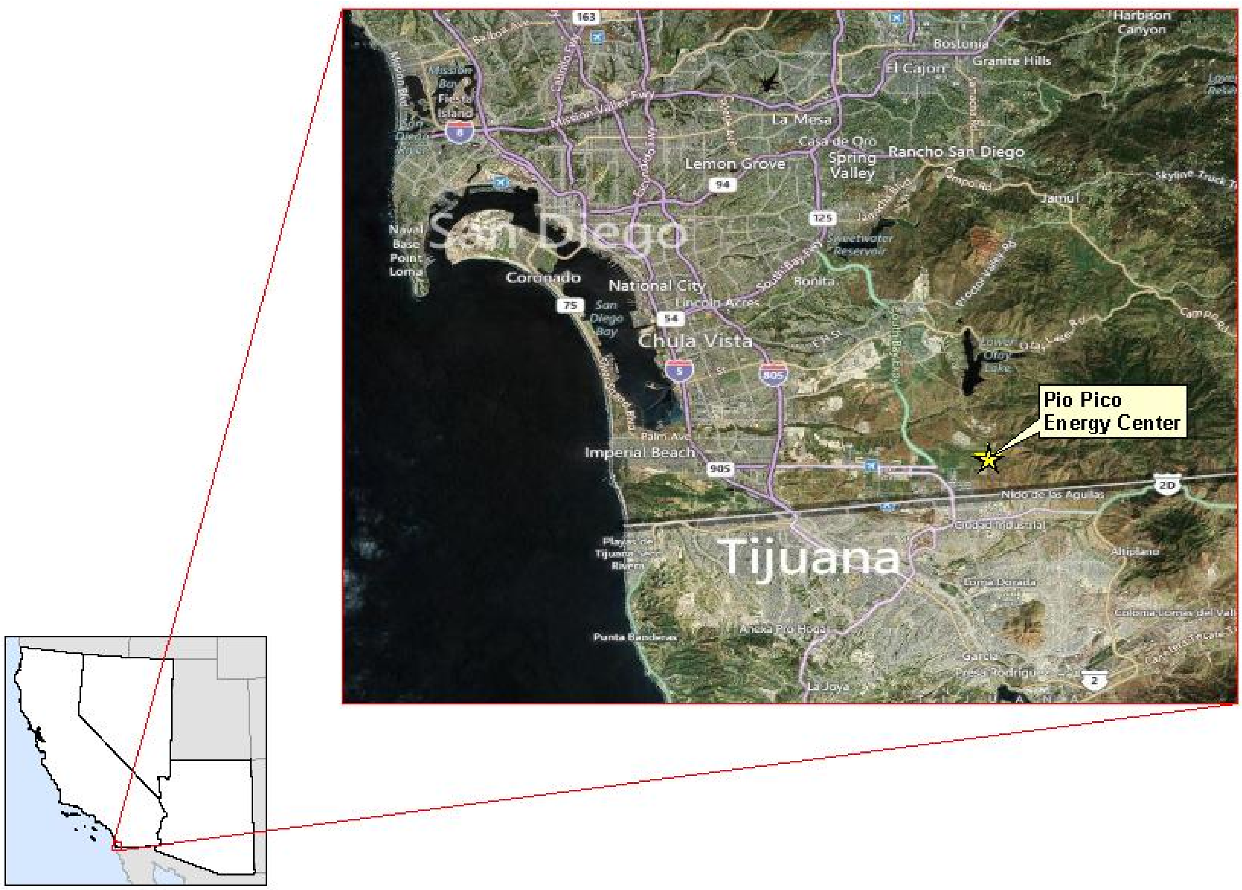
The name and address of the applicant is as follows:

Pio Pico Energy Center, LLC
P.O. Box 95592
2542 Singletree Lane
South Jordan, UT 84095

3. Project Location

The project site is located in an unincorporated area of San Diego County known as Otay Mesa. It is comprised of a 9.99 acre parcel located at 7363 Calzada de la Fuente in the Otay Mesa Business Park. The site is located within the San Diego County Air Pollution Control District (SDAPCD, or District).

The map below shows the approximate location of the proposed project.



4. Project Description

The applicant has submitted a PSD permit application to EPA for the PPEC. The application materials for the PSD permit for the Project are included in EPA's administrative record for EPA's proposed PSD permit.

We note that PPEC also has submitted applications for State and local construction approvals for the Project that are separate from EPA's PSD permitting process. These applications are referred to as an Application for Certification (AFC) submitted to the California Energy Commission (CEC) and an application for a Determination of Compliance (DOC) submitted to the District. The District issued a Final DOC for the Project on May 4, 2012.

The primary equipment for the generating facility will be three General Electric (GE) LMS100 natural gas-fired combustion turbine-generators (CTGs) with a total net generating capacity of 100 megawatts (MW) each. Table 4-1 lists the equipment that will be regulated by this PSD permit:

Table 4-1: Equipment List

Equipment	Description
Three natural gas-fired GE LMS100 combustion turbine generators (CTG)	• Each 100 MW CTG, with a maximum heat input rate of 903 MMBtu/hr (HHV)[1] • Emissions of NO_x controlled by water injection and Selective Catalytic Reduction (SCR)
Partial Dry Cooling System	• 7,000 gal/min maximum circulation rate (wet) • 16,520 gal/min maximum circulation rate (dry) • Total dissolved solids (TDS) concentration in makeup water of 5,600 ppm (560 mg/L) • Drift eliminator with drift losses less than or equal to 0.001 percent
Circuit Breakers	• 3 switchyard and 2 generator breakers containing SF6

The simple-cycle turbines will be operated as a peaking facility. 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 100 megawatts (MW) of electricity from each turbine.

Air Pollution Control

The PPEC will use Selective Catalytic Reduction (SCR) to reduce NO_x emissions from the CTGs. The SCR process will use aqueous ammonia as the reagent, where the catalyst facilitates the reaction of the ammonia with NO_x to create atmospheric nitrogen (N_2) and

[1] This heat input occurs when load is at 100% and at an ambient temperature of 63° F.

water. Pipeline quality natural gas fuel and good combustion practices will be used to minimize particulate emissions. Thermal efficiency will be used to minimize GHG emissions.

We note that the PPEC will use an oxidation catalyst to reduce emissions of CO and volatile organic compounds (VOC). Although CO and VOC are not regulated in this proposed PSD permit, these pollutants will be regulated by the New Source Review (NSR) permit issued by the District, as explained in Section 6 below. The federally enforceable District permit serves to limit the CO and VOC potential to emit (PTE) to less than the PSD significance thresholds. The District permit contains practically enforceable short-term and annual emission limits for CO and VOC, and requires the installation of post-combustion air pollution control equipment to control emissions of these two pollutants.

Power Plant Startup

The GE LMS100 is an intercooled gas turbine system developed especially for the power generation industry. The applicant states that each LMS100 produces approximately 100 MW at an efficiency rate that is approximately ten percent higher than that of other commercial simple-cycle gas turbines. The applicant also notes that the LMS100 is specifically designed for cyclic applications; it provides flexible power and, according to the manufacturer, can deliver 100 MW of power in 10 minutes.

5. Emissions from the Proposed Project

This section describes the pollutants that are covered by the PSD program within the SDAPCD, which is the area in which the Project is proposed to be located.

The CAA's NSR provisions include two preconstruction permitting programs. First, the CAA PSD program is intended to protect air quality in "attainment areas,"[2] which are areas that meet the NAAQS. EPA is responsible for issuing PSD permits for major new stationary sources emitting pollutants that are in attainment with (or unclassifiable for) the NAAQS, in general, and within the District.

Second, the CAA nonattainment NSR program applies in areas where pollutant concentrations exceed the NAAQS ("nonattainment areas"). The District implements the nonattainment NSR program for facilities within its boundaries emitting nonattainment pollutants and their precursors (*e.g.*, VOC and NO_x, which are precursors to ambient ozone). For purposes of nonattainment NSR, PPEC will not be a major source of any nonattainment pollutant; therefore requirements of nonattainment NSR, including Lowest Achievable Emission Rate (LAER) and emission offsets, do not apply to the Project. Instead, the minor NSR permit issued by SDAPCD addresses both attainment and nonattainment pollutants.

[2] PSD also applies to pollutants where the status of the area is uncertain (unclassifiable) for NAAQS and to any other pollutant subject to regulation under the CAA.

Table 5-1 below describes the regulated pollutants that will be emitted by the Project and their attainment status within the District.

Table 5-1: National Ambient Air Quality Standard Attainment Status for San Diego County Air Pollution Control District

Pollutant	Attainment Status	Permit Program
Nitrogen Dioxide (NO_2)	Attainment/Unclassifiable	PSD
Sulfur Dioxide (SO_2)	Attainment/Unclassifiable	PSD
Carbon Monoxide (CO)	Attainment	PSD
Particulate Matter (PM)	n/a[3]	PSD
Particulate matter under 10 micrometers diameter (PM_{10})	Attainment	PSD
Particulate Matter under 2.5 micrometers diameter ($PM_{2.5}$)	Attainment	PSD
Ozone	Nonattainment	NA-NSR
Lead (Pb)	Attainment/Unclassifiable	PSD
Sulfuric Acid Mist (H_2SO_4)	n/a[3]	PSD
Hydrogen Sulfide (H_2S)	n/a[3]	PSD
Total Reduced Sulfur (TRS)	n/a[3]	PSD
Fluorides	n/a[3]	PSD
Greenhouse Gases (GHG)	n/a[3]	PSD

The PSD program (40 CFR § 52.21) applies to "major" new sources of pollutants for which an area has been designated attainment or is unclassifiable. A new source is defined as a "major source" if emits or has the potential to emit (depending on the source type) either 100 or 250 tons per year (tpy) or more of any "regulated NSR pollutant," as that term is defined in the PSD regulations, including greenhouse gases (GHG) when they are emitted by the source in amounts that are "subject to regulation" as defined in 40 CFR § 52.21(b)(49), currently 100,000 tpy or more of GHG on a carbon dioxide equivalent (CO2e) basis for new sources such as this Project .

[3] There are no national ambient air quality standards (NAAQS) for PM, H_2SO_4, H_2S, TRS, fluorides, or GHGs. However, in addition to other pollutants for which no NAAQS have been set, these pollutants are regulated NSR pollutants with defined applicability thresholds under the PSD regulations (*see* 40 CFR §§ 52.21(b)(23), (49), and (50)).

6. Applicability of the Prevention of Significant Deterioration Regulations

This section describes the PSD applicability thresholds, and our conclusion that the Project's emissions of NO_x, PM, PM_{10}, $PM_{2.5}$, and GHG will be regulated by EPA's proposed PSD permit.

The annual emission data in Tables 6-1 and 6-2 (based on allowable operation up to 8,760 hours per year) are based on the applicant's maximum expected emissions, including emissions from startup and shutdown cycles. The data submitted by the applicant is based on the assumption that all of the Project's combustion-related particulate emissions are $PM_{2.5}$. As a result, the PTE for PM and PM_{10} equals the PTE for $PM_{2.5}$. This is a conservative approach, as some particulate emissions may be larger than 2.5 micrometers.

The estimated emissions in Table 6-1 and Table 6-2 show that the PPEC will be a major source for GHG. GHG emissions from the Project are a regulated NSR pollutant because the emissions exceed the 100,000 tpy CO2e subject to regulation threshold provided in 40 CFR § 52.21(b)(49), and the GHG emissions on a mass basis exceed the 250 tpy major source threshold. Once a source is considered major for at least one regulated NSR pollutant, PSD also applies to any other regulated pollutant that the facility has the potential to emit in a significant amount, *i.e.*, at or above the significant emission rate. The data in Table 6-1 show that the Project has the potential to emit NO_x, PM, PM_{10}, and $PM_{2.5}$ in a significant amount; therefore, the Project is subject to PSD review for these pollutants in addition to GHG. Estimated emissions of the PSD-regulated pollutants from the facility are listed in Table 6-1.

Carbon monoxide (CO), and sulfur dioxide (SO_2) will be less than the major source threshold and less than the significant emission rate for each pollutant. Therefore, PSD review does not apply to these pollutants for the PPEC.

Table 6-1: Estimated Emissions and PSD Applicability

Pollutant	Estimated Annual Emissions (tons/year)	Major Source Threshold (tons/year)	Significant Emission Rate (tons/year)	Does PSD apply?
CO	96.4	250	100	No
NO_2	70.4	250	40	Yes
PM	37.2	250	25	Yes
PM_{10}	37.2	250	15	Yes
$PM_{2.5}$	37.2	250	10	Yes
SO_2	4.1	250	40	No

Pb	0	250	0.6	No
H_2SO_4	3.4	250	7	No
H_2S (incl. TRS)	0	250	10	No
Fluorides	0	250	3	No
GHG (in mass tons)	623,299	250	0	Yes

Table 6-2: Estimated Emissions of PSD-Regulated Pollutants by Unit (tpy)

	CO	NO_x	PM	PM_{10}	$PM_{2.5}$	GHG[(a)(c)]	CO_2e[(b)(c)]
Total Facility	96.4	70.4	37.2	37.2	37.2	623,299	685,626
CTG (each unit)	32.1	23.5		11.9	11.9	207,753	228,528
Circuit Breakers (5)	n/a	n/a	n/a	n/a	n/a	3.36 lb/yr	40
Partial Dry Cooling System	n/a	n/a		1.4	1.4	n/a	n/a

Notes:
(a) Represents all GHG emissions on a mass basis.
(b) Represents the carbon dioxide equivalent (CO_2e) of all GHG emissions, rounded to the nearest 1,000 tons.
(c) The applicant used 2007 California Air Resources Board (CARB) GHG emission factors to calculate its GHG emissions. CARB updated its GHG reporting regulations in 2010 to incorporate emission factors from EPA's Mandatory Greenhouse Gas Reporting Rule (40 CFR Part 98). EPA has recalculated the applicant's GHG emissions using emission factors from Part 98.

7. Best Available Control Technology

This section describes EPA's Best Available Control Technology (BACT) analysis for the control of NO_x, PM, PM_{10}, $PM_{2.5,}$ and GHG emissions from this facility. 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 [or NESHAPS] 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 (PTE) in significant amounts.

EPA outlines the process it generally uses to do this case-by-case analysis (referred to as a "top-down" BACT analysis) in a June 13, 1989 memorandum. The top-down BACT analysis is a well-established procedure that EPA's Environmental Appeals Board (EAB) has consistently followed in adjudicating PSD permit appeals. *See, e.g., In re Desert Rock Energy Center*, 14 E.A.D. ___, slip op. at 52-53 (Sept. 24, 2009); *In re Knauf*, 8 E.A.D. 121, 129-31 (EAB 1999); *In re Maui Electric*, 8 E.A.D. 1, 5-6 (EAB 1998).

In brief, under the top-down process, all available control technologies are ranked in descending order of control effectiveness. The PSD applicant first examines the most stringent technology. That technology 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 case at hand. 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.

The proposed Project is subject to BACT for NO_x, PM, PM_{10}, $PM_{2.5}$, and GHG emissions. A BACT analysis was conducted for the three natural gas combustion turbines. Tables 7-1 and 7-2 provide a summary of the BACT determinations for NO_x, PM, PM_{10}, $PM_{2.5}$, and GHG from the emission units listed above.

Table 7-1: Summary of NO_x, PM, PM_{10}, and $PM_{2.5}$ BACT Limits and Requirements for Testing and Monitoring

	NO_X	PM, PM_{10}, and $PM_{2.5}$	Restrictions on Usage
3 Combustion Turbines (each)	• 2.5 ppmvd, 15% O_2 • 1-hr average • 8.18 lb/hr • 26.6 lb/hr during each startup or shutdown • 22.5 lb per startup event, 6.0 lb per shutdown event • CEMS • quarterly and annual RATA for CEMs	• 0.0065 lb/MMBtu • 9-hr average • PUC natural gas (sulphur $\leq$ 0.25 gr/dscf on a 12-month rolling average, and not to exceed of 1.0 grains per 100 dscf, at any time) • annual performance testing	• Maximum of 500 startups per calendar year • 30 minute maximum startup duration • 10.5 minute maximum shutdown duration
Partial Dry Cooling System	n/a	• drift rate of 0.001% or less • $\leq$ 5,600 ppm total dissolved solids	n/a

Table 7-2: Summary of GHG BACT Limits and Requirements for Testing and Monitoring

	GHG	Testing and Monitoring	Restrictions on Usage
3 Combustion Turbines (each)	• initial heat rate limit of 9,196 btu_{hhv}/$kw\text{-}hr_{gross}$ • 1181 lb CO_2/MWh net output • 8,760 rolling operating-hour average	• initial performance test • CEMS	n/a
circuit breakers	• the use of enclosed-pressure SF6 circuit breakers with a maximum annual leakage rate of 0.5% by weight and a 10% by weight leak detection system • emission cap of 40.2 tpy	• mass balance	n/a

7.1 *BACT for Natural Gas Combustion Turbine Generators*

PPEC has proposed three simple-cycle, natural gas-fired combustion turbines (CTs). Each CT has a maximum generating capacity of 103 MW and a maximum heat input capacity of 7,815 BTU/kw-hr (LHV) at ISO conditions. The CTs are subject to BACT for NOx, PM, PM10, PM2.5, and GHGs. A top-down BACT analysis for each pollutant has been performed and is summarized below.

7.1.1 Nitrogen Oxide Emissions

Step 1 - Identify All Control Technologies

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

- Low NO_x burner design (*e.g.*, dry low NO_x combustors)
- Water or steam injection
- Inlet air coolers

The available add-on NO_x control technologies include:

- Selective Catalytic Reduction (SCR) system
- EMx™ system (formerly SCONOx)
- Selective non-catalytic reduction (SNCR)[4]

Step 2 – Eliminate Technically Infeasible Options

With the exception of EMx™, all of the available control options identified in Step 1 are technically feasible. EMxTM technology (formerly SCONOx) is a relatively newer technology that 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 NOx guarantees of <1.5 ppm are available. However, this technology is designed to operate at a maximum temperature of approximately 700°F. Simple cycle gas turbines operate with exhaust gas temperatures of up to 1100° F, which exceeds the maximum temperature that EMx catalysts can tolerate while remaining effective. For this reason, we do not consider EMx to be technically feasible for simple-cycle gas turbines, and are eliminating this technology from further consideration as BACT. We also note that we are not aware of any simple-cycle gas turbines currently operating with EMx, or any permit application for a simple-cycle gas turbine power plant that proposes the use of EMx to control NOx emissions. Therefore we do not consider this technology achievable for simple-cycle gas turbines at this time.

Step 3 – Rank Control Technologies

[4] According to the applicant, the PPEC is "designed to directly satisfy the San Diego area peaking and load-shaping generation current and long-term requirements. Key among these requirements is supporting wind and solar generation, whose overall output varies." (PPEC PSD permit application, p. PSD – 2.1) The PPEC's capacity for frequent and fast turbine startups will provide necessary power to compensate for the intermittent nature of wind and solar generation, and thus will ultimately provide critical support for the growth of renewable energy sources in the area. Solar and wind power generation would be incompatible with the applicant's peaking power generation purpose because they are not steady state power sources that can be relied on to generate power during periods when intermittent renewable resources cannot. Therefore, we have not included solar and wind in our BACT analyses based on our determination that these technologies would fundamentally redefine the source.

Selective catalytic reduction (SCR) is a well-demonstrated technology for NO_X control and has specifically achieved NO_X emissions of 2.5 ppm on a 1-hr average on large simple cycle CTs (greater than 100 MW).[5]

The available control technologies are ranked according to control effectiveness in Table 7-3. Since inlet air cooling reduces the amount of thermal NOx formed during combustion and are inherent to the design of all new gas turbines, we have evaluated the highest ranked control technologies with the assumption that they will utilize this inherent control. A summary of recent BACT limits for similar simple-cycle, natural gas-fired CTs is provided in Table 7-4. All recently issued permits for such facilities indicate that a limit of 2.5 ppm based on a 1-hr average represents the highest level of NO_x control.

Table 7-3: NO_x Control Technologies Ranked by Control Effectiveness

NO_x Control Technology	Emission Rate (ppmvd @ 15% O_2, 1-hr average)
SCR with water injection	2.5
SCR with Dry Low NO_X combustors	2.5
SNCR	~4.5[6]
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. We have determined that 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.[7] Ammonia has not been identified as a carcinogen. It is noted that the applicant will use aqueous ammonia, which is considered a safer storage method than anhydrous ammonia. Additionally, we note that the California Energy Commission's Final Staff Analysis for the project proposes to include Conditions of Certification to ensure the safe receipt and storage of aqueous ammonia at the PPEC.[8]

Ammonia slip emissions for the proposed source are limited to 5 ppm by the NSR permit

[5] While a NOx emission rate of 2.0 ppm has been demonstrated to achieve with combined cycle gas turbine configurations, SCR has not been able to achieve this emission rate on simple cycle turbines due to their higher exhaust gas temperatures. EPA is not aware of any source that has proposed or achieved this emission rate with SCR on a simple cycle gas turbine power plant.
[6] This is an approximate value that was estimated considering that the control effectiveness of SNCR has been demonstrated to be between 40 and 60 percent.
[7] 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.
[8] This information is available at http://www.energy.ca.gov/sitingcases/piopico/index.html. See conditions HAZ-3 through HAZ-5.

issued by the District. 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 (0.011 and 0.11, respectively).[9]

Considering the above factors, the possible risks associated with onsite storage and use of ammonia do not appear to outweigh the benefits associated with significant NO_x reductions.

SCR with Water Injection versus SCR with Low NO_x Burners: The applicant has proposed to use water injection with SCR to control NO_x from the Project. As noted above, this technology is expected to achieve the same level of control as would SCR with low NO_x burners. We have determined that the amount of water needed for water injection will not result in a significant environmental impact warranting elimination of this technology as BACT for the Project. . Therefore, we concur that the applicant's selection of SCR with water injection as BACT is appropriate in this case.

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 these CTs is the use of SCR and water injection with an emissions limit of 2.5 ppm at 15% O_2 based on a 1-hr average.

Table 7-4: Summary of Recent NO_x BACT Limits for Similar Simple-Cycle, Natural gas-fired CTs

Facility	NO_X Limit	Averaging Period	Control	Permit Issuance	Source
El Cajon Energy	2.5 ppm	1-hr	water injection and SCR	Dec 2009	RBLC # CA-1174
Escondido Energy Center	2.5 ppm	1-hr	water injection and SCR	Jul 2008	RBLC # CA-1175
Orange Grove Energy	2.5 ppm	1-hr	LNB, water injection, and SCR	Dec 2008	RBLC # CA-1176
CalPeak Power El Cajon	3.5 ppm	1-hr	SCR	Jun 2001	CARB BACT Clearinghouse
El Colton	3.5 ppm	3-hr	SCR	Jan 2003	CARB BACT Clearinghouse
Lambie Energy Center	2.5 ppm	3-hr	SCR	Dec 2002	CARB BACT Clearinghouse
TID Almond 2 Power Plant	2.5 ppm	1-hr	LNB, water injection, and SCR	Dec 2010	California Energy Commission
Canyon Power Plant	2.5 ppm	60 minutes	LNB, water injection, and SCR	Mar 2010	California Energy Commission

[9] See FDOC for PPEC issued by the District on May 4, 2012, Section 8.

Starwood Power – Midway	2.5 ppm	1-hr	water injection and SCR	Jan 2008	California Energy Commission
Panoche Energy	2.5 ppm	1-hr	water injection and SCR	Dec 2007	California Energy Commission
San Francisco Electric Reliability Project	2.5 ppm	1-hr	water injection and SCR	Oct 2006	California Energy Commission
Niland Power Plant	2.5 ppm	1-hr	water injection and SCR	Oct 2006	California Energy Commission
Miramar Energy Facility II	2.5 ppm	3-hr	water injection and SCR	Nov 2008	ATC
Walnut Creek Energy Park	2.5 ppm	1-hr	water injection and SCR	May 2011	California Energy Commission

Note: All facilities listed in the table are located in California.

7.1.2 PM, PM_{10} and $PM_{2.5}$ Emissions

Because the applicant has taken the conservative approach and assumed that all particulate emissions from the turbines are $PM_{2.5}$, the BACT analyses for PM, PM_{10} and $PM_{2.5}$ have been combined. Additionally, the analysis evaluates 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 include[10]:

- Low particulate fuels, low sulfur fuels, and/or pipeline natural gas
- Good combustion practices (including air inlet filter)

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

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

Step 2 – Eliminate Technically Infeasible Control Options
All of the control technologies identified are technically feasible except for cyclones. Although cyclones have been identified as being capable of marginal $PM_{2.5}$ control, the

[10] As noted in the footnote 5 above, we have excluded solar and wind generation from our BACT analyses for the PPEC based on our determination that these technologies would fundamentally redefine the source.

low grain loading makes them technically infeasible for this application.[11] EPA's Air Pollution Control Technology Fact Sheet for Cyclones (EPA-452/F-03-005) identifies typical grain loading for cyclones as ranging from 1.0 to 100 gr/scf and being as low as 0.44 gr/scf.[12] In contrast, the grain loading for the CTs' exhaust stream in this case would be about 0.0027 gr/scf based on the applicant's proposed BACT limits. Cyclones are generally used in high dust applications where a majority of the particulate emissions are filterable emissions. In contrast, the majority of emissions from the CTs will be condensable particulate matter. For this reason, we are eliminating cyclones in this step due to technical infeasibility.

Step 3 – Rank Remaining Control Technologies

The applicant proposed a total PM limit of 0.0065 lb/MMBtu (HHV) to be achieved through the use of pipeline-quality natural gas and good combustion practices (including air inlet filter). EPA evaluated this proposal by reviewing recent PM performance test data from other similar simple cycle plants in southern California. These plants and test data are shown in Table 7-5.

Table 7-5: Southern California Simple Cycle Turbine PM Performance Test Results

Facility	Test Result
Orange Grove Unit Turbine 1	0.0031 lb/MMBtu
Orange Grove Unit Turbine 2	0.0049 lb/MMBtu
El Cajon Energy	0.0008 lb/MMBtu
Canyon Power Project Unit 1	0.00311 lb/MMBtu
Canyon Power Project Unit 2	0.00311 lb/MMBtu

Note: These tests were conducted in 2010 and 2011 on GE LMS 6000 turbines, and represent the test average.

Based on these test data, we have concluded that the applicant's proposed PM emission limit for this project is reasonable for simple cycle gas turbines located in southern California. BACT will be achieved by the use of low sulfur pipeline-quality natural gas and good combustion practices. We have included the applicant's proposed emission limit of 0.0065 lb/MMBtu (HHV) in order to ensure the use of low sulfur natural gas and good combustion practices. This limit represents the expected PM emissions based on the engineering design of this specific model (GE LMS100) of natural-gas fired turbine.

Step 4 – Economic, Energy and Environmental Impacts

The applicant provided a cost analysis for PM controls based on information provided in *Controlling Fine PM*. A modified version of this analysis is provided in Table 7-6. The amount of $PM_{2.5}$ removed is based on the manufacturer's guaranteed emission rate of 5.5 lb/hr. Because add-on PM controls have not been applied to CTs, the control efficiencies evaluated are considered conservative. With cost-effectiveness values ranging between $317,902 and $438,860 per ton of $PM_{2.5}$ removed, add-on controls are considered cost-prohibitive for the PPEC. Therefore we are eliminating ESP, baghouse, and wet

[11] –Information is available at http://www.epa.gov/apti/Materials/APTI%20413%20student/413%20Student%20Manual/SM_ch%204.pdf.

[12] Information is available at http://www.epa.gov/ttn/catc/dir1/fcyclon.pdf.

scrubber technologies in this step due to economic impacts.

Table 7-6: Cost Analysis for Add-on PM Control Technologies

	Dry ESP	Baghouse (pulse-jet)	Wet Scrubber (venturi)
Flowrate (ft^3/min)	915,000	915,000	915,000
Capital Costs ($/scfm)	10	6	2.50
Capital Costs (total $)	9,150,000	5,490,000	2,287,500
Cost Recovery Factor	0.11	0.11	0.11
Annualized Capital Costs ($/yr)	1,006,500	603,900	251,625
O & M Costs ($/scfm)	3	5	4.40
O & M Costs ($/yr)	2,745,000	4,575,000	4,026,000
Total Annualized Costs ($/yr)	3,751,500	5,178,900	4,277,625
Removal Efficiency	99%	99%	90%
Tons of $PM_{2.5}$ Removed (TPY)	11.80	11.80	10.73
Cost Effectiveness ($/ton removed)	317,902	438,860	398,735

Step 5 – Select BACT
After eliminating ESP, baghouse, and wet scrubber technologies due to economic impacts, we have determined that BACT is the use of low sulfur pipeline quality natural gas, good combustion practices, and a PM, PM_{10}, and $PM_{2.5}$ limit of 0.0065 lb/MMBtu based on a 9-hr average. By "pipeline quality natural gas" we mean Public Utilities Commission (PUC)-quality natural gas. While the PUC sets a sulfur content limit of 5.0 grains per 100 dscf, the average sulfur content of natural gas in San Diego County is 0.20 g/100 dscf. Therefore we are proposing a sulfur content limit for the natural gas of 0.25 grains per 100 dry standard cubic feet on a 12-month rolling average and a sulfur content of 1.0 grains per 100 dry standard cubic feet that shall not be exceeded at any time.

7.1.3 GHG Emissions

<u>Step 1 – Identify all control technologies</u>

The following control technologies are potentially available for the PPEC:

- Alternative generating technologies such as combined-cycle gas turbines or reciprocating internal combustion (IC) engines.

  <u>Combined-cycle gas turbines</u> recover waste heat from the gas turbine exhaust using a heat recovery steam generator (HRSG). In many applications, combined-cycle facilities are more efficient than simple-cycle operations because the use of the HRSG allows the production of more electricity without additional fuel consumption.

Reciprocating IC engines consist of one or more cylinders in which the process of combustion takes place within the cylinders. Reciprocating IC engines are generally well suited for peaking applications such as the proposed Project.

- Use of the most energy efficient simple-cycle gas turbines.

- Carbon capture and sequestration (CCS).

  CCS is a technology that involves the capture and storage of CO_2 emissions to prevent their release to the atmosphere.

Step 2 – Eliminate technically infeasible control technologies

Reciprocating IC Engines
As noted above, reciprocating IC engines are well-suited for peaking applications and are technically feasible for the proposed Project.

Combined-Cycle Gas Turbines
As stated in the permit application, the applicant seeks approval from EPA for construction of the PPEC in order to satisfy an obligation to supply electrical capacity and energy to San Diego Gas & Electric (SDG&E) under a 20-year Power Purchase Agreement (PPA). The purpose of this project is to meet the specific objectives of SDG&E's 2009 Request for Offers (RFO) and the resulting contractual requirements contained in the PPA between SDG&E and PPEC LLC. Key among these requirements is supporting renewable power generation such as wind and solar, whose overall output varies. As output from these renewable resources drops, the PPEC must be able to come online quickly to make up the lost grid capacity. Thus, in order to satisfy its business purpose, the PPEC must be able to offer units that: 1) are highly flexible and that can provide regulation during the morning and evening ramps, 2) can be repeatedly started and shut down as needed, and 3) can be brought online quickly, even under cold-start conditions. There are a number of issues that make combined-cycle gas turbines technically infeasible for such a project.

The start-up sequence for a combined-cycle plant includes three phases: 1) purging of the HRSG; 2) gas turbine speed-up, synchronization, and loading; and 3) steam turbine speed-up, synchronization, and loading. The third phase of this process is dependent on the amount of time that the plant has been shut down prior to being restarted; the HRSG and steam turbine contain parts that can be damaged by thermal stress and they require time to heat up and prepare for normal operation. For this reason, the complete startup time for a combined-cycle plant is typically longer than that of a similarly-sized simple cycle plant. For example, the PPEC can be dispatched from "cold iron" to 300 MW in less than 30 minutes[13]. By comparison, the most likely combined-cycle alternative in GE's product offering – a 107FA power block – would be capable of providing at most 160 MW in approximately the same amount of time (General Electric Company, n.d.[1]).

[13] According to GE, the gas turbine proposed by the applicant (LMS100) offers fast start capability that can deliver 100 MW in 10 minutes (General Electric Company, n.d.[2]).

Even with fast-start technology, new combined-cycle units like the GE 7FA may require up to 3½ hours to achieve full load under some conditions. These longer startup times are incompatible with the purpose of the Project to provide quick response to changes in the supply and demand of electricity. Furthermore, gas turbines used in peaking duty cycles experience high levels of thermal mechanical fatigue due to the large numbers of startups and shutdowns, and the impacts of such fatigue would be even greater in the steam-side equipment of a combined cycle plant. Thus, even if the long startup durations were not prohibitive in this case, the use of a combined-cycle design would still be inconsistent with the PPEC's stated need for flexibility to start up and shut down multiple times in a single day in response to changing demand; such a duty cycle would likely result in excessive wear to combined-cycle units. Therefore, EPA has concluded that a combined-cycle facility is technically infeasible for the Project as defined by the applicant and we have eliminated that control option from further consideration as BACT in this case.[14]

CCS

The three main approaches for CCS are pre-combustion capture, post-combustion capture, and oxyfuel combustion (IPCC, 2005). Of these approaches, pre-combustion capture is applicable primarily to gasification plants, where solid fuel such as coal is converted into gaseous components by applying heat under pressure in the presence of steam and oxygen (U.S. Department of Energy, 2011). At this time, oxyfuel combustion has not yet reached a commercial stage of deployment for gas turbine applications and still requires the development of oxy-fuel combustors and other components with higher temperature tolerances (IPCC, 2005). The third approach, post-combustion capture, is applicable to gas turbines.

With respect to post-combustion capture, a number of methods may potentially be used for separating the CO_2 from the exhaust gas stream, including adsorption, physical absorption, chemical absorption, cryogenic separation, and membrane separation (Wang et al., 2011). Many of these methods are either still in development or are not suitable for treating power plant flue gas due to the characteristics of the exhaust stream (Wang, 2011; IPCC, 2005). Of the potentially applicable technologies, post-combustion capture with an amine solvent such as monoethanolamine (MEA) is currently the preferred option because it is the most mature and well-documented technology (Kvamsdal et al., 2011), and because it offers high capture efficiency, high selectivity, and the lowest energy use compared to the other existing processes (IPCC, 2005). Post-combustion capture using MEA is also the only process known to have been previously demonstrated in practice on gas turbines (Reddy, Scherffius, Freguia, & Roberts, 2003). As such, it is the sole carbon capture technology considered in this analysis.

In a typical MEA absorption process, the flue gas is cooled before it is contacted counter-currently with the lean solvent in a reactor vessel. The scrubbed flue gas is cleaned of

[14] We note that although the applicant also submitted an analysis to show that the use of a combined-cycle design for the Project would not be cost-effective, we are not relying on that analysis as we have determined that such a design is technically infeasible. The applicant's economic analysis is available in EPA's administrative record for the PPEC for reference.

solvent and vented to the atmosphere while the rich solvent is sent to a separate stripper where it is regenerated at elevated temperatures and then returned to the absorber for re-use. Fluor's Econamine FG Plus process operates in this manner, and it uses an MEA-based solvent that has been specially designed to recover CO_2 from oxygen-containing streams with low CO_2 concentrations typical of gas turbine exhaust (Fluor, 2009). This process has in fact been used successfully to capture 365 tons per day of CO_2 from the exhaust of a natural gas combined-cycle plant owned by Florida Power and Light in Bellingham, Massachusetts. The CO_2 capture plant was maintained in continuous operation from 1991 to 2005 (Reddy, Scherffius, Freguia, & Roberts, 2003). As this technology is commercially available and has been demonstrated in practice on a combined-cycle plant, EPA generally considers it to be technically feasible for natural gas combined-cycle sources.

In 2003, Fluor and BP completed a joint study that examined the prospect of capturing CO_2 from eleven *simple cycle* gas turbines at a BP gas processing plant in Alaska known as the Central Gas Facility (CGF) (Hurst & Walker, 2005; Simmonds et al., 2003). Although this project was not actually implemented (S. Reddy, personal communication, December 13, 2011; available in EPA's administrative record for the PPEC), the feasibility study provides valuable information about the design of a capture system for simple-cycle applications, particularly with respect to flue gas cooling and heat recovery. Absorption of CO_2 by MEA is a reversible exothermic reaction. Before entering the absorber, the turbine exhaust gas must be cooled to around 50 ^{o}C to improve absorption and minimize solvent loss due to evaporation (Wang, 2011). In the case of the CGF design, the flue gas is cooled by feeding it first to a HRSG for bulk removal of the heat energy and then to a direct contact cooler (DCC). It should be noted that while Hurst & Walker (2005) found that the HRSG could be omitted from the design for another type of source studied (heaters and boilers at a refinery), the DCC alone would be insufficient for the gas turbines due to the high exhaust gas temperature (480-500 ^{o}C). After the MEA is loaded with CO_2 in the absorber, it is sent to a stripper where it is heated to reverse the reaction and liberate the CO_2 for compression. The heat for this regeneration stage comes from high- and intermediate-pressure steam generated in the HRSG. Excess steam from the CGF HRSGs would also be used to export electricity to the local grid.

The integral nature of the HRSG to the overall process for the CGF is notable because it would essentially require conversion of the turbines from simple-cycle to combined-cycle operation. Therefore, based on this information, we conclude that while carbon capture with an MEA absorption process is feasible for a combined-cycle operation, it is not feasible for simple-cycle units (*i.e.,* those without a HRSG). Given that combined-cycle gas turbines are not technically feasible for the proposed Project, as discussed above, CCS is also technically infeasible for the proposed Project.

Notwithstanding the foregoing finding that CCS is technically infeasible for the proposed Project due to issues associated with flue gas cooling and heat recovery, there is another (and perhaps more critical) issue to consider regarding the technical feasibility of CCS in the present case. As previously discussed, the PPEC is contracted under a 20-year PPA and is designed to directly satisfy the San Diego area peaking and load-shaping generation current and long-term requirements. The SDG&E contract for the facility allows for 500 startups and shutdowns per unit per year. Thus the operation of the facility will be transient in nature as a direct requirement of its fundamental business purpose. The high degree of transiency in this case is incompatible with current carbon capture systems, which are more suitable for steady-state operations (National Petroleum Council, 2007). Chalmers and Gibbins (2007) concluded, for example, that the synchronization of power plant startup with capture operations has not yet been fully addressed, and that changes in power cycle efficiency as a result of variable steam flow and heat integration between the power cycle and CO_2 capture plant must be subjected to more detailed analysis. Consequently, even if the flue gas cooling and heat integration issues could be addressed through a combined-cycle design, CCS would still be technically infeasible for this project, given its non-steady state operation. Therefore, we have eliminated CCS from further consideration in this analysis.

Step 3 – Rank Remaining Control Technologies

After elimination of combined-cycle gas turbines and CCS as potential control technologies, the use of IC engines and thermally efficient simple-cycle gas turbines are the only remaining control methods. These technologies are ranked below by their heat rate, which is a measure that reflects how efficiently a generator uses heat energy; the heat rate is expressed as the number of BTUs of heat energy required to produce a kilowatt-hour of electricity.

Table 7-7: Ranking of Potential Control Technologies by Heat Rate

Technology	Heat Rate (HHV Basis)
IC engines	~7,500 Btu/kWh
Simple-cycle gas turbines	~8,700 to 10,000 Btu/kWh

Step 4 – Economic, Energy, and Environmental Impacts

Reciprocating IC engines are fast-starting and, as shown above, generally have a lower heat rate than simple-cycle gas turbines. From a GHG perspective, these factors may make IC engines the preferred generation alternative in some situations. In this case, however, there are collateral environmental impacts that we have determined make the use of IC engines inappropriate.

In 2010, Wartsila introduced its 18V50SG gas engine. With a maximum electrical output of 18.759 MW, it is the world's largest engine and it is marketed by Wartsila as a viable alternative to gas turbine power plants up to 500 MW (Wideskog, 2011). In order to provide the 300 MW of electricity called for by the PPA applicable in this case, approximately 16 engines operating in simple cycle mode would be required. Multi-engine plants of this scale are feasible and have in fact been built in a number of locations (Wartsila, 2011). At this time, however, the NO_x rate guaranteed by Wartsila for this engine following SCR is 5 ppm, or 2.63 lbs/hr (C. Whitney, personal communication, January 25, 2012). Sixteen engines running at full load would therefore emit approximately 42 lbs/hr of NO_x. In comparison, each of the proposed simple cycle

LMS100 gas turbines would emit a maximum of 8.18 lbs/hr, for a total maximum NO_x rate of 24.5 lbs/hr. The IC engines would thus emit 71% more NO_x at full load than the gas turbines.

In weighing the trade-offs between the lower NO_x emissions associated with the gas turbines and the lower GHG missions associated with the IC engines, EPA is swayed by the fact that San Diego County is currently designated nonattainment for the 1997 8-hour ozone standard (69 Fed. Reg. 23858). In addition, both the state of California and EPA recently recommended that San Diego County be designated nonattainment for the revised 2008 ozone NAAQS (EPA, 2011). Given the current and projected ozone nonattainment status of the area, EPA believes it is appropriate in this case to favor the technology that reduces NOx emissions over GHG emissions, particularly when the difference in NO_x emissions between the two technologies is so great. Consequently, EPA has eliminated the IC engines as the top control option. After elimination of IC engines from the BACT analysis, highly efficient simple-cycle gas turbines represent the top control option.

Step 5 – Select BACT

Based on the foregoing analysis, EPA has concluded that BACT for GHGs for this source is the use of new thermally efficient simple-cycle combustion turbines combined with good combustion and maintenance practices to maintain optimum efficiency. The GE LMS100 gas turbines proposed by the applicant have a maximum efficiency of 44% under ISO conditions (General Electric Company, n.d.[2]). This is at the high end of the efficiency range for gas turbines of this size category;[15] thus, we believe that the applicant's proposal is consistent with the BACT requirement to use highly efficient simple-cycle turbines. To ensure that the plant operates as efficiently as possible over its entire lifetime, BACT will include a heat rate limit that applies at initial startup in addition to a separate emission limit that applies on an ongoing basis. Both the initial heat rate limit and the ongoing emission limit must account for a number of factors including various tolerances in the manufacturing and construction of the equipment as well as actual ambient operating conditions. Based on these factors, and turbine performance data provided by GE and the applicant (Hill, 2012), EPA is proposing to establish the initial heat rate limit at 9,196 btu_{hhv}/kw-hr_{gross}. This limit reflects the initial equipment performance levels provided by GE plus 3% to account for slight variations in the manufacturing, assembly, construction, and actual performance of the new turbines. Where the long-term emission limit is concerned, EPA is using a slightly higher margin of compliance than that used for the initial heat rate limit to account for unrecoverable losses in efficiency the plant will experience over its entire lifetime as well as seasonal

[15] See, for example, the Siemens product documentation (Siemens, 2008; Siemens, 2011), which states that its gas turbine products over 100 MW have efficiencies "approaching 40%" in simple cycle configuration, and that the 112 MW Siemens SGT6-2000E specifically has an efficiency of 33.9% under ISO conditions. See also the Rolls Royce product information (Rolls Royce, n.d.) sating that its Trent 60 gas turbine delivers up to 64 MW in simple cycle service with an efficiency of 42%. See also GE's product information page for the LMS100 (General Electric, n.d.[3]), which states that over the course of a peaking season, the high-efficiency LMS100 gas turbine system running at full capacity avoids over 34,000 metric tons of CO_2 emissions compared to a typical simple cycle system. Finally, information on simple-cycle gas turbine efficiency from EPA's RBLC (see Table 7-8 below) shows efficiencies no higher than approximately 37%.

variation in site-specific factors that affect turbine performance such as temperature and humidity. In this instance, we believe a margin of 6% is appropriate. Using this margin of compliance and the emissions data provided in the permit application, EPA is proposing an emission limit of 1,181 lbs CO_2/MWh net output.[16] Due to the nature of the emissions, GHG BACT limits established thus far have generally been based on an annual average such as a 365-day rolling basis. However, as a peaking facility, the PPEC will operate intermittently; on some days it may start up and shut down multiple times while on others it may not operate at all. Thus, it is preferable to monitor compliance with the limit based on actual hours of operation. To achieve this and still afford the facility the necessary flexibility of an annual limit, the averaging period for the CO_2 emission limit will be a rolling 8,760-operating hour average as monitored by a CO_2 CEMS.

Table 7-8 Simple Cycle Combustion Turbine Efficiency Data from RBLC

Facility	State	Description	Heat Capacity MMBtu/hr (HHV)	Net MW	Heat Rate Btu/kWh (HHV)	Calculated Efficiency (%)
Western Farmers Electric	OK	Simple cycle combustion turbine	462.7	50	9,254	36.9
El Colton, LLC	CA	LM6000	456.5	48.7	9,374	36.4
Bayonne Energy Center	NJ	Rolls Royce Trent 60WLE	603	64	9,422	36.2
Creole Trail LNG	LA	Simple cycle combustion turbine	290	30	9,667	35.3
Arvah B. Hopkins	FL	GE LM6000PC	489.5	50	9,790	35

16 The pollutant GHGs (or greenhouse gases) that is subject to regulation under the Clean Air Act for PSD permitting purposes consists of the combination of six gases (carbon dioxide, methane, nitrous oxide, sulfur hexafluoride, hydrofluorocarbons, and perfluorocarbons). However, we are expressing the GHG emission BACT limit for the gas turbines in this permit as a CO_2 limit because the GHG emissions from the gas turbines are overwhelmingly in the form of CO_2 and will allow the facility to use a continuous emissions monitoring system for compliance monitoring. For example, Table 1C.7 of the permit application shows that, on a tonne/MWh basis, the methane and nitrous oxide emissions from the turbines are many orders of magnitude lower than the CO_2 emissions. Even after accounting for the global warming potential of methane and nitrous oxide, on a ton per year basis, the CO_2 emissions from the gas turbines represent 99.9% of the total CO_2e emissions, and an efficiency-based emission limitation that limits CO_2 emissions from the combustion of natural gas inherently limits the emission of other emissions created through combustion, such as methane and nitrous oxide, from the same units at the same efficiency. Accordingly, since BACT for GHGs emissions from the turbines at this facility has been determined to be 39.3% combustion efficiency and the CO_2 limit selected ensures combustion efficiency at that level, adherence to the CO_2 limit (which will be determined through the use of CEMS) will also ensure that the BACT (39.3% combustion efficiency) is also achieved for emissions of methane and nitrous oxide.

Generating Station						
Indigo Energy Facility	CA	LM6000	450	45	10,000	34.1
Lambie Energy Center	CA	GE LM6000PC	500	49.9	10,020	34.1

7.1.4 BACT During Startup and Shutdown

It is not technically feasible to use SCR to control NO_x emissions when the equipment is outside of the manufacturer's recommended operating temperature ranges. For SCR, this occurs during turbine startup or shutdown. Based on vendor information, each turbine startup and shutdown is expected to last 30 and 10.5 minutes, respectively. The expected NO_x emissions associated with individual turbine startup and shutdown events are:

- Startup: 22.5 pounds of NO_x per turbine
- Shutdown: 6.0 pounds of NO_x per turbine

Since SCR is not effective during startup and shutdown periods, and there are no add-on PM controls, EPA has determined that limiting the duration and number of startups and shutdowns is BACT for NO_x and PM during these transient periods. The permit limits the duration of these events to 30 minutes for startups and 10.5 minutes for shutdowns, and the total number of startups to 500 per turbine per calendar year. In addition, the permit requires the use of SCR as soon as the system reaches the minimum temperature to become effective, which occurs when the catalyst temperature exceeds 575 degrees F. In order to ensure the lowest level of NO_x emissions during startup and shutdown, we have also set an emission limit from each CT of 22.5 pounds of NO_x per startup event, and 6.0 pounds of NO_x per shutdown event. Further, in order to ensure compliance with the NO_2 NAAQS, we have also set a limit requiring that NO_X emissions from each CT during startup or shutdown not exceed 26.6 lb/hr.

We have also determined that these startup and shutdown duration limits also constitute BACT for GHG emissions during these periods, because the short startup and shutdown times will also increase the overall thermal efficiency of the facility.

7.2 BACT for Cooling System

Step 1 – Identify All Possible Control Technologies
Options for controlling PM (including PM_{10} and $PM_{2.5}$) emissions from cooling systems include:

- Dry Cooling System

- Partial Dry Cooling System (including small wet cooling tower)
- Spray-enhanced Dry Cooling (dry cooling with heat transfer enhanced by spraying water on the outside of the heat exchanger tubes)
- Plume-abated Wet Cooling (wet cooling tower with a dry section that reduces the visible plume by heating the wet air from the wet section)
- Non-Plume-abated Wet Cooling Tower (wet cooling tower)
- Once-Through Cooling

Step 2 – Eliminate Technically Infeasible Options

Once-Through Cooling

Once-through cooling involves the water withdrawn from rivers, streams, lakes, reservoirs, estuaries, oceans, or other waters. In general, once-through cooling is only technologically feasible when a large surface water body exists in immediate proximity to a power plant. Since this situation does not exist for the PPEC, we conclude that once-through cooling is not technologically feasible BACT for the Project.

Step 3 – Rank Remaining Control Technologies

After eliminating one technically infeasible option, five options remain. In descending order of control effectiveness, these options are:

- Dry Cooling System
- Partial Dry Cooling System (including small wet cooling tower)
- Spray-enhanced Dry Cooling (dry cooling with heat transfer enhanced by spraying water on the outside of the heat exchanger tubes)
- Plume-abated Wet Cooling (wet cooling tower with a dry section that reduces the visible plume by heating the wet air from the wet section)
- Non-Plume-abated Wet Cooling Tower (wet cooling tower)

The Partial Dry Cooling System proposed by the applicant for the PPEC is comprised of two components: a dry cooling component that provides necessary cooling most of the time and has zero emissions, and a small (7,000 gpm circulation rate) wet cooling component that supplements the dry cooling component when ambient temperatures are too high for the dry cooling system to function effectively. Because dry cooling does not produce emissions, and the wet cooling portion of the system is much smaller than systems designed for condensing steam from a combined cycle unit, the Partial Dry Cooling System produces the lowest PM emissions of the six remaining technologies except dry cooling, which has zero emissions.

Step 4 – Economic, Energy and Environmental Impacts

A technical issue associated with using 100% dry cooling to provide adequate cooling is its limited ability to provide adequate cooling under high-temperature conditions. Specifically, plant capacity would begin to decrease at ambient temperatures greater than

70 degrees F, and plant output would be no greater than 284 MW at the plant design maximum ambient temperature of 93 degrees F. The additional energy cost of the parasitic load required by a 100% dry cooling system would not be cost-effective ($109,275/ton of PM reduced), given that total PM emissions are not expected to exceed 1.4 tons per year. Therefore, 100% dry cooling is not cost-effective as BACT for the Project, and we are eliminating it as the top-ranked control option due to economic infeasibility.

Step 5 – Select BACT

EPA concurs with the applicant's selection of the highest ranked remaining BACT option, a Partial Dry Cooling System, with a drift rate of 0.001%, as BACT for the cooling system. We note that while drift rates of 0.0005% have been achieved for once-through and recirculating water towers, this has occurred at facilities with much larger wet cooling components in their cooling towers, with much higher water recirculation rates. Because most of the cooling for the PPEC's cooling towers will be accomplished in the dry cooling portion of the system, we have determined that the proposed drift rate of 0.001% is sufficiently equivalent to the lower drift rate for a system that relies entirely on wet cooling. To ensure this drift rate is achievable, we are proposing a TDS limit not to exceed 5,600 ppm.

7.3 BACT for Circuit Breakers

The circuit breakers are subject to BACT for GHG emissions. The only GHG emitted from circuit breakers is sulfur hexafluoride (SF_6).

Step 1 – Identify all control technologies

The following control technologies are potentially available for the PPEC:

- Use of dielectric oil or compressed air circuit breakers. These types of circuit breakers do not contain any GHG pollutants.

- Totally enclosed SF6 circuit breakers with leak detection systems. These types of circuit breakers have a specified maximum leak rate and have an alarm warning when a certain percentage of the SF6 has escaped. The use of an alarm identifies potential leak problems before the bulk of the SF6 has escaped.

No add-on control options for GHG emissions were identified. Additionally, alternative gases to SF_6 other than compressed air are currently not available (EPRI, 2003; NIST, 1997).

Step 2 – Eliminate technically infeasible control technologies
We assume both control options are technically feasible.

Step 3 – Rank remaining control technologies
The expected emissions from the two control options are compared in Table 7-8 below. Dielectric oil and compressed air circuit breakers do not contain GHG pollutants and therefore would not result in any GHG emissions. As such, these technologies represent the top-ranked control option.

Table 7-8: Circuit Breaker Control Technologies Ranked by Control Effectiveness

GHG Control Technologies	CO2e Emission Rate (tpy)
Dielectric oil or compressed air circuit breakers	0
Enclosed-pressure SF6 circuit breakers with 0.5% (by weight) annual leakage rate and leak detection systems	40.2

Step 4 – Economic, Energy, and Environmental Impacts
SF_6 became commercially available in 1947 and has been used in the utility industry since the 1960s (NIST, 1997). Despite efforts over several decades to develop a desirable alternative to SF_6, none has been found and SF_6 is still the preferred gas for electrical insulation and for arc quenching and current interruption equipment used in the transmission and distribution of electricity. For circuit breakers, for example, SF_6 has high thermal conductivity and high dielectric strength. These properties along with its fast thermal and dielectric recovery are what make SF_6-based circuit breakers superior to currently available alternative systems (NIST, 1997; EPRI, 2003). Additionally, NIST (1997) reports that equipment insulated with SF_6 "offers significant savings in land use, is aesthetically acceptable, has relatively low radio and audible noise emissions and enables substations to be installed in populated areas close to the loads" as compared with dielectric oil and compressed air circuit breakers. Therefore, compared to circuit breakers with SF_6, dielectric oil and compressed air circuit breakers have clear adverse environmental and energy impacts, and we are eliminating dielectric oil and compressed air circuit breakers as the top-ranked control option.

Step 5 – Select BACT
Elimination of dielectric oil or compressed air circuit breakers from consideration leaves enclosed-pressure SF_6 circuit breakers with leak detection systems as the sole control option. A review of recent BACT determinations for this equipment further supports our conclusion:

Table 7-9: Recent BACT Determinations for Circuit Breakers at Electric Generating Facilities

Facility	Date Issued	BACT Determination
Lower Colorado River Authority – Thomas C. Ferguson Power Plant	11/10/11	Enclosed-pressure SF6 circuit breakers with leak detection
Palmdale Hybrid Power	10/18/11	Enclosed-pressure SF6 circuit breakers with an annual leakage rate of 0.5% by weight, a 10% by weight leak detection system

Based on the above information, we have concluded that GHG BACT for the circuit breakers is:

- the use of enclosed-pressure SF_6 circuit breakers with a maximum annual leakage rate of 0.5% by weight and a 10% by weight leak detection system, and
- an emission cap of 40.2 tpy

The SF_6 emissions from the circuit breakers shall be determined by using the mass balance in equation DD-1 at 40 CFR Part 98, Subpart DD.

8. Air Quality Impacts

Clean Air Act section 165 and EPA's PSD regulations at 40 CFR section 52.21 require an examination of the impacts of the proposed PPEC 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 NAAQS, or (2) the applicable PSD increments (explained below in Sections 8.4 and 8.5). These sections of the Fact Sheet include a discussion of the relevant background data and air quality modeling, and EPA's conclusion that the Project will not cause or contribute to an exceedance of the applicable NAAQS or applicable PSD increments and is otherwise consistent with PSD requirements governing air quality.

8.1 *Introduction*

8.1.1 Overview of PSD Air Impact Requirements

Under the PSD regulations, permit applications for major sources must include an air quality analysis demonstrating that the facility's emissions of the PSD-regulated air pollutants will not cause or contribute to a violation of the applicable NAAQS or applicable PSD increments. (A PSD increment for a pollutant applies only to areas that meet the corresponding NAAQS.) The applicant provides separate modeling analyses for each criteria pollutant emitted above the applicable significant emission rate. If a preliminary analysis shows that the ambient concentration impact of the project by itself is greater than the Significant Impact Level (SIL), then a full or cumulative impact analysis is required for that pollutant. The cumulative impact analysis includes nearby pollution sources in the modeling, and adds a monitored background concentration to account for sources not explicitly included in the model. The cumulative impact analysis must demonstrate that the Project will not cause or contribute to a NAAQS or increment violation. If a preliminary analysis shows that the ambient concentration impact of the project by itself is less than the Significant Impact Level (SIL), then further analysis is generally not required. Required model inputs characterize the various emitting units, meteorology, and the land surface, and define a set of receptors (spatial locations at which to estimate concentrations, typically out to 50 km from the facility). Modeling should be performed in accordance with EPA's Guideline on Air Quality Modeling, in Appendix W to 40 CFR Part 51 (GAQM or Appendix W). AERMOD with its default settings is the standard model choice, with CALPUFF available for complex wind situations.

A PSD permit application typically includes a Good Engineering Practice (GEP) stack height analysis, to ensure that a) downwash is properly considered in the modeling, and b) stack heights used as inputs to the modeling are no greater than GEP height, so as to disallow artificial dispersion from the use of overly tall stacks. The application may also include initial "load screening," in which a variety of source operating loads and ambient temperatures are modeled, to determine the worst-case scenario for use in the rest of the modeling.

The PSD regulations also require an analysis of the impact on nearby Class I areas, generally those within 100 km, though the relevant Federal Land Manager (FLM) may specify additional or fewer areas. This analysis includes the NAAQS, PSD increments, and Air Quality Related Values (AQRVs). AQRVs are defined by the FLM, and typically limit visibility degradation and the deposition of sulfur and nitrogen. Generally, CALPUFF is the standard model choice for Class I analyses, since it can handle visibility chemistry as well as the typically large distances (over 50 km) to Class I areas.

Finally, the PSD regulations require an additional impact analysis, showing the Project's effect on visibility, soils, vegetation, and growth. This visibility analysis is independent of the Class I visibility AQRV analysis. The additional impact analysis for the PPEC is discussed in Section 9 below.

8.1.2 Identification of PPEC Modeling Documentation

The PPEC modeling analysis comprises the documents listed in Table 8-1 below. The Nearby Sources (July 2011) letter proposes the nearby non-project source inventory for use in the cumulative impact modeling. The re-submitted PSD Application and associated hard-drive (September 2011) contains the results of the modeling. The applicant submitted a letter, Response-EPA Modeling Questions #1 (December 2011) addressing EPA's comments on its choice of background monitors, meteorological data, and its justification, procedures and data used in its Tier 3 NO_2 analysis. In addition, in this letter, the applicant presented results of a $PM_{2.5}$ increment analysis for Class I and Class II areas along with an annual NO_2 Class I increment analysis. Clarifying Information on 1-hr NO_2 Results (December 2011) is an e-mail from the applicant that provided information clarifying the method used to obtain NO_2 values for compliance with the 1-hr NO_2 NAAQS. Response-EPA Modeling Questions #2 (January 2012) is a letter from the applicant that further clarified the representativeness of the meteorological data chosen for the modeling analysis, and addressed the NO_2/NOx in-stack ratio for use in the NO_2 input data. Response-EPA Modeling Questions #1b (February 2012) is a letter from the applicant that presented an NO_2 compliance demonstration using El Cajon as an alternate monitoring site, and, to a limited extent, Otay Mesa, and their data as background concentrations. The applicant's letter Response-EPA Modeling Questions #3 (March 2012) provided further justification for its use of the Tier 3 PVMRM non-regulatory default option for determining NO_2 concentrations for compliance with the NAAQS. This letter also provided supplementary information about surface roughness representativeness between the project site and the meteorological site. In addition, the applicant provided EPA with its Class II Level 2 Visibility Response (March 2012), a letter presenting the results of a Level 2 VISCREEN screening analysis for two federal land manager (FLM) Class II areas within 50 km of the project site. A letter containing the results of an alternate modeling analysis based on a corrected in-stack NO_2/NOx ratio for a nearby facility are given in the applicant's Response-EPA NO_2 Alternate Modeling Request (May 2012).

Table 8-1: Modeling Documentation for PPEC Project PSD Application

Short name	**Citation**
Nearby Sources	Letter from Sierra Research (S. Hill) to EPA (C. Bohnenkamp) on nearby sources to be modeled, July 2011
Original PSD Application	Initial PPEC PSD Permit Application, September 2011
Response-EPA Modeling Questions #1	Letter from Sierra Research (S. Hill) to EPA (G. Rios) on modeling, December 2011 including Class I impact analysis
Clarifying Information on 1-hr NO_2 Results	Email from Sierra Research (S. Hill) to EPA (C. Holladay) forwarding NO_2 data, both monitoring and modeling results, December 2011
Response EPA Modeling Questions #2	Letter from Sierra Research (S. Hill) to EPA (G. Rios) on modeling & PM BACT, January 2012.
Response EPA Modeling Questions #1b	Letter from Sierra Research (S. Hill) to EPA (G. Rios) on 1-hour ozone compliance demonstration and further background NO_2 information, February 2012.
Response EPA Modeling Questions #3	Letter from Sierra Research (S. Hill) to EPA (G. Rios) on SF6 emissions and modeling, March 2012
Class II Level 2 Visibility Response	Letter from Sierra Research (S. Hill) to EPA (G. Rios), Class II Level 2 Visibility Analysis Results, March 2012
Response-EPA NO2 Alternate Modeling Request	Letter from Sierra Research (S. Hill) to EPA (G. Rios), Alternative Modeling Analysis (Donovan NO2/NOx ratio), May 2012

8.2. Background Ambient Air Quality

The PSD regulations 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. In addition, 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 accounts for all contributions to current air quality.

Ambient air concentrations of ozone (O_3), NO_2, PM_{10} and $PM_{2.5}$ are recorded at monitoring stations throughout San Diego County. The area surrounding the Project site (within 1.5-2 miles) is an area with sparse population. Farther out, areas to the north, northeast, east, and southeast are all generally vacant, hilly terrain with sparse population. However, areas more than 2 miles to the south (Tijuana, Mexico), 5 miles west (Otay Mesa West) and northwest (Sunbowl) are urban or suburban areas with moderate to high-density residential areas. The closest air quality monitoring station to the project site is located in Otay Mesa at the Otay Mesa-Paseo International Border crossing 1.2 miles south of the Project site. Pollutant concentrations recorded at this station are heavily influenced by the emissions from hundreds of vehicles queued and waiting at the Otay Mesa-Paseo International border crossing. The San Diego-1110 Beardsley Street monitoring station is more than 15 miles away from the Project site, and is located in the coastal area. The air quality at this monitoring station is not representative of the greater Lower Otay Lake area. In consultation with SDAPCD, the applicant chose the Chula Vista monitoring station, which is approximately 9 miles from the Project site, to represent background air pollutant concentrations for the area near the Project site. This site is further inland than the San Diego-1110 Beardsley Street monitoring station. It is also the closest source of existing data that is not heavily impacted by a known nearby source. The most recent years of data available at the time SDAPCD recommended the site for use for this Project was 2004-2008. However, EPA has added in the results of the 2009-2010 data to the table below.

At EPA's request, the applicant submitted additional NO_2 modeling using the El Cajon monitoring site located 15 miles to the north as a second site to characterize background concentrations for input into the modeling. Also, at EPA's request, the applicant did modeling within 0.5 km of the Otay Mesa monitor to characterize background concentrations due to Mexican sources not included in the modeling inputs for the Pio Pico modeling analysis. (Letter from Sierra Research (S. Hill) to EPA (G. Rios) on modeling, including Class I impact analysis, December, 2011; Letter from Sierra Research (S. Hill) to EPA (G. Rios) on modeling & PM BACT, January, 2012).

Table 8-2 below describes the maximum background concentrations of the PSD-regulated pollutants for which there are NAAQS that may be affected by the Project's emissions, and the corresponding NAAQS.

Table 8-2 Maximum Background Concentrations and NAAQS 2004-2010-Chula Vista Site

NAAQS pollutant & averaging time	Background Concentration, $\mu g/m^3$	NAAQS, $\mu g/m^3$
NO_2, 1-hr	118(63 ppb)	188 (100 ppb)
NO_2, annual	36(19 ppb)	100 (53 ppb)
PM_{10}, 24-hr	57	150
$PM_{2.5}$, 24-hr	30	35
$PM_{2.5}$, annual	12	15

Note: The $PM_{2.5}$ 24-hr value is 98th percentile averaged over three years rather than maximum

The NO_2 1-hr value is 98^{th} percentile averaged over three years rather than maximum

8.3 Modeling Methodology for Class II areas

The applicant modeled the impact of PPEC on the NAAQS and PSD Class II increments using AERMOD in accordance with EPA's GAQM (Appendix W of 40 CFR Part 51). The modeling analyses included the maximum air quality impacts during normal operations and startups and shut-downs, as well as a variety of conditions to determine worst-case short-term air impacts.

8.3.1 Model selection

As discussed in the PSD Application (PSD Application p.4.38 pdf.147), the model that the applicant selected for analyzing air quality impacts in Class II areas is AERMOD, along with AERMAP for terrain processing and AERMET for meteorological data processing. This is in accordance with the default recommendations in EPA's GAQM, Section 4.2.2 on Refined Analytical Techniques.

8.3.2 Meteorology model inputs

AERMOD requires representative meteorological data in order to accurately simulate air quality impacts. SDAPCD provided the applicant surface meteorological data collected for a five consecutive-year period (2004-2008) at the Otay Mesa/Paseo International meteorological monitoring station maintained by the District. The District processed these data using EPA's AERMET data processor and the applicant concurred with the processing. This station is located only 1.9 miles (3.0 km) from the Project site, with no intervening structures, hills, or water bodies that might significantly affect meteorological conditions. The Project site, the meteorological site and the "area of interest" are located inland and close to each other. For analyzing the representativeness of the meteorological data, the area of interest includes the SIA where screening modeling predicts the Project's pollutant impact to be greater than the SILs, and also includes the sources and receptors used in the modeling. Other nearby surface meteorological sites were examined, but the Otay Mesa station had sufficient data completeness, is the closest, and is the most representative with no intervening high ground between the Project site and the meteorological tower. (PSD Application, p.4.41 pdf.150). EPA believes that the chosen 2004-2008 Otay Mesa data from SDAPCD is the most representative for the PPEC analysis. Further discussion of the meteorological data used in the analysis is given in the following section on land characteristics.

For upper air data, the applicant selected 2004-2008 Marine Corps Air Station (MCAS) at Miramar, California, located approximately 24 miles (39 km) northwest of the Project site as being the most representative site available that had data complete enough to use. No other upper air meteorological monitoring stations are located in the San Diego Air Basin. (PSD Application, p-PSD-4.41pdf.150). EPA agrees that it is appropriate to use the MCAS upper air data for the PPEC analysis.

8.3.3 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 length, Bowen ratio, and albedo. The surface roughness length is related to the height of obstacles to the wind flow and is an important factor in determining the magnitude of mechanical turbulence. The Bowen ratio is an indicator of surface moisture. The albedo is the fraction of total incident solar radiation reflected by the surface back to space without absorption

The applicant used terrain elevations from United States Geological Survey (USGS) National Elevation Dataset (NED) data in the GeoTIFF format (at a horizontal resolution of 30 meters), for receptor heights for AERMOD,, which uses them to assess plume distance from the ground for each receptor. All coordinates were referenced to UTM North American Datum 1983 (NAD83, Zone 11. The AERMOD, receptor elevations were interpolated among the Digital Elevation Model (DEM) nodes according to standard AERMAP procedure. For determining concentrations in elevated terrain, the AERMAP terrain preprocessor receptor-output (ROU) file option was chosen.

The applicant used surface roughness values in the modeling inputs developed by SDAPCD. The District followed EPA's "AERMOD Implementation Guide" (2009 version) in using EPA's AERSURFACE processor with the National Land Cover Data 1992 archive to determine surface characteristics for AERMET (Letter from Sierra Research (S. Hill) to EPA (G. Rios) on SF6 emissions and modeling, March 2012). The surface roughness characteristics are representative of the area surrounding the site where the meteorological data is collected. The applicant also used the criteria described in Section 3 (Representativeness) from EPA's Meteorological Monitoring Guidance for Regulatory Modeling Applications (2000). AERSURFACE uses a Land Use data base from 1992, and does not take buildings into account. In addition, SDAPCD reviewed recent aerial photos for the area, which show that the Otay Mesa Meteorological tower is surrounded by a light industrial and residential area that includes northern Mexico and the United States border area. Using this information, SDAPCD adjusted the surface roughness factor from the value of approximately 0.2 meters calculated by AERSURFACE to 0.7 meters to more accurately represent the current terrain and structures surrounding the Otay Mesa meteorological site. SDAPCD's adjustment is supported by AERSURFACE/AERMOD guidance.

EPA requested additional detail characterizing the surface roughness surrounding the Project site and correspondingly in the "area of interest". The Meteorological Monitoring Guidance referenced above states that a quantitative method does not exist for determining representativeness absolutely. The applicant did a qualitative comparison of the following factors from the Meteorological Monitoring Guidance (p.3-3) recommended for consideration for siting: proximity, height of measurement, boundary layer profile considerations, and surface characteristics (Letter from Sierra Research (S.

Hill) to EPA (G. Rios) on SF6 emissions and modeling, March 2012). Based on this comparison, the applicant and EPA conclude that the use of Otay Mesa meteorological data is adequately representative of the "area of interest" and the Project site.

8.3.4 Model receptors

Receptors in the model are geographic locations at which the model estimates concentrations. The applicant places the receptors such that they have good area coverage and are 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, since 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 possibly by knowledge of the distance at which impacts fall to negligible levels. Receptors need be placed only in ambient air, that is, locations to which the public has access, and that are not inside the project fence line.

The applicant used Cartesian coordinate receptor grids to provide adequate spatial coverage surrounding the project area, to identify the extent of significant impacts, and to identify maximum impact location. In the screening analyses, the applicant placed over 11,000 receptors spaced no more than 250 meters apart out to 30 km. The most distant receptor with a significant project impact was 24 km east of the project site (1-hour NO_2). The significant impact receptors were used to define the domain where the cumulative impact analysis was be performed.

For the cumulative impact analyses, the applicant used over 9600 receptors to determine NO_2 impacts and over 1600 receptors to determine $PM_{2.5}$ impacts. The applicant developed a nested grid to fully represent the maximum impact areas. This grid has 25-meter resolution along the facility fence-line, 100-meter resolution from 100 meters to 1,000 meters from the fence-line, and 250-meter spacing out to at least 10 km from the most distant source modeled. Additional refined receptor grids with 25-meter resolution were placed around the maximum first-high and maximum second-high coarse grid impacts and extended out 1,000 meters in all directions. Receptor locations at which the model did not predict NO_2, PM_{10}/ $PM_{2.5}$ significant impact level exceedances were not included in cumulative analyses for these pollutants. (p.3 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). (PSD Application p.PSD-4.40 pdf.149)

8.3.5 Load screening and stack parameter model inputs

The applicant performed initial "load screening" modeling, in which six source operating loads and ambient temperatures were modeled, to determine the "worst case" stack parameter scenario for use in the rest of the modeling, whenever normal operations are considered. It modeled two loads: a minimum load of 50% and a maximum load of 100%. The choice of "worst case" is different for each pollutant and averaging time, because different pollutants' emissions respond differently to temperature and flow rate. Ambient temperatures modeled were 30°F, 63° F and 110°F. The "worst case" hourly scenario (for this project the only hourly pollutant is NO_2) is expected to occur under the conditions with the highest firing rate: 100% load and 30°F ambient temperature. The worst case annual scenario for $PM_{10}/PM_{2.5}$ is expected under low load, cold temperature conditions; for annual NO_2 it is the peak load, 63° F case. The "worst case" 24-hour average (for this project only $PM_{10}/PM_{2.5}$) scenario is the same as for the annual average (PSD Application p.PSD-4.42 pdf.151). In addition, for the NO_2 1-hour averaging time, the PPEC's startup and shutdown emissions would be higher than the normal operating emissions because the emission control systems are not fully operational. For the PPEC, startup emissions are higher than shutdown emissions. The "worst case" load scenario for startup is the low load cold temperature scenario. Further discussion of the impact of these emissions is provided in Section 8.4.3.5. The remainder of the modeling done by the applicant used the corresponding stack parameters to provide conservative estimates of PPEC impacts and are represented in the Table 8.3 below.

Table 8-3: Load screening and stack parameters

Screening Modeling Inputs
Pio Pico Energy Center

	Ambient Temp	Stack Height	Stack Diameter	Stack Flow	Stack Velocity	Stack Temp
Operating Mode	degrees F	feet	feet	wacfm	ft/sec	degrees F
Startup/shutdown	30	100	14.5	645,580	65.16	820
Hot Peak	110	100	14.5	877,825	88.60	802
Average Peak	63	100	14.5	913,777	92.22	785
Cold Peak	30	100	14.5	909,632	91.81	754
Hot Low	122	100	14.5	733,309	74.01	825
Average Low	63	100	14.5	646,428	65.24	831
Cold Low	30	100	14.5	645,580	65.16	820

Pollutant	NOx	$PM_{10}/PM_{2.5}$	NOx	$PM_{10}/PM_{2.5}$
Operating Mode	lb/hr	lb/hr	g/sec	g/sec
Startup/Shutdown	26.63	5.50	3.36	0.69
Hot Peak	7.72	5.50	0.97	0.69
Average Peak	8.18	5.50	1.03	0.69
Cold Peak	8.07	5.50	1.02	0.69
Hot Low	5.92	5.50	0.75	0.69
Average Low	4.94	5.50	0.62	0.69
Cold Low	4.92	5.50	0.62	0.69

Startup Modeling Inputs

	Ambient Temperature	Stack Height	Stack Diameter	Stack Flow	Stack Velocity	Stack Temp
Case	degrees F	feet	feet	wacfm	ft/second	degrees F
Cold Low	30	100	14.5	645,580	65.16	820

Source: PSD Application Appendix Table 1D.1 and 1D.2, p.PSD-App-1.57-1.58pdf.370-371

8.3.6 Good Engineering Practice (GEP) Analysis

The applicant performed a Good Engineering Practice (GEP) stack height analysis, to ensure that a) downwash is properly considered in the modeling, and b) stack heights used as inputs to the modeling are 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 EPA's BPIP (Building Profile Input Program) software, which uses building dimensions and stack heights as inputs. Based on the analysis, the applicant shows that the GEP stack height for the main combustion turbines was greater than 65 m (213 ft), which is greater than the planned actual height of 30.4 m (100 ft). The applicant showed that the GEP stack height for the other equipment was similarly greater than the planned heights. So, for all emitting units, the applicant used the planned actual stack heights for inputs in AERMOD modeling, and included wind direction-specific Equivalent Building Dimensions to properly account for downwash. (PSD Application p.PSD 4-39 pdf.148)

8.4 *National Ambient Air Quality Standards and PSD Class II Increment Consumption Analysis*

8.4.1 Pollutants with significant emissions

40 CFR 52.21 requires an air quality impact analysis for each PSD-regulated pollutant (for which there is a NAAQS) that a major source has the potential to emit in a significant amount, *i.e.*, an amount greater than the Significant Emission Rate for the pollutant. Applicable PPEC emissions and the Significant Emission Rates are shown in Table 8-4 (derived from PSD Application Table 1-1, p.PSD1.1 pdf.11). As shown in Table 8-4, EPA does not expect PPEC to emit CO, Pb and SO_2 in significant amounts. However, based on the estimates submitted by the applicant EPA expects the PPEC to emit NO_X, PM_{10}, and $PM_{2.5}$ in significant amounts. Therefore, this project triggers the air impact analyses for NO_2, PM_{10} and $PM_{2.5}$.

Table 8-4: PSD Applicability to PPEC: Pollutants Emitted in Significant Amounts

Criteria Pollutant	PPEC Emissions, tons/year	Significant Emission Rate, tons/year	PSD applicable?
CO	96.4	100	No
NO_X	70.4	40	Yes
PM_{10}	37.2	15	Yes
$PM_{2.5}$	37.2	10	Yes
SO_2	4.1	40	No
Pb	0.0	0.6	No

Source: PSD Application Table 1-1, p.PSD1.1 pdf.11

8.4.2 Preliminary analysis: Project-only impacts (Normal Operations and Startup)

EPA has established Significant Impact Levels (SILs) to characterize air quality impacts.

A SIL is the ambient concentration resulting from the facility's emissions, for a given pollutant and averaging period, below which the source is considered to have an insignificant impact. For maximum modeled concentrations below the SIL, further air quality analysis for the pollutant may not be necessary. For maximum concentrations that exceed the SIL, EPA requires a cumulative modeling analysis which incorporates the combined impact of nearby sources of air pollution to determine compliance with the NAAQS and PSD increments.

Table 8-5 shows the results of the preliminary or Project-only analysis based on normal operations for the PPEC. Startup emissions are used for determining the maximum 1-hr NO_2 impacts with maximum project impacts from normal operations included in parentheses. PPEC impacts are significant only for 1-hour NO_2 and 24-hour $PM_{2.5}$, and we have determined that cumulative impact analyses are required for only these two pollutants.

Table 8-5: PPEC Significant Impacts

NAAQS pollutant & averaging time	Project-only Modeled Impact ug/m^3	Significant Impact Level (SIL), µg/m^3	Project impact significant?
NO_2, 1-hr	111 (27)	7.5 (4 ppb)	Yes
NO_2, annual	0.3	1	No
PM_{10}, 24-hr	3	5	No
$PM_{2.5}$, 24-hr	2.6	1.2	Yes
$PM_{2.5}$, annual	0.26	0.3	No

Sources: PSD Application Table 4-24, p.PSD 4-43pdf.152

8.4.3 Cumulative impact analysis

A cumulative NAAQS or PSD increment impact analysis considers impacts from nearby sources in addition to impacts from the Project itself. In addition, for demonstrating compliance with the NAAQS, the applicant adds a background concentration to represent those sources not explicitly included in the modeling, so that the total accounts for all contributions to current air quality. In this case, the applicant submitted cumulative impact analyses demonstrating compliance with the annual $PM_{2.5}$ NAAQS, the 24-hour $PM_{2.5}$ NAAQS and the 1-hour NO_2 NAAQS.

For demonstrating compliance with the PSD increment, only increment-consuming sources need to be included, because the increment concerns only changes occurring since the applicable baseline date. In this analysis, there is no 1-hour NO_2 PSD increment; therefore, only 24-hour $PM_{2.5}$ requires a cumulative PSD increment analysis.

With respect to the PSD increment analysis for $PM_{2.5}$, the applicable trigger date is October 20, 2011. In general, for $PM_{2.5}$, the minor source baseline date is the earliest date after the trigger date of a complete PSD permit application for a source with a proposed increase in emissions of $PM_{2.5}$ that is significant. No source triggered the minor source baseline date in the area at issue prior to the submittal of PPEC's complete PSD permit application. Thus, the first source to submit a complete PSD permit application in the area at issue is PPEC, and the applicable minor source baseline date for $PM_{2.5}$ is the date on which the PPEC PSD permit application was complete, *i.e.*, June 14, 2012. The minor source baseline area established by this source for the $PM_{2.5}$ increment is San Diego County; PPEC will not have an air quality impact equal to or greater than 0.3 ug/m^3 (annual average) for $PM_{2.5}$ in any other intrastate area designated attainment or unclassifiable. (See 40 C.F.R. 52.21(b)(15)(i).) There have been no actual emissions changes of $PM_{2.5}$ from any new or modified major stationary source on which construction commenced after October 20, 2010, the major source baseline date for $PM_{2.5}$, for purposes of analyzing $PM_{2.5}$ increment consumption here. Therefore, the applicant considered only the allowable emissions increase from PPEC in the 24-hour $PM_{2.5}$ increment analysis.

8.4.3.1 Nearby source emission inventory

For both the PSD increment and NAAQS analyses, there may be a large number of sources that could potentially be included, so judgment must be applied to exclude small and/or distant sources that have only a negligible contribution to total concentrations. 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. (GAQM 8.2.3)

SDAPCD provided a list of all stationary sources within the District and within 80 km of the project (approximate distance to the farthest significant impact plus 50 km). A comprehensive procedure was used to determine which sources were included in the emissions inventory.

It should be noted that short-term maximum emission rates rather than annual emission rates determine the distance over which a facility might have a significant impact for short-term standards (*e.g.*, hourly NO_2). Peak rates that occur during startup determine the PPEC significant impact area for hourly NO_2.

The applicant identified five facilities nearby for inclusion in the emission inventory for the cumulative analysis, based on discussions with SDAPCD. The following non-PPEC facilities and their NOx and PM2.5 emissions are included in the cumulative compliance demonstration: Larkspur Energy Facility (a small peaking plant 2.5 km west of the Project site); Pacific Recovery Corp. (a landfill gas waste-to-energy facility 9.2 km west of the Project site); Calpeak Border (a 50 MW peaking plant located 2.6 km southwest of the Project site); Donovan Correctional Facility (a small turbine 1.5 km northwest of the Project site) and Otay Mesa Energy Center (a baseload power plant located adjacent to the Project site). These facilities are large enough and close enough to the Project site to have the potential to directly impact the Project's significant impact area. (PSD Application, p. App-1.134 pdf.451).

Current EPA NO_2 guidance suggests that emphasis on determining which nearby sources to include in the nearby source inventory should focus on the area within about 10 kilometers of the project location in most cases, which indicates that the PPEC inventory is adequate for performing these cumulative analyses (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).

Nevertheless, as an additional factor, the applicant also considered emission levels and distance as factors for determining which sources with small emissions and/or at large distances would be reasonable to exclude from the analysis. The applicant proposed that NO_2 sources with a ratio less than 70 TPY/24 km=2.9 and $PM_{2.5}$ sources with a ratio less than 35.8TPY/3.8 km = 9.4 (based on the ratio of annual emissions to the distance to the limits of significant impact) be eligible for consideration for exclusion from the relevant inventories. This ratio was used to classify non-Project sources into three categories: those that could clearly be excluded, those that clearly should be included and those where additional judgment is required.

Therefore, taking into consideration the current EPA guidance suggesting a focus on sources within 10 km, EPA concludes that the combination of a representative background monitored concentration, and the additional consideration of emission levels and distance, provide sufficient justifications for the inventory used in the cumulative analysis.

8.4.3.2 PM2.5-specific issues

EPA has issued guidance on how to combine modeled results with monitored background concentrations, which the applicant adequately followed. ("Modeling Procedures for Demonstrating Compliance with $PM_{2.5}$ NAAQS", memorandum from Stephen D. Page, Director, EPA OAQPS, March 23, 2010.)

The applicant provided a cumulative $PM_{2.5}$ analysis. The applicant's analysis conservatively assumed that all PM_{10} emissions were also $PM_{2.5}$ emissions, and therefore made use of PM_{10} emissions data as input to the modeling, so actual $PM_{2.5}$ impacts would be expected to be lower than those indicated in the model results.

$PM_{2.5}$ is either directly emitted from a source (primary emissions) or formed through chemical reactions with pollutants already in the atmosphere (secondary formation). EPA has not developed and recommended a near-field model that includes the necessary chemistry algorithms to estimate secondary impacts in an ambient air analysis.

The PPEC application does not specifically address secondarily formed $PM_{2.5}$ (as distinguished from directly emitted primary $PM_{2.5}$). Secondary $PM_{2.5}$ is formed through the emission of non-particulates (*i.e.*, gases) – such as SO_2 and NO_X – that turn into fine particulates in the atmosphere through chemical reactions or condensation. Using the results for $PM_{2.5}$ impacts given in Tables 8-5 and 8-7 and the projected emission rates of SO_2, NO_X and $PM_{2.5}$, EPA notes that the PPEC emissions of 4.1 TPY SO_2 are less than the SO_2 SER of 40 TPY, and would not be expected to result in significant secondary $PM_{2.5}$. The PPEC NO_X emissions of 70.4 TPY are above the NO_X SER of 40 TPY. However, secondary $PM_{2.5}$ formation occurs only as a result of chemical transformations that would affect only a portion of those emissions, and which occur gradually over time as the plume travels and becomes increasingly diffuse, and would be expected to be considerably smaller than the impacts from the 37.2 TPY of directly emitted primary $PM_{2.5}$. The maximum impact of source primary $PM_{2.5}$ was 2.6 ug/m^3 for 24-hour $PM_{2.5}$ and 0.26 ug/m^3 for annual $PM_{2.5}$. The $PM_{2.5}$ cumulative impacts analysis indicates that at least 7.3 ug/m^3 and 2.5 ug/m^3 remain available for the 24-hour and annual averaging times, respectively, before the NAAQS is challenged (35 ug/m^3 – 27.7 ug/m^3 for the 24-hour averaging time, and 15 ug/m^3 – 12.5 ug/m^3 for the annual averaging time). Because the secondary $PM_{2.5}$ formation from PPEC's NO_X emissions would be expected to be considerably smaller than the primary $PM_{2.5}$ impacts, they would also be smaller than the additional 7.3 ug/m^3 or 2.5 ug/m^3 needed to cause or contribute to a $PM_{2.5}$ NAAQS violation. In addition, because most of these chemical transformations in the atmosphere occur slowly (over hours or even days, depending on atmospheric conditions and other variables), secondary $PM_{2.5}$ impacts generally occur at some distance from the source of its gaseous emissions precursors, and are unlikely to overlap with maximum primary $PM_{2.5}$ impacts that are close by.

8.4.3.3 NO_2-specific issues

While the new 1-hour NO_2 NAAQS is defined relative to ambient concentrations of NO_2, the majority of NOx emissions from stationary sources are in the form of nitric oxide (NO) rather than NO_2. Appendix W notes that the impact of an individual source on ambient NO_2 depends in part "on the chemical environment into which the source's plume is to be emitted" (see Section 5.1.j). Because of the role NOx chemistry plays in determining ambient impact levels of NO_2 based on modeled NOx emissions, Section 5.2.4 of Appendix W recommends a three-tiered screening approach for NO_2 modeling. Later guidance documents issued by EPA expand on this approach. Tier 1 assumes full conversion of NO to NO_2. Tiers 2 and 3 are refinements of the amount of conversion of NO to NO_2. The applicant used the Tier 3 Plume Volume Molar Ratio Method (PVMRM) option in AERMOD, which simulates the interaction of NO with ambient O_3 to form NO_2. The PVMRM determines the conversion rate for NOx to NO_2 based on a calculation of the NOx emitted into the plume, and the number of O_3 moles contained within the volume of the plume between the source and receptor. In addition to requiring monitored ozone, the method requires specification of an in-stack NO_2/NO_X ratio. The following presents a discussion of the in-stack NO_2/NOx ratios used in PVMRM for the proposed turbines and nearby sources for the cumulative impact analysis.

A. In-stack NO_2/NO_x ratio

Defining source-specific in-stack NO_2/NOx ratios is part of the refinement of the Tier 3 PVMRM. An in-stack NO_2/NOx ratio of 0.50 is the default value and can be used without further justification. This applies not only for the proposed LMS100 turbines but also for the other sources used in the cumulative impacts analysis. As discussed in

Section 8.4.3.1, five facilities (with ten emission units among them) were included in the cumulative impacts analysis. For the proposed turbines and units in the cumulative impacts analysis, the applicant did not use the default value of 0.50. Therefore, to determine whether the proposed values would be acceptable, we requested additional information from the applicant, obtained available source test summary results for the five facilities' emission units, and further discussed the selection of the ratios with the applicant and the SDAPCD. Table 8-6 presents the resulting PVMRM in-stack NO_2/NOx ratios.

Table 8-6: In-stack NO_2/NOx Ratios

Source / Emission Units	NO_2 / NOx ratio
Pio Pico turbines – startup operations	0.24
Pio Pico turbines – normal operations	0.13
CalPeak Border	0.10
Otay Mesa, Units #1, #2	0.05
Pacific Recovery Landfill, Units #1, #2, #3, #4	0.75
Larkspur, Units #1, #2	0.10
Donovan Detention Center	0.56

1. Proposed Turbines

The applicant proposed an in-stack NO_2/NOx of 0.13 for normal operations and 0.24 for startup, when the SCR is not fully operational. Absent available ratios specific for LMS100 turbine operations, the SDAPCD recommended these two ratios based on source test results of gas turbines with operations considered similar to a LMS100 turbine. For normal operations, the average of source test results from four LM6000 PC SPRINT turbines were used to establish the 0.13 ratio. These turbines were selected by the SDAPCD because, similar to the LMS100, the LM6000PC SPRINT turbines are aeroderivative turbines with diffusion flame combustors, operating in simple-cycle mode with add-on catalyst system controls. While the LM6000PC SPRINT uses water injection to reduce combustion temperatures and the formation of thermal NOx by cooling, the LMS100 interstage cooling system achieves a similar and more effective outcome. For startup operations when the SCR is not fully operational, the average of source test results from eleven natural gas-fired, water injection-only GE Frame 5 turbines without SCR and oxidation catalyst add-on controls were used to establish the 0.24 ratio.

2. Nearby Sources for Cumulative Impacts Analysis

The applicant performed a full impacts analysis, which included the ten emission units at the five nearby facilities. In-stack ratios for these emission units were based on available SDAPCD historical source test data. In a January 2012 response to an EPA December 2011 request for additional information,[17] the applicant presented its approach for

[17] Letter from Sierra Research (S. Hill) to EPA (G. Rios) on modeling & PM BACT, January, 2012.

selecting the in-stack NO_2/NOx ratios. After review of this data, we requested further clarification in March 2012[18] including more details about the source test data. In May 2012, we reviewed additional source test summary results. We further discussed the selection of the ratios with the applicant and the SDAPCD and requested that an alternate modeling evaluation be performed replacing an originally proposed ratio of 0.10 with 0.56 for the Donovan Detention Center to reflect the average of seven source tests for this emission unit. Table 8-7 in Section 8.4.3.5 presents the modeling results.

B. NO_2 monitor representativeness/conservativeness

As mentioned above, the applicant chose the Chula Vista monitor for background NO_2 concentrations. This monitor is 9 miles from the PPEC site. As mentioned in Section 8.2, EPA requested that the applicant perform additional modeling using background concentrations from El Cajon and, to a limited extent, from Otay Mesa.

C. 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 (NO_2 Memo #1 p.10 pdf.10). The Chula Vista monitor is 9 miles away from the PPEC site, and EPA agrees that it is adequately representative.

D. Missing O_3 data procedure

The applicant reported and provided the procedure that SDAPCD used to fill in missing ozone data to ensure that NO to NO_2 conversion is not underestimated.

EPA concurs that SDAPCD followed a reasonable and conservative procedure for filling in missing ozone values.

E. Combining modeled and monitored values

Originally, the applicant proposed to combine each modeled concentration with the background concentration from the corresponding hour ("hour-by-hour" approach). The applicant later switched to a variant of EPA's March 2011 memo's[19] "first tier" approach: it used month by hour-of-day temporal pairing. The applicant correctly used the first highest values from the distribution for each temporal combination. (The EPA March 2011 memo's "first-tier" approach uses the 98th percentile of the annual distribution of daily maximum 1-hour values averaged across the most recent three years of monitored data as a uniform background contribution but also mentions the above procedure as a

[18] Email from EPA (C.Holladay) to Sierra Research (S. Hill), NO2/NOx In-Stack Ratio Documentation and Test Results for Pio Pico, March, 2012.
[19] "Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO2 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

suggested temporal pairing option on p.20.) This procedure is based on a conservative assumption.

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

8.4.3.4 Startup and shutdown analyses

As stated in Section 8.3.5, the applicant estimated combustion turbine NO_X emissions during startup and shutdown to be substantially higher than during normal operations, and thus the applicant also modeled for startup (as emissions are highest during startup). The stack parameters input into the model such as exit temperature and exhaust velocity were consistent with a 50% operating load; the ambient temperature the applicant used represented worst-case meteorological conditions, *i.e.*, emission into a cold morning stable layer. Since startup duration may not exceed half an hour, worst case hourly emissions consist of a half-hour of startup emissions followed by a half hour of normal operations. For NO_X, this is 1/2 of 45.0 (22.5) lb/hr, plus 4.1 lb/hr, for a combined rate of 26.6 lb/hr per turbine (PSD Application Tables 4-18 and 4-19. p.PSD-4.33-4.34 pdf.142-143). This 1-hour NO_2 startup analysis continues to use the conservative assumptions discussed above for the analysis of normal operations. The model results are shown in Table 8-6 for the cumulative impacts analysis. The results demonstrate that emissions from PPEC will also comply with the 1-hour NO_2 NAAQS during startup and shutdown conditions.

8.4.3.5 Results of the cumulative impacts analysis

The results of the PSD cumulative impacts analysis for PPEC's normal operations for $PM_{2.5}$ and startup emissions for 1-hr NO_2 are shown in Table 8-6. In addition, the results include additional modeling using background NO_2 concentrations from the El Cajon monitor to the north of the Project site and from the Otay Mesa monitor 2 miles to the southwest. The analysis demonstrates that emissions from PPEC will not cause or contribute to exceedances of the NAAQS for 1-hour NO_2 or 24-hour $PM_{2.5}$ or for any applicable PSD increments. As discussed above, PPEC's maximum modeled concentrations are below the SILs for annual NO_2, 24-hour PM_{10}, and annual $PM_{2.5}$; therefore, a cumulative impacts analysis was not required to demonstrate compliance for these pollutants/averaging times. A cumulative impacts analysis was also done for $PM_{2.5}$ annual, however, and the results included in the table.

EPA also considered additional information to ensure that the Project would not be responsible for causing a new NAAQS exceedance outside this modeling area. EPA considered sources in San Diego County (no sources of interest were located outside of the county) that were not included, but which had been evaluated for inclusion/exclusion, in the cumulative impacts modeling above. EPA concluded that these sources are either small enough or distant enough that the Project's expected emissions along with emissions from these sources would not create any new NAAQS exceedance in the modeling area outside of the SIA.

Table 8-7: PPEC Compliance with Class II PSD Increments and NAAQS

NAAQS pollutant & averaging time	All Sources Modeled Impact	PSD Increment Consumption	Background Concentration	Cumulative impact w/ background	NAAQS (ug/m^3)	PSD Increment
NO_2, 1-hr	111	NA	(hourly)	179	188 (100 ppb)	NA
$PM_{2.5}$, 24-hr	0.7	2.6	27.0	27.7	35	9
$PM_{2.5}$, annual	1.9	0.3	12.5	14.4	15	4

Notes: - There are no PSD increments defined for 1-hour NO_2.
Sources:
NO_2, $PM_{2.5}$ (NAAQS): PSD Application Table 4-25, p. PSD-4.45 pdf154 and Letter from Sierra Research (S. Hill) to EPA (G. Rios), Alternative Modeling Analysis (Donovan NO2/NOx ratio), May 2012

$PM_{2.5}$ (PSD increment): Letter from Sierra Research (S. Hill) to EPA (G. Rios) on modeling, December 2011

8.5 Class I Area Analysis

8.5.1 Air Quality Related Values

The two nearest Class I areas are listed below, with only one being located within 100 km of the Project site:

- Agua Tibia Wilderness (91 km)
- San Jacinto Wilderness (122 km)

Based on the most recent Federal Land Managers' Air Quality Related Values (AQRV) Work Group (FLAG) published guidance[20] the following screening approach is used to determine whether a more refined Class I Air Quality Analysis is required. This approach, which only applies to projects located more than 50 km from a Class I area, requires adding all of the visibility-related emissions (SO_2, NOx, PM_{10} and sulfuric acid mist) from a project (based on 24-hour maximum allowable emissions expressed in units of tons per year) and dividing the sum by the distance between the project and the Class I area. If the result is less than 10, the project is presumed to have negligible impacts to Class I AQRVs. The table below shows that the Project's emissions are well below the FLAG screening criteria. Therefore, no further Class I AQRV analysis is required.

CLASS I AIR QUALITY IMPACT SCREENING ANALYSIS

Pollutant	PPEC Emissions (max 24-hours, lb/day)	PPEC Emissions[a] (max 24-hours, TPY)	Q/D Screening Threshold[b]	Class I Analysis Required?
SO_2	136.8	25.0	--	--
PM_{10}	411.8	75.2	--	--
NOx	864.3	157.7	--	--
Sulfuric Acid Mist	0	0	--	--
Total	--	257.9	--	--
Distance, km	--	91	--	--
Q/D	--	2.8	10	**NO**

[a] TPY = max daily emissions (lb/day) *365/2000

[b] U.S Forest Service et. al., "Federal Land Managers' Air Quality Related Values Work Group (FLAG), Phase I Report—Revised (2010)," October 2010, p. 18-19

8.5.2 Class I Increment Consumption Analysis

EPA requires an analysis addressing Class I increment impacts for the applicable pollutants regardless of the results of the Class I AQRV analysis. This analysis was not in the original application. EPA requested that the applicant provide an analysis to address increment consumption in the Class I areas within 300 km of the project site. The applicant provided an analysis (Letter from Sierra Research (S. Hill) to EPA (G. Rios) on modeling, including Class I impact analysis, December 2011) using AERMOD to show that the most distant location where the impacts of NO_2 or $PM_{2.5}$ emissions from the Project exceed the Class I SILs is 52 km. The closest Class I area, the Agua Tibia Wilderness, is 91 km from the Project site. Impacts from the Project would continue to decrease as the distance from the Project site increases. As shown in Table 8-8, for the PSD pollutants for which there are applicable increments, PPEC impacts are less than the Class I SILs almost 40 km away from the nearest Class I area.

As discussed above, PPEC's complete application on June 14, 2012 established the minor source baseline date and established San Diego County as the minor source baseline area for the $PM_{2.5}$ increment. As noted previously, there have been no changes in actual emissions of $PM_{2.5}$ from any major stationary source on which construction commenced after October 20, 2010, the major source baseline date for $PM_{2.5}$, for purposes of analyzing $PM_{2.5}$ increment consumption here. Therefore, for purposes of this Class I $PM_{2.5}$ increment analysis, we consider only PPEC's increment consumption. Because PPEC impacts are less than the Class I SILs at a substantial distance from the closest Class I area, and the Class I SILs are much lower than the increments, EPA has determined that PPEC's maximum impacts are well below the $PM_{2.5}$ increments. Therefore, the applicant has demonstrated that the Project will not cause or contribute to any Class I PSD increment violation for $PM_{2.5}$.

For NO_2 annual increment impacts, extrapolating the Project's predicted impacts out to the border of the closest Class I area would result in extremely low impacts since the significant impact distance is only 7 km. In addition, with the continued NOx reductions since the NOx baseline date (1988), EPA concludes no increment violation is likely even if other sources outside of the significant impact distance were to be modeled.

Table 8-8: PPEC Class I Increment Impacts

Class I Area	Pollutant and averaging time	Project Impact, less than SIL, distance km	SIL, μg/m^3	Class I PSD Increment, μg/m^3
Agua Tibia (91 km)	NO_2, annual	7	0.1	2.5
	$PM_{2.5}$, 24-hr	52	0.07	2
	$PM_{2.5}$, annual	6	0.06	1

Source: Letter from Sierra Research (S. Hill) to EPA (G. Rios) on modeling, including Class I impact analysis, December 2011

9. Additional Impact Analysis

In addition to assessing the ambient air quality impacts expected from a proposed new source, the PSD regulations require that EPA evaluate other potential impacts on 1) soils and vegetation; 2) growth; and 3) visibility impairment. 40 CFR § 52.21(o). 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.

9.1 *Soils and Vegetation*

The additional impact analysis includes consideration of potential impacts to soils and vegetation associated with the PPEC's emissions. 40 CFR § 52.21(o). This component generally includes:

- a screening analysis to determine if maximum modeled ground-level concentrations of project pollutants could have an impact on plants; and
- a discussion of soils and vegetation that may be affected by proposed project emissions and the potential impacts on such soils and vegetation associated with such emissions.

The PPEC is proposed within an industrial park, the Otay Mesa Business Park, in the County of San Diego, with the majority of the area being previously disturbed or developed with commercial and public infrastructure. The industrial park developer graded the Project property, which was planned prior to the inception of, and would have occurred regardless of, the proposed PPEC. The applicant presented its discussion of the potential impacts on soils and vegetation in Section 5.0 of its PSD permit application. Section 5.0 included a discussion of the existing setting, nitrogen deposition potential, modeled impacts, and biological resources (including observed vegetation communities/land cover types and plants).

The initial application (dated September 2011) presents the applicant's use of EPA's

"Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals" (1980)[20] to determine if maximum modeled ground-level concentrations of SO_2, NO_2 and CO from the PPEC could have an impact on plants, soils, and animals. In addition, the applicant submitted information that included a discussion of the Project location and adjacent areas, the observed vegetation communities/land cover types, the observed plants, and soil types as part of the description of the various vegetation communities/land cover types and plant habitat observed within the project study area. The modeled impacts of SO_2, NO_2, and CO emissions from the facility, individually, and in addition to the background concentrations of NO_2 and CO,[21] are well below the minimum impact levels/screening concentrations identified in the Screening Procedure for sensitive plants. The following table summarizes information in this regard from Section 5.0 (Impacts on Soils and Vegetation) in the PSD application (Table 5-1, p. PSD-5.4).

Table 9. 1 Project Maximum Concentrations and EPA Guidance Levels for Screening Concentrations for Ambient Exposures

Criteria Pollutant and Guidance Averaging Time	EPA Screening Concentration (µg/m^3)	Modeled Maximum Concentrations (µg/m^3)	Modeling Averaging time
SO_2 1-Hour	917	6	1 hour
SO_2 3-Hours	786 (0.30 ppm)	3 (0.0011 ppm)	3 hour
SO_2 Annual	18	<0.1	Annual
NO_2 4-Hours	3,760	111	1 hour
NO_2 8-Hours	3,760	111	1 hour
NO_2 1-Month	564	111	1 hour
NO_2 Annual	94 (0.05 ppm)	0.3 (0.00016 ppm)	Annual
CO Weekly	1,800,000	52	8 hour

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 animals, plants, soils, and materials. The modeled maximum concentrations of SO_2, NO_2, $PM_{2.5}$[22] and PM_{10}[23] are also significantly below the secondary NAAQS that have been established by EPA:[24]

[20] "Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals," EPA 450/2-81-078, December 1980.

[21] The PPEC is not subject to PSD review for SO_2, and therefore background data is not included.

[22] The modeled maximum concentrations for the annual and 24-hour secondary $PM_{2.5}$ standards are 0.26 µg/m^3 and 2.6 µg/m^3, respectively.

[23] The modeled maximum concentrations for the 24-hour secondary PM_{10} standard is 57 µg/m^3.

[24] EPA has not promulgated secondary NAAQS for CO.

- secondary 3-hour NAAQS for SO_2 = 0.5 ppm
- secondary annual NAAQS for NO_2 = 0.053 ppm
- secondary annual NAAQS for $PM_{2.5}$ = 15 $\mu g/m^3$
- secondary 24-hour NAAQS for $PM_{2.5}$ = 35 $\mu g/m^3$, and
- secondary 24-hour NAAQS for PM_{10} = 150 $\mu g/m^3$

The applicant's description of the soils and vegetation that may be affected by the Project included a discussion of the Project location and adjacent areas, the observed vegetation communities/land cover types, and the observed plants in the Project's biological study area or study area. The study area includes the physical ground disturbance footprint (*i.e.*, generating facility site, construction laydown area, transmission line pole locales, gas line) plus a 1,000-foot buffer (Section 5.0, p. PSD 5-6) as presented in Figure 5.6-1 (Section 5.0, p. PSD-5.43). A description of soil types was part of the description of the various vegetation communities/land cover types and plant habitat observed within the study area. Types of soils identified include loam or clay, sandy, serpentine/serpentinite, gabbroic, metavolcanic, mesic, and alkaline soils. Thirty-nine special-status plant species were identified in the study area (Section 5.0, Table 5.6-4, pp. PSD-5.14 to 5.17). All 39 special-status plant species were determined not to occur within the project disturbance footprint or were negligible within the project disturbance footprint.

The applicant's discussion of impacts associated with potential nitrogen deposition from the Project included the following:

- For characterizing a threshold of significance for sensitive habitats, the applicant chose a nitrogen deposition rate of 5 kg/ha/yr that is based on a threshold used by the California Energy Commission (CEC). (Section 5.0, p. PSD-5.2, p. PSD-5.87).
- The estimated Project contribution is 1.6 kg/ha/yr compared to the CEC-specified regional background deposition (Section 5.0, p. PSD-5.97) estimate of 11.56 kg/ha/yr (without the Project).
- The applicant estimated a 6% Project contribution to the area as a percentage of the total cumulative nitrogen deposition. (Section 5.0, p. PSD-5.2, p. PSD-5.98).
- The applicant provided cumulative nitrogen deposition isopleths showing a 19 kg/ha modeled maximum cumulative impact in the area presented in Figure DR-BIO 29.1 (Section 5.0, p. PSD-5.99), which included nitrogen deposition impacts from four nearby sources.

The applicant discussed other activities contributing to (although not initiated specifically for the purposes of) the minimization of impacts to soils and vegetation. NO_x emission offsets from the decommissioning of a power plant located 10 miles west of the Project site were provided, as required by the local air agency permitting requirements.

The applicant has also agreed to voluntarily contribute to funds in support of weeding efforts at an approved research and habitat management area that would include periodic weeding of non-native plants to minimize potential impacts associated with nitrogen deposition. As discussed in Section 10 of this Fact Sheet, the applicant and EPA identified one plant species listed under the federal Endangered Species Act (ESA), the Otay tarplant (*Deinandra conjugens*), that might be affected by the proposed PSD permitting action for the Project due to nitrogen deposition. The applicant submitted a Biological Assessment (BA) to EPA in December 2011, in which the applicant addressed the possible cumulative effects of nitrogen deposition on this and other Federally-listed species. In a letter to the U.S. Fish & Wildlife Service (FWS or Service) dated December 23, 2011, EPA requested the initiation of formal consultation to address potential effects to these species including the Otay tarplant. EPA will proceed with its final PSD permit decision after making a determination that issuance of the permit will be consistent with ESA requirements, including the requirement that impacts to the Otay tarplant are satisfactorily addressed pursuant to the requirements of the ESA. In making this determination, EPA will consider actions taken, or to be taken, by the applicant to ensure ESA compliance.

In sum, based on our consideration of the information and analysis provided by the applicant, and other relevant information, we do not believe that emissions associated with the Project will generally result in adverse impacts to soils or vegetation. While nitrogen deposition from the Project has the potential to impact the Otay tarplant, those potential impacts are being appropriately considered and addressed through the ESA consultation process with the FWS.

9.2 *Visibility Impairment*

The additional impact analysis also evaluates the potential for visibility impairment (*e.g.*, plume blight) associated with PPEC. 40 CFR § 52.21(o). Using procedures from EPA's Workbook for Plume Visual Impact Screening and Analysis[25], the potential for visibility impairment is characterized for:

- Class I areas located within 50 km of the proposed PPEC; and
- Class II areas identified as potentially sensitive state or federal parks, forests, monuments, or recreation areas.

There are no Federal Class I areas located within 50 km of the Project site; the nearest Class I area is Agua Tibia (91 km away), as presented in Section 8.5.1. For Class II areas, the applicant evaluated visibility impairment for two federal Class II areas within 50 km of the project site:

- Cleveland National Forest (23 km away)
- Cabrillo National Monument (33 km away)

Because EPA has not yet established a quantitative visibility impairment threshold for Class II areas (similar to what exists for Class I areas), the applicant proposed a threshold and methodology to demonstrate whether the two Class II areas would be affected by visibility impairment from the Project. The applicant concluded that although the results

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

of the Level 1 VISCREEN screening analysis for these two areas exceeded the established Class I threshold, the results were below the applicant's proposed Class II threshold.

At EPA's request, the applicant subsequently provided a Level 2 VISCREEN screening analysis for these two areas. The results of the Level 2 analysis show that maximum predicted visual impacts inside these two Class II areas are below the Class I significance criteria. Consequently, EPA guidance indicates that these results may be used to determine that the project will not contribute to visibility impairment, and no further analysis is required.

9.3 *Growth*

The growth component of the additional impact analysis involves a discussion of general commercial, residential, industrial, and other growth associated with the PPEC. 40 CFR § 52.21(o). This analysis considers emissions generated by growth that will occur in the area due to the source. In conducting this review, we focus on residential, commercial and industrial growth that is likely to occur to support the source under review including, for example, employment expected during construction and operations and potential growth impacts associated with such employment, such as impacts to local population and housing needs.

Construction on PPEC is projected by the applicant to begin in February 2013, with commercial operations beginning May 2014. For the periods of construction and plant operations, the applicant provided a discussion of potential growth impacts in Section 6.0 (Growth-Inducing Impacts) of its PSD application submitted to EPA in September 2011. This information included a discussion of the socioeconomics of the project. Topics included population, housing, economic base, employment, public services and utilities (*e.g.*, fire protection, medical facilities, law enforcement, schools and libraries, water supply and sewage services, electrical power and natural gas), and fiscal resources. The applicant also provided a description of the Project in Section 2.0 (Executive Summary) and Section 3.0 (Project Description) of the PSD permit application.

As noted above, the PPEC is proposed within an industrial park, the Otay Mesa Business Park, in the County of San Diego. During the construction and commissioning phase, the applicant estimates a required average of 148 workers, with a peak workforce of 284 workers in the eighth month of construction. The applicant estimates that the maximum percentage of nonlocal workers (excluding management) supporting the Project during construction would be five percent. During construction, these workers are expected to temporarily lodge in hotels and motels within the project vicinity; following construction, the nonlocal workers are expected to return to their existing residences. During commercial operations, 12 full-time employees are expected. Operation of the PPEC is not expected to cause an influx of operation workers to relocate to the local area and, therefore, will have no significant impact on the population and housing in the region.

With respect to public services and utilities, additional medical facilities, schools and libraries, water supply and sewage services, and electrical power and natural gas are not needed as a result of the proposed PPEC. PPEC is designed and intended to use recycled water. For recycled water, the Otay Water District is in the process of completing the planned Otay Mesa area recycled water system. Connections will be made to existing infrastructure, *e.g.*, the San Diego County sewer lines, utility natural gas transmission pipelines, and electrical transmission lines. The existing Otay Water District will supply the facility's potable water needs and fire protection water; if recycled water is not available upon start-up of the Project, potable water would be used until recycled water is available.

With respect to fire protection, there are existing San Diego Rural Fire Protection District (RFPD) fire stations in the East Otay Mesa Planning area where the PPEC is proposed; one interim fire station and a permanent station are located within 0.25 mile of the Project. With respect to law enforcement, no sheriff facilities are located within East Otay Mesa where the Project is located; the nearest sheriff station is approximately 11.5 miles west of the site. Patrol functions in the East Otay Mesa area (which includes the Project area) are performed by several patrol units assigned to the East Otay Mesa area. Independent of the proposed Project, a permanent facility less than one mile from the site is currently being planned for both RFPD and sheriff stations.

In sum, based on our consideration of the information and analysis provided by the applicant, we do not expect the Project to result in any significant growth.

10. Endangered Species

Pursuant to section 7 of the ESA, 16 U.S.C. § 1536, and its implementing regulations at 50 CFR Part 402, EPA is required to ensure that any action authorized, funded, or carried out by 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. EPA has determined that this PSD permitting action is subject to ESA section 7 requirements.

The applicant and EPA identified three federally-listed species, the Otay tarplant (*Deinandra conjugens*), the Quino Checkerspot butterfly (*Euphydryas editha quino*), and coastal California gnatcatcher (*Polioptila californica californica*), that might be affected by the proposed PSD permitting action for the Project. The applicant submitted a Biological Assessment (BA) to EPA in December 2011, in which the applicant addressed the possible cumulative effects of nitrogen deposition on these species. In a letter to the FWS dated December 23, 2011, EPA requested the initiation of formal consultation for PPEC to address potential impacts to the Quino Checkerspot butterfly, the Otay tarplant, and the coastal California gnatcatcher. That consultation is ongoing.

As noted above, EPA will proceed with its final PSD permit decision after making a determination that issuance of the permit will be consistent with ESA requirements. In making this determination, EPA will consider actions taken, or to be taken, by the applicant to ensure ESA compliance.

11. Environmental Justice Screening 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 PPEC 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.

12. Clean Air Act Title IV (Acid Rain Permit) and Title V (Operating Permit)

The applicant must apply for and obtain an acid rain permit and a Title V operating permit from the SDAPCD. The Title V permit application is due within 12 months of the date that the new facility commences operation, while acid rain permit applications for new units are due 24 months before the applicant commences operation of the new units. The District has jurisdiction to issue the Acid Rain Permit and the Operating Permit for the facility.

13. Comment Period, Procedures for Final Decision, and EPA Contact

The comment period for EPA's proposed PSD permit for the Project begins on June 20, 2012. Any interested person may submit written comments on EPA's proposed PSD permit for the Project. All written comments on EPA's proposed action must be received by EPA via email by July 24, 2012, or postmarked by July 24, 2012. Comments must be sent or delivered in writing to Roger Kohn at one of the following addresses:

E-mail:R9airpermits@epa.gov

U.S. Mail: Roger Kohn (AIR-3)
U.S. EPA Region 9
75 Hawthorne Street
San Francisco, CA 94105-3901
Phone: (415) 972-3811

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

1. The Best Available Control Technology (BACT) determinations;
2. The effects, if any, on Class I areas;
3. The effect of the proposed facility on ambient air quality; and
4. The attainment and maintenance of the NAAQS.

Alternatively, written or oral comments may be submitted to EPA at the Public Hearing for this matter that EPA will hold on July 24, 2012**,** pursuant to 40 CFR § 124.12, to provide the public with further opportunity to comment on the proposed PSD permit for the Project. At this Public Hearing, any interested person may provide written or oral comments, in English or Spanish, and data pertaining to the proposed permit.

The date, time and location of the Public Hearing are as follows:

Date: July 24, 2012
Time: 6:00 p.m. – 8:00 p.m.
Location: San Ysidro High School
Performing Arts Center
5353 Airway Road
San Diego, California 92154

English-Spanish translation services will be provided at the Public Hearing. If you require a reasonable accommodation, by July 10, 2012 please contact Philip Kum, EPA Region 9 Reasonable Accommodations Coordinator, at (415) 947-3566, or kum.philip@epa.gov.

All information submitted by the applicant is available as part of the administrative record. The proposed air permit, Fact Sheet, permit application and other supporting information are available on the EPA Region 9 website at http://www.epa.gov/region09/air/permit/r9-permits-issued.html#pubcomment. The administrative record may also be viewed in person, Monday through Friday (excluding Federal holidays) from 9:00 AM to 4:00 PM, at the EPA Region 9 address above. Due to building security procedures, please call Roger Kohn at (415) 972-3973 at least 24 hours in advance to arrange a visit. Hard copies of the administrative record can be mailed to individuals upon request in accordance with Freedom of Information Act requirements as described on the EPA Region 9 website at http://www.epa.gov/region9/foia/.

Additional information concerning the proposed PSD permit may be obtained between the hours of 9:00 a.m. and 4:00 p.m., Monday through Friday, excluding holidays, by contacting Roger Kohn at the telephone and email address listed above.

EPA's proposed PSD permit for the Project and the accompanying Fact Sheet are also available for review at the following locations: SDAPCD, 10124 Old Grove Road, San Diego, California 92131, (858) 586-2600; San Ysidro Library in San Diego, CA; Otay Mesa Nestor Library in San Diego, CA; Civic Center Branch Library in Chula Vista, CA; National City Public Library in National City, CA; and Central Library in San Diego, CA.

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 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 EPA's final decision regarding the permit.

EPA will consider all written comments submitted during the public comment period and all written and oral comments submitted during the public hearing before taking final action on the PSD permit application and will send notice of the final decision to each person who submitted comments and contact information during the public comment period or requested notice of the final permit decision. EPA will respond to all substantive comments in a document accompanying EPA's final permit decision and will make the Public Hearing proceedings available to the public.

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 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.

14. Conclusion and Proposed Action

EPA is proposing to issue a PSD permit for the PPEC. We believe that the proposed Project will comply with PSD requirements, including the installation and operation of BACT, and will not cause or contribute to a violation of the applicable NAAQS or applicable PSD increments. We have made this determination based on the information supplied by the applicant and our review of the analyses contained in the permit application and other relevant information contained in our administrative record. EPA will make this proposed permit and this Fact Sheet available to the public for review, and make a final decision after considering any public comments on our proposal.

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