The Electric Company®
El Paso Electric

P.O. Box 982
El Paso, Texas
79960-0982
(915) 543-5711

July 31, 2012

Mr. Jeff Robinson
Permit Section Chief
U.S. Environmental Protection Agency (6PD-R)
1445 Ross Ave.
Dallas, TX 75202-2733

RE: Response to Completeness Determination (June 15, 2012) for El Paso Electric Company (EPE) Greenhouse Gas Prevention of Significant Deterioration (PSD) Permit Application
Montana Power Station Project
El Paso County, Texas

Dear Mr. Robinson:

Enclosed is EPE's response to the EPA's Completeness Determination Letter. Our response provides additional information, requested in support of EPE's application for Prevention of Significant Deterioration Permit for Greenhouse Gas Emissions submitted on April 20, 2012. Many of EPE's responses to the completeness determination questions include references to the recent Environmental Protection Agency (EPA) – Region 9's permitting actions in support of a power generation facility that will employ the LMS100 simple cycle combustion turbine technology similar to the Montana Power Station project.

If you have any questions or comments about the information presented in this letter, please do not hesitate to call Mr. Robert Daniels, P.E., EPE's Project Manager, at (915) 543-4081 or me at (915) 543-5827.

Sincerely,

Roger Chacon

Roger Chacon
El Paso Electric Company
Environmental Department Manager

Enclosures: Response to Completeness Determination

Response to Completeness Determination
Application for GHG/PSD Permit
El Paso Electric Company – Montana Power Station

Table of Contents

List of Appendices

A. PUBLIC NOTICE, THE PIO PICO ENERGY CENTER

B. PUBLIC INFORMATION SHEET OVERVIEW PIO PICO ENERGY CENTER PROPOSED CLEAN AIR ACT PSD PERMIT

C. PIO PICO ENERGY CENTER (SD 11-01) PREVENTION OF SIGNIFICANT DETERIORATION PERMIT PROPOSED PERMIT CONDITIONS

D. EMISSIONS CALCULATIONS AND ASSUMPTIONS USED IN AIR DISPERSION MODELING
SOURCE: CALIFORNIA ENERGY COMMISSION

E. REPORT ON COMBINED CYCLE VS. QUICK START COMBUSTION TURBINE EXPANSION ANALYSIS
SOURCE: EL PASO ELECTRIC COMPANY

F. NATURAL GAS ANALYSIS REPORT
SOURCE: EL PASO ELECTRIC COMPANY

G. GHG EMISSION CALCULATIONS FOR COMBUSTION TURBINES
SOURCE: EL PASO ELECTRIC COMPANY

H. U.S. ENVIRONMENTAL PROTECTION AGENCY REGION IX FACT SHEET AND AMBIENT AIR QUALITY IMPACT REPORT

EPA QUESTION 1: Consideration of Combined Cycle Project

On page 3 of the permit application, it states "the Montana Power Station will be designed to have a total power generation output capacity of approximately 400 MW for peaking/intermediate load operation during all year demand periods." Also, the permit application indicates on page 41 "EPEC's primary objective in pursuing the proposed project is to construct a Peaking Electric Generating Station that will be used during periods of high demand ... Compared with SCCTs, CCCTs simply have slower ramp rates and are designed for intermediate load and baseload operations." Since you indicate that this power station could be used for intermediate load operation, and have proposed a 5,000 hours per year operational limit, which is indicative of more than a peaking operation (as explained below), please explain whether you evaluated combined cycle units. If you did consider combined cycle units, please explain the technical and/or economic basis for rejecting the technology.

Response:

As explained in detail in Appendix A of the Application as filed on April 20, 2012, titled *Alternatives Analysis Used to Define Project Scope*, EPE certainly did evaluate all potentially available options for achieving its business requirements, including natural gas-fired combined cycle generation. To summarize and expound on Appendix A, in order to determine the power generation requirements for the Montana Power Station Project, 2014 to 2016, EPE conducted an intense study of its forecasted load requirements, which is included as Appendix E of this response (Modeling Report on Combined Cycle VS Quick Start Combustion Turbine Expansion Analysis- PROMOD). As stated in this study, EPE has an adequate amount of baseload capacity; therefore, more base load generation such as coal and nuclear would not address the need for additional peaking power load demands. In addition, renewable power, such as solar and wind, are unreliable due to inconsistent weather patterns. Therefore, gas-fired generation was determined to be the only practical solution to meet the increasing summer peak load with the capability of starting and ramping up and cycling off at night when the load drops.

This study provided a detailed comparison of electrical generation from natural gas-fired simple cycle versus combined cycle combustion turbines. Through this model simulation analysis, the optimal expansion plan, along with the optimal operating characteristics, were examined specific to EPE's expansion needs. The side-by-side comparison of total production cost, surplus energy cost, gas demand charges, and net cost determined that the driving force for savings in the LMS100 Resource Plan is the cycling ability of the unit. The benefit of being able to shut the unit down daily dramatically reduced the excess unused energy, fuel combustion and associated emissions. The Net Present Value savings over the studied period (2014 - 2016) is $116,757,640 in favor of the LMS100 plan.

As defined in the objective of this project, EPE's intent is to construct a Peaking Electric Generating Station. "Peaking" describes the pattern of use of the electric generating station, not its annual duration of use. The GE LMS100 gas turbines are designed to have quick startup and shutdown with no thermal penalty, which is synonymous with a peaking mode of operation. EPE's expansion plan required the selection of the electric generating units to have quick startup and shutdown to augment the EPE existing baseload units. The following is a summary of the evaluation between generation from natural gas fired simple cycle versus combined cycle combustion turbines and the technical justification for rejecting combined cycle turbine technology for this project.

Simple Cycle Turbine Flexibility Creates Efficiencies That Reduce Costs and Emissions as Compared to CCCT

Combined cycle combustion turbines (CCCT) are very efficient when operated at full load and using waste heat recovery; however, these units can take up to eight hours to start-up and achieve full load operation. The CCCT efficiency drops rapidly when the unit operates at less than full load and can often result in these typically large units having lower overall efficiency than a simple cycle combustion turbine (SCCT). Due to the time required to start up a CCCT and EPE's need to have generation capabilities in 10 min or less upon dispatch, a CCCT could not be shut down during off peak hours, leading to constant generation. By shutting down when the peak demand abates, SCCT will reduce emissions that would otherwise have occurred with the use of CCCT, which do not provide the same level of operational flexibility. Computer-modeled load forecasting shows that SCCTs provide operating flexibility and fill a unique spot in EPEC's generation portfolio with better emission efficiency than could be achieved with a CCCT.

Past practices and market conditions have and continue to appropriately define an efficient role for SCCTs, both in terms of emissions and cost to consumers. EPE's goal when selecting a type of generation is to match the resource to the load in the most efficient, reliable manner. Screening curves specific to electric generators are developed through modeling that takes the specific facts of the generator's portfolio and historical load duration curves into account to establish the cross points where SCCT becomes more economical than CCCT. That analysis influences planning for future generation and actual cost efficiency informs the dispatch of the optimal resources.

The criteria pollutant and GHG emissions produced from the newest, highly efficient simple cycle LMS100 turbines, outperform many of El Paso Electric's older baseload units. To the extent the cost and operating factors might allow, the simple cycle turbines will be dispatched ahead of less efficient (and older) local generation units. Further, ramping up generation at an older plant with spinning reserves may be less efficient and less reliable than dispatching the technological advanced simple cycle turbines. The market conditions, like those recently experienced (low natural gas prices), could financially incentivize the dispatch of gas instead of coal. If individualized analysis suggests that simple cycle units are needed in a particular generation portfolio, leaving operating flexibility for additional discretionary use for up to intermediate load could ultimately provide environmental and financial benefit by leaving open the ability to dispatch simple cycle gas units instead of coal.

SCCC Offers Reliability and Operational Flexibility Greater than NGCC

- Thermal Penalties- resulting by operating our local generation combined cycle turbines in a simple cycle mode.

  Combined cycle units are not designed for peaking duty, which includes multiple start-ups and shut-downs during short periods of time. CCCT can be used in this operation mode but will incur an increase in maintenance cost due to thermal gradients. The LMS100, an aeroderivative gas turbine, has no thermal penalty for starts and stops, unlike the combined cycle frame machines. By cycling a CCCT you would incur a shorter window between overhauls thereby increasing maintenance costs.

- Drop in Reliability:

EPE is subject to operational reliability obligations imposed not just by customer expectations, but by NERC. Satisfaction of those obligations is made much more difficult by imposing mechanical stress to a system not designed to be continually operated in simple cycle mode. The recent fires in Arizona and New Mexico highlighted the fact that EPE's remote generation is brought into the El Paso region via several critical 345 kv lines that run through the area recently plagued by fires. A disruption of that remote generation could result in a loss of 738 MWs in a 1750 MW El Paso regional system. Under this scenario, local generation becomes extremely important. The addition of 4-LMS100s rather than a 2x1 combined cycle unit provides immediate dispatch capabilities and operational flexibility during emergency scenarios. If remote generation is lost, in combination with the loss of a local 300 MW CCCT, a system blackout is probable. EPE must plan and design a generation portfolio for not only the best economical system solution but also the one that creates a high degree of operational flexibility and reliability. EPE is further subjected to the mandatory and enforceable NERC Reliability Standards imposed by the North American Electric Reliability Corporation to ensure the reliable operation of the bulk electric system. Failure to adhere to the mandatory and enforceable standards may result in civil penalties of up to $1 million per day per violation until the situation is corrected.

- Incorporate the use of LMS100s into EPE's energy portfolio as a benefit to "Backing up Renewables"

  The LMS100 is an excellent addition to complement and encourage additional renewable resources. The LMS100 units can be ramped at 50 MWs per minute. By virtue of its quick start capability, it can be used to back up the immediate fluctuations in power associated with loss of a renewable due the loss of wind or sun. The LMS100 units can be ramped at 50 MWs per minute to back-up the non-firm renewable resources, which greatly enhance the ability to incorporate renewable resources into our electrical system.

Other EPA-Permitted Projects Involve the Use of Simple Cycle Plants with Extended Service

Similar proposed projects that have been the subject of recent EPA permitting actions show that other generators also plan to use the LMS100 for intermediate load and peaking modes of operation. For example, the EPA has recently issued a proposed permit for a facility similar to the Montana Power Station. The proposed facility is named Pio Pico Energy Center LLC, located in San Diego County, CA, and proposes to construct and operate three (3) GE LMS100s. The following EPA-published information reflects several similarities in the operational approach EPE outlined in GHG permit application:

> "*On June 20, 2012, the United States Environmental Protection Agency (EPA) Region IX provided notice of, and requested public comment on, action relating to the Prevention of Significant Deterioration (PSD) permit application for the Pio Pico Energy Center (Project). EPA has issued a proposed permit that would grant conditional approval, in accordance with the PSD regulations (40 CFR 52.21), to Pio Pico Energy Center, LLC (PPEC) to construct and operate a 300 megawatt (MW, nominal) electric generating facility. The public comment period for this proposed permit, which is ongoing, will close on July 24, 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 each. 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)".[1]

The following is a description of the power plant operations for the Pio Pico Energy Center facility as written by the California Energy Commission.

> "*Pio Pico Energy Center, LLC, the applicant, proposes to construct and operate the 300 MW (nominal net output) simple cycle, quick start PPEC providing flexible peaking and intermediate power to the San Diego area.*
>
> ***Power Plant Operations***
>
> *As an intermediate load and peaking facility, each CTG will be limited to operate no more than 4,000 hr/yr. The plant will be dispatched by SDG&E in accordance with its economic dispatch procedures. The time required for startup is approximately ten minutes. The SDG&E contract allows for 500 startups and shutdowns per unit per calendar year in addition to the 4,000 hours of normal operation.*
>
> *PPEC is designed as a simple-cycle, peaking, and intermediate load facility. Each unit is proposed to be limited to operate no more than 4,000 hr/yr*[2].

In the Final Staff Assessment conducted by the California Energy Commission for Pio Pico Energy Center project, a section was devoted to compare the emissions from the alternative technologies based on the same or a similar operating scenario as that for Pio Pico. The California Energy Commission Staff compared the simple-cycle technology proposed for Pio Pico with two other alternative technologies: reciprocating Wartsila engine technology and combined-cycle technology, as shown in Appendix D of this response.

1. With similar capacity, combined-cycle CTGs have higher emissions of NOx and CO during startups and lower emission rates of all pollutants during normal operations compared to simple-cycle CTGs of PPEC. Annual emissions of all pollutants from combined-cycle CTGs are lower than simple-cycle CTGs of PPEC assuming same operating capacity factor.

2. Wartsila engines have higher modeled air impacts for all pollutants than those from the simple-cycle CTGs of PPEC and as modeled at the Pio Pico site would cause new violations of 24-hour PM2.5 and federal 1-hour NO2 standard.

3. Combined cycle CTGs, with necessary auxiliary sources such as auxiliary boiler, have higher modeled air impacts of all pollutants because of lower exit temperature and slower exit velocity. As modeled at the Pio Pico site, combined cycle CTGs would cause new violations of both state and federal 1-hour NO2 standards because of high startup emissions.

[1] EPA Public Information Sheet Overview Pio Pico Energy Center Proposed Clean Air Act PSD Permit
[2] California Energy Commission, Pio Pico Energy Center, Final Staff Assessment http://www.energy.ca.gov/sitingcases/piopico/index.html

The EPE System Needs Units that Can Offer Quick Starts up to 5000 Hours a Year

EPE's application for the Montana Power Station requests a maximum annual operation limit of 5,000 hours per year per turbine. The following is an explanation on how the 5,000 hours per year of simple cycle operation was derived and is needed to meet expected energy demands.

PROMOD is a software program that simulates the economic dispatch of EPE's system. This software takes into account the existing generation units, as well as the additional resources to meet load demands. PROMOD is also used to analyze alternative generation expansion plans as in this case. The inputs required in PROMOD include fuel and purchased power data, generating unit characteristics, load data, and general system data.

The PROMOD analysis showed that one of the LMS100 units would be dispatched up to a maximum of 5121 hours in year 2018. Several items must be considered when assessing PROMOD's dispatch of the LMS100 to a maximum of 5,121 service hours. PROMOD analyzes numerous input variables during unit dispatch including unit capacity, unit availability, heat rate, and system demand. The first units dispatched are those with the best heat rate and efficiency. Since the LMS100 units have an excellent heat rate, the LMS100 would be extremely dis-patchable due to the quick start and ramping capability. LMS100 is the best choice for PROMOD's unit dispatch algorithm.

In April 2012, EPE conducted an additional PROMOD analysis to determine the maximum number of service hours in which the new GE LMS100 units would operate at within EPE's system from 2011-2021. As previously stated, the analysis showed that one of the LMS100 units would be dispatched up to a maximum of 5121 hours in year 2018. The analysis also examined the effects of limiting the LMS100 units to 2900 service hours per units per year.

When limiting the use of the LMS100 units within EPE's system, several negative implications would result. The efficiency of the LMS100 is sacrificed by limiting the potential of the unit to 2900 hours. When the unit is dispatched freely and the PROMOD software is fully able to optimizing the system, the LMS100 exhibits a heat rate of 9.99 MMBtu/MWh vs. 10.65 MMBtu/MWh when the unit is limited to 2900 service hours per year.

The tables below illustrate the resulting data from the PROMOD analysis:

Generating Unit	Heat Rate with no LMS100 limit	Heat Rate with LMS100 limited to 2900 Service Hrs
LMS100	9.99	10.65
Rio Grande	11.51	11.46
Newman	8.78	8.82
Copper	12.19	12.17
Four Corners	9.80	9.80
Palo Verde	10.20	10.20
Combined	8.33	8.33

The PROMOD analysis also showed a substantial effect on unit generation over the period. The total generation of the LMS100 units from the initial commercial operation date to 2021 was decreased from 7,110 GWh to 4,580 GWh. That loss in generation must be supplemented through market purchases and increased generation by EPE's older and less efficient units.

Generating Unit	Generation with no LMS100 limit (GWh)	Generation with LMS100 limited to 2900 Service Hrs (GWh)
LMS100	7110.1	4579.5
Rio Grande	6151.4	6568.3
Newman	29013.8	29298.6
Copper	105.6	115.8
Four Corners	4832.8	4831.3
Palo Verde	54545.3	54545.4
Combined	8541.4	8612.3
Purchases	6772.6	6975.2
Sum	117073.0	115526.4
Additional generation required through Market Purchase =		1546.6

By dispatching less efficient generation and making more market purchase, there is a resulting economic impact. The analysis shows that by limiting the LMS100 to 2900 service hours per year based on a modeled 6 year period from 2016-2021; there would be a cost increase of $21,116,000 in order for EPE to provide reliable electricity to its customers.

Generating Unit	Total Cost with no LMS100 limit (k$)	Total Cost with LMS100 limited to 2900 Service Hrs (k$)	
LMS100	524,658	377,140	
Rio Grande	513,040	542,835	
Newman	1,573,884	1,594,453	
Copper	14,219	15,072	
Four Corners	155,687	155,638	
Palo Verde	1,555,712	1,555,713	
Combined	500,206	506,195	
Purchases	401,052	417,239	
Sales	-586369	-491081	
Sum	4,652,089	4,673,205	21,116

COMBINED CYCLES IN EPE FUTURE

EPE is proposing the construction of 4 LMS100s for simple cycle generation in years 2014 to 2017 to meet the peak demand needs. EPE is evaluating a project to construct two combined cycle units in 2018 and 2020. EPE has recently constructed a combined cycle gas turbines in 2011. The Loads & Resources LMS100 Scenario Table 2 located in Appendix E (Report on Combined Cycle vs. Quick Start Combustion Turbine Expansion Analysis) demonstrates that the EPE Expansion Plan does include combined cycle units in the past and the future.

EPE optimal energy requirements will necessitate the use of a combination of both combined and simple cycles in the future to ensure the EPE can meet the City of El Paso, Fort Bliss, West Texas and Southern New Mexico's energy needs. In conclusion, EPE's studies indicated that only simple cycle can accomplish the technical objectives of the project at the Montana Power Station.

EPA QUESTION 2: Provide Additional Information to Support the Selection of Simple Cycle Turbine in the BACT Analysis

We note that, on page 36 of the permit application, you reference the proposed Standards of Performance for GHG Emissions from Electric Utility Generating Units (EGUs), which was signed by the EPA Administrator on March 27, 2012. Your application specifically states that EPA has proposed an emissions limit of 1,000 lb. CO_2/MWh, on a 12-month annual average for all EGUs that do not employ CCS technology, and exempted simple cycle combustion turbines. However, it is important to note EPA's reason for the exemption, as stated in the proposed NSPS:

> *"Combined cycle plants and coal-fired plants are typically designed to provide base load or intermediate-load power, while simple cycle turbines are designed to provide peaking power ... because peaking turbines operate less and because it would be much more expensive to lower their emission profile to that of a combined cycle power plant or a coal-fired plant with CCS, the EPA does not believe it is appropriate to include them in this source category." (77 FR 22411)*

The proposed NSPS for EGU's also states:

> *"The potential electric output requirement in the definition of electric generating unit would exclude facilities with permit restricting limiting operation to less than 1/3 of their potential electric output, approximately 2,900 hours of full load operation annually. The peaking season is generally considered to be less than 2.500 hours annually and EPA is requesting comment if the capacity factor exemption is sufficient such that specifically exempting simple cycle turbine is unnecessary." (77 FR 2243 1-2)*

Furthermore, 40 CFR 72.2 defines a "peaking unit" as having "an average capacity factor of no more than 10.0 percent during the previous three calendar years and a capacity factor of no more than 20.0 percent in each of those calendar years." The proposed 5,000 hour annual operational limit is substantially greater than either a 10 (average annual) or 20 percent (maximum annual) capacity factor.

The proposed 5,000 hour annual operational limit for the Montana Power Station is greater than the 2,900 operational hours contemplated for peaking units in the proposed NSPS for EGUs, and also appears to be greater than either the 10 (average annual) or 20 percent (maximum annual) capacity factor in the federal definition of "peaking unit."

Accordingly, please provide supplemental details on expected load shift and duration of periods of reduced generation or no load that would negatively impact EPE from selecting combined cycle turbines and/or any data/plant metrics that supports the selection of simple cycle turbines in the BACT analysis. Please also provide a calculated annual load factor for the proposed combustion turbines.

<u>Response:</u>

Although preceded by commentary based on EPA's pending NSPS proposal, the request/question centers on EPE's conclusion that it needs to use a simple cycle-based project to meet its customers' needs, as opposed to building a combined cycle project. As noted above in response to Question 1, EPE determined that only a 4x100 simple cycle turbine project would satisfy its generation needs, and reported the basis for that conclusion in an alternatives analysis that accompanied its permit application as filed.

Although the presentation of possible positions in the preamble to a proposed rule does not set firm EPA policy, it should be noted that the rule as proposed actually supports EPE's position (because it does not restrict the exclusion of simple cycle units to only those operating at less than a defined capacity factor). Further, EPE has commented to EPA that the exclusion should be preserved for any simple cycle unit, regardless of annual operating hours. Although simple cycle turbines most often are installed only when needed for peaking service (the ability to react on the shortest possible basis to changes in load), it is not at all true that simple cycle units are used only for a few hours a day, or that peak service means infrequent, seasonal usage.[3] Accordingly, the deletion of the definition and exemption for simple cycle turbines, regardless of hours of service, would not accomplish EPA's stated objectives.

Simple cycle turbines play a critical role not only in addressing daily peaks and seasonal variations, but also in dealing with overall system maintenance and exigencies. Units may need to run for longer periods or in off-peak periods when units are taken offline for maintenance or when there are unexpected outages of other EGUs or transmission lines affecting the dispatch of other EGUs. Operating reserve margins in many regions require units with a 10-minute startup; otherwise, there must be spinning reserves, meaning units operating at less than full load and therefore at lower efficiencies.[4] If there were an operating hour cap, it could limit the utility of simple cycle turbines in providing operating reserve capacity and meeting demands during planned maintenance as well as unanticipated demands or system back up needs.

The first part of this Question No. 2 asks for the duration of periods during which a combined cycle negatively impacts EPE. This means that periods during which a combined cycle is not needed and the output needs to be sold at any price (forced sales during the night when there is not enough load to support generation on line). Normally load drops dramatically when people go to sleep around 10-11:00 PM and picks up in the morning when people start waking up and getting ready for work around 6:00-7:00 AM. This averages to around 8-9 hours of the day where generation usually is higher than loads. This happens all over the country, so the market reacts to it by lowering prices (supply and demand) and sometimes it even results in negative pricing where a supplier actually has to pay someone to take energy in order for the generator of power to balance the system (generation need to equal loads). This situation also occurs all day Sunday and holidays (New Years, Christmas, 4th of July, Labor Day, Thanksgiving, to name a few; there are 9 official holidays recognized by NERC). These days are considered light load days because load drops dramatically and the same situation occurs as the night situation discussed above.

Using these two parameters, a simple calculation can be used to determine how many hours in a year excess generation exists, and the need to be able to cycle (turn units on and off) becomes evident. First we identify the number of days during which there will be extended periods of excess generation: 365 days in a year, minus 52 Sundays, minus 9 holidays, leaves us with 304 days during which 8 hours of each day will experience generation in excess of load, for a total of 2,432 hours per year. For the other days (those 52 Sundays plus 9 holidays), the entire 24-hour day would experience generation above load, adds another 1,464 hours (61 days x 24 hr/day) during which supply would exceed demand. Adding those 8-hour days with the 24-hour days yields a total of 3,896 hours a year which the flexibility to shut

[3] Statements in the proposed rule preamble suggest some potential confusion, such as "the peaking season is generally considered to be less than 2,500 hours annually." *Id.* at 22,432. This suggests that peaking is strictly seasonal, but it is not. Peaks occur is every measure of averaging time, from annual to hourly, and not just seasonally. It is the task of the power provider to have the right mix of generation to most efficiently adjust generation to load profiles in all averaging periods.

[4] *See e.g.*, WECC Standard BAL-STD-002-0 - Operating Reserves.

down generation becomes a necessity. There are 8,760 hours in a year, so this means approximately 44 percent of the time, there is excess generation over low loads (light loads hours). This excess generation, results in a negative impact that would equate to higher emissions.

The next logical question may be, if there are 8,760 hours in a year and 3,896 are considered light load hours (excess generation over load) and the remaining 4,864 hours are potential peaking hours, why would a permit request 5,000 hours? The answer is simple: The additional hours are needed to account for unexpected generation outages, loads spikes during heat waves, operational constraints, Volt-Amp Reactive (VAR), voltage support, etcetera.

For example, if a base load unit goes off-line unexpectedly, a simple cycle unit would have to be run more hours than usual to make up some of the lost generation. Also, if loads are spiking up and the market gets tight, a simple cycle unit can be run longer than expected to take care of the increased load and/or higher demand in the market.

EPA QUESTION 3: Natural gas analysis and basis for methane emission estimates from start-ups

On page 25 of the permit application, it is indicated that the "site specific natural gas heating value was obtained from the natural gas analysis." Please provide the results of the natural gas analysis. The application states that each turbine will release "a small amount of unburned methane" during a startup and shutdown event: The startup emissions = 0.8 lbs./event and shutdown emissions = 1.07 lbs./event." The permit application indicates that these startup and shutdown emissions have been included in the calculations that determined the proposed emission limits. Please provide supplemental data that supports the basis for the proposed emission limit data.

Response:

A copy of the natural gas analysis used as the basis for the site specific natural gas heating value is provided in Appendix F of this response.

The start-up and shut-down emissions of unburned methane shown for the LMS100 were provided by General Electric (GE), the manufacturers proposed equipment. The startup emissions = 0.8 lbs./event and shutdown emissions = 1.07 lbs./event are based on the tests run at the GE facility as part of the LMS100 product launch. Actual test data for start-up and shut down is proprietary. It is important to note that on any gas turbine in start-up/ shut down mode, the small amount of unburned methane remaining is purged. This function is not a unique feature to the LMS 100 unit; rather this is true for all combustion turbine configurations.

EPA QUESTION 4: Justification for Number of Start-Ups

On page 25 of the permit application, the application indicates a proposed 832 startup and 832shutdown events for each turbine. Please provide supplemental data to support the rationale for this number of proposed startup and shutdowns. The discussion should include a detailed explanation of the power plant's operating mode that justifies the proposed startup and shutdown events used to calculate the emission limits. On startup and shutdown, please specify if it is a cold or a hot standby startup.

Response:

The number of startups and shutdowns is based on the number of operational hours per year, in this case, 5,000 service hours per year per turbine. If run continuously, the 5,000 hours per year equates to 208 days at 24 hours per days. At four (4) startups/shutdowns per day, 208 days would equal 832 startups/shutdowns per year. For the LMS100, which is an aeroderivative gas turbine, there are no distinctions in hot or cold startups. All startups are ten (10) minutes in duration. The 5,000 service hours per year per turbine was discussed in Question No. 1. The four (4) startups/shutdowns per day are based on a worst case condition. The Flexible Unit Cycling diagrams presented below, provided by General Electric, indicates that actual LMS100 users cycled the units up to four times per day.

For comparison purposes, Pio Pico also used four (4) startups/shutdowns per day in its PSD permit application. The final Pio Pico PSD permit application requested 500 startups/shutdowns per year and 4,000 hours per year per turbine.

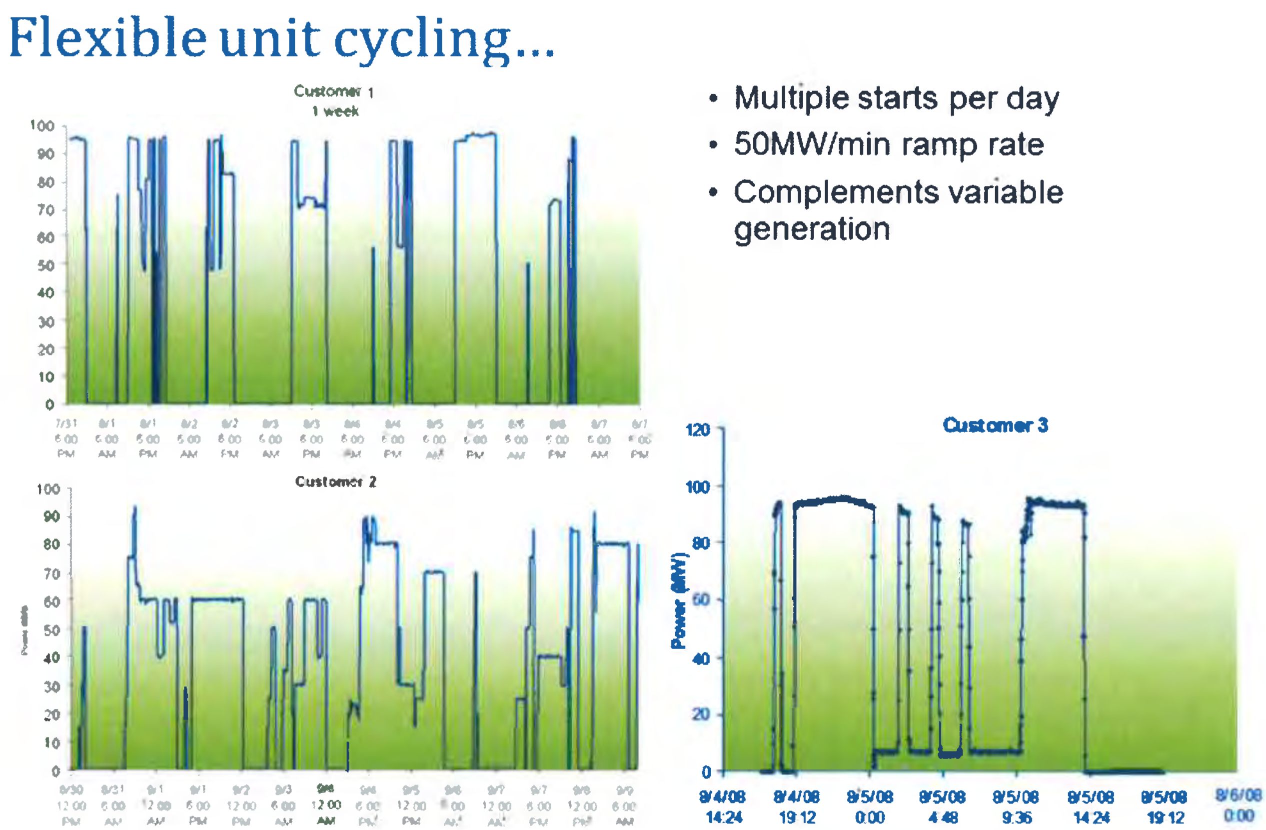
Using the same calculations EPE used to determine startups/shutdowns, at 4,000 hours per year per turbine, the total number of startups per year would be 668. This demonstrates similarity in the number of proposed startups/shutdowns based on annual hours per turbine operation.

Side by side comparison of Operational Conditionals, Startup and Shutdown		
Parameters	**Pio Pico Energy Center**	**EPE Montana Station**
Number of Turbines	3	4
Proposed Annual Hours per Turbine	4000	5000
Equivalent Days to Annual Hours	Annual Hours/ 24 Hrs/day = Equivalent Days	
Equivalent Days to Annual Hours	167	208
Proposed Number of Startups per Day	4	4
Total Number of Startups per Year	Equivalent Days x Startups per Day = Total/Year	
Total Number of Startups per Year	668	832

4.3.2.1 Gas Turbines (each, of three)

LMS100 simple cycle combustion gas turbines 4,000 hours per year normal operation plus 500 startup/shutdown cycles (per turbine)

Impacts based on 4 startups and 4 shutdowns of each turbine in a single day, remainder of day at peak operation. [5]



[5]Application to the U.S. EPA for a Prevention of Significant Deterioration Permit Pio Pico Energy Center, San Diego County, California, prepared for: Pio Pico Energy Center, LLC. September 2011

EPA QUESTION 5: Provide suggested monitoring plan for GHGs

What are the proposed monitoring and recordkeeping requirements for the combustion turbine's operating parameters? How will the air/fuel ratio be assured during operation of the combustion turbine, (i.e., alarms, alerts, computer monitored, etc...) Will O_2 analyzers be utilized? What will be the target ratio? Please provide more details of what operating parameters will be monitored to ensure good combustion. What is the company's proposed compliance monitoring methodology? Please provide more information pertaining to the automation of the combustion turbine operation that will ensure optimal fuel combustion. What will be the operating control parameters of the evaporative cooling system? How will the system be maintained to ensure it is operating properly and efficiently?

Response:

Continuous emission monitoring systems (CEMS) will be used to monitor and record the combustion turbines' operating parameters. CO_2 and O_2 analyzers are utilized within the CEMS. The O_2 analyzer will monitor the required oxygen levels in the turbines. Accordingly, further parametric monitoring should not be needed or required as furthered discussed by the manufacturer (GE) below.

The engine is designed to maintain the proper fuel air ratio through variable geometry. Once the proper control limits are determined, control schedules are developed, and the engine operates with those parameters. The air fuel ratio is variable depending on load. At lower loads, the air to fuel ratio is higher than that at lower loads. Exact air to fuel ratio is confidential. Emissions at the exhaust are an indicator of the combustion process. Monitoring emissions is typically accomplished through a continuous emission monitoring system or CEMS for short. CEMS ports are provided before and at the exit of the SCR/COR. All turbine monitoring and control is accomplished through the GE Mark VI controls system. All engine parameters are measured and controlled within the proprietary software. The operation of the evaporative cooling system is automatic. Once enabled, the system is design to accommodate maximum effectiveness without moisture carry over. The GTG package has online monitoring and diagnostics. When control parameters are out of specification, an alert is provided. In the event the situation is harmful to the turbine, the engine will take measures to protect the equipment. Emissions output changes will be monitored in the CEMS equipment. Alarm setting can be included in the customer supplied plant control system. Appropriate action can be taken after the alarm if any. [6]

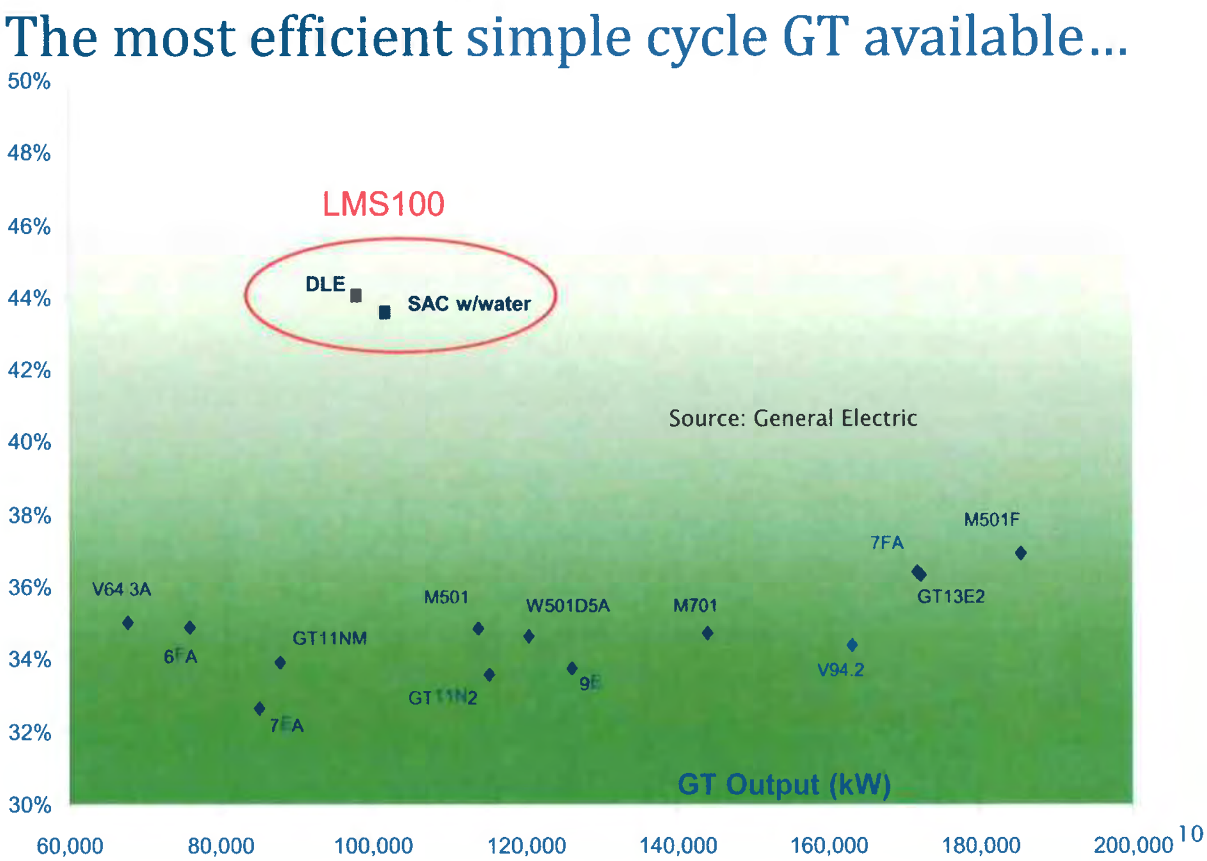
[6] General Electric

EPA QUESTION 6: Basis for selection of LMS100's

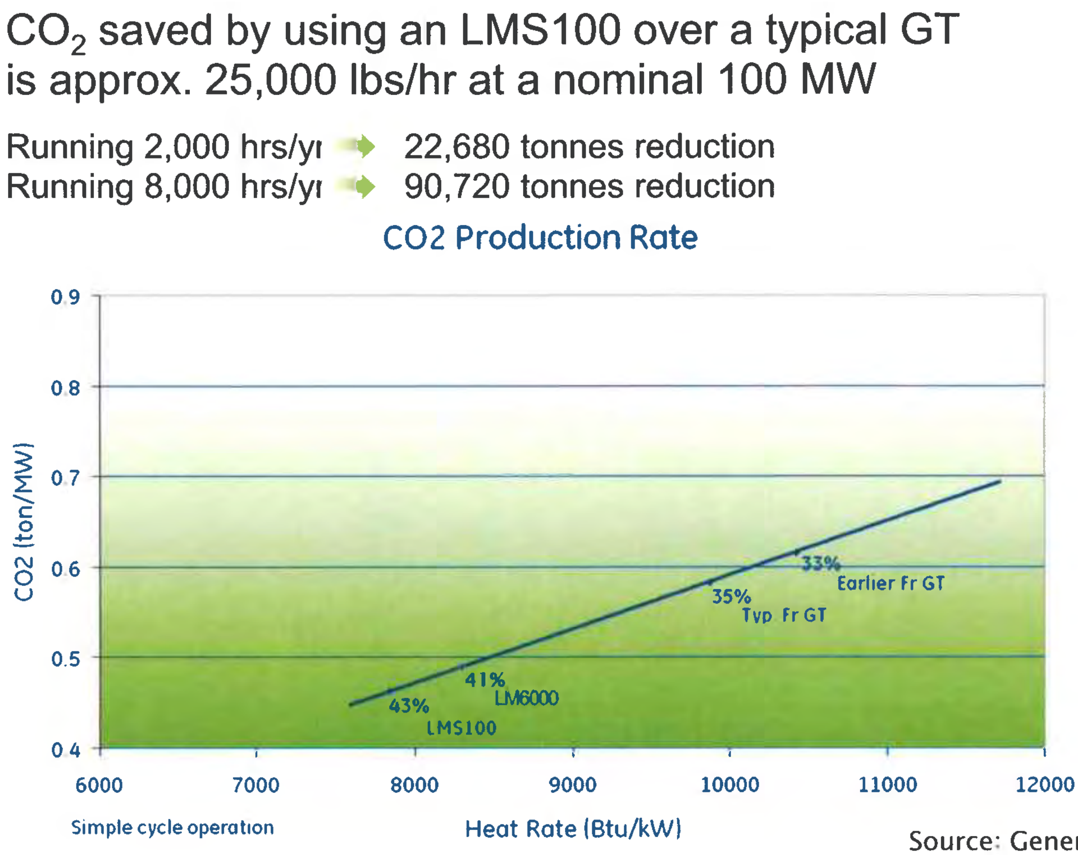
On page 47 in Table 10.2, the permit application includes a list of available simple cycle combustion turbines that you evaluated for this project. In order to support the selection of the proposed combustion turbine model, please supplement this comparative analysis with additional data that includes production output, gross heat rate and percent efficiency of each existing or similarly designed combustion turbines (this information may be represented graphically in load/efficiency curves).

<u>Response:</u>

The following schematic, provided by General Electric (GE), compares the LMS100 against all other available GE simple cycle gas turbines. The graph clearly shows that the LMS100 is most efficient simple cycle unit on an output basis.



GE also provided the following schematic that shows the CO_2 production rate per heat rate of the LMS100 compared other GE simple cycle turbines.



Source: General Electric

High efficiency = low CO_2

Simple cycle	versus	**Combined cycle**
2 LMS100s		2 less efficient GTs

- GE estimate, LMS100 saves 25,000 lbs/Hr CO_2 over other GTs
- 2 LMS100s saves 50,000 lbs/hr over 2 other GTs.
- On an annual operational basis of 5,000 hours per year,
- 2 LMS100s will save 125,000 tons of CO_2 from reaching the atmosphere.
  4 LMS100s will save 250,000 tons of CO_2 from reaching the atmosphere.
- The LMS100 will be equipped with an SCR/COR and additional CO_2 emissions will be saved by cycling the LMS100, as needed

GT= gas turbine

The EPA has recently issued a proposed permit for the Pio Pico Energy Center LLC project, which is similar to the proposed Montana Power Station project. The EPA has agreed with the applicant (Pio Pico Energy) that the LMS100 when compared to other alternatives was the most appropriate choice of machine for the Pio Pico project. Details provided as follows:

Alternatives to the LMS100

Alternative machines that can meet the project's objectives are the LM6000 SPRINT, FT8 TwinPac, and the SGT-800, which are aeroderivative machines adapted from General Electric, Pratt & Whitney, and Siemens Power Generation aircraft engines, respectively.

The General Electric LM6000PC SPRINT gas turbine generator in a simple cycle configuration is nominally rated at 50.5 MW and 40.3 % efficiency LHV at ISO conditions (GTW 2011).

The Pratt & Whitney FT8 TwinPac gas turbine generator in a simple cycle configuration is nominally rated at 51.4 MW and 38.4 % efficiency LHV at ISO conditions (GTW 2011).

The Siemens SGT-800 gas turbine generator in a simple cycle configuration is nominally rated at 47 MW and 37.5 % efficiency LHV at ISO conditions (GTW 2011).

Machine	Generating Capacity (MW)	ISO Efficiency (LHV)
GE LMS100	**103.5**	**43.6 %**
GE LM6000PC SPRINT	50.5	40.3 %
P & W FT8 TwinPac	51.4	38.4 %
Siemens SGT-800	47	37.5 %

Source: GTW 2011

While the LMS100 enjoys a significant advantage in fuel efficiency over these alternative machines (especially the FT8 TwinPac and SGT-800), its operating flexibility makes it even more attractive for peaking, load following and ancillary service than these efficiency numbers reflect. Staff agrees with the applicant that the GE LMS100 is the most appropriate choice of machine for the PPEC project.

The project, if constructed and operated as proposed, would generate 300 MW (nominal net output) of peaking electric power at an overall project fuel efficiency of 43 % LHV at typical ambient conditions. While it would consume substantial amounts of energy, it would do so in the most efficient manner practicable. It would not create significant adverse effects on energy supplies or resources, would not require additional sources of energy supply, and would not consume energy in a wasteful or inefficient manner. No energy standards apply to the project. Staff therefore concludes that the project would present no significant adverse impacts upon energy resources. No cumulative impacts on energy resources are likely.[7]

[7] California Energy Commission, Pio Pico Energy Center, Final Staff Assessment http://www.energy.ca.gov/sitingcases/piopico/index.html

EPA QUESTION 7: Site-Specific Limitations on Possible Use of CCS

Beginning on page 49 of the permit application, the cost estimates provided for the Carbon Capture and Storage appear to solely relay on the August 2010 report entitled "Report of the Interagency Task Force on Carbon Capture and Storage." BACT is a case-by-case determination. Please provide site-specific facility information to evaluate and eliminate CCS from consideration. This information should contain detailed information on the quantity and concentration of CO_2 that is in the waste stream and the equipment for capture, storage, and transportation. Please include cost of construction, operation, and maintenance, cost per pound of CO_2 removed by technologies evaluated and include the feasibility and cost of analysis for storage and transportation for these options. Please discuss in detail any site specific safety or environmental impacts associated with the removal system.

Response:

As stated in EPE's GHG PSD permit application, CCS is not a viable, technically feasible option for this project due to the fact that CO_2 capture has not been achieved in practice for a large scale, 400 MWe natural gas electric generation facilities and the application of the CCS technology is cost-prohibitive for this project.

The exhaust from the SCCTs would have a conservative CO_2 concentration of approximately 5% as show in Table 1 below. In addition, the exhaust steam from the SCCTs contains a mixture of different constituents including products of combustion; NO_x, SO_2, VOC, CO, and particulate matter. Depending on the final destination of the exhaust stream, these impurities may make the exhaust stream undesirable. This is consistent with the EPA PSD and Title V permitting guidance for Greenhouse Gases, March 2011, page 32. As stated in EPA's guidance,

> *"Current technologies could be used to capture CO_2 from new and existing fossil energy power plants; however, they are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant application. Since the CO_2 capture capacities used in current industrial processes are generally much smaller than the capacity required for the purposes of GHG emissions mitigation at a typical power plant, there is considerable uncertainty associated with capacities at volumes necessary for commercial deployment."*

Table 1: Stack GHG Exhaust Parameters and CO_2 Content

EPN	Description	CO_2 (tons/year)	CO_2 (MMscf/yr)[a]	Minimum Exhaust Flow Rate @ 100% Load (scfm)	Total Exhaust[b] (MMscf/yr)	Percent CO_2 (vol%)
GT-1	Combustion Turbine 1	250885	4390.49	320792	96237	**5%**
GT-2	Combustion Turbine 2	250885	4390.49	320792	96237	**5%**
GT-3	Combustion Turbine 3	250885	4390.49	320792	96237	**5%**
GT-4	Combustion Turbine 4	250885	4390.49	320792	96237	**5%**
	Total CO_2 emissions	**1003541**				

The following is a list of the site specific safety or environmental impacts associated with a potential CO_2 removal system.

1. **Economic Feasibility**: The low purity and concentration of CO_2 in the combustion turbines' exhaust means that the per ton cost of removal and storage will be much higher than the public data estimates for much larger carbon rich fossil fuel power facilities due to the loss of economies of scale. Even using low-side published estimates for CO_2 capture and storage of \$256 per ton for a new natural gas combined cycle facility, assuming a conservative \$6/MBtu gas price (Anderson, S., and Newell, R. 2003. Prospects for Carbon Capture and Storage Technologies. Resources for the Future. Washington DC) means added cost to the project over \$200,000,000 per year.

2. **Energy penalty**: Published studies mentioned elsewhere in this response estimate energy penalties in the range of 15% to 30% of produced energy for CCS. This would also mean that approximately 15% - 30% more fuel will be consumed and up to an additional 15% - 30% tons of CO_2 per year will be produced. This equates to burning up to an additional 5.1 billion cubic feet[8] of natural gas per year and producing an additional 273,407 tons of CO_2 per year just to support CCS.

3. **Criteria Emissions penalty**: Combustion of up to 5.1 billion cubic feet of natural gas to account for the energy penalty would result in the following additional emissions on an annual basis:
   - **NO_x** – 21.49 tpy
   - **CO** – 31.38 tpy
   - **$PM/PM_{10}/PM_{2.5}$** – 16.40 tpy
   - **SO_2** – 1.64 tpy
   - **VOC** – 6 tpy

4. **Long-term storage uncertainty**: A study of the risks associated with long-term geologic storage of CO_2 places those risks on par with the underground storage of natural gas or acid-gas. (Benson, S. 2006. CARBON DIOXIDE CAPTURE AND STORAGE, Assessment of Risks from Carbon Dioxide Storage in Deep Underground Geological Formations. Lawrence Berkley National Laboratory) The liability of underground CO_2 storage, however, is less understood. A recent publication from MIT states that "The

[8] Energy and criteria emissions penalties are calculated based on operating the 4 proposed LMS100 combustion turbines an additional 30% of full load operation.

characteristics (of long term CO_2 storage) pose a challenge to a purely private solution to liability." (de Figueiredo, M., 2007. The Liability of Carbon Dioxide Storage, Ph.D. Thesis, MIT Engineering)

As discussed in EPE's GHG PSD Permit application, given the limited deployment of only slipstream/demonstration applications, CCS is not commercially available as BACT for the combustion turbines and is therefore considered infeasible and not BACT for the proposed SCCTs. However, in response to this question, EPE is including estimated costs for implementation of CCS. The attached includes costs for the amine removal of CO_2 from the SCCTs exhaust combined with the compression and transfer to pipeline of the CO_2.

EPE utilized the March 2010 National Energy Technology Laboratory (NETL) Document, *Quality Guidelines for Energy System Studies Estimating Carbon Dioxide Transport and Storage Costs DOE/NETL- 2010/1447* to estimate the cost associated with the pipeline and associated equipment. This document provides a best estimate of transport storage and monitoring costs for a "typical" sequestration project. In addition, EPE estimated the capital and operating and maintenance cost of equipment necessary for separation of the CO_2 from the combustion turbine gas stream and amine treatment system exhaust stream, compression and transfer via pipeline to either underground injection or for Enhanced Oil Recovery. The conservatively estimated cost of over \$95 million dollars per year equates to 30% of the initial total capital cost of the Montana Power Station. A financial penalty of \$95 million dollars per year would make this project economically infeasible to construct and operate as the total capital cost of this proposed project is estimated at \$311 million.

Carbon Capture and Storage (CCS) Component	**Cost (\$/ton of CO_2 Controlled)[1,2]**	**Tons of CO_2 Controlled per Year**	**Total Annual Cost**
CO_2 Capture and Compression - NGCC[3]	103	903187	\$93,407,698.99
CO_2 Transport Facilities [4]	1.61	903187	\$1,453,713.48
CO_2 Storage Facilities [5]	0.36	903187	\$327,746.31
Total Cost For Capture, Compression, Transport, and Storage[6]	**105.39**	**N/A**	**\$95,189,158**

1. Cost Factors are converted from dollars per metric ton to dollars per short ton using a conversion factor of 1 metric ton = 1.1023 short tons.
2. Costs are from Report of the Interagency Task Force on Carbon Capture (August, 2010). A range of costs was provided for transport and storage facilities; for conservatism, the low ends of these ranges were used in this analysis as they contribute little to the total cost.
3. The cost factor for post-combustion capture of CO_2 from a Natural Gas Combined Cycle (NGCC) system is selected because it is the most similar process with available cost information to that of the proposed project.
4. The original cost factor for CO_2 transport obtained from the *Report of the Interagency Task Force on Carbon Capture and Storage* was \$1.00 / ton and is based on a pipeline length of 62 miles. As such, this factor has been linearly adjusted to account for the hypothetical pipeline length (110 miles) associated with the proposed project.
5. Storage cost includes consideration for initial site screening and evaluation, operation of injection equipment, and post-injection site monitoring. It should be noted that in the *Report of the Interagency Task Force on Carbon Capture and Storage*, storage costs range from \$0.4 to \$20 / ton are cited.
6. Total Cost for implementation of a CCS system equals the sum of the individual Capture, Compression, Transport, and Storage costs.

EPA QUESTION 8: Design of firewater pump

On page 52 of the permit application, the application states that "EPE will purchase a firewater pump internal combustion engine (ICE) certified by the manufacturer to meet applicable emission standards." Please provide supplemental data manufacturer design data and comparative benchmark data to existing or similar sources documenting the efficiency of proposed engines for this project.

Response:

The firewater diesel driven pump, internal combustion engine (ICE), is only a component of the complete skid mounted fire pump unit, see diagram below. The proposed fire suppression skid selected for this project was chosen based on the safety design basis fire events or other similar emergencies. If an alternative engine with higher emission efficiency is located, the engine would have to be retrofitted into the skid mounted fire pump unit. A retrofit could impede the design of the fire pump unit, causing possible failure during a fire event.

EPE believes the higher emission efficiency would not offset the safety considerations of the retrofitting the fire pump unit.

EPA QUESTION 9: Basis for proposed LDAR program

On page 53 of the permit application, EPE proposes to implement fugitive emission monitoring through the 28 MID LDAR. Please provide the basis used to select the TCEQ 28 MID LDAR program for fugitive emissions. Were other TCEQ LDAR programs considered as a possibility for this project? Is so, what was the basis for elimination of the other programs as a part of your 5-Step BACT analysis?

Response:

Fugitive emissions are produced from the piping component leaks in the natural gas and ammonia systems. The fugitive emissions are calculated using the methodology described in the TCEQ document entitled Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000 and emission factors for Oil and Gas Production Operations. Calculations are based on Title 30 Texas Administrative Code (30 TAC) Chapter 115 and Audio/Visual/Olfactory (AVO) leak detection and repair (LDAR) requirements.

Hydrocarbon emissions from leaking piping components (process fugitives) associated with the proposed project include methane and CO_2. The total estimated fugitive CO_2 and methane emissions as CO_2e have a very minor contribution to the Plant's total GHG emissions. EPE will be implementing the AVO LDAR program to minimize emissions from piping fugitive leaks. While this operational practice is designed to reduce VOC emissions, it has a collateral effect on GHG emissions.

A small amount of GHGs may be emitted via piping equipment leaks (i.e., due to CO_2 and methane in the gas streams). It is infeasible to capture GHG emissions from fugitive sources such as piping leaks. However, fugitive GHG emissions can be reduced by utilizing a leak detection and repair (LDAR) program. There are many structured LDAR programs that have been developed as part of state and federal rulemaking and BACT. LDAR programs are designed to control VOC emissions and vary in stringency. LDAR is currently only required for VOC sources. Methane is not considered a VOC, so LDAR is not required for streams containing a high content of methane.

The TCEQ published the Control Efficiencies for TCEQ Leak Detection and Repair Programs, Revised 07/11. This table provides the control efficiencies associated with each TCEQ LDAR program. EPE has chosen to implement an AVO program to monitor fugitive emissions. This LDAR program results in the highest efficiency and lowest GHG emissions of all the TCEQ programs.

Table 9-1. Control Efficiencies for TCEQ Leak Detection and Repair Programs

Equipment/Service	28M	28RCT	28VHP	28MID	28LAER	Audio/Visual/Olfactory[1]
Valves						
Gas/Vapor	75%	97%	97%	97%	97%	97%
Light Liquid	75%	97%	97%	97%	97%	97%
Heavy Liquid[2]	0%[3]	0%[4]	0%[4]	0%[4]	0%[4]	97%
Pumps						
Light Liquid	75%	75%	85%	93%	93%	93%
Heavy Liquid[2]	0%[3]	0%[3]	0%[5]	0%[6]	0%[6]	93%
Flanges/Connectors						
Gas/Vapor[7]	30%	30%	30%	30%	97%	97%
Light Liquid[7]	30%	30%	30%	30%	97%	97%
Heavy Liquid	30%	30%	30%	30%	30%	97%
Compressors	75%	75%	85%	95%	95%	95%
Relief Valves (Gas/Vapor)	75%	97%	97%	97%	97%	97%
Open-ended Lines[8]	75%	97%	97%	97%	97%	97%
Sampling Connections	75%	97%	97%	97%	97%	97%

1. Audio, visual, and olfactory walk-through inspections are applicable for inorganic/odorous and low vapor pressure compounds such as chlorine, ammonia, hydrogen sulfide, hydrogen fluoride, and hydrogen cyanide.
2. Monitoring components in heavy liquid service is not required by any of the 28 Series LDAR programs. If monitored with an instrument, the applicant must demonstrate that the VOC being monitored has sufficient vapor pressure to allow reduction.
3. No credit may be taken if the concentration at saturation is below the leak definition of the monitoring program (i.e. (0.044 psia/14.7 psia) x 106 = 2,993 ppmv versus leak definition = 10,000 ppmv).
4. Valves in heavy liquid service may be given a 97% reduction credit if monitored at 500 ppmv by permit condition provided that the concentration at saturation is greater than 500 ppmv.
5. Pumps in heavy liquid service may be given an 85% reduction credit if monitored at 2,000 ppmv by permit condition provided that the concentration at saturation is greater than 2,000 ppmv.
6. Pumps in heavy liquid service may be given a 93% reduction credit if monitored at 500 ppmv by permit condition provided that the concentration at saturation is greater than 500 ppmv.
7. If the applicant decides to monitor connectors using an organic vapor analyzer (OVA) at the same leak definition as valves, then the applicable valve reduction credit may be used instead of the 30% reduction credit. If this option is chosen, the applicant shall continue to perform the weekly physical inspections in addition to the quarterly OVA monitoring.
8. The 28 Series quarterly LDAR programs require open-ended lines to be equipped with an appropriately sized cap, blind flange, plug, or a second valve. If so equipped, open-ended lines may be given a 100% control credit.

EPA QUESTION 10: Basis for emission estimates

In Appendix B in the table entitled "Combustion Sources of GHG Emissions", please provide supplemental data that is referenced in footnote 3, the "Natural gas heating values obtained from the natural gas analysis provided by M. Robert Daniels (El Paso Electric Company) to Ms. Christine Chambers (Trinity Consultants) via email on February 27, 2012. Also provide data that is referenced in footnote 5, the "Annual hours of operation information provided by Mr. Robert Daniels (El Paso Electric Company) to Ms. Latha Kambham (Trinity Consultants) via email on March 26, 2012. This includes hours for MSS activities."

Response:

A copy of the natural gas analysis reference in footnote 3 used as the basis for the site specific natural gas heating value is provided in Appendix F of this response.

(See response to Question 1 for EPE on the basis of the annual hours of operation).

EPA QUESTION 11: Convert to Short tons

EPA acknowledges that, per 40 CFR 98, GHG emissions are reported in metric tons; however in the PSD and Title V Permitting Guidance for Greenhouse Gases March 2011 on page 11, short tons (2000 lbs), not long or metric tons, are used in PSD applicability calcualtions. Please change the GHG emission rates that are presented in the tables found in Appendix B and throughout the permit application from metric to short tons.

Response:

The GHG emission calculations for the Montana Power Station have been updated to report all emissions in short tons. The calculation spreadsheets are provided in Appendix G of this response.

Appendix A

Appendix
A.

SOURCE:
U.S. ENVIRONMENTAL PROTECTION AGENCY

REGION IX

PUBLIC NOTICE,
THE PIO PICO ENERGY CENTER

* * * PUBLIC NOTICE * * *

THE PIO PICO ENERGY CENTER

ANNOUNCEMENT OF PROPOSED PERMIT, PUBLIC HEARING, AND REQUEST FOR PUBLIC COMMENT ON PROPOSED
CLEAN AIR ACT PREVENTION OF SIGNIFICANT DETERIORATION PERMIT
PERMIT APPLICATION NO. SD 11-01

The United States Environmental Protection Agency, Region 9 (EPA) provides notice of, and requests public comment on, EPA's proposed action relating to the Prevention of Significant Deterioration (PSD) permit application for the Pio Pico Energy Center (Project). EPA is issuing a proposed PSD permit that would grant conditional approval, in accordance with the PSD regulations (40 CFR 52.21), to Pio Pico Energy Center, LLC to construct and operate a 300 megawatt (MW, nominal) electric generating facility. The mailing address for the Pio Pico Energy Center, LLC is P.O. Box 95592, 2542 Singletree Lane, South Jordan, UT 84095. The proposed location for the Project is 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 proposed Project consists of three General Electric (GE) LMS100 natural gas-fired combustion turbine-generators (CTGs) with a total net generating capacity of 100 megawatts each. The Project is located within the San Diego County Air Pollution Control District (District).

The proposed PSD permit for the Project would require the use of 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), to the greatest extent feasible. Air pollution emissions from the Project would not cause or contribute to violations of any National Ambient Air Quality Standards (NAAQS) for the pollutants regulated under the PSD permit.

The emissions of other air pollutants from the proposed Project, including the pollutants for which the area is not meeting the NAAQS (and precursors that lead to the formation of such pollutants), are regulated by the District. On May 4, 2012, the District issued a Final Determination of Compliance (FDOC) for the Project

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) 972-3973

Alternatively, written comments may be submitted to EPA at the Public Hearing for this matter that will be held on **July 24, 2012**, as described below.

Comments should address the proposed 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.

Pursuant to 40 CFR 124.12, EPA also intends to hold a Public Hearing to provide the public with further opportunity to comment on the proposed permit. 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 please contact Philip Kum, EPA Region 9 Reasonable Accommodations Coordinator, by **July 10, 2012** 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 PSD permit, fact sheet/ambient air quality impact report, permit application and certain 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 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/.

EPA's proposed PSD permit for the Project and the accompanying fact sheet/ambient air quality impact report are available for review at the following locations: San Diego Air Pollution Control District, 10124 Old Grove Road, San Diego, CA 92131, (858) 586-2600; San Ysidro Public Library, 101 W. San Ysidro Boulevard, San Diego, CA 92173, (619) 424-0475; Chula Vista Public Library, Civic Center Branch, 365 F Street, Chula Vista, CA 91910, (619) 691-5069; Otay Mesa-Nestor Library, 3003 Coronado Avenue, San Diego, CA 92154 (619) 424-0474; San Diego Central Library, 820 E Street, San Diego, CA 92101, (619) 236-5800; National City Public Library, 1401 National City Boulevard, National City, CA 91950, (619) 470-5800.

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 you consider CBI or otherwise protected should be clearly identified as such and should not be submitted through e-mail. If you send e-mail directly to the EPA, your 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 your comments if you wish to receive direct notification of EPA's final decision regarding the permit.

EPA will consider all written and oral comments submitted during the public comment period 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.

If EPA issues a final decision granting the PSD permit application for the Project, and there is no appeal, construction of the Project may commence, subject to the conditions of the PSD permit and other applicable permit and legal requirements.

If you have questions, or if you wish to obtain further information, please contact Roger Kohn at (415) 972-3973, via email at R9airpermits@epa.gov, or at the mailing address above. If you would like to be added to our mailing list to receive future information about this proposed permit decision or other PSD permit decisions issued by EPA Region 9, please contact Roger Kohn at (415) 972-3973 or send an email to R9airpermits@epa.gov, or visit EPA Region 9's website at http://www.epa.gov/region09/air/permit/psd-public-guidelines.html.

Please bring the foregoing notice to the attention of all persons who would be interested in this matter.

Appendix B

Appendix
B.

SOURCE:
U.S. ENVIRONMENTAL PROTECTION AGENCY

REGION IX

PUBLIC INFORMATION SHEET OVERVIEW
PIO PICO ENERGY CENTER
PROPOSED CLEAN AIR ACT PSD PERMIT

United States Environmental Protection Agency

PUBLIC INFORMATION SHEET
OVERVIEW
PIO PICO ENERGY CENTER
PROPOSED CLEAN AIR ACT
PSD PERMIT

Summary of the Proposed Permit

On June 20, 2012, the United States Environmental Protection Agency (EPA) Region IX provided notice of, and requested public comment on, action relating to the Prevention of Significant Deterioration (PSD) permit application for the Pio Pico Energy Center (Project). EPA has issued a proposed permit that would grant conditional approval, in accordance with the PSD regulations (40 CFR 52.21), to Pio Pico Energy Center, LLC (PPEC) to construct and operate a 300 megawatt (MW, nominal) electric generating facility. The public comment period for this proposed permit, which is ongoing, will close on July 24, 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 each. 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).

This document is intended to provide a brief, informal summary of information to assist members of the public attending the public hearing scheduled for July 24, 2012 for EPA's proposed PSD permit for the Project. For official permit documents developed in accordance with 40 CFR Part 124 and more details about the permit requirements, refer to EPA's public notice, the proposed permit, and the Fact Sheet/Ambient Air Quality Impact Report (FACT Sheet) for this proposed permit action, which are linked to the EPA Region 9 permit website: http://www.epa.gov/region09/air/permit/r9-permits-issued.html#pubcomment. **The administrative record for the proposed permit may be viewed in person at the EPA Region 9 office in San Francisco, California; for more information, or to obtain copies of relevant documents, please contact Roger Kohn at (415) 972-3973 or via email at R9airpermits@epa.gov.**

What Laws and Regulations Apply to EPA's Proposed PSD Permit?

We have prepared this proposed permit based on our PSD regulations issued under the Clean Air Act at 40 Code of Federal Regulations (CFR) 52.21. We believe that the proposed Project will comply with PSD requirements including the installation and operation of Best Available Control Technology (BACT), and will not cause or contribute to a violation of the National Ambient Air Quality Standards (NAAQS) for the pollutants regulated under the proposed permit. We have made this determination based on the information supplied by the applicant, our review of the analyses contained in the permit application, and other relevant information contained in the administrative record for this proposed action. EPA has provided the proposed permit and Fact Sheet to the public for review, and will make a final decision on the Project's PSD permit application after considering all public comments on our proposal submitted during the public comment period.

Environmental requirements from other federal, State, or local laws are not included in EPA's proposed PSD permit unless they are also part of the Clean Air Act PSD program. The Project is required to comply with all other environmental requirements. To this end, PPEC also has submitted applications for State and local pre-construction approvals, respectively 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 SDAPCD. The emissions of other air pollutants from the proposed Project, including the pollutants for which the area is not meeting the NAAQS (and precursors that lead to the formation of such pollutants), are regulated by the District, which implements the Nonattainment New Source Review (NA-NSR) permitting program for this area. The District is designated as a non-attainment area for ozone. The non-attainment pollutants subject to NA-NSR permitting by the District include nitrogen oxides (NO_x) and volatile organic compounds (VOC) as ozone precursors. On May 4, 2012, the District issued a Final DOC for the Project, which includes the District's NA-NSR permit requirements. For power plants over 50 MW, the CEC must issue a license to authorize construction. The District and CEC approval processes are separate from EPA's PSD permitting process

The applicant must also apply for and obtain an Acid Rain permit and a Title V operating permit from the District for this Project. The applicant will apply for the Title V operating permit, which will incorporate the acid rain permit, after the facility is constructed, as these permits are not required prior to construction.

What Does EPA's Proposed PSD Permit Regulate?

The PSD program (40 CFR 52.21) applies to "major" new sources of attainment pollutants. The estimated emissions for this project show that the facility will be a major source for greenhouse gases (GHG). Once a source is considered major for a PSD pollutant, PSD also applies to any other pollutant regulated under the PSD program that is emitted in a significant amount. The emissions of oxides of sulfur (SOx) will be less than the major source threshold and less than the significant emission rate. Therefore, PSD does not apply for SOx. In addition, because the area in which the Project is located is designated non-attainment for ozone, the PSD program does not apply to ozone and the PSD permit does not address ozone.

In accordance with 40 CFR 52.21(j), a new major stationary source is required to apply best available control technology (BACT) for each PSD pollutant that it has the potential to emit (PTE) in significant amounts. With respect to the Project, NO_2, PM, PM_{10}, $PM_{2.5}$, and GHG are emitted in significant amounts, and therefore the proposed permit requires the Project to apply BACT to all equipment that emits these pollutants.

How Would EPA's Proposed PSD Permit Affect Air Quality?

The PSD regulations require an examination of the impacts of the proposed Project on ambient air quality for the pollutants regulated under the PSD permit. EPA has reviewed the computer modeling analysis that predicts the effect of the proposed Project on ambient air quality. Based on the modeling results, and the technical information that we have reviewed to date, the Project's impacts on air quality and visibility are consistent with limits allowed under the Clean Air Act. The proposed emission limits will protect the NAAQS for NO_2, PM_{10}, and $PM_{2.5}$. There are no NAAQS for PM or GHG.

The PSD regulations require that EPA evaluate other potential impacts on 1) soils and vegetation; 2) visibility impairment; and 3) growth. Based on our review of the analyses provided by the applicant and the maximum potential concentrations of the visibility-related criteria pollutants -- NO_2, PM_{10}, and $PM_{2.5}$ -- we do not expect any adverse impacts on visibility, nor do we expect this project to result in any adverse impacts on plants and soils or significant growth.

What Other Actions is EPA Taking in Connection with Its Decision making Process?

EPA has been engaged in consultation with the U.S. Fish and Wildlife Service under section 7 of the federal Endangered Species Act (ESA) to ensure that its proposed PSD permit decision for the Project is not likely to jeopardize the continued existence of any federally-listed endangered or threatened species or result in the destruction or adverse modification of critical habitat for such species. EPA will proceed with issuance of its final PSD permit decision after making a determination that its decision will be consistent with ESA requirements.

In addition, in accordance with Executive Order 12898, "Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations," EPA determined that it would be appropriate to prepare an analysis to consider environmental justice issues in connection with the issuance of this federal PSD permit. In our Environmental Justice Analysis, we conclude that the Project will not cause or contribute to air quality levels in excess of health standards for the pollutants regulated under the permit, including NO_2, PM_{10}, or $PM_{2.5}$, and that therefore it 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 the community as a whole. The Environmental Justice Analysis is available to the public as part of the administrative record supporting EPA's proposed PSD permit for the Project.

Appendix C

Appendix
C.

SOURCE:
U.S. ENVIRONMENTAL PROTECTION AGENCY

REGION IX

PIO PICO ENERGY CENTER
(SD 11-01)
PREVENTION OF SIGNIFICANT DETERIORATION
PERMIT
PROPOSED PERMIT CONDITIONS

PIO PICO ENERGY CENTER (SD 11-01)
PREVENTION OF SIGNIFICANT DETERIORATION PERMIT
PROPOSED PERMIT CONDITIONS

PROJECT DESCRIPTION

The proposed Pio Pico Energy Center (Project) consists of three General Electric (GE) LMS100 natural gas-fired combustion turbine-generators (CTGs) rated at 100 megawatt each. The Project will have an electrical output of 300 MW. The Project will be located in an unincorporated area of San Diego County known as Otay Mesa. The Project's footprint is 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).

This proposed Prevention of Significant Deterioration (PSD) permit for the Project requires the use of 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), to the greatest extent feasible. Air pollution emissions from the Project will not cause or contribute to violations of any National Ambient Air Quality Standards (NAAQS) or any applicable PSD increments for the pollutants regulated under the PSD permit.

EQUIPMENT LIST

The following devices and activities are subject to this PSD permit:

Unit ID	Description
Turbine 1	• 100 MW (gross) combustion turbine generator (CTG), with a maximum heat input rate of 903 MMBtu/hr (HHV) • Natural gas-fired GE Model LMS100 CTG • Emissions of NO_X controlled by water injection, Selective Catalytic Reduction (SCR)
Turbine 2	• 100 MW (gross) combustion turbine generator (CTG), with a maximum heat input rate of 903 MMBtu/hr (HHV) • Natural gas-fired GE Model LMS100 CTG • Emissions of NO_X controlled by water injection, Selective Catalytic Reduction (SCR)
Turbine 3	• 100 MW (gross) combustion turbine generator (CTG), with a maximum heat input rate of 903 MMBtu/hr (HHV) • Natural gas-fired GE Model LMS100 CTG • Emissions of NO_X controlled by water injection, Selective Catalytic Reduction (SCR)
Partial Dry Cooling System	• Dry cooling tower with a 16,520 gallons per minute (GPM) maximum circulation rate, supplemented by 7,000 GPM wet cooling tower. • 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 based on circulation rate
Circuit Breakers	• 3 switchyard and 2 generator breakers containing SF6

PERMIT CONDITIONS

I. PERMIT EXPIRATION

As provided in 40 CFR § 52.21(r), this PSD Permit shall become invalid if construction:

A. is not commenced (as defined in 40 CFR § 52.21(b)(9)) within 18 months after the approval takes effect; or

B. is discontinued for a period of 18 months or more; or

C. is not completed within a reasonable time.

II. PERMIT NOTIFICATION REQUIREMENTS

The Permittee shall notify EPA Region IX by letter or by electronic mail of the:

A. date construction is commenced, postmarked within 30 days of such date;

B. actual date of initial startup, as defined in 40 CFR § 60.2, postmarked within 15 days of such date;

C. date upon which initial performance tests will commence, in accordance with the provisions of Condition IX.G, postmarked not less than 30 days prior to such date. Notification may be provided with the submittal of the performance test protocol required pursuant to Condition IX.G; and

D. date upon which initial performance evaluation of the continuous emissions monitoring system (CEMS) will commence in accordance with 40 CFR § 60.13(c), postmarked not less than 30 days prior to such date. Notification may be provided with the submittal of the CEMS performance test protocol required pursuant to Condition IX.G.

III. FACILITY OPERATION

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

IV. MALFUNCTION REPORTING

A. The Permittee shall notify EPA at R9.AEO@epa.gov within two (2) working days following the discovery of any failure of air pollution control equipment or process equipment, or failure of a process to operate in a normal manner, which results in an increase in emissions above any allowable emission limit stated in Section IX of this permit.

B. In addition, the Permittee shall provide an additional notification to EPA in writing or electronic mail within fifteen (15) days of any such failure described under Condition IV.A. This notification shall include a description of the malfunctioning equipment or abnormal operation, the date of the initial malfunction, the period of time over which emissions were increased due to the failure, the cause of the failure, the estimated resultant emissions in excess of those allowed in Section IX, and the methods utilized to mitigate emissions and restore normal operations.

C. Compliance with this malfunction notification provision shall not excuse or otherwise constitute a defense to any violation of this permit or any law or regulation such malfunction may cause.

V. RIGHT OF ENTRY

The EPA Regional Administrator, and/or an authorized representative, upon the presentation of credentials, shall be permitted:

A. to enter the premises where the Facility is located or where any records are required to be kept under the terms and conditions of this PSD Permit;

B. during normal business hours, to have access to and to copy any records required to be kept under the terms and conditions of this PSD Permit;

C. to inspect any equipment, operation, or method subject to requirements in this PSD Permit; and

D. to sample materials and emissions from the source(s).

VI. TRANSFER OF OWNERSHIP

In the event of any changes in control or ownership of the Facility, this PSD Permit shall be binding on all subsequent owners and operators. Within 14 days of any such change in control or ownership, the Permittee shall notify the succeeding owner and operator of the existence of this PSD Permit and its conditions by letter. The Permittee shall send a copy of this letter to EPA Region IX within thirty (30) days of its issuance.

VII. SEVERABILITY

The provisions of this PSD Permit are severable, and, if any provision of the PSD Permit is held invalid, the remainder of this PSD Permit shall not be affected.

VIII. ADHERENCE TO APPLICATION AND COMPLIANCE WITH OTHER ENVIRONMENTAL LAWS

The Permittee shall construct the Project in compliance with this PSD permit, the application on which this permit is based, and all other applicable federal, state, and local air quality regulations. This PSD permit does not release the Permittee from any liability for compliance with other applicable federal, state and local environmental laws and regulations, including the Clean Air Act.

IX. SPECIAL CONDITIONS

A. Air Pollution Control Equipment and Operation

As soon as practicable following initial startup of the power plant (startup as defined in 40 CFR § 60.2) but prior to commencement of commercial operation (as defined in 40 CFR § 72.2), and thereafter, except as noted below in Condition IX.C, the Permittee shall install, continuously operate, and maintain the SCR system for control of NO_X on Turbine 1, Turbine 2, and Turbine 3. The Permittee shall also perform any necessary operations to minimize emissions so that emissions are at or below the emission limits specified in this permit.

B. Emission Limits

1. On and after the date of initial startup, the Permittee shall not discharge or cause the discharge of emissions from each CTG (Turbine 1, Turbine 2, and Turbine 3) into the atmosphere in excess of the following limits. The emission limits in this condition shall apply at all times, except that for NOx only, the alternate emission limits in Condition IX.C shall apply during startup and shutdown, after which the limits in this condition shall apply:

Pollutant	Emission Limit (per CTG)
NO_X	• 2.5 ppmvd @ 15% O_2 • 1-hr average • 8.18 lb/hr
PM, PM_{10}, and $PM_{2.5}$	• 0.0065 lb/MMBtu (HHV) • 9-hr average • PUC-quality natural gas (sulfur content of no greater than 0.25 grains per 100 dscf on a 12-month rolling average and not greater than 1.0 gr per 100 dscf at any time)
CO_2	• 1,181 lb/MWh net output • 8,760 rolling operating-hour average

2. CO_2e emissions from the circuit breakers shall not exceed 40.2 tons per calendar year.

3. The Permittee shall install, operate, and maintain enclosed-pressure SF6 circuit breakers with a maximum annual leakage rate of 0.5% by weight.

C. Requirements during Gas Turbine (Turbine 1, Turbine 2, and Turbine 3) Startup and Shutdown Periods

The CTG NO_X emission limits in Condition IX.B.1 shall not apply during CTG startup and shutdown periods. During these periods, the following requirements shall apply:

1. The CEMS shall be in operation during each startup and shutdown period.

2. Duration of startups and shutdowns of each CTG (Turbine 1, Turbine 2, and Turbine 3) shall not exceed 30 and 10.5 minutes, respectively, per occurrence.

3. Total number of startups shall not exceed 500 per turbine, per calendar year.

4. For CTGs, "initial startup" is defined as the first fire of each unit.

5. Startup is defined as the period beginning with combustion turbine ignition and lasting until the equipment has reached a continuous operating level and the emissions from the turbines are at or below the emission limits specified in Condition IX.B.1.

6. Shutdown is defined as the period beginning with the initiation of combustion turbine shutdown sequence and lasting until fuel flow is completely off and combustion has ceased.

7. NO_X emissions during startup or shutdown from each CTG shall not exceed 26.6 lb/hr based on a 1-hr average.

8. NOx emissions from each CTG shall not exceed 22.5 pounds per startup event, or 6.0 pounds per shutdown event.

D. Operational Limits

1. The hours of operation for each turbine (Turbine 1, Turbine 2, and Turbine 3) shall not exceed 4,000 hours in any calendar year.

2. During any turbine startup, ammonia injection shall be initiated as soon as the SCR catalyst temperature exceeds 575 degrees F.

3. The cooling tower drift rate shall not exceed 0.001%; and the maximum total dissolved solids (TDS) shall not exceed 5,600 ppm.

4. Within 60 days after achieving normal operation, but not later than 180 days after the initial startup of equipment, each CTG (Turbine 1, Turbine 2, and Turbine 3) shall achieve an initial heat rate at full load that does not exceed 9,196 Btu_{hhv}/kWh_{gross}.

5. The circuit breakers shall be equipped with a 10% by weight leak detection system. The leak detection system shall be calibrated in accordance with manufacturer's specifications. The manufacturer's specifications and records of all calibrations shall be maintained on site.

E. Fuel Use

1. To fire Turbines 1, 2 and 3, the Permittee shall use only Public Utilities Commission (PUC)-pipeline quality natural gas with a sulfur content that (1) is less than or equal to 0.25 grains per 100 dscf on a 12-month rolling average, and (2) shall not at any time exceed 1.0 grains per 100 dscf.
2. The Permittee shall keep a monthly record of the quantity of natural gas used in Turbine 1, Turbine 2, and Turbine 3.
3. The Permittee shall sample and record the sulfur content of the natural gas fuel on a monthly basis.
4. The fuel sulfur content of the natural gas shall be determined using any of the following test methods: ASTM D1072, D3246, D4468, D5504 or D6667.

F. Continuous Emissions Monitoring System (CEMS) for Turbines

1. Before Turbines 1, 2, and 3 commence commercial operation (as defined in 40 CFR § 72.2), the Permittee shall install and calibrate CEMS to measure stack gas NO_X, CO_2, and O_2 concentrations and a continuous monitoring system (CMS) to measure exhaust gas flow and moisture content to demonstrate compliance with the emission limits in Conditions IX.B.1, IX.C.7, and IX.C.8.

2. The CEMS and CMS required by this permit shall be installed, calibrated, operated, audited, tested, and maintained in accordance with the manufacturers' recommendations and the appropriate performance standards and quality assurance requirements in the appendices of either 40 CFR part 60 or 40 CFR part 75.

3. The Permittee shall reduce CEMS and CMS data to one-hour averages in a manner meeting the specifications in 40 CFR § 60.13(h) for all operating hours, including startup and shutdown.

4. No later than 90 days after commencement of commercial operation, the Permittee shall submit to EPA a CEMS and CMS quality assurance plan. The plan shall specify how the Permittee will demonstrate compliance with emission limits in Conditions IX.B.1, IX.C.7, and IX.C.8, including emission limits that apply during startup and shutdown.

5. The Permittee shall perform for each CEMS:

a. Daily calibration checks,

b. Quarterly linearity checks, and

c. Annual relative accuracy test audits (RATA).

6. The Permittee shall perform initial RATAs no later than the initial performance test for the associated emission unit.

7. The Permittee shall submit RATA test plans and reports of RATA test results to EPA as described in Condition IX.G.1.h.

8. The Permittee shall maintain the following records for at least five years from the date of origin:

   a. One-hour averages calculated pursuant to Condition IX.G.3,

   b. The results of all calibration and linearity checks, and

   c. RATA test plans and reports of test results.

G. Performance Tests

1. Stack Tests

   a. Within 60 days after achieving normal operation, but not later than 180 days after the initial startup of equipment, and, unless otherwise specified, annually thereafter (within 30 days of the initial performance test anniversary), the Permittee shall conduct performance tests (as described in 40 CFR § 60.8) as follows:

      i. NO_X, CO_2, PM, PM_{10}, and $PM_{2.5}$ emissions from each gas turbine (Turbine 1, Turbine 2, and Turbine 3);

      ii. PM, PM_{10}, and $PM_{2.5}$ emissions from the cooling tower (annual testing not required).

      iii. Heat rate performance according to the requirements of the American Society of Mechanical Engineers Performance Test Code on Overall Plant Performance (ASME PTC 22).

   b. The Permittee shall submit a performance test protocol to EPA no later than 30 days prior to the test to allow review of the test plan and to arrange for an observer to be present at the test. The performance test shall be conducted in accordance with the submitted protocol, and any changes required by EPA.

c. Performance tests shall be conducted in accordance with the test methods set forth in 40 CFR § 60.8 and 40 CFR Part 60 Appendix A, as modified below. In lieu of the specified test methods, equivalent methods may be used with prior written approval from EPA:

   i. EPA Methods 1-4 and 7E for NO_X emissions measured in ppmvd

   ii. EPA Methods 1-4, 7E, and 19 for NO_X emissions measured on a heat input basis

   iii. EPA Methods 1-4 and 3B for CO_2 emissions

   iv. EPA Method 5 for PM, Method 201A for filterable PM_{10} and $PM_{2.5,}$ and Method 202 for PM_{10} and $PM_{2.5}$. In lieu of Method 202, the Permittee may use EPA Conditional Test Method CTM-039.

   v. Modified Method 306 for PM emissions from the wet cooling tower, and

   vi. the provisions of 40 CFR § 60.8 (f).

d. The initial performance test conducted after initial startup shall use the test procedures for a "high NO_2 emission site," as specified in San Diego Test Method 100, to measure NO_X emissions. The source shall be classified as either a "low" or "high" NO_2 emission site based on these test results. If the emission source is classified as a:

   i. "high NO_2 emission site," then each subsequent performance test shall use the test procedures for a "high NO_2 emission site," as specified in San Diego Test Method 100.

   ii. "low NO_2 emission site," then the test procedures for a "high NO_2 emission site," as specified in San Diego Test Method 100, shall be performed once every five years to verify the source's classification as a "low NO_2 emission site."

e. The performance test methods for NO_X emissions specified in Condition IX.G.1.c.i and ii., may be modified as follows:

   i. Perform a minimum of 9 reference method runs, with a minimum time per run of 21 minutes, at a single load level, between 90 and 100 percent of peak (or the highest physically achievable) load, and

   ii. Use the test data both to demonstrate compliance with the applicable NO_X emission limit and to provide the required reference method data for the RATA of the CEMS.

f. Upon written request and adequate justification from the Permittee, EPA may waive a specific annual test and/or allow for testing to be done at less than maximum operating capacity.

g. For performance test purposes, sampling ports, platforms, and access shall be provided on the emission unit exhaust system in accordance with the requirements of 40 CFR § 60.8(e).

h. The Permittee shall furnish EPA with a written report of the results of performance tests within 60 days of completion.

2. Cooling Tower Total Dissolved Solids Testing

a. The Permittee shall perform weekly tests of the blow-down water quality using an EPA-approved method. This weekly test shall not be required for any 7-day period in which the wet cooling tower is not in operation, provided that the Permittee maintains a log of wet cooling tower operation.

b. The Permittee shall maintain a log that contains the date and result of each blow-down water quality test, and the resulting mass emission rate. This log shall be maintained onsite for a minimum of five years and shall be provided to EPA and District personnel upon request.

c. The Permittee shall calculate the PM, PM_{10}, and $PM_{2.5}$ emission rates using an EPA-approved calculation based on the TDS and water circulation rate.

d. The Permittee shall conduct all required cooling tower water quality tests in accordance with an EPA-approved test and emissions calculation protocol. Thirty (30) days prior to the first such test, the Permittee shall provide a written test and emissions calculation protocol for EPA review and approval, and send a copy to the District.

e. A maintenance procedure shall be established that states how often and what procedures will be used to ensure the integrity of the drift eliminators, to ensure that the TDS limits are not exceeded, and to ensure compliance with recirculation rates. This procedure is to be kept onsite and made available to EPA and District personnel upon request. The Permittee shall promptly report any deviations from this procedure.

H. Recordkeeping and Reporting

1. The Permittee shall maintain a file of all records, data, measurements, reports, and documents related to operation of the Facility. All records shall be in a permanent form suitable for inspection.

2. The Permittee shall maintain CEMS records that include the following: the occurrence and duration of any startup, shutdown, or malfunction, performance testing, evaluations, calibrations, checks, adjustments, maintenance, duration of any periods during which a CEMS is inoperative, and corresponding emission measurements.

3. The Permittee shall maintain records of the hours of operation for each turbine (Turbine 1, Turbine 2, and Turbine 3), on a monthly basis.

4. The Permittee shall maintain records and submit a written report of all excess emissions and any other noncompliance with permit conditions to EPA for each six-month reporting period from January 1 to June 30 and from July 1 to December 31, except when more frequent reporting is specifically required by an applicable subpart, or EPA, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. The report shall be postmarked by the 30^{th} day following the end of each semi-annual period and shall include the following:

    a. Time intervals, data and magnitude of the excess emissions, the nature and cause (if known), corrective actions taken and preventive measures adopted;

    b. Applicable time and date of each period during which the CEMS was inoperative (monitor down-time), except for zero and span checks, and the nature of CEMS repairs or adjustments;

    c. A statement in the report of a negative declaration; that is, a statement when no excess emissions occurred or when the CEMS has not been inoperative, repaired, or adjusted;

    d. Any failure to conduct any required source testing, monitoring, or other compliance activities; and

    e. Any violation of limitations on operation, including but not limited to restrictions on hours of operation.

5. Excess emissions shall be defined as any period in which any turbine exceeds any emission limits set forth in this permit.

6. A period of monitor down-time shall be defined as any unit operating clock hour in which sufficient data are not obtained by the CEMS to validate the hour for NO_X, CO_2, or O_2, while the CEMS is also meeting the requirements of Condition IX.F.3.

7. Excess emissions indicated by the CEM system, source testing, or compliance monitoring shall be considered violations of the applicable emission limit for the purpose of this permit.

8. All records required by this PSD Permit shall be retained for not less than five years following the date of such measurements, maintenance, reports, and/or records.

9. The Permittee shall measure and record the following for each CTG (Turbine 1, Turbine 2, and Turbine 3) on an hourly basis:

   a. Net energy output (MWh_{net});

   b. Pounds of CO_2 per net energy output (lb CO_2/MWh_{net});

   c. The 8,760-operating hour rolling average emission rate of lb CO_2/MWh_{net} based on the average hourly recordings.

10. The Permittee shall maintain a log describing maintenance and repair activities, including the following information:

   a. Date of activity

   b. Description of activity

   c. For scheduled maintenance, the elapsed time, hours of turbine operation, or other applicable measure since the activity was last performed.

   d. For scheduled maintenance, the elapsed time, hours of turbine operation, or other applicable measure until the activity should next be performed.

11. The Permittee shall calculate the SF6 emissions due to leakage from the circuit breakers by using the mass balance in equation DD-1 at 40 CFR Part 98, Subpart DD on an annual basis. Records of such calculations shall be maintained on site.

I. Shakedown Periods

The combustion turbine emission limits and requirements in Conditions IX.B, IX.C and IX.D shall not apply during combustion shakedown periods. Shakedown is defined as the period beginning with initial startup as defined in Condition IX.C.4 and ending no later than initial performance testing, during which the Permittee conducts operational and contractual testing and tuning to ensure the safe, efficient and reliable operation of the plant. The shakedown period shall not exceed 90 days. The requirements of Section III of this permit shall apply at all times.

X. AGENCY NOTIFICATIONS

All correspondence as required by this Approval to Construct must be sent to:

A. Director, Air Division (Attn: AIR-5)
EPA Region IX
75 Hawthorne Street
San Francisco, CA 94105-3901

Email: R9.AEO@epa.gov
Fax: (415) 947-3579

With a copy to:

B. Air Pollution Control Officer
San Diego County Air Pollution Control District
10124 Old Grove Road
San Diego, CA 92131-1649
Fax: (858) 586-2701

XI. ACROYNMS AND ABBREVIATIONS

Act	Clean Air Act [42 U.S.C. Section 7401 et seq.]
Agency	U.S. Environmental Protection Agency
BACT	Best Available Control Technology
BTU	British thermal units
CAA	Clean Air Act [42 U.S.C. Section 7401 et seq.]
CEMS	Continuous Emissions Monitoring System
CMS	Continuous Monitoring System
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CO2e	Carbon Dioxide Equivalent
CTG	Combustion Turbine Generator
GE	General Electric
GHG	Greenhouse Gas (Greenhouse Gases)
g/hp-hr	grams per horsepower-hour
gr/scf	Grains per Standard Cubic Feet
EAB	Environmental Appeals Board
EPA	U.S. Environmental Protection Agency
GHG	Greenhouse Gases
HHV	Higher Heating Value
HP	Horsepower
kW	Kilowatts of electrical power

kWhr	Kilowatt-hour
mg/L	Milligrams per liter
µg/m3	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
NMHC	Non-methane Hydrocarbons
NO	Nitrogen oxide or nitric oxide
NO2	Nitrogen dioxide
NOx	Oxides of Nitrogen (NO + NO2)
NP	National Park
NSPS	New Source Performance Standards, 40 CFR Part 60
NSR	New Source Review
O2	Oxygen
PM	Total Particulate Matter
PM2.5	Particulate Matter less than 2.5 micrometers (µm) in diameter
PM10	Particulate Matter less than 10 micrometers (µm) in diameter
PPEC	Pio Pico Energy Center
PPM	Parts per Million
PPMVD	Parts per Million by Volume, on a Dry basis
PSD	Prevention of Significant Deterioration

Appendix D

Appendix D.

SOURCE:
FINAL STAFF ASSESSMENT
CALIFORNIA ENERGY COMMISSION

EMISSIONS CALCULATIONS
AND ASSUMPTIONS
USED IN AIR DISPERSION MODELING

EMISSIONS CALCULATIONS AND ASSUMPTIONS USED IN AIR DISPERSION MODELING

The maximum hourly emissions for PPEC, Wartsila engines, and combined-cycle technology are listed in Table 1. The PPEC project includes the emissions from three CTGs and the partial dry cooling tower as proposed. For the other two technologies, in addition to the Wartsila engines and CTGs, staff added other emitting sources according to those included in the Quail Brush Generation Project and GWF Tracy Combined-Cycle Power Plant. For the Wartsila engine technology, staff added 3 fuel gas heaters, 3 warm start heaters, and a fire pump. For the combined-cycle technology, staff used the same additional sources (an auxiliary boiler, a wet surface air cooler, a fire pump, and an emergency generator) as those in the GWF Tracy Combined-Cycle Power Plant.

During normal operating conditions, the 33 Wartsila engines would give higher emissions than three simple-cycle CTGs of PPEC. On the other hand, two CTGs with combined-cycle technology during normal operation (even with duct burner firing) from GWF Tracy would have lower emission rates than three simple-cycle CTGs of PPEC during normal operation. If all the 33 Wartsila engines startup and shutdown simultaneously, emissions of every pollutant are higher than those from three simple-cycle CTGs of PPEC in startup or shutdown mode simultaneously. The combined-cycle technology has higher NOx and CO emissions but lower VOC, PM10/PM2.5, and SOx emissions during startup than those from all three simple-cycle CTGs of PPEC in startup or shutdown mode simultaneously.

The maximum daily emissions from PPEC (listed in Table 2) are based on 4 hours of startup, 4 hours of shutdown mode and 16 hours of full load operation. Maximum annual emissions (Table 3) are calculated based on 500 hours in startup mode, 500 hours in shutdown mode, and 3,335 hours per year at full-load operation under average conditions for all three CTGs.

Staff compared the emissions from the alternative technologies based on the same or a similar operating scenario as that for PPEC. The maximum daily emissions from 33 Wartsila engines are based on 1 hour in cold start mode, 3 hours in warm start mode, 4 hours in shutdown mode, and 16 hours at 100 percent load steady state operation. The maximum annual emissions from the 33 Wartsila engines are based on 375 hours in cold start mode, 125 hours in warm start mode, 500 hours in shutdown mode, and 3,335 hours in full load operation mode. The ratio between the hours in cold start and warm start modes is based on that for the Quail Brush Generation Project. The emissions and operating parameters of other sources are also based on those used in the Quail Brush Generation Project; daily emissions of fuel gas heaters and warm start heaters are based on 24 hours of operation. Daily emission of the fire pump is based on 1 hour of operation per day. Annual emissions of fuel gas heaters are based on 4,232 hours of operation. Annual emissions of warm start heaters are based on 4,928 hours of operation. Annual emissions from the fire pump are based on 50 hours of operation.

On the other hand, the startups of the GWF Tracy Combined-Cycle Power Plant would take more than an hour to complete: 180 min for cold start, 118 min for warm start, and 61 min for hot start, suggesting it is not really a comparable technology to PPEC. However, staff considered this factor and tried to match the combined cycle operation to the number of startups/shutdowns of PPEC as closely as possible. For the maximum daily emissions, staff assumed 1 cold startup, 3 hot startups, 4 shutdowns, and 15.35 hours of operation at 15°F with evaporative coolers operating and duct burners firing. For the maximum annual emissions, staff assumed 38 cold startups, 76 warm startups, 386 hot startups, 500 shutdowns, 3,335 hours of operation at 59°F with evaporative coolers operating and duct burners firing. The ratio between the cold, warm, and hot startups is based on that used in the GWF Tracy Combined-Cycle Power Plant. The emissions and operating parameters of other sources are also based on those for the GWF Tracy Combined-Cycle Power Plant: daily emissions for the fire pump and emergency standby generator engine are based on a very conservative assumption with 24 hours of operation. Daily emissions from the WSAC (Wet Surface Air Cooler) and auxiliary boiler are also based on 24 hours of operation. Annual emissions for the fire pump and emergency standby generator engine are shown for 50 hours of operation for routine testing and maintenance. Annual emissions from WSAC and auxiliary boiler are based on 4,000 hours of operation.

Maximum daily and annual emissions of all pollutants from the Wartsila engine technology are higher than those of PPEC. This is due to the higher emissions from the total 33 Wartsila engines during both startup/shutdown and normal operation modes than the simple-cycle technology of PPEC. Maximum daily emissions of NOx and CO are higher from the combined-cycle technology because it has higher emission rates of NOx and CO during cold startup and shutdown. Maximum annual emissions of all pollutants from the combined-cycle technology are lower than the simple-cycle technology mainly because the combined-cycle technology has lower hourly emissions during normal operation.

IMPACTS

Air quality impacts are determined using an air dispersion model (AERMOD) and local meteorology to determine ground-level pollutant concentrations downwind of the facilities. Included in the analysis are factors such as emissions rates, plume rise and stack height. Project impacts are added to base-line (background) values to obtain totals that are then compared to applicable ambient air quality standards.

Staff used the project setup, such as receptor locations, terrain heights, meteorology, and background data from the PPEC modeling files. For the simple-cycle technology of PPEC, staff used the same impact results in the PSA of PPEC. For the other two alternative technologies, staff placed the emitting sources within the project boundary of PPEC and modeled the impacts with the PPEC project setup. The modeling assumptions for the Wartsila engine technology are based on the AFC of Quail Brush

Generation Project[4]. For this analysis, staff adopted all the assumptions including the 0.0115 in-stack NO_2/NOx ratio. If a higher in-stack NO_2/NOx ratio is found later in the Quail Brush Generation Project, the impact of NO_2 from the Wartsila engine technology would be even higher than what staff has modeled in this analysis.

The modeled project impacts from all three technologies are listed in Table 4. The impacts from the 33 Wartsila engines are higher than those from the simple-cycle CTGs of PPEC. The reason for the higher impacts is because of the higher hourly, daily, and annual emissions from the total 33 of the Wartsila engines. The other sources such as fire pump and heaters play a minor role in determining the total project impact.

On the other hand, impacts from the combined-cycle CTGs are also higher than those from the simple-cycle CTGs of PPEC even though some of the emissions are lower than those from the simple-cycle technology. Staff took a close look at the stack parameters in the modeling for these different technologies. Staff found that the reason for higher impacts from the combined-cycle CTGs is because the air plume exit temperatures and exit velocities from the stack tops are much lower than those from the simple-cycle CTGs or the Wartsila engines. The worst case modeled impacts from the combined-cycle CTGs are based on an exit temperature of 365.37 degrees K (Kelvin) and exit velocity of 9.754 m/s. For the simple-cycle CTGs of PPEC, the lowest exit temperature is 674 K and the slowest exit velocity is 19.86 m/s. The Wartsila engines are modeled with either the combination of 663.15 K and 24.983 m/s or the combination of 712.039 K and 14.771 m/s. Less buoyant air plumes from the combined-cycle CTGs will have greater impact closer to the stacks where there hasn't been enough time and distance for dispersion of the plumes.

Staff also noticed that for the combined cycle technology, the maximum annual impacts and 24-hour PM10/PM2.5 impacts are mainly determined by the auxiliary boiler. However, the difference in the modeled impacts due to the auxiliary boiler and CTGs is small compared to the limiting standards (5 to 6 percent). For comparison purposes, Staff listed the impacts of the combined cycle technology into 3 source groups in Table 4: impacts due to CTGs only, impacts due to an auxiliary boiler, and impacts due to all sources. The auxiliary boiler exhaust has a low exit temperature of 421 K and slow exit velocity of 5.8 m/s which leads to maximum impacts on the fence line. On the other hand, the CTGs still dominate the short term impacts because the high startup emissions play a major role in determining the maximum short term impacts.

In addition to the existing violations of 24-hour and annual PM10 and annual PM2.5 standards, there would be additional violations from the two alternative technologies. The 33 Wartsila engines would cause new violation of 24-hour PM2.5 and federal 1-hour NO_2 standard even if the modeling assumption of pairing the worst project impact and worst background is relaxed and the modeled impacts and background are paired temporally (daily for PM2.5 and hourly for NO_2). The combined-cycle CTGs as modeled would cause new violations of state and federal 1-hour NO_2 standards. However, these

---

[4] Staff still hasn't signed off on the Quail Brush applicant's modeling protocol which assumes a low value of 0.0115 for the in-stack NO_2/NOx ratio for the Wartsila engines.

alternative technologies are not proposed for this site but rather are modeled at this site and shown for comparison purposes. If different meteorology, terrain, and background data are used as inputs to the modeling for different sites, the results could be quite different even if the same emitting sources are used. The 11 instead of 33 Wartsila engines as proposed for Quail Brush will be evaluated against all ambient air quality standards at that site, just as the combined cycle technology was evaluated and found to comply with ambient air quality standards at the Tracy site.

CONCLUSIONS

Staff compared the simple-cycle technology proposed for Pio Pico with two other alternative technologies: reciprocating Wartsila engine technology and combined-cycle technology. For comparison purposes of this analysis, staff assumed the same operating capacity factor for all three technologies, while in reality a combined-cycle power plant would not match the quick start times of PPEC or the Warsilas, and would also likely be operated at a much higher annual capacity factor. Based on this analysis, staff concludes that:

1. With the same capacity, Wartsila engines have higher maximum hourly, daily, and annual emissions than the simple-cycle CTGs of PPEC.

2. With similar capacity, combined-cycle CTGs have higher emissions of NOx and CO during startups and lower emission rates of all pollutants during normal operations compared to simple-cycle CTGs of PPEC. Annual emissions of all pollutants from combined-cycle CTGs are lower than simple-cycle CTGs of PPEC assuming same operating capacity factor.

3. Wartsila engines have higher modeled air impacts for all pollutants than those from the simple-cycle CTGs of PPEC and as modeled at the Pio Pico site would cause new violations of 24-hour PM2.5 and federal 1-hour NO_2 standard.

4. Combined cycle CTGs, with necessary auxiliary sources such as auxiliary boiler, have higher modeled air impacts of all pollutants because of lower exit temperature and slower exit velocity. As modeled at the Pio Pico site, combined cycle CTGs would cause new violations of both state and federal 1-hour NO_2 standards because of high startup emissions.

Table 1
Maximum Hourly Emissions during Routine Operation (pounds per hour [lb/hour])

Source	NOx	VOC	PM10/PM2.5	CO	SOx
PPEC[1]					
Each CTG (normal operation)	8.18	2.28	5.5	7.97	1.9
Each CTG (startup or shutdown)	26.6	5.81	5.5	53.5	1.9
Cooling Tower	--	--	0.7	--	--
Maximum Total	**79.9**	**19.6**	**17.2**	**160.5**	**5.7**
Wartsila Engines[2]					
Each engine (steady state, 100% load)	1.3	1.6	1.4	1.6	0.3
Each engine (w/startup & shutdown)	9.5	7.5	2.4	13.4	0.3
Fuel Gas Heater (each)	0.2	0.2	0.03	0.4	0.00
Warm Start Heater (each)	0.2	0.2	0.03	0.4	0.00
Subtotal (33 engines)	313.2	248.2	78.5	443.5	9.2
Subtotal (3 Fuel Gas Heaters)	0.6	0.5	0.1	1.1	0.01
Subtotal (3 Warm Start Heaters)	0.6	0.5	0.1	1.1	0.01
Fire Pump	0.9	0.03	0.03	0.3	0.002
Maximum Total	**315.2**	**249.2**	**78.7**	**446.0**	**9.3**
Combined Cycle[3]					
Source	**NOx**	**VOC**	**PM10/PM2.5**	**CO**	**SOx**
Each Combustion Turbine (maximum lb/hr with duct burner firing)	10.3	3.22	5.8	6	2.63
Each Combustion Turbine (maximum lb/hr without duct burner firing)	8.1	1.13	4.4	3.9	2.02
Both Combustion Turbines (maximum lb/hr combined startup)	399	11	9.4	375	4.9
Auxiliary Boiler	0.62	0.43	0.6	3.15	0.16
Wet Surface Air Cooler	--	--	0.2	--	--
Fire Pump Engine	1.7	0.1	0.076	1.52	0.003
Emergency Standby Generator	4.9	0.042	0.03	0.12	0.005
Maximum Total	**406.2**	**11.6**	**10.3**	**379.8**	**5.1**

1. Emissions of PPEC are based on Air Quality FSA and FDOC for PPEC (San Diego APCD 2012).
2. Emissions of Wartsila engines and corresponding heaters and fire pump are based on AFC of Quail Brush Generation Project (Quail Brush GenCo 2011).
3. Emissions of combined-cycle technology are based on FSA of GWF Tracy Combined-Cycle Power Plant (CEC 2009).

Table 2
Maximum Daily Emissions during Routine Operation (pounds per day [lb/day])

Source	NOx	VOC	PM10/PM2.5	CO	SOx
PPEC[1]					
Each CTG	288.1	79.2	132.0	428.9	45.6
Cooling Tower	--	--	15.8	--	--
Total	**864.3**	**237.5**	**411.8**	**1,286.6**	**136.8**
Wartsila Engines[2]					
Each engine	46.1	48.4	38.1	52.5	6.2
Fuel Gas Heater (each)	4.6	3.8	0.7	8.6	0.1
Warm Start Heater (each)	4.6	3.8	0.7	8.6	0.1
Subtotal (33 engines)	1,522.4	1,597.3	1,258.1	1,731.6	205.5
Subtotal (3 Fuel Gas Heaters)	13.9	11.5	2.0	25.9	0.2
Subtotal (3 Warm Start Heaters)	13.9	11.5	2.0	25.9	0.2
Fire Pump	0.9	0.03	0.03	0.3	0.002
Total	**1,551.0**	**1,620.4**	**1,262.2**	**1,783.8**	**205.8**
Combined Cycle[3]					
Combustion Turbine #1	1,036.6	75.4	121.0	1,549.6	52.4
Combustion Turbine #2	1,036.6	75.4	121.0	1,549.6	52.4
Auxiliary Boiler	15.0	10.2	14.3	75.5	3.8
Wet Surface Air Cooler	--	--	4.8	--	--
Fire Pump Engine	41.0	2.4	1.8	36.0	0.1
Emergency Standby Generator	117.0	1.0	0.7	3.0	0.1
Total	**2,246.2**	**164.5**	**263.7**	**3,213.7**	**108.8**

1. Emissions of PPEC are based on Air Quality PSA and PDOC for PPEC (San Diego APCD 2011).
2. Emissions of Wartsila engines and corresponding heaters and fire pump are based on AFC of Quail Brush Generation Project (Quail Brush GenCo 2011).
3. Emissions of combined-cycle technology are based on FSA of GWF Tracy Combined-Cycle Power Plant (CEC 2009).

Table 3
Maximum Annual Emissions during Routine Operation (tons per year [tpy])

Source	NOx	VOC	PM10/PM2.5	CO	SOx
PPEC[1]					
Each CTG	23.5	6.5	11.9	32.1	4.1
Cooling Tower	--	--	1.4	--	--
Total	**70.4**	**19.4**	**37.2**	**96.4**	**12.4**
Wartsila Engines[2]					
Each engine	4.5	4.6	3.3	5.7	0.6
Fuel Gas Heater (each)	0.4	0.3	0.1	0.8	5.1E-03
Warm Start Heater (each)	0.5	0.4	0.1	0.9	5.9E-03
Subtotal (33 engines)	149.2	153.1	107.6	187.4	18.5
Subtotal (3 Fuel Gas Heaters)	1.2	1.0	0.2	2.3	1.5E-02
Subtotal (3 Warm Start Heaters)	1.4	1.2	0.2	2.7	1.8E-02
Fire Pump	2.2E-02	7.5E-04	7.5E-04	8.0E-03	5.3E-05
Total	**151.8**	**155.3**	**108.0**	**192.4**	**18.6**
Combined Cycle[3]					
Combustion Turbine #1	33.9	5.7	9.2	39.7	2.2
Combustion Turbine #2	33.9	5.7	9.2	39.7	2.2
Auxiliary Boiler	1.2	0.9	1.2	6.3	0.1
Wet Surface Air Cooler	--	--	0.1	--	--
Fire Pump Engine	4.3E-02	2.6E-03	1.9E-03	3.8E-02	7.5E-05
Emergency Standby Generator	1.2E-01	1.1E-03	7.5E-04	3.1E-03	1.2E-04
Total	**69.2**	**12.3**	**19.7**	**85.6**	**4.5**

1. Emissions of PPEC are based on Air Quality PSA and PDOC for PPEC (San Diego APCD 2011).
2. Emissions of Wartsila engines and corresponding heaters and fire pump are based on AFC of Quail Brush Generation Project (Quail Brush GenCo 2011).
3. Emissions of combined-cycle technology are based on FSA of GWF Tracy Combined-Cycle Power Plant (CEC 2009).

Table 4
Comparison of Routine Operation Maximum Impacts (µg/m³)

Pollutant	Averaging Time	Modeled Impact			Background	Total Impact			Limiting Standard	Percent of Standard		
		PPEC	Wartsila Engines	Combined Cycle[1] CTGs Aux Boiler All Sources		PPEC	Wartsila Engines	Combined Cycle CTGs Aux Boiler All Sources		PPEC	Wartsila Engines	Combined Cycle CTGs Aux Boiler All Sources
PM10	24 hour	2	39	3.6 6.1 7	**57**	**59**	**96**	**61** **63** **64**	**50**	**118**	**192**	**121** **126** **127**
PM10	Annual	0.2	2	0.17 0.79 0.81	**26.7**	**27**	**29**	**27** **27** **28**	**20**	**135**	**146**	**134** **137** **138**
PM2.5	24 hour[2]	--	--	--	--	26	**39**	26 27 28	35	74	**112**	74 77 79
PM2.5	Annual	0.2	2.5	0.17 0.79 0.81	**12.5**	**13**	**15**	**13** **13** **13**	**12**	**107**	**125**	**106** **111** **111**
CO	1 hour	268	2,739	1,151 NA 1,170	3,565	3,833	6,304	4,716 NA 4,735	23,000	17	27	21 NA 21
CO	8 hour	64	190	347 NA 351	2,489	2,553	2,679	2,836 NA 2,840	10,000	26	27	28 NA 28
NO_2	1 hour (state)	133	167	303 NA 328	154	287	321	**457** NA **482**	**339**	85	95	**135** NA **142**
NO_2	1 hour (federal)[3]	--	--	--	--	138	**199**	**311** NA **316**	**188**	73	**106**	**165** NA **168**
NO_2	Annual	0.3	4	0.6 0.8 1	29	29	33	30 30 30	57	51	57	53 53 53

Pollutant	Averaging Time	Modeled Impact			Background	Total Impact			Limiting Standard	Percent of Standard		
		PPEC	Wartsila Engines	Combined Cycle[1] CTGs Aux Boiler All Sources		PPEC	Wartsila Engines	Combined Cycle CTGs Aux Boiler All Sources		PPEC	Wartsila Engines	Combined Cycle CTGs Aux Boiler All Sources
	1 hour	8	56	16 NA 16	31	37	87	47 NA 47	196	19	44	24 NA 24
	24 hour	1.0	4.8	1.7 NA 1.7	18.2	19	23	20 NA 20	105	18	22	19 NA 19
SO_2	Annual	<0.1	0.42	0.04 0.07 0.07	10.5	11	11	11 11 11	80	13	14	13 13 13

1. The impacts of the combined cycle are listed for 3 separate groups of sources. The upper numbers represent the impacts due to the two CTGs, the middle numbers represent the impacts due to the auxiliary boiler, and the lower numbers represent the impacts due to all the sources.
2. The total impacts of 24-hour PM2.5 are shown as 3-year average of the annual 98th percentile of paired-sum of 24-hour modeled impacts and daily background data.
3. The total impacts of 1-hour NO_2 are shown as 3-year average of the 98th percentile of the yearly distribution of daily maximum paired-sum of 1-hour modeled impacts and hourly NO_2 background data.

REFERENCES

CEC 2009, Final Staff Assessment, GWF Tracy Combined Cycle Power Plant Project (08-AFC-7), dated October 30, 2009.

Quail Brush GenCo 2011, Application for Certification Volume I and II (TN 62026), dated August 25, 2011.

San Diego APCD 2011, Pio Pico Energy Center Project (11-AFC-01) San Diego Air Pollution Control District's Publication of the Preliminary Determination of Compliance (TN 63192), dated December 20, 2011.

ACRONYMS

CO: carbon monoxide
NO_2: nitrogen dioxide
NOx: nitrogen oxides
PM10: particulate matter less than 10 micrometers in diameter
PM2.5: particulate matter less than 2.5 micrometers in diameter
SO_2: sulfur dioxide
SOx: sulfur oxides
VOC: volatile organic compound

Appendix
E.

SOURCE:
EL PASO ELECTRIC COMPANY

REPORT ON
COMBINED CYCLE VS. QUICK START
COMBUSTION TURBINE
EXPANSION ANALYSIS

Report
On
Combined Cycle vs. Quick Start Combustion Turbine Expansion Analysis

Daniel Holguin
Resource and Delivery Planning Engineer
El Paso Electric

September 21, 2011

TABLE OF CONTENTS

Generating Station	Net Capacity (MW)	Start-Up Date	Retirement Date	Age
Rio Grande	***229***			
Unit 6	45	1957	12/31/2014	54
Unit 7	46	1958	12/31/2017	53
Unit 8	138	1972	12/31/2022	39
Newman	***762***			
Unit 1	74	1960	12/31/2019	51
Unit 2	76	1963	12/31/2015	48
Unit 3	97	1966	12/31/2019	45
Unit 4	227	1975	12/31/2017	36
Unit 5	288	2011	12/31/1951	NEW
Copper	***62***			
Unit 1	62	1980	12/31/2020	31
Four Corners	***104***			
Unit 4	52	1969	12/31/2019	42
Unit 5	52	1970	12/31/2020	41
Palo Verde	***633***			
Unit 1	211	1986	12/31/2026	25
Unit 2	211	1986	12/31/2026	25
Unit 3	211	1988	12/31/2028	23
Hueco Mtn. Wind	***1***	2001	12/31/2021	10
Newman Solar Unit	***0.064***	2009	12/31/2029	2
Rio Grande Solar Unit	***0.064***	2009	12/31/2029	2
Total Net Capacity	**1,791**			

Table 1 – EPE's Unit's Capacity and Retirements

Due to the shape of EPE's daily load profile, which has a high peak load during the day and a significantly smaller off peak load, EPE's system needs the flexibility to shut down the generating units during off peak hours or at night. This critical characteristic will allow the units to easily conform to EPE's daily load profile. See Figure 1 for a plot of EPE's Daily Load Profile. New generation units must be able to start and ramp up quickly to meet the daytime summer loads and cycle off at night when the load drops considerably

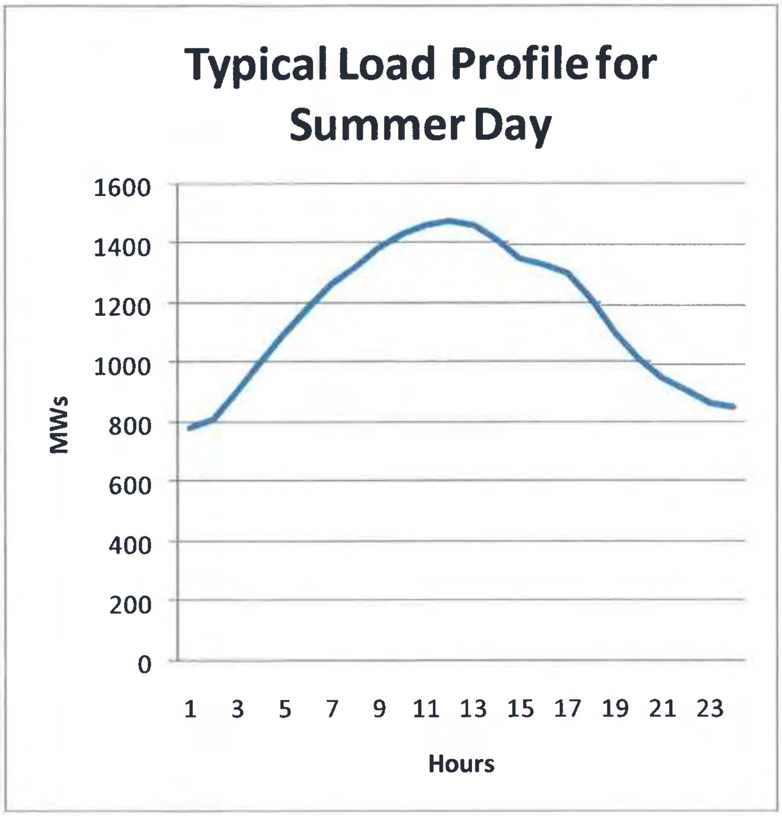


Figure 1 – EPE's Daily Load Profile

If future generating additions to EPE's system, be it Combined Cycles or Combustion Turbines, cannot be cycled on and off then EPE could be forced to sell off the energy or worse case, EPE would have to pay another utility to take the energy. The purpose of this study was to evaluate what type of new generation will eliminate or reduce the unneeded energy.

Based on recent Generation Expansion Plan Analyses and evaluation of Requests For Proposals (RFP), it is evident that the best fit for EPE's resource mix is gas-fired generation in the form of a Combustion Turbine (CT) or a Combined Cycle (CC). For modeling proposes in PROMOD the CTs share many of the same operating characteristics of Rio Grande 9, the LMS100 peaking unit coming online in 2013. The CCs in PROMOD are mostly modeled based on the operating characteristics of our newest and most efficient combined cycle unit, Newman 5 which came online in May of 2011.

The LMS100 is an aero-derivative combustion turbine that is produced by General Electric with many advantages. This turbine utilizes technology that was derived from jet aircraft applications. Currently the LMS100 is the largest and most efficient combustion turbine in its class and at our location the unit will produce 87MW. The LMS offers a wide range of flexibility when it comes to unit operation. This turbine can be used as a peaker, for intermediate load, and even for base load. The LMS100 offers quick starts which create excellent cycling capability, while keeping emissions low, and a Heat Rate of approximately 9,900 BTU/kWh. The disadvantages of the LMS100 is that it has a higher heat rate compared to the Combined Cycle and thus could have higher natural gas cost associated to its generation.

The Combined Cycle unit is a combination of combustion and steam turbine technology that also has its own advantages. The CC modeled in PROMOD is a 2x1 unit, which utilizes two combustion turbines and one steam turbine. Combined Cycle units are very efficient since they utilize waste heat recovery recovered from the combustion turbine exhaust to power the steam turbine. The CC modeled in PROMOD is based on the operation characteristics of EPE's most efficient unit, Newman 5. At our location Combined Cycle units can produce 288MW while offering a Heat Rate of about 8,500 BTU/kWh. Cycling is limited with a Combined Cycle since these units operate with a boiler making them often used for intermediate and base load applications. This is a disadvantage of the CC compared to the LMS100.

PROMOD DESCRIPTION

PROMOD is a software program that simulates the economic dispatch of our system. This software takes into account our generation units as well as our additional resources to meet our load demands. PROMOD is also used to analyze alternative generation expansion plans as in this case. The inputs required in PROMOD include fuel and purchased power data, generating unit characteristics, load data, and general system data. . Various scenarios of PROMOD were modeled with differences in minimum loads, cycling capabilities, and heat rates.

SCENARIO DESCRIPTION/MAJOR ASSUMPTIONS

The PROMOD runs covered a time frame 2011-2021. Two basic scenarios were evaluated – Scenario A is the CC scenario and Scenario B is the CT scenario. The two expansion plans contain the same input values through 2014. Both expansion plans include EPE's NRG, Sun Edison, and Hatch solar projects, Rio Grande 9 in 2013, a 15MW Biomass project in 2014, and a generic LMS100 unit in 2014. All of the current and planned generation resources through 2014 share the same input characteristics for all of the PROMOD iterations. In 2015 the Loads and Resources (L&R) Scenario begin to take different paths for each expansion plan. The L&R for the LMS100 Expansion Plan, see Table 2, requires an LMS100 in 2015, two LMS100 units in 2016, a Combined Cycle in 2018, another LMS100 in 2019, and a Combined Cycle in 2020.

Loads & Resources LMS100 Scenario

2011 - 2020

	ST2	solar	LMS100	LMS100	LMS100	LMS100 LMS100		CC	LMS100	CC
Year	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1.0 GENERATION RESOURCES [1]	**1,791**	**1,792**	**1,879**	**1,966**	**2,008**	**2,106**	**2,106**	**2,121**	**2,208**	**2,326**
1.1 RIO GRANDE	229	229	229	229	184	184	184	138	138	138
1.2 NEWMAN	762	762	762	762	762	686	686	459	459	288
1.3 FOUR CORNERS	104	104	104	104	104	104	104	104	104	104
1.4 COPPER	62	62	62	62	62	62	62	62	62	62
1.5 PALO VERDE	633	633	633	633	633	633	633	633	633	633
1.6 WIND/SOLAR (renewables)	1	2	2	2	2	2	2	2	2	2
1.7 NEW BUILD (local)	-	-	87	174	261	435	435	723	810	1,098
1.0 TOTAL GENERATION RESOURCES	**1,791**	**1,792**	**1,879**	**1,966**	**2,008**	**2,106**	**2,106**	**2,121**	**2,208**	**2,325**
2.0 RESOURCE PURCHASES	**59**	**114**	**111**	**96**	**106**	**96**	**129**	**134**	**134**	**101**
2.1 MARKET BLOCK PURCHASE	40	40	40	40	40	40	40	40	40	40
2.2 RENEWABLE PURCHASE (SunEdison & NRG)	-	37	37	37	37	37	37	37	37	37
2.3 RENEWABLE PURCHASE (Hatch)	4	4	4	4	4	4	4	4	4	4
2.4 RENEWABLE PURCHASE (Biomass)	-	-	-	15	15	15	15	20	20	20
2.5 RESOURCE PURCHASE	15	33	30	-	10	-	33	33	33	-
3.0 TOTAL NET RESOURCES (1.0 + 2.0)	**1,850**	**1,906**	**1,990**	**2,062**	**2,114**	**2,202**	**2,235**	**2,255**	**2,342**	**2,426**
4.0 SYSTEM DEMAND [3]	**1,605**	**1,659**	**1,725**	**1,775**	**1,837**	**1,897**	**1,950**	**2,001**	**2,045**	**2,093**
4.1 NATIVE SYSTEM DEMAND	1,677	1,738	1,810	1,865	1,932	1,996	2,056	2,114	2,163	2,217
4.2 CLMCOG	(17)	(23)	(28)	(33)	(37)	(41)	(47)	(53)	(58)	(64)
4.3 LINE LOSSES	1	1	1	1	1	1	1	1	1	1
4.4 INTERRUPTIBLE SALES	(56)	(57)	(58)	(58)	(59)	(59)	(60)	(61)	(61)	(61)
	-	-	-	-	-	-	-	-	-	-
5.0 TOTAL SYSTEM DEMAND (4.0)	**1,605**	**1,659**	**1,725**	**1,775**	**1,837**	**1,897**	**1,950**	**2,001**	**2,045**	**2,093**
6.0 MARGIN OVER TOTAL DEMAND (3.0 - 5.0)	**245**	**247**	**265**	**287**	**277**	**305**	**285**	**254**	**297**	**333**
7.0 PLANNING RESERVE 15%	**241**	**249**	**259**	**266**	**276**	**285**	**293**	**300**	**307**	**314**
8.0 MARGIN OVER RESERVE (6.0 - 7.0)	**4**	(2)	**6**	**21**	**1**	**20**	(8)	(46)	(10)	**19**
9.0 DEMAND PLUS RESERVE (5.0 + 7.0)	**1,846**	**1,908**	**1,984**	**2,041**	**2,113**	**2,182**	**2,243**	**2,301**	**2,352**	**2,407**

Table 2 – EPE's 2011-2020 Loads & Resources LMS100 Scenario

The alternative L&R for the CC Expansion Plan would replace the three LMS100 units in 2015 and 2016 with a Combined Cycle Unit phased in over the same two years, see Table 3. The LMS100 unit and the Combined Cycle unit are both top quality generators, this analysis is to determine which is best for EPE's system.

Loads & Resources CC Scenario

2011 - 2020

	ST2	solar	LMS100	LMS100	CT	ST3		CC	LMS100	CC
Year	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1.0 GENERATION RESOURCES (1)	**1,791**	**1,792**	**1,879**	**1,966**	**2,091**	**2,137**	**2,137**	**2,152**	**2,239**	**2,356**
1.1 RIO GRANDE	229	229	229	229	184	184	184	138	138	138
1.2 NEWMAN	762	762	762	762	762	686	686	459	459	288
1.3 FOUR CORNERS	104	104	104	104	104	104	104	104	104	104
1.4 COPPER	62	62	62	62	62	62	62	62	62	62
1.5 PALO VERDE	633	633	633	633	633	633	633	633	633	633
1.6 WIND/SOLAR (renewables)	1	2	2	2	2	2	2	2	2	2
1.7 NEW BUILD (local)	-	-	87	174	344	466	466	754	841	1,129
1.0 TOTAL GENERATION RESOURCES	**1,791**	**1,792**	**1,879**	**1,966**	**2,091**	**2,137**	**2,137**	**2,152**	**2,239**	**2,356**
2.0 RESOURCE PURCHASES	**59**	**114**	**111**	**96**	**96**	**96**	**111**	**134**	**116**	**101**
2.1 MARKET BLOCK PURCHASE	40	40	40	40	40	40	40	40	40	40
2.2 RENEWABLE PURCHASE (SunEdison & NRG)	-	37	37	37	37	37	37	37	37	37
2.3 RENEWABLE PURCHASE (Hatch)	4	4	4	4	4	4	4	4	4	4
2.4 RENEWABLE PURCHASE (Biomass)	-	-	-	15	15	15	15	20	20	20
2.5 RESOURCE PURCHASE	15	33	30	-	-	-	15	33	15	-
3.0 TOTAL NET RESOURCES (1.0 + 2.0)	**1,850**	**1,906**	**1,990**	**2,062**	**2,187**	**2,233**	**2,248**	**2,286**	**2,355**	**2,457**
4.0 SYSTEM DEMAND (3)	**1,605**	**1,659**	**1,725**	**1,775**	**1,837**	**1,897**	**1,950**	**2,001**	**2,045**	**2,093**
4.1 NATIVE SYSTEM DEMAND	1,677	1,738	1,810	1,865	1,932	1,996	2,056	2,114	2,163	2,217
4.2 CLMCOG	(17)	(23)	(28)	(33)	(37)	(41)	(47)	(53)	(58)	(64)
4.3 LINE LOSSES	1	1	1	1	1	1	1	1	1	1
4.4 INTERRUPTIBLE SALES	(56)	(57)	(58)	(58)	(59)	(59)	(60)	(61)	(61)	(61)
	-	-	-	-	-	-	-	-	-	-
5.0 TOTAL SYSTEM DEMAND (4.0)	**1,605**	**1,659**	**1,725**	**1,775**	**1,837**	**1,897**	**1,950**	**2,001**	**2,045**	**2,093**
6.0 MARGIN OVER TOTAL DEMAND (3.0 - 5.0)	**245**	**247**	**265**	**287**	**350**	**336**	**298**	**285**	**310**	**364**
7.0 PLANNING RESERVE 15%	**241**	**249**	**259**	**266**	**276**	**285**	**293**	**300**	**307**	**314**
8.0 MARGIN OVER RESERVE (6.0 - 7.0)	**4**	**(2)**	**6**	**21**	**74**	**51**	**6**	**(15)**	**3**	**50**
9.0 DEMAND PLUS RESERVE (5.0 + 7.0)	**1,846**	**1,908**	**1,984**	**2,041**	**2,113**	**2,182**	**2,243**	**2,301**	**2,352**	**2,407**

Table 2 – EPE's 2011-2020 Loads & Resources CC Scenario

To effectively analyze which expansion plan and which units would best fit in our system, several iterations of the PROMOD simulation were required to compare the Combined Cycle Expansion vs. the LMS100 Expansion Plan. Through this analysis the optimal expansion plan, along with the most favorable unit operating characteristics were examined. Four different case studies were required to fully assess each plan and each unit. Each of the studies did not consider any opportunity sales. Since PROMOD did not utilize opportunity sales for this analysis, the software will classify any excess or unused energy as Surplus Energy.

RESULTS

The first case study that compared the CC vs. the LMS100 defined the minimum capacity of the CC to be 70MW and the minimum capacity for the LMS100 to be 25MW. To determine which unit and expansion plan would be the best fit tor EPE's system, a side-by-side comparison of Total Production Cost, Surplus Energy Cost, Gas Demand Charges, and Net Cost was completed. Through this comparison it was determined that from 2015 to 2021 the CC Resource Plan created more Surplus Energy. This additional Surplus Energy led to greater Total Production Cost as well as higher Gas Demand Charges. Examining the Net Present Value from 2011 to 2021, the LMS100 Resource Plan is $37,300,820 less than the CC Resource Plan during the same period of time. The driving force for the savings in the LMS100 Resource Plan is the cycling ability of the unit. PROMOD was often able to shut down the unit and often exhibited over 200 unit starts per year for the LMS100. The benefit of being able to shut the unit down daily dramatically reduced the excess unused energy.

The second case study defined the minimum CC capacity as 70MW and the minimum LMS100 capacity as 40 MW. NO_x limits may require that the unit run at no lower than 40MW. NO_x limits may be exceeded at operating levels below 40MW. The unit will also be operating at a better heat rate due to the unit being at approximately a 50% capacity factor minimum versus a 25% capacity factor minimum. Total Production Cost, Surplus Energy Cost, Gas Demand Charge, and Net Cost were compared and the results were similar to the first scenario. The CC Resource Plan generated more Surplus Energy, thus creating higher system cost over the study period. Since PROMOD cannot shut down the CC due to its operating characteristics, it can only ramp it down to 70MW, there is added cost from the excess energy. When evaluating the Net Present Value of the study from 2011 to 2021, the LMS100 Resource Plan would save EPE $35,999,610 over the ten year period.

Case study three considers the minimum capacity of the CC to be 135MW and the LMS100 to be 25MW. This puts the CC in a more efficient operating range. Increasing the minimum capacity from 70MW to 135MW could also lead to more surplus energy. Comparing the expansion plans based on the same criteria as the previous two studies, it is determined that the CC option has higher Total Production, Surplus Energy and Gas Demand Costs. The Net Present Value savings over the observed period is $116,757,640 in favor of the LMS100 plan.

Finally, the forth scenario defines the minimum capacity of the CC to be 135MW and the LMS100 to be 40MW. Once again, increasing the minimum capacity of the LMS100 from 25 to 40MW will capture a realistic operating range but this can also lead to surplus energy. The same analysis was conducted in this case study as that was conducted in the previous three studies and it is concluded that the LMS100 Resource Plan is more cost effective. The LMS100 Resource Plan produced a savings of $115,548,820 over the CC option.

RECOMMENDATIONS

Through this extensive study, with the use of the PROMOD software, it can be concluded that the LMS100 Resource Plan option is superior to the CC Resource Plan. The LMS100 option generated less surplus energy and saves not only on Total Production Cost but Net Cost as well. The technology offered by the LMS100 creates advantages that cannot be offered by Combined Cycle units. The advantages offered with LMS100 units are essential for EPE's needs going into the future and an Expansion Plan that utilizes this technology is proposed.

- The side-by-side comparison tables that include the cost are provided below

Case Study #1

2011 Expansion Plan Cost Evaluation Considering Surplus Energy

Combined Cycle Expansion Plan Costs (70MW)						LMS100 Expansion Plan Cost (25MW)							
Year	Total Production Cost (k$)	Surplus Energy Costs(k$)	[1]Gas Demand Charges (K$)	Net Cost(k$)	Present Value (k$)	Year	Total Production Cost (k$)	Surplus Energy Costs(k$)	[1]Gas Demand Charges (K$)	Net Cost(k$)	Present Value (k$)	Present Value Cost Difference (k$)	Present Value Cumulative Difference (k$)
2011	309714	9814	11923	331450	331450	2011	309714	9814	11923	331450	331450	0	0
2012	323660	7709	11790	343159	319485	2012	323660	7709	11790	343159	319485	0	0
2013	342430	6344	12826	361600	313429	2013	342430	6344	12826	361600	313429	0	0
2014	359583	3517	13755	376855	304117	2014	359583	3517	13755	376855	304117	0	0
2015	376633	3882	15019	395534	297170	2015	375594	3869	15027	394490	296386	(784)	(784)
2016	380159	1619	15126	396904	277627	2016	375638	461	15065	391163	273612	(4015)	(4799)
2017	391789	3051	16379	411219	267797	2017	385621	524	16300	402446	262083	(5713)	(10513)
2018	397461	3876	16366	417703	253253	2018	389382	875	15936	406193	246274	(6979)	(17492)
2019	422725	3901	17377	444002	250627	2019	413888	1114	16771	431773	243724	(6905)	(24594)
2020	435706	2731	17771	456208	239751	2020	423548	524	17081	441152	231839	(7912)	(32507)
2021	454688	2711	18676	476075	232932	2021	446510	1124	18234	465868	227938	(4994)	(37501)
				4,410,710	3,087,637					4,346,150	3,050,336		

NPV Saving from LMS Plan (k$):	$37,300.82

Note:
[1] Gas Demand Charges are based on FRCMCD Fuel Consumption plus 25% to account for Daily Peaking Needs. Includes Reservation and Usage Charges.

Case Study #2

2011 Expansion Plan Cost Evaluation Considering Surplus Energy														
Combined Cycle Expansion Plan Costs (70MW)						LMS100 Expansion Plan Cost (40MW)								
Year	Total Production Cost (k$)	Surplus Energy Costs(k$)	(1)Gas Demand Charges (K$)	Net Cost(k$)	Present Value (k$)	Year	Total Production Cost (k$)	Surplus Energy Costs(k$)	(1)Gas Demand Charges (K$)	Net Cost(k$)	Present Value (k$)	Present Value Cost Difference (k$)	Present Value Cumulative Difference (k$)
2011	309714	9814	11923	331450	331450	2011	309714	9814	11923	331450	331450	0	0
2012	323660	7709	11790	343159	319485	2012	323660	7789	11790	343159	319485	0	0
2013	342394	6343	12823	361560	313395	2013	342394	6343	12823	361560	313395	0	0
2014	361325	3523	13888	378736	305634	2014	361325	3523	13888	378736	305634	0	0
2015	377090	3883	15049	396023	297537	2015	376036	3870	15056	394962	296740	(797)	(797)
2016	380236	1619	15132	396987	277685	2016	376109	461	15100	391669	273965	(3720)	(4517)
2017	392045	3053	16396	411494	267975	2017	385686	524	16305	402515	262128	(5847)	(10364)
2018	397542	3875	16372	417789	253305	2018	389669	876	15953	406498	246459	(6846)	(17210)
2019	422951	3902	17391	444244	250763	2019	414255	1114	16799	432167	243946	(6817)	(24027)
2020	435765	2731	17775	456271	239784	2020	424578	524	17148	442250	232416	(7568)	(31595)
2021	454901	2712	18687	476300	233042	2021	447464	1125	18300	466889	228437	(4605)	(36000)
				4,414,013	3,090,056					4,351,856	3,054,057		

NPV Saving from LMS Plan (k$):	$35,999.61

Note:

(1) Gas Demand Charges are based on PROMOD Fuel Consumption plus 25% to account for Daily Peaking Needs. Includes Reservation and Usage Charges.

Case Study #3

2011 Expansion Plan Cost Evaluation Considering Surplus Energy														
Combined Cycle Expansion Plan Costs (135MW)						LMS100 Expansion Plan Cost (25MW)								
Year	Total Production Cost (k$)	Surplus Energy Costs(k$)	[1]Gas Demand Charges (K$)	Net Cost(k$)	Present Value (k$)	Year	Total Production Cost (k$)	Surplus Energy Costs(k$)	[1]Gas Demand Charges (K$)	Net Cost(k$)	Present Value (k$)	Present Value Cost Difference (k$)	Present Value Cumulative Difference (k$)
2011	316326	16412	12612	345350	345350	2011	316326	16412	12612	345350	345350	0	0
2012	332439	15189	12584	360212	335362	2012	332439	15189	12584	360212	335362	0	0
2013	350703	12533	13532	376768	326576	2013	350703	12533	13532	376768	326576	0	0
2014	366069	8166	14290	388525	313534	2014	366069	8166	14290	388525	313534	0	0
2015	383996	8979	15632	408607	306992	2015	382925	8949	15637	407511	306168	(824)	(824)
2016	392615	9250	16151	418016	292395	2016	378868	2895	15355	397118	277777	(14618)	(15442)
2017	406471	12877	17560	436907	284525	2017	387676	2401	16491	406569	264768	(19757)	(35199)
2018	422006	22427	18362	461795	180592	2018	397741	6711	16642	421094	255309	(25283)	(60482)
2019	453100	25504	19709	498313	281284	2019	425249	8366	17657	451272	254730	(26555)	(87056)
2020	466234	23057	20034	509324	267665	2020	442408	11637	18486	472531	248329	(19336)	(106371)
2021	481649	19578	20640	521867	255336	2021	466332	14630	19678	500639	244950	(10386)	(116758)
				4,726,686	3,289,612					4,527,589	3,172,854		

NPV Saving from LMS Plan (k$):	$116,757.64

Note:

[1] Gas Demand Charges are based on FRCMCD Fuel Consumption plus 25% to account for Daily Peaking Needs. Includes Reservation and Usage Charges.

Case Study #4

2011 Expansion Plan Cost Evaluation Considering Surplus Energy														
Combined Cycle Expansion Plan Costs (135MW)						LMS100 Expansion Plan Cost (40MW)								
Year	Total Production Cost (k$)	Surplus Energy Costs(k$)	[1]Gas Demand Charges (K$)	Net Cost(k$)	Present Value (k$)	Year	Total Production Cost (k$)	Surplus Energy Costs(k$)	[1]Gas Demand Charges (K$)	Net Cost(k$)	Present Value (k$)	Present Value Cost Difference (k$)	Present Value Cumulative Difference (k$)
2011	316326	16412	12612	345350	345350	2011	316326	16412	12612	345350	345350	0	0
2012	332439	15189	12584	360212	335362	2012	332439	15189	12584	360212	335362	0	0
2013	350670	12531	13529	376730	326543	2013	350670	12531	13529	376730	326543	0	0
2014	367907	8182	14430	390520	315144	2014	367907	8182	14430	390520	315144	0	0
2015	384475	8982	15664	409122	307378	2015	383417	8953	15670	408039	306565	(815)	(815)
2016	392148	9242	16109	417499	292033	2016	379959	2900	15445	398304	278607	(13427)	(14240)
2017	406505	12875	17563	436943	284548	2017	387878	2400	16506	406783	264908	(19641)	(33880)
2018	421277	22408	18303	461987	280103	2018	396832	6702	16565	420098	254705	(25597)	(59278)
2019	453030	25500	19703	498233	281239	2019	425044	8361	17640	451044	254602	(26637)	(85914)
2020	466204	23054	20031	509289	267647	2020	441716	11624	18432	471772	247930	(19716)	(105631)
2021	481637	19576	20639	521853	255329	2021	467206	14637	19739	501582	245411	(9918)	(115549)
				4,727,738	3,290,677					4,530,435	3,175,128		

NPV Saving from LMS Plan (k$):	$115,548.82

Note:

(1) Gas Demand Charges are based on PROMOD Fuel Consumption plus 25% to account for Daily Peaking Needs. Includes Reservation and Usage Charges.

Appendix F

Appendix
F.

SOURCE:
EL PASO ELECTRIC COMPANY

NATURAL GAS ANALYSIS REPORT

Atlantic
Analytical
Laboratory

Natural Gas Analysis Report

El Paso Electric
100 North Stanton
El Paso, TX 79901
Phone: (915)543-4166 (Fax: (915)543-5802)
Attn: Luis Perez
Email: lperez1@epelectric.com

AAL Number: 17707-1
Received On: 24 Jan 11
Report Date: 01 Feb 11
PO Number:

Sample ID.: Natural Gas; Rio Grande Station
Sample ID.: 1 of 4 Samples rec'd in a 300 cc Cyl # 316

Sample Date: 19 Jan 11

Composition (Normalized, % v/v)

Non-Hydrocarbon Gases	Result	DL
Hydrogen:	nd	0.05
Nitrogen:	1.55	0.01
Oxygen:	nd	0.01
Carbon Monoxide:	nd	0.05
Carbon Dioxide:	0.47	0.05
Water Vapor:	--	0.001

Hydrocarbons	Result	DL
Methane:	95.12	0.001
Ethylene:	nd	0.001
Ethane:	2.58	0.001
Propylene:	nd	0.001
Propane:	0.176	0.001
Isobutane:	0.027	0.001
n-Butane:	0.044	0.001
Butenes:	nd	0.001
Isopentane:	0.013	0.001
n-Pentane:	0.011	0.001
Pentenes:	nd	0.001
Hexanes +:	0.021	0.001

	ppm v/v	DL	ppm w/w	DL	Grains/100ft^3	DL
Total Sulfur (as H_2S):	1.6	0.5	3.4	1.0	0.10	0.03
H_2S:	0.14	0.05	0.3	0.1	0.009	0.003

Comments: Total Sulfur determined by ASTM D5504

ISO/IEC 17025:2005 ACCREDITED
PJLA Testing
Accreditation # 59415

Atlantic Analytical Laboratory, LLC
291 Rte 22 East • Salem Industrial Park – Building # 4 • Whitehouse, NJ 08888
Phone (908) 534-5600 • Fax (908) 534-2017 • www.AtlanticAnalytical.com

El Paso Electric AAL Number: 17707-1

Elemental Composition (Normalized, % w/w)

Element		Result
Carbon Content (% C, w/w):	--	72.8
Hydrogen Content (% H, w/w):	--	23.7
Oxygen Content (% O, w/w):	--	0.89
Nitrogen Content (% N, w/w):	--	2.58

Heat of Combustion & Physical Properties (by ASTM D 3588-91)

I. @ ASTM Base Conditions: 14.696 psia, 60°F, dry gas format		Result
Net Heat of Combustion	(Lower Heating Value, Btu/ft^3):	914
Gross Heat of Combustion	(Higher Heating Value, Btu/ft^3):	1,015
Gross Heat of Combustion	(Water Saturated Gas Format, Btu/ft^3):	997
Net Heat of Combustion	(Lower Heating Value, Btu/lb):	20,628
Gross Heat of Combustion	(Higher Heating Value, Btu/lb):	22,890
Density (lb/ft^3):		0.0443
Specific Gravity (vs dry/normal air):		0.5811
Compressibility Factor (z):		0.9979

II. @ ASME Base Conditions: 14.73 psia, 60°F, dry gas format		Result
Net Heat of Combustion	(Lower Heating Value, Btu/ft^3):	916
Gross Heat of Combustion	(Higher Heating Value, Btu/ft^3):	1,017
Gross Heat of Combustion	(Water Saturated Gas Format, Btu/ft^3):	1,000
Net Heat of Combustion	(Lower Heating Value, Btu/lb):	20,628
Gross Heat of Combustion	(Higher Heating Value, Btu/lb):	22,890

DL = instrumental detection limit for the reported analyte. nd = indicates the concentration is less than the accompanying report detection limit. -- = test not performed. % = parts per hundred (percent). ppm = parts per million. w/w = weight analyte/weight sample format. v/v = volume analyte/volume sample format (equivalent to mole fraction for normalized, ideal gas mixtures). Conversions: 0.0001% = 1 ppm.

Comments:

Reviewed By,

Ralph J. Ciotti, Laboratory Manager

Attachments: None
Addendum: Chromatograms and notebook data on-file

Atlantic Analytical Laboratory, LLC
291 Rte 22 East • Salem Industrial Park – Building # 4 • Whitehouse, NJ 08888
Phone (908) 534-5600 • Fax (908) 534-2017 • www.AtlanticAnalytical.com

Atlantic Analytical Laboratory

Natural Gas Analysis Report

El Paso Electric
100 North Stanton
El Paso, TX 79901
Phone: (915)543-4166 (Fax: (915)543-5802)
Attn: Luis Perez
Email: lperez1@epelectric.com

AAL Number: 17707-2
Received On: 24 Jan 11
Report Date: 01 Feb 11
PO Number:

Sample ID.: Natural Gas; Newman U4
Sample ID.: 2 of 4 Samples rec'd in a 300 cc Cyl # 303

Sample Date: 19 Jan 11

Composition (Normalized, % v/v)

Non-Hydrocarbon Gases	Result	DL
Hydrogen:	nd	0.05
Nitrogen:	*33.4	0.01
Oxygen:	1.18	0.01
Carbon Monoxide:	nd	0.05
Carbon Dioxide:	0.34	0.05
Water Vapor:	--	0.001

Hydrocarbons	Result	DL
Methane:	63.11	0.001
Ethylene:	nd	0.001
Ethane:	1.72	0.001
Propylene:	nd	0.001
Propane:	0.120	0.001
Isobutane:	0.018	0.001
n-Butane:	0.030	0.001
Butenes:	nd	0.001
Isopentane:	0.009	0.001
n-Pentane:	0.008	0.001
Pentenes:	nd	0.001
Hexanes +:	0.017	0.001

	ppm v/v	DL	ppm w/w	DL	Grains/100ft^3	DL
Total Sulfur (as H_2S):	0.5	0.5	1.1	1.0	0.03	0.03
H_2S:	nd	0.05	nd	0.1	nd	0.003

Comments: Total Sulfur determined by ASTM D5504

Atlantic Analytical Laboratory, LLC
291 Rte 22 East • Salem Industrial Park – Building # 4 • Whitehouse, NJ 08888
Phone (908) 534-5600 • Fax (908) 534-2017 • www.AtlanticAnalytical.com

ISO/IEC 17025:2005 ACCREDITED
PJLA Testing
Accreditation # 59416

El Paso Electric AAL Number: 17707-2

Elemental Composition (Normalized, % w/w)

Element		Result
Carbon Content (% C, w/w):	--	39.4
Hydrogen Content (% H, w/w):	--	12.8
Oxygen Content (% O, w/w):	--	2.36
Nitrogen Content (% N, w/w):	--	45.4

Heat of Combustion & Physical Properties (by ASTM D 3588-91)

I. @ ASTM Base Conditions; 14.696 psia, 60°F, dry gas format		Result
Net Heat of Combustion	(Lower Heating Value, Btu/ft^3):	607
Gross Heat of Combustion	(Higher Heating Value, Btu/ft^3):	674
Gross Heat of Combustion	(Water Saturated Gas Format, Btu/ft^3):	662
Net Heat of Combustion	(Lower Heating Value, Btu/lb):	11,162
Gross Heat of Combustion	(Higher Heating Value, Btu/lb):	12,386
Density (lb/ft^3):		0.0544
Specific Gravity (vs dry/normal air):		0.7129
Compressibility Factor (z):		0.9987

II. @ ASME Base Conditions; 14.73 psia, 60°F, dry gas format		Result
Net Heat of Combustion	(Lower Heating Value, Btu/ft^3):	609
Gross Heat of Combustion	(Higher Heating Value, Btu/ft^3):	675
Gross Heat of Combustion	(Water Saturated Gas Format, Btu/ft^3):	664
Net Heat of Combustion	(Lower Heating Value, Btu/lb):	11,162
Gross Heat of Combustion	(Higher Heating Value, Btu/lb):	12,386

DL = instrumental detection limit for the reported analyte. nd = indicates the concentration is less than the accompanying report detection limit. -- = test not performed. % = parts per hundred (percent). ppm = parts per million. w/w = weight analyte/weight sample format. v/v = volume analyte/volume sample format (equivalent to mole fraction for normalized, ideal gas mixtures). Conversions: 0.0001% = 1 ppm.

Comments: * Large amount of nitrogen in sample, cylinder received at low pressure. Possible sampling error or cylinder leak during shipment.

Reviewed By,

Ralph J. Ciotti, Laboratory Manager

Attachments: None
Addendum: Chromatograms and notebook data on-file

Atlantic
Analytical
Laboratory

Natural Gas Analysis Report

El Paso Electric
100 North Stanton
El Paso, TX 79901
Phone: (915)543-4166 (Fax: (915)543-5802)
Attn: Luis Perez
Email: lperez1@epelectric.com

AAL Number: 17707-3
Received On: 24 Jan 11
Report Date: 01 Feb 11
PO Number:

Sample ID.: Natural Gas; Copper
Sample ID.: 3 of 4 Samples rec'd in a 300 cc Cyl # 305

Sample Date: 19 Jan 11

Composition (Normalized, % v/v)

Non-Hydrocarbon Gases	Result	DL
Hydrogen:	nd	0.05
Nitrogen:	1.37	0.01
Oxygen:	nd	0.01
Carbon Monoxide:	nd	0.05
Carbon Dioxide:	0.42	0.05
Water Vapor:	---	0.001

Hydrocarbons	Result	DL
Methane:	95.80	0.001
Ethylene:	nd	0.001
Ethane:	2.20	0.001
Propylene:	nd	0.001
Propane:	0.134	0.001
Isobutane:	0.020	0.001
n-Butane:	0.027	0.001
Butenes:	nd	0.001
Isopentane:	0.009	0.001
n-Pentane:	0.007	0.001
Pentenes:	nd	0.001
Hexanes +:	0.020	0.001

	ppm v/v	DL	ppm w/w	DL	Grains/100ft^3	DL
Total Sulfur (as H_2S):	1.8	0.5	1.1	1.0	0.03	0.03
H_2S:	nd	0.05	nd	0.1	nd	0.003

Comments: Total Sulfur determined by ASTM D5504

El Paso Electric AAL Number: 17707-3

Elemental Composition (Normalized, % w/w)

Element		Result
Carbon Content (% C, w/w):	---	73.0
Hydrogen Content (% H, w/w):	---	23.9
Oxygen Content (% O, w/w):	---	0.80
Nitrogen Content (% N, w/w):	---	2.29

Heat of Combustion & Physical Properties (by ASTM D 3588-91)

I. @ ASTM Base Conditions: 14.696 psia, 60°F, dry gas format		Result
Net Heat of Combustion	(Lower Heating Value, Btu/ft^3):	912
Gross Heat of Combustion	(Higher Heating Value, Btu/ft^3):	1,013
Gross Heat of Combustion	(Water Saturated Gas Format, Btu/ft^3):	995
Net Heat of Combustion	(Lower Heating Value, Btu/lb):	20,727
Gross Heat of Combustion	(Higher Heating Value, Btu/lb):	23,003
Density (lb/ft^3):		0.0440
Specific Gravity (vs dry/normal air):		0.5771
Compressibility Factor (z):		0.9979

II. @ ASME Base Conditions: 14.73 psia, 60°F, dry gas format		Result
Net Heat of Combustion	(Lower Heating Value, Btu/ft^3):	915
Gross Heat of Combustion	(Higher Heating Value, Btu/ft^3):	1,015
Gross Heat of Combustion	(Water Saturated Gas Format, Btu/ft^3):	998
Net Heat of Combustion	(Lower Heating Value, Btu/lb):	20,727
Gross Heat of Combustion	(Higher Heating Value, Btu/lb):	23,003

DL = instrumental detection limit for the reported analyte. nd = indicates the concentration is less than the accompanying report detection limit. -- = test not performed. % = parts per hundred (percent). ppm = parts per million. w/w = weight analyte/weight sample format. v/v = volume analyte/volume sample format (equivalent to mole fraction for normalized, ideal gas mixtures). Conversions: 0.0001% = 1 ppm.

Comments:

Reviewed By,

Ralph J. Ciotti, Laboratory Manager

Attachments: None
Addendum: Chromatograms and notebook data on-file

Atlantic
Analytical
Laboratory

Natural Gas Analysis Report

El Paso Electric
100 North Stanton
El Paso, TX 79901
Phone: (915)543-4166 (Fax: (915)543-5802)
Attn: Luis Perez
Email: lperez1@epelectric.com

AAL Number: 17707-4
Received On: 24 Jan 11
Report Date: 01 Feb 11
PO Number:

Sample ID.: Natural Gas; Newman U3
Sample ID.: 4 of 4 Samples rec'd in a 300 cc Cyl # 300

Sample Date: 19 Jan 11

Composition (Normalized, % v/v)

Non-Hydrocarbon Gases	Result	DL
Hydrogen:	nd	0.05
Nitrogen:	2.49	0.01
Oxygen:	nd	0.01
Carbon Monoxide:	nd	0.05
Carbon Dioxide:	0.35	0.05
Water Vapor:	--	0.001

Hydrocarbons	Result	DL
Methane:	94.21	0.001
Ethylene:	nd	0.001
Ethane:	2.68	0.001
Propylene:	nd	0.001
Propane:	0.167	0.001
Isobutane:	0.024	0.001
n-Butane:	0.039	0.001
Butenes:	nd	0.001
Isopentane:	0.011	0.001
n-Pentane:	0.010	0.001
Pentenes:	nd	0.001
Hexanes +:	0.019	0.001

	ppm v/v	DL	ppm w/w	DL	Grains/100ft^3	DL
Total Sulfur (as H_2S):	2.1	0.5	4.5	1.0	0.13	0.03
H_2S:	nd	0.05	nd	0.1	nd	0.003

Comments: Total Sulfur determined by ASTM D5504

ISO/IEC 17025:2005 ACCREDITED
PJLA Testing
Accreditation # 59416

El Paso Electric AAL Number: 17707-4

Elemental Composition (Normalized, % w/w)

Element		Result
Carbon Content (% C, w/w):	--	71.8
Hydrogen Content (% H, w/w):	--	23.4
Oxygen Content (% O, w/w):	--	0.67
Nitrogen Content (% N, w/w):	--	4.13

Heat of Combustion & Physical Properties (by ASTM D 3588-91)

I. @ ASTM Base Conditions; 14.696 psia, 60°F, dry gas format		Result
Net Heat of Combustion	(Lower Heating Value, Btu/ft^3):	907
Gross Heat of Combustion	(Higher Heating Value, Btu/ft^3):	1,007
Gross Heat of Combustion	(Water Saturated Gas Format, Btu/ft^3):	989
Net Heat of Combustion	(Lower Heating Value, Btu/lb):	20,361
Gross Heat of Combustion	(Higher Heating Value, Btu/lb):	22,593
Density (lb/ft^3):		0.0446
Specific Gravity (vs dry/normal air):		0.5840
Compressibility Factor (z):		0.9979

II. @ ASME Base Conditions; 14.73 psia, 60°F, dry gas format		Result
Net Heat of Combustion	(Lower Heating Value, Btu/ft^3):	909
Gross Heat of Combustion	(Higher Heating Value, Btu/ft^3):	1,009
Gross Heat of Combustion	(Water Saturated Gas Format, Btu/ft^3):	992
Net Heat of Combustion	(Lower Heating Value, Btu/lb):	20,361
Gross Heat of Combustion	(Higher Heating Value, Btu/lb):	22,593

DL = instrumental detection limit for the reported analyte. nd = indicates the concentration is less than the accompanying report detection limit. -- = test not performed. % = parts per hundred (percent). ppm = parts per million. w/w = weight analyte/weight sample format. v/v = volume analyte/volume sample format (equivalent to mole fraction for normalized, ideal gas mixtures). Conversions: 0.0001% = 1 ppm.

Comments:

Reviewed By,

Ralph J. Ciotti, Laboratory Manager

Attachments: None
Addendum: Chromatograms and notebook data on-file

ISO/IEC 17025:2005 ACCREDITED
PJLA Testing
Accreditation # 69415

Atlantic Analytical Laboratory, LLC
291 Rte 22 East • Salem Industrial Park – Building # 4 • Whitehouse, NJ 08888
Phone (908) 534-5600 • Fax (908) 534-2017 • www.AtlanticAnalytical.com

AAL

ATLANTIC ANALYTICAL LABORATORY

Natural Gas Analysis Report

El Paso Electric
100 North Stanton
El Paso, TX 79901
Phone: (915) 543-4166
Attn: Mr. Luis Perez
Email: Lperez1@epelectric.com and LValenzu@epelectric.com

AAL Number: 9388-2
Received On: 14 Jan 09
Report Date: 29 Jan 09
PO Number: Pending

Sample ID.: Nat Gas Rio Grande
Sample ID.: Received in 1 - 300 cc cylinder # 318
Comments: 1 sample received.

Sample Date: 06 Jan 09

Composition (Normalized, % v/v)

Non-Hydrocarbon Gases	Result	DL
Hydrogen:	--	0.05
Nitrogen:	2.10	0.01
Oxygen:	--	0.01
Argon:	--	0.05
Carbon Monoxide:	--	0.05
Carbon Dioxide:	0.52	0.05
Water:	0.014	0.001

Hydrocarbons	Result	DL
Methane:	93.25	0.001
Ethylene:	nd	0.001
Ethane:	3.37	0.001
Propylene:	nd	0.001
Propane:	0.493	0.001
Isobutane:	0.070	0.001
n-Butane:	0.095	0.001
Butenes:	nd	0.001
Isopentane:	0.026	0.001
n-Pentane:	0.021	0.001
Pentenes:	nd	0.001
Hexanes +:	0.058	0.001

	ppm v/v	DL	ppm w/w	DL	Grains/100ft^3	DL
Total Sulfur (as H_2S):	nd	0.5	nd	1.0	nd	0.03
H_2S:	nd	0.05	nd	0.1	nd	0.003

Comments: Total Sulfur determined by ASTM D5504

Ninyo & Moore

AAL Number: 9388-2

Elemental Composition (Normalized, % w/w)

Element		Result
Carbon Content (% C, w/w):	------------------------------------	72.3
Hydrogen Content (% H, w/w):	------------------------------------	23.3
Oxygen Content (% O, w/w):	------------------------------------	0.97
Nitrogen Content (% N, w/w):	------------------------------------	3.42

Heat of Combustion & Physical Properties (by ASTM D 3588-91)

I. @ ASTM Base Conditions: 14.696 psia, 60°F, dry gas format		Result
Net Heat of Combustion	(Lower Heating Value, Btu/ft^3):	923
Gross Heat of Combustion	(Higher Heating Value, Btu/ft^3):	1,024
Gross Heat of Combustion	(Water Saturated Gas Format, Btu/ft^3):	1,006
Net Heat of Combustion	(Lower Heating Value, Btu/lb):	20,386
Gross Heat of Combustion	(Higher Heating Value, Btu/lb):	22,609
Density (lb/ft^3):		0.0453
Specific Gravity (vs. dry/normal air):		0.5935
Compressibility Factor (z):		0.9978

II. @ ASME Base Conditions: 14.73 psia, 60°F, dry gas format		Result
Net Heat of Combustion	(Lower Heating Value, Btu/ft^3):	925
Gross Heat of Combustion	(Higher Heating Value, Btu/ft^3):	1,026
Gross Heat of Combustion	(Water Saturated Gas Format, Btu/ft^3):	1,008
Net Heat of Combustion	(Lower Heating Value, Btu/lb):	20,386
Gross Heat of Combustion	(Higher Heating Value, Btu/lb):	22,609

DL = instrumental detection limit for the reported analyte. nd = indicates the concentration is less than the accompanying report detection limit. -- = test not performed. % = parts per hundred (percent). ppm = parts per million. w/w = weight analyte/weight sample format. v/v = volume analyte/volume sample format (equivalent to mole fraction for normalized, ideal gas mixtures). Conversions: 0.0001% = 1 ppm.

Comments:

Reviewed By,

Ralph J. Ciotti, Laboratory Manager

Attachments:
-none

Addendum:
Chromatograms on-file
Notebook data on-file

ISO/IEC 17025:2005 ACCREDITED
PJLA

ATLANTIC ANALYTICAL LABORATORY, LLC.
P.O. BOX 220 • SALEM INDUSTRIAL PARK – BUILDING #4 • WHITEHOUSE, NJ 08888
PHONE 908-534-5600 • FAX: 908-534-2017
WWW.ATLANTICANALYTICAL.COM

ATLANTIC ANALYTICAL LABORATORY

ATLANTIC ANALYTICAL LABORATORY

Natural Gas Analysis Report

El Paso Electric Comp.
123 West Mills
El Paso, TX 79901
915-543-5993 (Fax 915-543-5802)
Attn: Environmental Affairs
E-Mail: Lperez1@epelectric.com
LValenzu@epelectric.com

AAL Number: 5705-1
Received On: 11 Jan 08
Report Date: 17 Jan 08
PO Number:

Sample ID.: Nat Gas Rio Grande
Sample ID.: Received in 1 - 150 cc cylinder # 304
Comments: 1 sample received.

Sample Date: 01/08/08

Composition (Normalized, % v/v)

Non-Hydrocarbon Gases	Result	DL
Hydrogen:	--	0.05
Nitrogen:	2.06	0.01
Oxygen:	--	0.01
Argon:	--	0.05
Carbon Monoxide:	--	0.05
Carbon Dioxide:	0.32	0.05
Water:	nd	0.001

Hydrocarbons	Result	DL
Methane:	94.61	0.001
Ethylene:	nd	0.001
Ethane:	2.55	0.001
Propylene:	nd	0.001
Propane:	0.289	0.001
Isobutane:	0.044	0.001
n-Butane:	0.059	0.001
Butenes:	nd	0.001
Isopentane:	0.018	0.001
n-Pentane:	0.015	0.001
Pentenes:	nd	0.001
Hexanes +:	0.040	0.001

	ppm v/v	DL	ppm w/w	DL	Grains/100ft^3	DL
Total Sulfur (as H_2S):	2.1	0.5	4.4	1.0	0.13	0.03

Comments: Total Sulfur determined by ASTM D5504

El Paso Electric Comp. AAL Number: 5705-1

Elemental Composition (Normalized, % w/w)

Element		Result
Carbon Content (% C, w/w):	------------------------------------	72.4
Hydrogen Content (% H, w/w):	------------------------------------	23.6
Oxygen Content (% O, w/w):	------------------------------------	0.60
Nitrogen Content (% N, w/w):	------------------------------------	3.41

Heat of Combustion & Physical Properties (by ASTM D 3588-91)

I. @ ASTM Base Conditions: 14.696 psia, 60°F, dry gas format		Result
Net Heat of Combustion	(Lower Heating Value, Btu/ft^3):	914
Gross Heat of Combustion	(Higher Heating Value, Btu/ft^3):	1,015
Gross Heat of Combustion	(Water Saturated Gas Format, Btu/ft^3):	997
Net Heat of Combustion	(Lower Heating Value, Btu/lb):	20,526
Gross Heat of Combustion	(Higher Heating Value, Btu/lb):	22,774
Density (lb/ft^3):		0.0446
Specific Gravity (vs. dry/normal air):		0.5838
Compressibility Factor (z):		0.9979

II. @ ASME Base Conditions: 14.73 psia, 60°F, dry gas format		Result
Net Heat of Combustion	(Lower Heating Value, Btu/ft^3):	916
Gross Heat of Combustion	(Higher Heating Value, Btu/ft^3):	1,017
Gross Heat of Combustion	(Water Saturated Gas Format, Btu/ft^3):	999
Net Heat of Combustion	(Lower Heating Value, Btu/lb):	20,526
Gross Heat of Combustion	(Higher Heating Value, Btu/lb):	22,774

DL = instrumental detection limit for the reported analyte. **nd** = indicates the concentration is less than the accompanying report detection limit. **--** = test not performed. **%** = parts per hundred (percent). **ppm** = parts per million. **w/w** = weight analyte/weight sample format. **v/v** = volume analyte/volume sample format (equivalent to mole fraction for normalized, ideal gas mixtures). Conversions: 0.0001% = 1 ppm.

Comments:

Reviewed By,

Ralph J. Ciotti, Laboratory Manager

Attachments:
-none

Addendum:
Chromatograms on-file
Notebook data on-file

ATLANTIC ANALYTICAL LABORATORY
P.O. BOX 220 * SALEM INDUSTRIAL PARK • BUILDING #4 • WHITEHOUSE, N. J. 08888
PHONE 908-534-5600 * FAX 908-534-2017

AAL
ATLANTIC ANALYTICAL LABORATORY

Appendix G

Appendix
G.

SOURCE:
EL PASO ELECTRIC COMPANY

GHG EMISSION CALCULATIONS
FOR
COMBUSTION TURBINES

GHG EMISSION CALCULATIONS FOR COMBUSTION TURBINES

Combustion Sources of GHG Emissions

Parameter	Units	Fire Water Pump	Combustion Turbine 1	Combustion Turbine 2	Combustion Turbine 3	Combustion Turbine 4
EPN	-	FWP-1	GT-1	GT-2	GT-3	GT-4
Rated Capacity [1]	MMBtu/hr	2.03	858.55	858.55	858.55	858.55
Hours of Operation per Year [5]	hrs/yr	52	5,000	5,000	5,000	5,000
Natural Gas Potential Throughput [2]	scf/yr	--	4,233,481,262	4,233,481,262	4,233,481,262	4,233,481,262
Diesel Potential Throughput [4]	gal/yr	770	--	--	--	--
Natural Gas High Heat Value (HHV) [3]	MMBtu/scf	--	1.014E-03	1.014E-03	1.014E-03	1.014E-03
No.2 Fuel Oil High Heat Value (HHV) [3]	MMBtu/gal	0.138	--	--	--	--

[1] Estimated Maximum Heat Input (MMBtu/hr) = Fuel Heat Value (Btu/gal) x Fuel Usage (gal/hr) x (1 MMBtu/1,000,000 Btu)

Estimated Maximum Heat Input = 138,000 (Btu/gal) x 14.8 (gal/hr) x (1 MMBtu/ 1,000,000 Btu) = 2.03 MMBtu/ hr

[2] Natural gas throughput is based on heat capacity of the unit, hours of operation and the fuel's high heating value

[3] High heating value for No.2 Fuel Oil obtained from 40 CFR Part 98, Subpart C, Table C-1. 2 Natural gas heating values obtained from the natural gas analysis provided by Mr. Robert Daniels (El Paso Electric Company) to Ms. Christine Chambers (Trinity Consultants) via email on February 27, 2012.

[4] Diesel throughput is based on From Page 5 of the Spec sheet, located under References/Fire Pump Engine Spec Sheet folder ("John Deere JW6H.pdf"). 14.8 gal/hr

[5] Annual hours of operation information provided by Mr. Robert Daniels (El Paso Electric Company) to Ms. Latha Kambham (Trinity Consultants) via email on March 26, 2012. This includes hours for MSS activities.

GHG Emission Factors for Diesel Engine

Pollutant	Emission Factor	Emission Factor Units
CO_2 [1]	73.960	kg CO_2/MMBtu
CH_4 [2]	0.003	kg CH_4/MMBtu
N_2O [2]	0.0006	kg N_2O/MMBtu

[1] Emission factors from 40 CFR Part 98, Subpart C, Table C-1 for Distillate Fuel Oil No. 2.

[2] Emission factors Per 40 CFR Part 98, Subpart C, Table C-2 for petroleum fuel.

GHG Emission Factors for Natural Gas

Pollutant	Emission Factor	Emission Factor Units
CO_2 [1]	53.020	kg CO_2/MMBtu
CH_4 [2]	0.001	kg CH_4/MMBtu
N_2O [2]	0.0001	kg N_2O/MMBtu

[1] Emission factors from 40 CFR Part 98, Subpart C, Table C-1 for Natural Gas.

[2] Emission factors Per 40 CFR Part 98, Subpart C, Table C-2 for Natural Gas.

Turbine Capacities

Parameter[1]	Value
Rated KW	99991
MMBtu/Hr (HHV)	858.55

[1] Data obtained from the GE Performance Data provided by Mr. Rober Daniels (EPEC) via email on April, 10, 2012. Data represents the maximum values.

GHG Potential Emission Calculations

EPN	Description	Fuel Type	Tier Used	Annual Emissions [1, 2, 4] (tons/yr)				Hourly Emissions (lb/hr)			
				CO_2	CH_4	N_2O	CO_2e [5]	CO_2	CH_4	N_2O	CO_2e [5]
FWP-1	Fire Water Pump	No.2 Fuel Oil	Tier I	9	3.51E-04	7.02E-05	9	333	0.01	0.00	334
GT-1	Combustion Turbine 1	Natural Gas	Tier I	250,885	4.73	0.47	251131	100,354	1.89	0.19	100453
GT-2	Combustion Turbine 2	Natural Gas	Tier I	250,885	4.73	0.47	251131	100,354	1.89	0.19	100453
GT-3	Combustion Turbine 3	Natural Gas	Tier I	250,885	4.73	0.47	251131	100,354	1.89	0.19	100453
GT-4	Combustion Turbine 4	Natural Gas	Tier I	250,885	4.73	0.47	251131	100,354	1.89	0.19	100453
			Total	1,003,549.66	18.93	1.89	1,004,534	401,749.42	7.58	0.76	402,144
			Total CO_2e Emissions [4]	-	-	-	1,004,534	-	-	-	402,144

[1] CO_2 emissions from No.2 Fuel Oil and Natural Gas combustion calculated per Equation C-1 and Tier I methodology provided in 40 CFR Part 98, Subpart C.

[2] CH_4 and N_2O emissions No.2 Fuel Oil and Natural Gas combustion calculated per Equation C-8 provided in 40 CFR Part 98, Subpart C.

[3] tons to lb 2000 lb/ton

[4] metric ton to short ton 1.1023 short ton/metric ton

[5] Per 40 CFR 98 - Mandatory Greenhouse Gas Reporting, Subpart A, Table A-1. Total CO_2e emissions are calculated based on the following Global Warming Potentials.

CO_2	1
CH_4	21
N_2O	310

Appendix H

Appendix
H.

SOURCE:
U.S. ENVIRONMENTAL PROTECTION AGENCY

REGION IX

FACT SHEET AND AMBIENT
AIR QUALITY IMPACT REPORT

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

This page left intentionally blank.

PROPOSED PREVENTION OF
SIGNIFICANT DETERIORATION PERMIT

PIO PICO ENERGY CENTER

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

Table of Contents

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

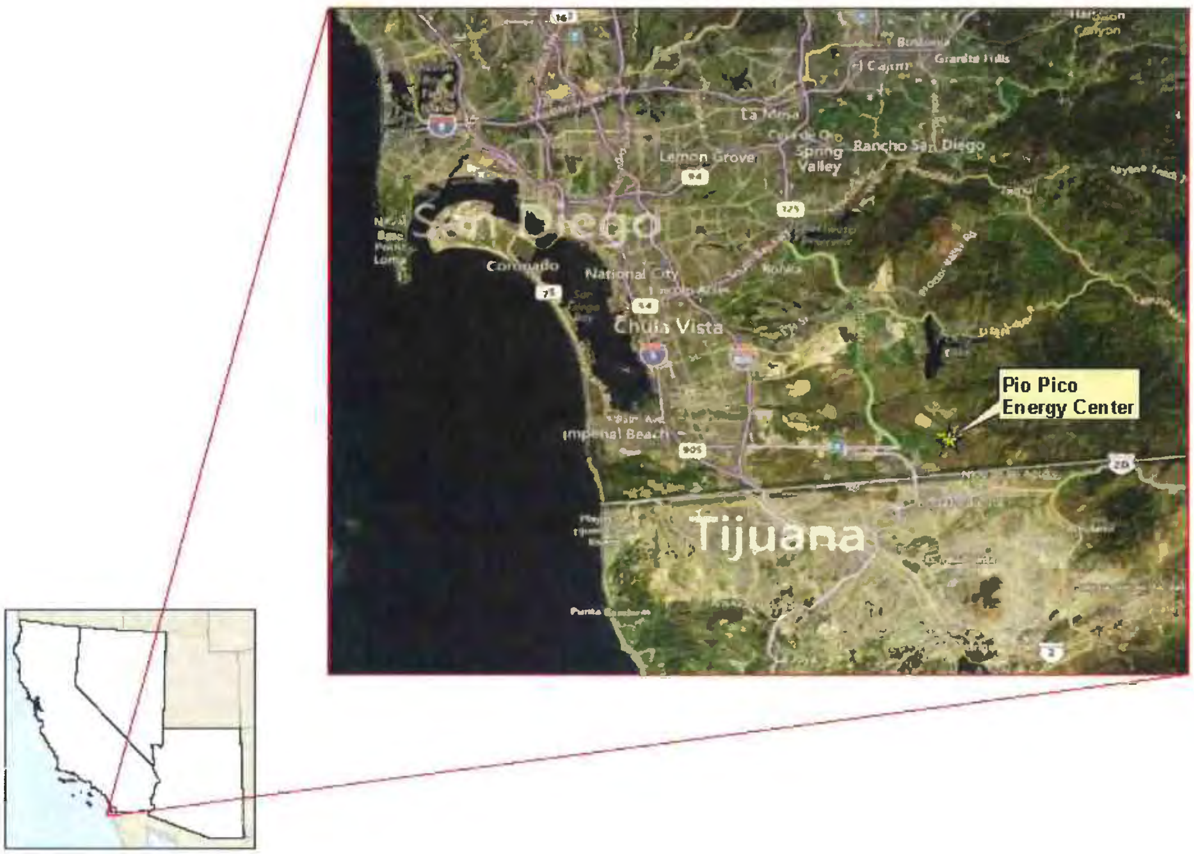
The name and address of the applicant is as follows:

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-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^{TM} system (formerly SCONOx)
- Selective non-catalytic reduction (SNCR)[4]

Step 2 – Eliminate Technically Infeasible Options

With the exception of EMx^{TM}, 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

Step 1 – Identify all control technologies

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.

  Combined-cycle gas turbines 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 $btu_{hhv}/kw\text{-}hr_{gross}$. 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 98^{th} percentile averaged over three years rather than maximum

The NO_2 1-hr value is 98th 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

[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

procedure as a 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/m³	Class I PSD Increment, µg/m³
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 ($\mu g/m^3$)	Modeled Maximum Concentrations ($\mu g/m^3$)	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 $\mu g/m^3$ and 2.6 $\mu g/m^3$, respectively.
[23] The modeled maximum concentrations for the 24-hour secondary PM_{10} standard is 57 $\mu g/m^3$.
[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.

References Cited in the GHG BACT Analysis

Chalmers, H., & Gibbins, J. (2007). Initial evaluation of the impact of post-combustion capture of carbon dioxide on supercritical pulverised coal power plant part load performance. *Fuel*, 86, 2109-2123.

Environmental Protection Agency. (2011, December 9). [Letter to the Honorable Edmund G. Brown, Jr.].

EPRI. (2003). *SF6 and the Environment: Guidelines for Electric Utility Substations* (Report No. 1002067). Retrieved from at DoD Environment, Safety, and Occupational Health Network and Information Exchange website at http://www.denix.osd.mil/cmrmd/upload/EPRI-SF6-Guidelines-for-Utility-Substations.pdf.

Fluor Corporation. (2009). Econamine FG Plus Process. Retrieved from http://www.fluor.com/econamine/Pages/efgprocess.aspx.

General Electric Company. (n.d.[1]). 7FA Heavy Duty Gas Turbine. Retrieved January 21, 2012 from http://www.ge-energy.com/products_and_services/products/gas_turbines_heavy_duty/7fa_heavy_duty_gas_turbine.jsp.

General Electric Company. (n.d.[2]). LMS100 Aeroderivative Gas Turbines. Retrieved May 24, 2012 from http://www.ge-energy.com/products_and_services/products/gas_turbines_aeroderivative/lms100.jsp.

General Electric Company. (n.d.[3]). LMS100. Retrieved from http://www.ecomagination.com/portfolio/lms100-simple-cycle-gas-turbine.

Hill, S. (April 13, 2012). [Letter to Gerardo Rios re: Pio Pico Energy Center PSD Permit Application Response to Supplemental Information Request].

Hurst, P., & Walker, G. (2005). Post-combustion Separation and Capture Baseline Studies for the CCP Industrial Scenarios. In Thomas, D.C., & Benson, S.M. (Eds.), *Carbon Dioxide Capture for Storage in Deep Geologic Formations, Volume 1* (pp. 117-131). Oxford: Elsevier Ltd.

Intergovernmental Panel on Climate Change. (2005). *IPCC Special Report on Carbon Dioxide Capture and Storage*. Prepared by Working Group III of the Intergovernmental Panel on Climate Change [Metz, B., O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.

Kvamsdal, H., Chikukwa, A., Hillestad, M., Zakeri, A., & Einbu, A. (2011). A comparison of different parameter correlation models and the validation of an MEA-based absorber model.

Energy Procedia, 4, 1526-1533.

National Petroleum Council. (2007). Hard Truths: Facing the Hard Truths about Energy. Retrieved from the National Petroleum Council website at http://www.npchardtruthsreport.org/.

National Institute of Standards and Technology. (1997). Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF6 (NIST Technical Note No. 1425). Retrieved from EPA website at http://www.epa.gov/electricpower-sf6/resources/index.html.

Reddy, S., Scherffius, J., Freguia, S., & Roberts, C. (2003, May). *Fluor's Econamine FG Plus^{SM} Technology: An Enhanced Amine-Based CO2 Capture Process*. Paper presented at the Second Annual Conference on Carbon Sequestration, Alexandria, VA.

Rolls Royce. (n.d.). Trent 60. Retrieved June 11, 2012 from http://www.rolls-royce.com/energy/energy_products/gas_turbines/trent_60/.

Siemens AG. (2008). Siemens Gas Turbines over 100 MW. Retrieved June 11, 2012 from http://www.energy.siemens.com.cn/CN/downloadCenter/Documents/E_F_SGT_over_100MW.pdf.

Siemens AG. (2011). SGT-2000E Series. Retrieved June 10, 2012 from http://www.energy.siemens.com/hq/en/power-generation/gas-turbines/sgt6-2000e.htm.

Simmonds, M., Hurst, P., Wilkinson, M.B., Reddy, S., & Khambaty, S., (2003, May). *Amine Based CO2 Capture from Gas Turbines*. Paper presented at the Second Annual Conference on Carbon Sequestration, Alexandria, VA.

U.S. Department of Energy. (2011). *DOE/NETL Advanced Carbon Dioxide Capture R&D Program: Technology Update*. Retrieved from DOE website at http://www.netl.doe.gov/technologies/coalpower/ewr/pubs/CO2Handbook/.

Wartsila Corporation. (2011). Power Plants Product Catalogue, 2nd Edition. Retrieved from http://www.wartsila.com/en/power-plants/smart-power-generation/gas-power-plants.

Wang, M., Lawal, A., Stephenson, P., Sidders, J., & Ramshaw, C. (2011). Post-combustion CO2 capture with chemical absorption: A state-of-the-art review. *Chemical Engineering Research and Design*, 89, 1609-1624.

Wideskog, M. (2011). Introducing the world's largest gas engine. *In Detail* [Wartsila Technical Journal], 1, 14-20.