CH2M HILL
2485 Natomas Park Drive
Suite 600
Sacramento, CA 95833
Tel 916.920.0300
Fax 916.920.8463

CH2MHILL

DOCKET
09-AFC-4
DATE FEB 11 2010
RECD. FEB 11 2010

February 11, 2010

Mr. Joseph Douglas
Project Manager
California Energy Commission
1516 Ninth Street
Sacramento, CA 95814

Subject: Response to the Oakley Generating Station Project (09-AFC-4) Data Request Set 1 (# 1-43)

Dear Mr. Douglas:

On behalf of Contra Costa Generating Station LLC please find attached 13 hard copies and one electronic copy on CD-ROM of the Contra Costa Generating Station LLC's response to Staff Data Request, Set 1 (# 1-43), dated January 19, 2010. Included in this submittal are two hard copies of the CAISO Transition Cluster Group I Phase I Interconnection Study Report in response to Data Request 43. This document has been submitted to the CEC under separate cover and in electronic format because of its large size (>500 pages). Additional copies of the CAISO report are available upon request.

If you have any questions, please contact me at (916) 286-0278.

Sincerely,

CH2M HILL

Doug Davy
AFC Project Manager

Attachment

cc: POS List
Project File

APPLICATION FOR CERTIFICATION

Response to Data Requests 1–43

Oakley Generating Station

09-AFC-4

February 2010

Submitted by

RADBACK ENERGY

Submitted to

California Energy Commission

With Technical Assistance by

CH2MHILL

Supplemental Filing

Response to CEC Staff Data Requests 1 through 43

In support of the

Application for Certification

for

Oakley Generating Station Project

Oakley, California

(09-AFC-4)

Submitted to the:

California Energy Commission

Submitted by:

RADBACK ENERGY

With Technical Assistance by:

CH2MHILL

Sacramento, California

February 2010

Contents

Tables

Figures

Attachments

Introduction

Attached are Contra Costa Generating Station, LLC's responses to California Energy Commission (CEC) Staff data requests numbers 1 through 43 for the Oakley Generating Station (OGS) project (09-AFC-04). The CEC Staff served the data requests on January 19, 2010, as part of the discovery process for the OGS project.

The responses are grouped by individual discipline or topic area. Within each discipline area, the responses are presented in the same order as CEC Staff presented them and are keyed to the Data Request numbers (1 through 43). New or revised graphics or tables are numbered in reference to the Data Request number. For example, the first table used in response to Data Request 15 would be numbered Table DR15-1. The first figure used in response to Data Request 28 would be Figure DR28-1, and so on.

Additional tables, figures, or documents submitted in response to a data request (supporting data, stand-alone documents such as plans, folding graphics, etc.) are found at the end of a discipline-specific section and are not sequentially page-numbered consistently with the remainder of the document, though they may have their own internal page numbering system.

Air Quality (1-33)

Correspondence Regarding Project Permit Applications

1. *Please provide copies of all substantive District correspondence regarding the Oakley Generating Station (OGS) Project permit application, including e-mails, within one week of submittal or receipt. This request is in effect until the final Commission Decision has been recorded.*

Response: OGS will supply all substantive Bay Area Air Quality Management District (BAAQMD) correspondence to the CEC within one week of submittal.

It should be noted that the Application for Certification (AFC) is currently being revised to reflect changes to operational emissions during base load, startup/shutdown, and commissioning activities. It is expected that the revised air section will be finalized within the next two weeks, with copies provided to the BAAQMD and the CEC.

Supplemental Air Quality and Emissions Data

2. *Please provide the supplemental data that was submitted to the District between July 6, 2009 and September 9, 2009 for Energy Commission staff review and analysis.*

Response: The supplemental data is provided as an attachment to these data responses (Attachment DR2-1). It should be noted that this information has been updated, parts of which are reflected in this data response.

Revisions to the Original AFC

3. *Please describe where revisions were made to the original Application for Certification (AFC) or provide an explanation stating that no revisions were made.*

Response: The following are revisions to the original AFC:

- The daily operational modeling limitation of 11 hours per day was removed and replaced with 24 hours of operation. Additionally, the PM10/2.5 emission rate was set to 9 lb/hr for each turbine/heat recovery steam generator (HRSG).
- The BAAQMD was formally designated as non-attainment for PM2.5. Revisions to the application were made to reflect this redesignation.
- Startup/shutdown emissions were revised.
- The annual operational profile was modified to reflect the revised startup and shutdown emissions.
- The carbon monoxide (CO) limits were set to 2.0 parts per million (ppm).
- The hourly PM10/2.5 emission rate was changed from 7.5 pounds per hour (lb/hr) to 9.0 lb/hr.

- The fire pump testing schedule was reduced to 40 hours per year.
- Commissioning emissions were revised.
- Overall plant-wide emissions were reduced.
- The inputs from a wind tunnel analysis to assess downwash structure dimensions that was conducted following U.S. Environmental Protection Agency (EPA) guidelines have been incorporated into the air quality modeling analysis.

These revisions are currently being incorporated into an updated and revised air quality analysis. The current changes in emissions of criteria pollutants are summarized in the following tables.

TABLE DR3-1
Combustion Turbine/HRSG and Aux Boiler Emissions for the Project (Steady State Operation-Controlled Per Turbine)

Pollutant	Emission Factor and Units	Max Hour Emissions (pounds)	Max Daily Emissions (pounds)	Max Annual Emissions (tons)[a]
NO_x	2.0 ppmvd[b]	15.52	372.48	49.3
CO	2.0 ppmvd[b]	9.45	226.80	49.0
POC	1.0 ppmvd	2.71	65.04	14.6
SO_x	<=0.00281 lb/MMBtu	6.00	144.00	6.3
$PM_{10/2.5}$	9.0 lb/hr	9.00	216.00	38.1
NH_3	5.0 ppmvd	14.36	344.64	60.7
Auxiliary Boiler at 4,324 hours per year				
NO_x	7.0 ppmvd	0.42	10.1	0.92
CO	10.0 ppmvd	0.37	8.88	0.79
POC	5.0 ppmvd	0.11	2.54	0.24
SO_x	0.00276 lbs/MMBtu	0.14	3.38	0.30
$PM_{10/2.5}$	0.007 lbs/MMBtu	0.354	8.50	0.77

[a]Annual Emissions assume startup/shutdown operation

[b]Annual NO_x emissions are based on 1.5 ppmvd and annual CO based on 1.0 ppmvd while short-term NO_x and CO emissions are based on 2.0 ppmvd. Annual SO_x is based on 0.25 gr/100 scf (1.5 lb/hr) while short-term emissions are based on 1.0 gr/100scf (6 lb/hr). Annual emissions for each pollutant assume annual operational profile with startups/shutdowns that provides the highest annual total for that pollutant.

Source: Radback-OGS Team, 2010.

lb/MMBtu = pound(s) per million British thermal unit
POC = reactive organic gas
ppvmd = parts per million by volume

TABLE DR3-2
Startup and Shutdown Emissions Per Turbine

Parameter/Mode	Cold Startup/Tuning[a]	Hot/Warm Startup	Shutdown
NO_x, lb/event	96.0/576.0	22.0	39.0
CO, lb/event	360.0/2,160.0	85.0	140.0
POC, lb/event	67.0/402.0	31.0	17.0
PM_{10}, lb/event	6.8/40.8	2.1	4.5
SO_x, lb/event	2.9/17.4	0.9	1.9
Event Time, minutes[b]	90 minutes	30 minutes	60 minutes
Maximum Number of Events/Year	25 (Annual Case 1)	311 (Annual Case 2)	312 (Annual Case 2)

[a] Combustor tuning not to exceed 6 hours per event
[b] The startup time presented represents expected worst-case. Actual startup event times will vary.

Source: Radback-OGS Team, 2010.

TABLE DR3-3
Each Combustion Turbine/HRSG Emissions for the Project (including base load cold, hot/warm startup and shutdown, whichever is greater) for the Non-commissioning Year

Pollutant	Emission Factor	Max Hour Emissions (pounds)	Max Daily Emissions (pounds)	Max Annual Emissions (tons)
NO_x	N/A	99.88	488.12	49.3
CO	N/A	362.36	715.00	49.2
POC	N/A	67.68	145.57	14.6
SO_x	N/A	6.0	144.0	6.3*
$PM_{10/2.5}$	N/A	9.0	216.0	38.1

Note: Annual average SOx is based on annual average grain loading of 0.25 gr/scf and 1.5 lb/hr emission rate
Source: Radback-OGS Team, 2009.

TABLE DR3-4
Evaporative Fluid Cooler and Fire Pump Engine Emissions for the Project

Pollutant	TDS (mg/L)	Max Hour Emissions (pounds)	Max Daily Emissions (pounds)	Max Annual Emissions (tons)
		Evaporative Fluid Cooler		
$PM_{10/2.5}$	1,500	0.132	3.17	0.099
Pollutant	**g/hp-hr**	**Max Hour Emissions (pounds)**	**Max Daily Emissions (pounds)**	**Max Annual Emissions (tons)**
		Fire Pump Engine		
NO_x	2.61	2.302	2.302	0.0457
CO	0.84	0.741	0.741	0.0147
POC	0.10	0.092	0.092	0.0018
SO_x	0.0015% by weight	0.0042	0.0042	0.0001
$PM_{10/2.5}$	0.10	0.091	0.091	0.0018

Notes: Evaporative fluid cooler operates up to 24 hours per day and up to 1,500 hours per year.
Fire pump operates 0.75 hour per day (one day per week), 40 hours per year.

Source: Radback-OGS Team, 2010.

g/hp-hr = grams per horsepower-hour
mg/L = milligram(s) per liter
TDS = total dissolved solids

During the first year of operation, plant commissioning activities, which are planned to occur over an estimated 734 hours, will have higher hourly, daily, and annual emission profiles than during normal operations in the subsequent years of operation. For commissioning, the worst-case hour was modeled assuming one turbine in cold start with the other turbine undergoing commissioning activities based on the activity that produced the highest emission rate. The worst-case day was modeled assuming one turbine in commissioning for 24 hours with the other turbine producing the maximum 24-hour emission rate.

TABLE DR3-5
Summary of Total Facility Emissions for the Project

Pollutant	pounds/hour (*commissioning hour*)	pounds/day[a] (*commissioning day*)[a]	tons/year (*commissioning year*)
NOx[b]	200.19 (399.88)	978.82 (7,688.96)	98.8 (98.8)
CO[c]	725.09 (1,862.36)	1,431.29 (36,716.3)	98.8 (98.89)
POC[d]	135.46 (167.68)	291.42 (2,545.85)	29.5 (29.5)
SOx[b]	12.14 (12.14)	288.29 (288.29)	12.6 (12.6)

TABLE DR3-5
Summary of Total Facility Emissions for the Project

Pollutant	pounds/hour (*commissioning hour*)	pounds/day[a] (*commissioning day*)[a]	tons/year (*commissioning year*)
TSP[b]	18.49 (18.49)	435.95 (435.95)	76.3 (76.3)
PM10/2.5[b]	18.49 (18.49)	435.95 (435.95)	76.3 (76.3)
NH_3[b]	28.84	689.74	117.72

Normal Operation Assumptions:

[a]Daily emissions assume 24 hours per day operation for the turbines and 2 hours per day for the auxiliary boiler. Plant-wide annual boiler emissions based on annual worst-case assumption per pollutant as noted. Worst-case commissioning day assumed 24-hours of no load operation for one turbine with the other turbine already commissioned and operating.

[b]Annual NO_x, PM, and SO_x based on 8,463 hours per year of operation from the turbines (1 cold start and 51 hot starts), 403 hours for the auxiliary boiler, and 1,500 hours per year for the evaporative condenser. Annual SO_x emissions based on annual average grain loading and 1.5 lb/hr.

[c]Annual CO is based on 5,390 hours of operation with 25 cold starts and 275 warm/hot starts with the auxiliary boiler at 4,324 hours per year.

[d]POC based on 5,662 hours of operation with one cold start and 311 warm/hot starts.

Note: Worst-case hourly assumes that the fire pump is not tested during turbine startup.

Source: Radback-OGS Team, 2010.

Conditions of Certification for Operating Profiles

4. *Please describe the conditions of certification that would be acceptable to OGS for agencies tracking compliance with the proposed capacity factor limitations, for example by limiting the combustion turbines in terms of daily or annual heat input rates, operating hours, or energy output.*

Response: The application is currently being revised in a way that will remove the need for a daily limit on operating hours. Installation and operation of the project will result in an emissions signature that will be less than 100 tpy for each criteria pollutant and will be considered a major New Source Review (NSR) source under the BAAQMD rules for NOx and POC. The project will not trigger the requirements of the Federal Prevention of Significant Deterioration (PSD) program since none of the single criteria pollutant emissions will exceed 100 tpy. Criteria pollutant emissions from the new combustion turbines/HRSGs and auxiliary equipment are specified in the responses below. Backup for these revised calculations will be provided in the amended AFC air quality section that will be provided at a later date.

The hourly, daily, and annual emissions modeling done for this application is based on worst-case assumptions for each criteria pollutant. The intent was to envelope the project emissions based on three dispatch profiles, called Annual Emissions Scenarios 1, 2, and 3 (See Attachments DR4-1, DR4-2, and DR4-3. For each scenario, the daily operation profile assumes 24 hours of operation with at least one cold or warm/hot start and one shutdown. All three emissions scenarios include 1,500 hours per year for the evaporative fluid cooler with up to 24 hours per day of operation. The worst-case annual emissions profiles then depend on which pollutant and worst-case dispatch assumption produces the maximum annual potential to emit. The three scenarios are as follows:

- Annual Emissions Scenario 1: For annual emissions of CO, this scenario assumes up to 5,157 hours per year of base load operation, up to 275 hot starts, 25 cold starts, and up to 300 shutdowns per year for a total of 5,390 hours per year, with up to 24-hours per day of operation. The auxiliary boiler would operate up to 4,324 hours per year. See Attachment DR4-1.
- Annual Emissions Scenario 2: For annual emissions of POC, this scenario assumes up to 5,433 hours at base load with up to 260 hot starts, 51 warm starts, one (1) cold start, and up to 312 shutdowns for a total of 5,662 hours per year, with up to 24 hours per day of operation. The auxiliary boiler would operate up to 3,992 hours per year. See Attachment DR4-2.
- Annual Emissions Scenario 3: For annual emissions of NO_x, SO_2, and PM10/2.5, this scenario assumes up to 8,424 hours of operation at base load, up to 51 hot starts, one (1) cold start, and up to 52 shutdowns per year, for a total of 8,463 hours of operation per year, with up to 24 hours per day of operation. The auxiliary boiler would operate up to 403 hours per year. See Attachment DR4-3.

Achievable PM10 and PM2.5 Emission Rate

5. *Please identify how the OGS project would be affected if the proposed combustion turbines were required by reviewing agencies to achieve a PM10 and PM2.5 emission rate of 3.14 lb/hr as identified in AFC Table 5.1-18.*

Response: The modeling emission rate of 3.14 lb/hr has been removed and replaced with a PM10 and PM2.5 emission rate of 9 lb/hr. The BAAQMD has proposed PM2.5 significance thresholds at 1.2 micrograms per cubic meter ($\mu g/m^3$) for 24-hour averages and 0.3 $\mu g/m^3$ for annual averages. The existing background 24-hour PM2.5 data from the Concord monitoring site already equals the federal standard but does not exceed the annual standard. The BAAQMD has been formally re-designated as a federal non-attainment area for PM2.5. The revised application will include hourly emissions of PM10 and PM2.5 set to 9 lb/hr for each combustion turbine and assumes 24 hours of continuous operation in order to determine the worst-case daily impacts.

Maximum Allowable PM10 and PM2.5 Emission Rates

6. *Please clearly identify the proposed maximum allowable PM10 and PM2.5 emission rates for the combustion turbines.*

Response: The proposed maximum emission rates for PM10 and PM2.5 will be 9 lb/hr for each turbine/HRSG. Additionally, 24 hours per day operation was assumed.

Citations for Class II Significance Levels

7. *Please provide the citations for the Class II Significance Levels shown in Table 5.1-19, especially for PM2.5 and nitrogen dioxide (NO_2).*

Response: The citations for the Class II Significance Levels shown in Table 5.1-19 are from the New Source Review Workshop Manual: Prevention of Significant Deterioration and

Non Attainment Area Permitting, Draft 1990. In addition, the significance level for PM2.5 is contained in:

> Prevention of Significant Deterioration (PSD) for Particulate Matter Less than 2.5 Micrometers (PM2.5) – Increments, Significant Impact Levels (SILs) and Significant Monitoring Concentration (SMC); Proposed Rule, 72 Fed. Reg. 54112, at 54138 (September 21, 2007) (hereinafter, "September 21, 2007 Proposed Rule").

Based on EPA interpretations and guidance, SILs have also been widely used in the PSD program as a screening tool for determining when a new major source or major modification that wishes to locate in an attainment or unclassifiable area must conduct a more extensive air quality analysis to demonstrate that it will not cause or contribute to a violation of the NAAQS or PSD increment in the attainment or unclassifiable area (72 Fed. Reg. at 54139):

> The EPA considers a source whose individual impact falls below a SIL to have a *de minimis* impact on air quality concentrations. Thus, a source that demonstrates its impact does not exceed a SIL at the relevant location is not required to conduct more extensive air quality analysis or modeling to demonstrate that its emissions, in combination with the emissions of other sources in the vicinity, will not cause or contribute to a violation of the NAAQS at that location.

Class II Significance Levels

8. *Please summarize the applicable requirements, including increment consumption analyses (identified in AFC Appendix 5.1C), that appear to be triggered by potentially exceeding the PM2.5 Class II Significance Levels, assuming turbine PM10 and PM2.5 emissions of 7.5 lb/hr per turbine, and by NO2 exceeding the significance levels in Table 5.1-19.*

Response: The increment consumption and ambient air quality analyses are only applicable for Federal attainment pollutants where air quality dispersion modeling demonstrates impacts above the applicable SIL. The attainment status for the BAAQMD is listed in Table DR8-1.

TABLE DR8-1
BAAQMD Attainment Status

Pollutant	Averaging Time	Federal Status	State Status
Ozone	1-hr	NA	NA
Ozone	8-hr	NA	NA
NO_2	All	UNC/ATT	ATT
CO	All	ATT	ATT
SO_2	All	ATT	ATT
PM_{10}	All	UNC	NA
$PM_{2.5}$	All	NA	NA

ATT = attainment
NA = non-attainment
UNC = unclassified

Source: BAAQMD Web site, 2008 and 40 CFR 81.305.

Based on the emission scenarios identified in the response to Data Request #4, the modeling results are as follows:

TABLE DR8-2
Air Quality Impact Results for Refined Modeling Analysis of Project

Pollutant	Avg. Period	Maximum Concentration ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total ($\mu g/m^3$)	Class II Significance Level ($\mu g/m^3$)	Ambient Air Quality CAAQS/NAAQS ($\mu g/m^3$)	($\mu g/m^3$)
Normal Operating Conditions							
NO_2	1-hour	177. 7	98.1	275.8	—	339	—
	Annual	0.62	20.8	41.4	1	57	100
CO	1-hour	65.5	3771	3836.5	2,000	23,000	40,000
	8-hour	33.6	2171	2204.6	500	10,000	10,000
SO_2	1-hour	10.1	122.2	132.3	—	655	—
	3-hour	7.5	65.0	72.5	25	—	1,300
	24-hour	2.9	23.4	26.3	5	105	365
	Annual	0.08	7.8	7.9	1	-	80
PM_{10}	24-hour	4.66	82	86.7	5	50	150
	Annual	0.53	24	24.53	1	20	—
$PM_{2.5}$	24-hour	4.66	35.2	39.9	1.2*	—	35
	Annual	0.53	9.3	9.83	0.3*	12	15.0
Start-up/Shutdown Periods							
NO_2	1-hour	211.72	98.1	309.82	—	339	—
CO	1-hour	1,141.09	3771	4,912.09	2,000	23,000	40,000
	8-hour	142.07	2171	2313.07	500	10,000	10,000
Commissioning Activities							
NO_2	1-hour	236.97	98.1	335.07	—	339	—
CO	1-hour	2205.6	3771	5,976.6	2,000	23,000	40,000
	8-hour	991.3	2171	3,162.3	500	10,000	10,000

*Proposed significance levels. The projects impacts exceed the proposed SILs for PM2.5. The area has now been redesignated to non-attainment for PM2.5, thus, no further analysis is proposed.

NO_2 annual calculated using ARM. 1-hour NO_2 for commissioning calculated using hourly OLM.

Source: Radback-OGS Team, 2009.

In order to assess the significance of the modeled concentrations for determining which pollutants triggered either an increment or NAAQS analysis, the modeled results were compared to the Class II PSD SILs for all attainment pollutants. All modeled facility pollutant concentrations are less than the SILs with the exception of tuning/commissioning activities for the 1- and 8-hour CO. Because there are no CO increments, a CO increment analysis is not required. In conjunction with the CEC requirements, however, a cumulative analysis will be performed for all pollutants.

Updated Impact Analysis

9. *Please update the impact analysis to reflect PM10 and PM2.5 impacts using the proposed maximum allowable PM10 and PM2.5 emission rate per turbine as identified in response to Data Request 6.*

Response: Please see the response to Data Request #8, where the PM10 and PM2.5 impacts were assessed using the maximum allowable emission rate of 9 lb/hr per turbine.

Federal Nonattainment NSR Requirements

10. *Please describe the applicability of the federal nonattainment NSR requirements of Title 40, Code of Federal Register Part 51 (40 CFR 51, Appendix S) for PM2.5.*

Response: Upon redesignation of the Bay Area as nonattainment for the PM2.5 standard, the PM2.5 requirements of Appendix S for major facilities would apply in the Bay Area air basin until the BAAQMD develops a State Implementation Plan (SIP)-approved NSR permitting program for sources of PM2.5. Appendix S includes the requirement that major facilities achieve LAER. However, the proposed facility would be exempt from the requirements of Appendix S because its emissions would be less than 100 tons per year for both PM2.5 and its precursors, as identified by Appendix S as SO_x. Accordingly, the proposed facility is not subject to the LAER standard for PM2.5.

Because the proposed facility is not a major stationary source of either PM2.5 or its only identified precursor for purposes of Appendix S (SO_x), the facility is not required to obtain a separate federal Non-Attainment NSR permit from the BAAQMD specifically addressing its emissions of PM2.5 and SO_x.

Evaluation of GHG Emissions

11. *Please describe whether the proposed OGS would be subject to the BAAQMD's evaluation of GHG emissions.*

Response: The proposed project is expected to exceed the BAAQMD's proposed GHG threshold of 10,000 metric tons per year. The BAAQMD's GHG program is still in draft form, however. If BAAQMD adopts the program, the OGS will comply with the Bay Area GHG evaluation methodology.

Carbon Monoxide Emission Limits

12. *Please either revise the proposed CO emission limits for the combustion turbines and heat recovery steam generators to 2.0 ppm or describe why this level would not be technically feasible, given that other similar projects indicate an ability to achieve this level. Verify that the impact analysis is consistent with this limit, or update this information to make it consistent.*

Response: The project will limit emissions of CO from the turbines/HRSGs to 2.0 ppm averaged over 1 hour. The emissions calculations and modeling analysis reflect the 2.0 ppm BACT limit.

Auxiliary Boiler Design

13. *Please clarify whether the proposed auxiliary boiler would include an oxidation catalyst and whether the emission reductions due to that catalyst have been taken into account in the Expected Auxiliary Boiler Emissions of AFC Appendix Table 5.1A-8.*

Response: The auxiliary boiler design has not been finalized. The CO limit of 10 ppm (BACT) may be achievable without the use of an oxidation catalyst. If this limit cannot be met, then a CO catalyst will be used.

Cooling System Emissions

14. *Please provide substantiating evidence or copies of technical reports supporting the assumption that only 60 percent of the cooling tower PM10 would qualify as PM2.5.*

Response: The evaporative fluid cooler emissions have been updated to reflect that 100 percent of the PM10 would be considered as PM2.5 (Table DR14-1).

TABLE DR14-1
Evaporative Fluid Cooler

Pollutant	TDS (mg/L)	Max Hour Emissions (pounds)	Max Daily Emissions (pounds)	Max Annual Emissions (tons)
$PM_{10/2.5}$	1,500	0.132	3.17	0.099

Drift Eliminators

15. *Please describe whether drift eliminators achieving 0.0005 percent would be feasible for the evaporative fluid coolers.*

Response: The Applicant reviewed the specifications for three major manufacturers of evaporative fluid coolers of the proposed type and size required for the OGS and has been unable to find one that will achieve a drift rate of 0.0005 percent. A drift rate of 0.0005 percent is more typical of coolers found with field-erected cooling towers. The proposed units are much smaller, packaged units that are similar to those that that might be used in a cooling system for a warehouse or office building. The three units that have been considered are:

- **SPX Marley MH Evaporative Fluid Cooler**—SPX, who provided a similar unit for the Gateway Generating Station, is willing to offer a drift rate of 0.003 percent in a unit sized for the OGS.
- **Evapco ATWB Closed Circuit Cooler**—Evapco's technical specifications indicate a drift rate of 0.001 percent.
- **Baltimore Aircoil Company FXV Closed Circuit Cooling Tower**—Baltimore Aircoil does not indicate the drift rate in their technical specifications; however, a company representative indicated that the drift rate is 0.005 percent.

Technical specifications documents for the cooling towers manufactured by each of these three companies can be provided to Staff on request. The Applicant is proposing a drift rate of 0.003 percent, which will allow competitive bidding between at least two manufacturers.

Emission Offsets

16. *Please provide a tabulated list showing expected emissions and emission offset accounting indicating the proposed quantity of offsets, including the locations of emission reductions, in a quantity sufficient to fully offset the projects emissions, including appropriate offset ratios. Please show the current updated ERC certificate number and former certificate numbers for certificates that have been recently split and/or re-issued in the name of the project.*

Response: The Bay Area AQMD maintains a listing of its current ERC bank for public review and inspection. The ERC bank listing can be obtained from the AQMD's website, and is not included here. The OGS project is required to purchase or acquire sufficient emission reduction credits to offset the proposed project emissions due to its proposed status as a major source for NOx and POC, in accordance with the AQMD NSR rule. The required quantities of ERCs are delineated in the Table DR16-1, where the emissions listed are based on the first year of operation (potential to emit).

TABLE DR16-1
Cumulative Emissions Increases and Required Offsets per Regulations 2-2-215, 2-2-302, 2-2-303

Pollutant	Cumulative Offset Threshold	Offset Ratio	Cumulative Increase Since April 5, 1991	OGS Emission Rates	Cumulative Emissions Increase	Offsets Required
POC	10/35 tpy	>10 but < 35 1:1 => 35 1.15:1	29.5	29.5	29.5	29.5
NO_x	10/35 tpy	>10 but < 35 1:1 => 35 1.15:1	98.8	98.8	98.8	113.6
PM_{10}	100 tpy	If major and increase is > 1 tpy, then 1:1	76.3	76.3	76.3	0
CO	100 tpy	> 100 tpy increase Modeling plus offsets to show attainment and maintenance of standard	98.8	98.8	98.8	0
SO_2	100 tpy	If major and increase is > 1 tpy, then 1:1	12.6	12.6	12.6	0

The proposed mitigation strategy for OGS has previously been submitted as a confidential filing under separate cover. This strategy will be finalized and approved by the BAAQMD prior to the issuance of the Authority to Construct for the proposed project.

BAAQMD regulations 2-2-215, 302 and 303 require OGS to provide emission offsets (emissions reduction credits, or ERCs) when emissions exceed specified levels on a pollutant-specific basis. Section 2-2-302 requires POC and NO_x emission reduction credits to be provided at an offset ratio of 1:1 or 1.15:1, depending on emissions levels. Because both POC and NO_x contribute to the Bay Area Basin ozone levels, Section 2-2-302.2 allows emission reduction credits of POCs to be used to offset increased emissions of NO_x, at the required offset ratios stated in Table DR16-1. Section 2-2-303 requires emission offsets for emissions increases at facilities that emit more than 100 tpy of SO_2 and PM10. Because facility emissions of SO_2 and PM10 will be below 100 tpy, SO_2 and PM10 offsets are not required per BAAQMD rules.

BAAQMD sections 2-2-304 and 2-2-305 impose emissions offset requirements, or require permit denial, if SO_2, NO_2, PM10, or CO air quality modeling results indicate emissions will interfere with the attainment or maintenance of the applicable ambient air quality standards or will exceed PSD increments. For many of the pollutants and averaging periods, BAAQMD regulations do not require OGS to conduct these analyses, since the modeled impacts of the proposed facility are not significant under BAAQMD rules. Modeling for these pollutants has been conducted to satisfy CEC requirements, however. The modeling analyses show that facility emissions will not interfere with the attainment or maintenance of the applicable air quality standards.

The project Applicant will provide all necessary documentation to show control or ownership of the required emissions offsets prior to issuance of the facility Permit to Operate by the BAAQMD per regulation 2-2-410. Offsets may be acquired from the BAAQMD bank or from other sources such as shutdowns, or non-traditional sources of emissions reductions credits.

The Applicant is proposing to mitigate the increases in NO_x and POC through the purchase of banked ERCs, per the BAAQMD rules and regulations. Because the BAAQMD offset trigger levels for PM10/PM2.5 and SO_2 are at 100 tons per year per pollutant and the projects emissions are less than those levels, ERCs for these pollutants are not proposed at this time for mitigation. See the responses to Data Requests #17 and #18 for the Applicant's proposed mitigation of PM and SO_2.

Mitigation for Particulate Matter

17. *Please identify and quantify a complete package of proposed mitigation, especially for PM10 and PM2.5. For example, proposed strategies to reduce emissions in the San Joaquin Valley and the effectiveness of such strategies would need to be explicitly identified by OGS and preferably developed in consultation with Energy Commission staff before staff makes the information available in the staff assessment.*

Response: The Applicant can commit to mitigate the PM10/PM2.5 emissions from the proposed project. The commitment is consistent with recent CEC permitting cases that provide for the mitigation of the impacts of PM10/2.5 emissions and other community public health concerns. (See the CEC decisions for the Pico Power Project [aka Donald Von Raesfeld Power Plant], the Metcalf Energy Center, the Tracy Peaker, Tesla Power Project, and Russell City Energy Center). To develop a PM10/2.5 mitigation/community benefits program that both addresses the project impacts and the environmental and public health concerns of the affected communities, including the potential impacts to the San Joaquin Valley air basin, the following programs could be used:

- **High-efficiency street sweeping of traffic lanes on high traffic streets**—The Applicant could provide funding to the City of Oakley for the purchase and operation of high-efficiency street sweepers. This method would directly benefit the communities in the project area.

- **Replacing wood fireplaces and wood stoves**—Funding could be provided to and administered through the BAAQMD for a program that would involve replacing wood-burning fireplaces with natural gas inserts and wood stoves with EPA-certified clean pellet stoves. Under this program, BAAQMD would provide reimbursements or refunds for fireplace and wood stove retrofits of up to $300 per fireplace and $500 per wood stove. This program is purely voluntary for those who wish to participate.
- **Sodding or paving high traffic areas**—Areas with large off-road traffic use could be paved or planted with sod to minimize particulate emissions.
- **Carl Moyer Program**—The Applicant could provide funding to the Carl Moyer program on a dollar per ton basis and this funding could be made available to the City and the nearby surrounding areas for a period of 24-months. The Carl Moyer program provides incentive grants for cleaner-than-required engines, equipment and other sources of pollution providing early or extra emission reductions. Eligible projects include cleaner on-road, off-road, marine, locomotive and stationary agricultural pump engines. The program achieves near-term reductions in emissions of NOx, PM10/2.5, and POC. Funding could be provided on a dollar-per-ton basis at a rate that is similar to the current ERC market rates. The funding would be directed toward local projects for a period of time, after which the funding would be open to projects in the nearby portions of the San Joaquin Valley air basin.

The PM10 and PM2.5 offset program provides local sources of mitigation that would directly offset the proposed source PM. This would then benefit both the local area and any areas immediately downwind from the project location, such as the San Joaquin Valley air basin.

Mitigation for SOx Emissions

18. *Please identify and quantify a mitigation strategy for proposed SOx emissions to ensure that OGS avoids contributing to additional PM10 and PM2.5 violations of ambient air quality standards.*

Response: OGS proposes to fund the Carl Moyer program for each ton of SOx that is emitted from the project during operation.

Maximum Emission Rates During Commissioning

19. *Please confirm that the maximum emission rates during commissioning in Table 5.1-20 are accurately reported, given that higher emission rates of CO would occur with a single cold start.*

Response: The commission emissions have been revised and are listed in Table DR19-1. The single cold-start emissions are expected to occur over 90 minutes and in all cases, are less than the commissioning emissions over a 60-minute period.

TABLE DR19-1
Estimated Single Turbine Maximum Emissions Rates During Commissioning and Cold Start*

		NO_X	CO	POC	PM10/2.5	SO_x
Commissioning	lb/hr	300.0	1,500.0	100.0	9.0	6.0
Cold Startup	lb/event	96.0	360.0	67.0	6.8	2.9

* Cold startup event is 90 minutes
Source: Radback-OGS Team, 2009.

Maximum NO_x and NO_2 Impacts

20. *Please confirm that the maximum NOx and NO_2 impacts have been considered given that the 120 lb/hr NOx commissioning emission rate would exceed the highest NOx emission rate in the analyses shown on CD-ROM with the AFC, and if not, update the impact analysis to reflect the maximum emission rates.*

Response: The modeled impacts of commissioning at 120 lb/hr were included in the CD-ROM as an Excel spreadsheet and are summarized in Attachment DR20-1. The commissioning modeling was based on the screening chi/Q table summary in the spreadsheet (turbscreengd.xls) where the maximum 1-hour NO_2 impacts were 126.08 $\mu g/m^3$. The 1- and 8-hour CO commissioning values were calculated the same way. These results were presented in Table 5.1-19 in the AFC. Both the startup and commissioning emissions have been revised. The results are presented in the response to Data Request #8.

Stack Conditions

21. *Please provide the expected stack conditions (exit velocity and temperature) for the various commissioning scenarios and confirm that the commissioning-phase dispersion modeling submitted with the AFC reflects the worst-case combination of stack conditions and emission rates.*

Response: Please refer to the modeling CD-ROM Excel spreadsheet (turbscreengd.xls) that was included with the AFC. The stack parameters for all phases of turbine operation were assessed for the turbine commissioning activities with the results identifying a Case 1E (49 percent load, 34°F) as having the worst-case stack condition for commissioning.

Fire Pump Engine and Startup Emissions

22. *Please describe the operating limitations that would be acceptable for ensuring that fire pump engine testing would not occur during a turbine startup.*

Response: Rather than specify an operating limitation, OGS proposes accepting a permit condition requiring that fire pump testing take place only during non-startup hours. Compliance with this condition could be tracked by requiring that the operational log for the fire pump track date, time, and duration of the test. This log could then be compared to the DAS (which records turbine start events) to ensure that no fire pump testing occurred during turbine startup.

Cumulative Modeling Analysis Permit File Review

23. *Please provide a copy of the results of applicant's BAAQMD permit file review regarding existing and planned cumulative projects located within eight miles of the OGS site, as offered in AFC Appendix 5.1H.*

Response: The BAAQMD has not yet provided the source listing within 8 miles of the project site. Once the source listing is provided, a copy will be docketed with the CEC.

Sources in Neighboring Air Districts

24. *Please describe whether reasonably foreseeable sources in the neighboring air districts, such as Sacramento Metropolitan and San Joaquin Valley, have been identified for analysis and how they would be considered in the analysis.*

Response: Other than the recent Marsh Landing project, no other foreseeable projects have been identified.

Cumulative Impacts Sources

25. *Please provide the list of sources to be considered in the cumulative air quality impact analysis.*

Response: Source lists requests have been sent to the BAAQMD, San Joaquin Valley Unified, and Sacramento Metropolitan Air Districts requesting a listing of recently permitted sources for inclusion into the cumulative modeling analysis. These lists will be forwarded to the CEC when received. OGS will work with the CEC in the review of the source inventory to identify which sources will be included in the cumulative modeling analysis. At this time, it is also expected that the Gateway and Marsh Landing projects will be included in the cumulative analysis.

Cumulative Modeling Analysis

26. *Please describe the progress for the cumulative air quality impact analysis following the protocol proposed in the AFC.*

Response: The Applicant has requested lists of sources to use in developing the cumulative emissions analysis from the applicable air districts. As soon as these agencies provide the source lists, copies will be sent to the CEC for review.

GHG Emissions Sources

27. *Please provide a clear description of all sources of GHG emissions, including the fuel heat input rates and power output rates, along with the totals of those emissions for each project-related source.*

Response: Descriptions of these sources were provided in Section 5.1.2.2 of the Air Quality section of the AFC, as well as in Appendix 5.1A of the AFC. Sources expected to emit GHG emissions from the OGS are shown in Table DR27-1 and Attachment DR27-1.

TABLE DR27-1
GHG Emissions Sources During Operations

Source	Heat Input	Output	CO_2e, metric tons/year
Turbine 1	2150 MMBtu/hr	~213 MW	982,290
Turbine 2	2150 MMBtu/hr	~213 MW	982,290
HRSGs (2)	Non-Fired	~218 MW (steam turbine)	n/a
Aux Boiler	50.6 MMBtu/hr	34000 lb steam/hr	11,741
Fire Pump Engine	2.78 MMBtu/hr	~400 hp	10.5
Total CO_2e			**~1,976,331**

Incidental GHG Sources

28. *Please provide a list of all sources other than the turbines, auxiliary boiler, and the fire pump that contribute to operational GHG emissions. This information should include the total emission estimates from these sources, i.e. leaking electrical equipment (sulfur hexafluoride), worker commutes, and material deliveries using trucks.*

Response: SF_6 emissions are estimated to be 10.3 metric tons CO_2e per year. Operational emissions from mobile vehicles resulting from site deliveries and worker commuting are presented on the attached “Operations Mobile Vehicle Emissions” spreadsheet (in Attachment DR28-1). Total estimated CO_2 emissions are 74.4 tons/year, or approximately 67.6 metric tons/year.

Construction PM10

29. *Please identify the phases of construction that would be most likely to cause PM10 24- hour concentrations over the California Ambient Air Quality Standard.*

Response: The highest PM10 24-hour concentrations would take place during cut and fill operations. During the worst-case day when cut-and-fill is taking place, up to 12.4 lb/day of fugitive PM10 would be generated.

Construction PM10 Control Measures

30. *Please describe what additional emission control measures could be implemented to mitigate this impact to a level below the standard. One example would be fence-line monitoring of ambient concentrations, with the results being used to trigger various corrective actions.*

Response: The Applicant believes that the standard set of mitigation measures imposed by CEC staff on previous projects will be more than sufficient to mitigate construction emissions from this site to below a level of significance. These standard mitigations are summarized in the Air Quality section of the AFC in subsection 5.1.3.5, and in Appendix 5.1E. The Applicant does not believe that fence-line monitoring of ambient PM concentrations would be effective for the following reasons:

- Such monitoring data would not be able to conclusively show the construction site contribution to overall PM ambient air quality (i.e., upwind versus downwind contributions) considering wind direction changes over the course of a specified sampling period, and upwind and downwind activities not associated with the project site, etc.
- Ambient PM monitoring would require the acquisition of long-term (24-hour minimum) samples, sample retrieval, sample desiccation, sample weight determination, and concentration calculation. The results of this process would result in a minimum time lapse of at least 24 to 36 hours from the time of sample acquisition, and would render the results of little value in making informed decisions on additional mitigations to be imposed as a result of sampling for an episode or time period which is past.
- The Applicant believes that the requirement for a construction mitigation manager, with appropriate training in visible emissions evaluation, will be far more effective at assessing onsite construction emissions and the potential for offsite emissions impacts. Visible emissions evaluations can be conducted during those periods where offsite emissions potentials are the highest, resulting in the timely implementation of additional mitigation measures.

Construction Phase GHG

31. *Please provide a clarifying table summarizing the sources and assumptions for developing the GHG emission estimates and the totals of those emissions from each source.*

Response: Table DR31-1 summarizes the estimated GHG emissions for the OGS construction phase. The assumptions for each source category are delineated on the construction calculation spreadsheets provided in AFC Appendix 5.1E, Table 5.1E-5. (See the CO_2e tab on Table 5.1E-5.)

TABLE DR31-1
GHG Emissions Sources During Construction

Construction Activity	Activity Comment	GHG Emissions, CO_2 short tons/period
Construction equipment	Site grading, foundations, structure erection, etc.	9,622
Construction worker travel	Worker commute	1,059.5
Construction material deliveries	Truck-related material deliveries and site support vehicles	842.5
	Total CO_2e, metric tons/period	*10,524*

Construction Vehicle Miles

32. *Please describe the vehicle miles of travel assumed and if the assumptions include onsite activities as well as offsite activities, such as material deliveries and construction worker commutes.*

Response: Table 5.1E-5 in AFC Appendix 5.1 (Worker Travel tab) presents the data used to compute the worker travel emissions estimates, including the assumed roundtrip distance, workers per day, vehicle occupancy rate, total roundtrips per day, etc., and emissions estimates on a daily and period basis.

Table 5.1E-5 in AFC Appendix 5.1 (Site Delivery tab) presents the data used to compute the construction materials delivery-related emissions estimates, including the delivery distance, number of expected deliveries per day and per period, etc. Site material delivery mileage is the one-way mileage only. These delivery trucks will not be dedicated to the site, and will not be controlled or owned by the Applicant, and as such, the back-haul vehicle miles traveled (VMT) cannot be attributed to the site.

Site support vehicle travel distances are presented in total VMT per day and VMT per period, as the roundtrip distance is not applicable in this case.

For purposes of vehicular GHG estimates for these categories of activities, the GHG factors were derived from EMFAC as delineated on the calculation sheet (tabs as noted above), and Attachment DR32-1.

Locomotive Emissions

33. *Please ensure that construction emission estimates include locomotive emissions from proposed deliveries by rail, if railroad traffic would be generated by the project. This emission estimate would focus on trips generated by the project and emissions in the Bay Area air basin.*

Response: Locomotive emissions have been estimated for the site based on data supplied by the Applicant. These emissions calculations and assumptions are included in Attachment DR33-1. CO_2e emissions from locomotive deliveries are estimated to be approximately 44 metric tons/construction period.

ATTACHMENT DR2-1

Supplemental Data Submitted to BAAQMD

From: Gregory Darvin <darvin@atmosphericdynamics.com>
Date: Tue, 08 Sep 2009 08:46:50 -0800
To: Kathleen Truesdell <ktruesdell@baaqmd.gov>
Cc: Bryan Bertacchi <bryan.bertacchi@radback.com>, <jim.mclucas@radback.com>, Greg Lamberg <greg.lamberg@radback.com>
Conversation: Revised Radback
Subject: Revised Radback

Hi Kathleen. Attached are the following for the Radback Contra Costa Generating Station:

1. Revised air quality section 5.1 that now represents the updated emissions profile for the project and includes 24-hours per day of operation for PM10/2.5. Additionally, the CO and POC emissions were also revised to reflect the 2.0 and 1.0 ppm BACT limits, respectively.

2. Oil water separator form.

3. Emissions spreadsheet that is the basis for the hourly, daily, and annual emissions in the permit application as well as startup and commissioning emissions.

4. Letter from the National Park Service exempting the project from performing a Class I air quality related values analysis.

Please let me know if you need anything else or additional support data in order for you to deem this application complete. We will be revising the PM10/2.5 modeling analysis over the next couple of weeks. The revised Section 5.1 is broken out into three PDF files. Also, please let me know if you need a hardcopy sent over to you.

Regards.

Gregory Darvin
ATMOSPHERIC DYNAMICS, INC.
805.569.6555
805.569.6558 (fax)
darvin@atmosphericdynamics.com

Revised Section 5.1 (Air Quality)

5.1 Air Quality

5.1.1 Introduction

This section presents the methodology and results of an analysis performed to assess potential effects of airborne emissions from the construction and routine operation of the Contra Costa Generating Station Project (CCGS). Section 5.1.1 presents the introduction, applicant information, and the basic Bay Area Air Quality Management District (BAAQMD) rules applicable to the project. Section 5.1.2 presents the project description, both current and proposed. Section 5.1.3 presents data on the emissions of criteria and air toxic pollutants from the project. Section 5.1.4 discusses the Best Available Control Technology (BACT) evaluation for the project. Section 5.1.5 presents the air quality effects analysis for the project. Section 5.1.6 presents applicable laws, ordinances, regulations, and standards (LORS). Section 5.1.7 presents agency contacts, and Section 5.1.8 presents permit requirements and schedules. Section 5.1.9 contains references cited or consulted in preparing this section.

Contra Costa Generating Station, LLC (Applicant) is proposing to construct and operate the Contra Costa Generating Station (CCGS) which will be a nominally rated 624 MW, natural gas-fired combined cycle facility.

The project will operate as a base loaded power plant and is proposed to be permitted for 8,449 hours of operation per year, with an expected facility capacity factor at 60 to 80 percent. The project will consist of the following:

- Installation of two (2) nominally rated 213 megawatt (MW) GE 7FA combustion turbines with Dry Low NO_x (DLN) combustors and evaporative inlet air cooling.
- Installation of two (2) non-fired HRSGs coupled to a single GE D11 condensing steam turbine generator capable with a nominal rating of 218 MW.
- SCR and CO catalyst systems on both turbine/HRSG power trains.
- Installation of air cooled condenser to provide cooling and heat rejection from the power block process.
- Installation of an auxiliary boiler rated at 34,000 lbs steam/hr, firing natural gas. The boiler will provide auxiliary steam when the main power block is offline and during startups. The boiler will be equipped with SCR and a CO catalyst.
- Installation of all required auxiliary support systems.

The project design will incorporate the air pollution emission controls designed to meet BAAQMD BACT determinations. These controls will include DLN combustors in the CTG to limit nitrogen oxide (NO_x) production, selective catalytic reduction (SCR) with aqueous ammonia for additional NO_x reduction in the HRSG, an oxidation catalyst to control carbon monoxide (CO) and precursor organic compounds (POC) emissions. Fuel to be used will be pipeline specification natural gas**.** The auxiliary boiler will be equipped with low NO_x burners, SCR, and a CO catalyst.

5.1.2 Project Description

5.1.2.1 Current Site and Facilities

The project site is a 21.95-acre site located within the boundary of an existing 210-acre site owned by E. I. DuPont. CCGS holds an option to purchase the 21.95-acre site, and DuPont is currently proceeding with a lot line adjustment to separate the site from the larger 210-acre parcel. The project site is currently zoned "heavy industrial", with surrounding land uses comprised of industrial, vacant industrial, commercial, and agricultural. The site is located in the City of Oakley, Contra Costa County, California. The City of Oakley is presently revising its zoning regulations to match the 2020 General Plan. The site zoning will change from "heavy industrial" to "utility energy" land use, with the reminder of the DuPont site classified as "business park" or "light industrial".

The project site is bounded to the west by the Pacific Gas and Electric Company's (PG&E's) Antioch Terminal, a large natural gas transmission hub, to the north by DuPont property that is either industrial or vacant industrial, to the east by DuPont's titanium dioxide landfill area, and to the south by the Atchison, Topeka and Santa Fe railroad. Immediately south of the railroad is a large parcel currently in agriculture. A 74.6-acre commercial development, the Rivers Oaks Crossing, has been proposed for this parcel.

The site Universal Transverse Mercator (UTM) coordinates are as follows: 610,176.8 meters easting, 4,207,415 meters northing, Zone 10 (NAD27).

The project site elevation is approximately 20 feet above mean sea level (MSL). Because the site is located within the existing disturbed property boundary, the project site and surrounding areas are highly developed, and have been subject to disturbance for many years.

5.1.2.2 Project Equipment Specifications

The facility will consist of the following major equipment.

- Two 213 MW GE 7FA combustion turbines
- One 218 MW GE D11 steam turbine
- Two unfired HRSGs
- One auxiliary boiler One air-cooled condenser
- One evaporative condenser
- One fire pump

All power from the facility will be delivered to the California power grid under the control of the California Independent System Operator (CAISO).

The equipment specifications for the emissions sources are summarized in Table 5.1-1, Plant Specifications, as follows:

TABLE 5.1-1
Plant Specifications

Parameter	59 F/60 Percent Relative Humidity
Net Facility Output, MW*	624
CTG Heat Input, MMBtu/hr (LHV)*	1,900
Net Facility Heat Rate, Btu/kWh (LHV)*	6,752

*Under ISO conditions.
Source: Radback-CCGS Team, 2009.

Specifically, the emission sources will have the following characteristics.

5.1.2.2.1 Combustion Turbine

- Manufacturer: GE
- Model: 7FA
- Fuel: Pipeline quality natural gas
- Heat Input: 2,150 MMBtu/hr (HHV) at 34°F
- Fuel consumption: up to ~2,103,718 standard cubic feet per hour
- Exhaust flow: ~1,161,633 actual cubic feet per minute at34 degrees Fahrenheit (°F) and 60 percent relative humidity
- Exhaust temperature: ~191 °F at the HRSG stack top exit

5.1.2.2.2 Heat Recovery Steam Generator

- Manufacturer: Not Selected
- Fuel: None
- Duct Burner Heat Input : No duct burners
- Steam Production Rating: 643 Klbs/hr (nominal)

5.1.2.2.3 Auxiliary Boiler

- Manufacturer: Not Selected
- Fuel: Pipeline quality natural gas
- Heat Input: 50.6 MMBtu/hr (HHV)
- Steam Production: 34,000 lb/hr

5.1.2.2.4 Evaporative Fluid Cooler

- Manufacturer: Marley or equivalent
- Number of Cells: 3
- Number of Fans: 3 (~190,600 actual cubic feet per minute each)
- Water circulation rate: 5,880 gallons per minute total
- Drift rate: 0.003 percent of circulating water flow (0.00003 fraction)
- Expected total dissolved solids (TDS): ~1,500 parts per million by weight (ppmw)

5.1.2.2.5 Fire Pump

- Manufacturer: Clarke model number JW6H-UFAD80
- Fuel: Ultra low sulfur diesel
- Horsepower: 400 BHP

Natural gas will be the only fuel used during plant operation with the exception of the fire pump which will fire ultra low sulfur diesel fuel. The typical natural gas composition is shown in Appendix 5.1A. Natural gas combustion results in the formation of NO_x, CO, precursor organic compounds (POCs), SO_2, PM_{10}, and $PM_{2.5}$. Because natural gas is a clean-burning fuel, there will be minimal formation of combustion PM_{10}, $PM_{2.5}$, and SO_2.

The fuel used on this project is similar to the fuels used on similar combined cycle power generation facilities. Table 5.1-2 presents a fuel use summary for the facility. Fuel use values are based on the maximum heat rating of each system, fuel specifications, and maximum operational scenario. Fuel analysis data for both natural gas and diesel fuel is presented in Appendix 5.1A, Air Quality Data.

TABLE 5.1-2
Estimated Fuel Use Summary for the Project

System	Fuel	Per Hour, mmscf	Per Day, mmscf	Per Year, mmscf
Combustion Turbine	Natural gas	2.101	50.434	17,219,158
Auxiliary Boiler	Natural Gas	0.0495	1.176	213.90
Fire Pump	Ultra Low Sulfur Diesel	20 gallons/hr	20 gallons/day	1060 gallons/yr

*Natural gas heat rate of ~1022 Btu/scf
Auxiliary Boiler operation up to 24-hours per day, 4,324 hours per year.
Source: Radback-CCGS Team, 2009.

5.1.2.3 Climate and Meteorology

The overall climate in the project area is dominated by the semi-permanent eastern Pacific high pressure system, centered over the northeastern Pacific Ocean. This high is typically centered between the 140 W and 150 W meridians. Its position and size typically governs California’s weather. In the summer, the high is strongest and moves to its northernmost position, which results in strong northwesterly air flow and negligible precipitation. A thermal low pressure area from the Sonoran-Mojave Desert also causes air to flow onshore over the San Francisco Bay area much of the summer.

The steady northwesterly flow around the eastern edge of the Pacific high pressure cell exerts a stress on the ocean surface along the west coast. This causes cold water to form at the surface, which cools the air even further. This cooling produces a high incidence of fog and clouds along the northern California coast in summer.

In the winter, the high weakens and moves southwestward toward Hawaii, which allows storms originating in the Gulf of Alaska to reach northern California, bringing wind and rain. About 80 percent of the region’s annual rainfall of approximately 19.5 inches occurs between November and March. During the winter rainy periods, inversions are weak or nonexistent, winds are often moderate, and the air pollution potential is very low. During summer and fall, when the Pacific high becomes dominant, inversions become strong and often are surface based; winds are light and the pollution potential is high. These periods are often characterized by winds that flow out of the Central Valley into the Bay Area and often include Tule fog.

Historical climatic data for the project area was derived from the following sites located near the project site:

- BAAQMD
- National Weather Service
- National Climatic Data Center

Data for the Antioch Pump Plant (#040232) for the period 3-1-1955 through 12-31-2008 shows the following:

- Annual average maximum temperature = 73.3 °F
- Annual average minimum temperature = 48.0 °F
- Annual average total precipitation = 13.17 in.

Appendix 5.1B contains summary climate and meteorological data for the Antioch station. Annual and quarterly wind roses for the CCP meteorological monitoring station for the period 2001 through 2006 are also presented in Appendix 5.1B. The annual wind rose data indicates that a majority of the regional wind flow is from the west through northwest, with periods of calm winds experienced approximately 8.48% of the time.

5.1.3 Emissions Evaluation

5.1.3.1 Facility Emissions

Installation and operation of the project will result in the emissions signature for the site that will be considered a major source under the BAAQMD rules and will trigger the major source threshold for CO, and the "significant emissions rate" thresholds for NO_x and $TSP/PM_{10/2.5}$ pursuant to the Federal Prevention of Significant Deterioration (PSD) program. Criteria pollutant emissions from the new combustion turbines/HRSGs and auxiliary equipment are delineated in the following sections, while emissions of hazardous air pollutants are delineated in Section 5.9. Backup data for both the criteria and hazardous air pollutant emission calculations are provided in Appendix 5.1A, Air Quality Data.

The hourly, daily and annual emissions for all criteria pollutants are based upon worst-case assumptions for each pollutant. The intent was to envelope the project emissions based upon the three (3) operational (capacity) profiles provided in Appendix 5.1A. The daily operation always assumes 24 hours of operation with at least one cold or warm/hot start and one shutdown. The worst-case annual emissions profiles will be dependent upon pollutant and which worst-case capacity assumption produces the maximum annual potential to emit. Thus, the following assumptions will apply to the proposed project:

- Up to 6,924 hours of operations at full load, up to 25 cold starts, up to 311 warm/hot starts and up to 312 shutdowns per year for a total maximum of 8,449 hours of operation per year (including startup and shutdown hours) with up to 24 hours per day of operation

- 4,324 hours per year of operation for the Auxiliary boiler with up to 24 hours per day of operation when the combustion turbines are not operational. It is also assumed that the auxiliary boiler may operate more than 4,324 hours per year, but the turbines will not be operational during this extended time period.
- 1,500 hours per year for the evaporative fluid cooler with up to 24 hours per day of operation
- 53 hours per year for fire pump testing

The BAAQMD has established $PM_{2.5}$ significance thresholds at 1.2 µg/m^3 for 24-hour averages and 0.3 µg/m^3 for annual averages. The existing background 24-hour $PM_{2.5}$ monitoring data from Concord is already at the Federal standard. Thus, this project must demonstrate that all 24-hour $PM_{2.5}$ impacts are less than significant. The BAAQMD is expecting to be formally re-designated as a Federal non-attainment area for $PM_{2.5}$, but until this formal re-designation occurs, the area is considered attainment. Additionally, the project will conform to the BAAQMD requirements for offsets, if needed, for $PM_{2.5}$.

The proposed project will be a major new source as defined by the air district's siting regulations, and will be subject to District requirements for emission offsets and air quality modeling analyses for criteria pollutants and toxics. The proposed project will trigger the PSD program requirements as the emissions of NO_x, CO, and TSP/$PM_{10/2.5}$ will be greater than the major source thresholds or the significant emissions rate thresholds.

The applicant has prepared an air quality emissions and impact analysis to comply with the BAAQMD and the California Energy Commission (CEC) regulations. The modeling analysis includes impact evaluations for those pollutants shown in Table 5.1-3 and the CEC requirements for evaluation of project air quality impacts.

TABLE 5.1-3
BAAQMD PSD Significant Emissions Thresholds

Pollutant	Cumulative Increase (tons/yr)	Major Source Thresholds/Significant Emissions Rates/ (tons/yr)	Major PSD Source
NO_x	98.8	100/40	Yes
SO_2	12.5	100/40	No
CO	164.5	100/100	Yes
$PM_{10}/PM_{2.5}$	63.5	100/15	Yes
POC	29.5	100/40	No
Sulfuric Acid Mist	1.9	7	No

Per Table 5.1-3, the project will result in emissions that will exceed BAAQMD PSD significance thresholds for NO_x, CO, and $PM_{10/2.5}$.

Emissions from the proposed project will also exceed the BAAQMD thresholds defining a major source for purposes of New Source Review (NSR). The project triggers the BAAQMD offset requirements for NO_x and POC only. Air quality, toxics, and cumulative impacts analyses are required as part of the major source permit application. Modeled ambient impacts are below the levels at which preconstruction monitoring is required.

The emissions calculations presented in the application represent the highest potential emissions. As stated previously, the turbines will be the General Electric Model 7FA, each equipped with dry low NOx combustors. Each turbine will incorporate General Electric's Rapid Response capability with cold, warm, and hot starts taking no longer than 1-hour to demonstrate compliance with normal steady state emission limits. Each turbine will also include an unfired HRSG. During periods of plant shutdown, a 50.6 MMBtu/hr auxiliary boiler will be utilized to maintain the plant in a hot-standby condition.

5.1.3.2 Normal Operations

Operation of the proposed process and equipment systems will result in emissions to the atmosphere of both criteria and toxic air pollutants. Criteria pollutant emissions will consist primarily of NO_x, CO, POCs, sulfur oxides (SO_x), total suspended particulates (TSP), PM_{10}, and $PM_{2.5}$. Air toxic pollutants will consist of a combination of toxic gases and toxic PM species. Table 5.1-4, lists the pollutants that may potentially be emitted from the project.

TABLE 5.1-4
Chemical Substances Potentially Emitted to the Air from the Project

Criteria Pollutants	
Particulate Matter	
Carbon Monoxide	
Sulfur Oxides	
Nitrogen Oxides	
Volatile Organic Compounds	
Lead	
Noncriteria Pollutants (Toxic Pollutants)	
Ammonia	Xylene
Polycyclic Aromatic Hydrocarbons (PAHs)	Arsenic
Acetaldehyde	Aluminum
Acrolein	Cadmium
Benzene	Chromium VI
1-3 Butadiene	Copper
Ethylbenzene	Iron
Formaldehyde	Mercury
Hexane (n-Hexane)	Manganese
Naphthalene	Nickel
Propylene	Silver
Propylene Oxide	Zinc
Toluene	Diesel PM

5.1.3.3 Criteria Pollutant Emissions

Tables 5.1-5 through 5.1-8 present data on the criteria pollutant emissions expected from the facility equipment and systems under normal operating scenarios. The maximum hourly emissions are based on Case 01C (34°F day at base load operation) or are based on cold start maximum hourly emission rates. A cold start is defined as a one hour event with the turbine/HRSG stack emissions in BACT compliance at the end of the first hour. The worst case day for emissions is defined at one cold start, one shutdown, and 22 hours of base load operation (Case 01F stack parameters at 80 percent load and Case 01C base load emissions). Three operational profiles were examined for this application and are summarized in Appendix 5.1A. The differences between the three operational profiles are based on annual run time hours and the total annual startup/shutdown events. For NO_x, PM, and SO_x, the maximum potential to emit are based on a profile having 8,449 hours of operation with one cold start 51 warm/hot starts and 52 shutdowns. For CO, the worst-case emissions are based on a profile having 5,310 hours of operation with 25 cold starts and 275 warm/hot starts while worst-case POC emissions are based on 5,579 hours of operation with one cold start and 311 warm/hot starts. Thus, for each pollutant, the maximum potential to emit is presented in Appendix 5.1A and in the tables below.

TABLE 5.1-5
Combustion Turbine/HRSG and Aux Boiler Emissions for the Project (Steady State Operation-Controlled Per Turbine)

Pollutant	Emission Factor and Units	Max Hour Emissions (lbs)	Max Daily Emissions (lbs)	Max Annual Emissions (tons)[a]
NO_x	2.0 ppmvd[b]	15.52	372.48	49.3
CO	2.0 ppmvd	9.45	226.8	78.1
POC	1.0 ppmvd	2.71	65.04	14.1
SO_x	<=0.00281 lb/MMBtu	6.00	144.0	6.3
$PM_{10/2.5}$	7.5 lb/hr	7.50	180.0	31.7
NH_3	5.0 ppmvd	14.36	344.64	60.66
Auxiliary Boiler at 4,324 hours per year				
NO_x	9.0 ppmvd	0.55	13.1	1.18
CO	50.0 ppmvd	1.85	44.3	3.99
POC	5.0 ppmvd	0.11	2.54	0.23
SO_x	0.00276 lb/MMBtu	0.14	3.39	0.31
$PM_{10/2.5}$	0.007 lb/MMBtu	0.354	8.50	0.77
NH_3	5.0 ppmvd	0.11	2.69	0.24

[a]Annual Emissions assume startup/shutdown operation

[b]Annual NOx emissions are based on 1.5 ppmvd. Annual SOx is based on 0.25 gr/100 scf (1.5 lb/hr) while short term is based on 1.0 gr/100scf (6 lb/hr).

Note: Auxiliary boiler operates up to 24 hours per day when turbines are not operational and up to 2 hours per day during turbine operation.

Source: Radback-CCGS Team, 2009.

TABLE 5.1-6
Startup and Shutdown Emissions Per Turbine

Parameter/Mode	Cold Startup	Hot/Warm Startup	Shutdown
NO_x, lbs/event	96.0	22.0	39.0
CO, lbs/event	540.0	138.0	206.0
POC, lbs/event	67.0	31.0	17.0
PM_{10}, lbs/event	5.6	1.8	1.8
SO_x, lbs/event	0.8	0.2	0.2
Event Time, minutes (hours)	45 minutes	14 minutes	14 minutes
Maximum Number of Events/Year	25 (Annual Case 1)	311 (Annual Case 2)	312 (Annual Case 2)

Source: Radback-CCGS Team, 2009.

TABLE 5.1-7
Combustion Turbine/HRSG Emissions for the Project (Including Base Load Cold, Hot/Warm Startup and Shutdown, Whichever is Greater)

Pollutant	Emission Factor	Max Hour Emissions (pounds)	Max Daily Emissions (pounds)	Max Annual Emissions (tons)
NO_x	N/A	99.88	492.26	49.3
CO	N/A	542.4	963.52	80.2
POCs	N/A	67.7	146.29	14.6
SO_x	N/A	6.0	144.0	6.3*
$PM_{10/2.5}$	N/A	7.5	180.0	31.7

Annual average SOx is based on annual average grain loading of 0.25 gr/scf and 1.5 lb/hr emission rate
Source: Radback-CCGS Team, 2009.

TABLE 5.1-8
Evaporative Fluid Cooler and Fire Pump Engine Emissions for the Project

Pollutant	TDS (mg/L)	Max Hour Emissions (pounds)	Max Daily Emissions (pounds)	Max Annual Emissions (tons)
		Evaporative Fluid Cooler		
$PM_{10/2.5}$	1,500	0.132	3.17	0.099
Pollutant	**g/hp-hr**	**Max Hour Emissions (pounds)**	**Max Daily Emissions (pounds)**	**Max Annual Emissions (tons)**
		Fire Pump Engine		
NO_x	2.61	2.302	2.302	0.0610
CO	0.84	0.741	0.741	0.0196
POC	0.10	0.092	0.092	0.0024
SO_x	0.0015% by weight	0.0049	0.0049	0.0027
$PM_{10/2.5}$	0.10	0.091	0.091	0.0024

Notes: Evaporative fluid cooler operates up to 24 hours per day and up to 1,500 hours per year.
Fire pump operates 1 hour per day, 53 hours per year.

Source: Radback-CCGS Team, 2009.

Table 5.1-9 presents a summary of the total proposed facility operational emissions.

TABLE 5.1-9
Summary of Total Facility Emissions for the Project

Pollutant	pounds/hour	pounds/day*	tons/year
NO_x[1]	200.31	987.92	98.8
CO[2]	1,086.57	1,931.47	164.5
POCs[3]	135.46	292.89	29.5
SO_x[1]	12.14	288.29	12.5
TSP[1]	15.49	363.97	63.5
$PM_{10/2.5}$[1]	15.49	363.97	63.5
NH_3[1]	28.84	689.74	117.72

[1]Annual based on 8,449 hours per year of operation from the turbines, 4,885 hours for the auxiliary boiler, and 1,500 hours per year for the evaporative condenser. Annual SO_x emissions based on annual average grain loading and 1.5 lb/hr.

[2] Annual CO is based on 5,310 hours of operation with 25 cold starts and 275 warm/hot starts

Worst case hourly assumes that the fire pump is not tested during turbine startup.

[3] POC based on 5,579 hours of operation with one cold start and 311 warm/hot starts.

* Daily emissions assume 24hours per day operation for the turbines and 2 hours per day for the auxiliary boiler. Plant wide annual boiler emissions based on 403 hours per year.

Source: Radback-CCGS Team, 2009.

5.1.3.3.1 Greenhouse Gas Emissions

Operational emissions of greenhouse gases (GHG) will be primarily from the combustion of fuels in the turbine, auxiliary boiler, and the fire pump. Appendix 5.1A, Air Quality Data, contains the support data for the GHG emissions evaluation. Estimated carbon dioxide (CO_2e) emissions for the project are as follows:

- CO_2e = 2,081,421 tons/year

The emission factors are based on the California Climate Action Registry General Protocol, June 2006 and BAAQMD guidance.

5.1.3.3.2 NSR Facility Status

BAAQMD regulations 2-2-215, 302 and 303 require CCGS to provide emission offsets (emissions reduction credits, or ERCs) when emissions exceed specified levels on a pollutant-specific basis. Section 2-2-302 requires POC and NO_x emission reduction credits to be provided at an offset ratio of 1:1 or 1.15:1 dependent upon emissions levels. Because both POC and NO_x contribute to the Bay Area Basin ozone levels, Section 2-2-302.2 allows emission reduction credits of POC's to be used to offset increased emissions of NO_x, at the required offset ratios as stated above. Section 2-2-303 requires emissions offsets for emissions increases at facilities that emit more than 100 tpy of SO_2 and $PM_{10/2.5}$. As facility emissions of SO_2 and $PM_{10/2.5}$ will be below 100 tpy, these pollutants will not need to be offset based upon BAAQMD rules.

Currently, the BAAQMD air basin is attainment/unclassified for nitrogen dioxide (NO_2), sulfur dioxide (SO_2), $PM_{2.5}$, and CO, and is non-attainment for PM_{10} and ozone. The BAAQMD is expecting to be re-designated as non-attainment for $PM_{2.5}$. Detailed emissions data on the facility are presented in Appendix 5.1A, Air Quality Data. Based upon the annual emission presented in Table 5.1-9, the facility will trigger the PSD program requirements for any attainment pollutant, including TSP. Therefore, a PSD increment analysis and a Class I effects assessment will be required (see Appendix 5.1C, Air Quality Data). However, the Federal Land Managers (National Park Service) have conducted a screening assessment of this project and will not require a formal Class I impact analysis. A copy of this letter is provided in Appendix 5.1C. The proposed criteria pollutant mitigation strategy for the project is discussed in Appendix 5.1G, Air Quality Data, and is summarized below.

- NO_x and POC mitigation, will be provided in the form of Emission Reduction Credits (ERCs) to satisfy BAAQMD Regulations 2-2-215, 302 and 303.
- $PM_{10/2.5}$ and SO_2 mitigation will be achieved by developing CEQA based mitigation programs, such as fireplace replacement, street sweeping, or funding the Carl Moyer program. These approaches will be discussed with the CEC staff.
- CO offsets are not required since the air basin is in attainment.

5.1.3.4 Hazardous Air Pollutants

See Section 5.9, Public Health, for a detailed discussion and quantification of HAP emissions from the project and the results of the health risk assessment. See Appendix 5.1D, HRA Support Data, for the public health analysis health risk assessment (HRA) support materials.

Sections 5.5 and 5.9 also discuss the need for Risk Management Plans pursuant to 40 CFR 68 and the California Accidental Release Program regulations.

5.1.3.5 Construction

Construction-related emissions are based on the following:

- Construction of the facility is expected to result in the temporary disturbance of approximately 20 acres. A 20-acre construction laydown and parking area will also be used for materials storage and craft labor parking.
- Moderate site preparation will be required prior to construction of the turbine/HRSGs, auxiliary boiler, fire pump, evaporative fluid cooler, building foundations, support structures, etc.
- Construction activity is expected to last for a total of 33 months.

Construction-related issues and emissions at the project site are consistent with issues and emissions encountered at any construction site. Compliance with the provisions of the following permits will generally result in minimal site emissions: (1) grading permit, (2) Stormwater Pollution Prevention Plan (SWPPP) requirements (construction site provisions), (3) use permit, (4) building permits, and (5) the BAAQMD Permit to Construct (PTC), which will require compliance with the provisions of all applicable fugitive dust rules that pertain to the site construction phase. An analysis of construction site emissions is presented in Appendix 5.1E, Air Quality Data. This analysis incorporates the following mitigation measures or control strategies:

- The Applicant will have an on-site construction mitigation manager who will be responsible for the implementation and compliance of the construction mitigation program. The documentation of the ongoing implementation and compliance with the proposed construction mitigations will be provided on a periodic basis.
- All unpaved roads and disturbed areas in the project and construction laydown and parking area will be watered as frequently as necessary to control fugitive dust. The frequency of watering will be on a minimum schedule of every 2.5 hours during the daily construction activity period. Watering may be reduced or eliminated during periods of precipitation.
- On-site vehicle speeds will be limited to 5 mph on unpaved areas within the project site construction site.
- The construction site entrance will be posted with visible speed limit signs.
- All construction equipment vehicle tires will be inspected and cleaned as necessary to be free of dirt prior to leaving the construction site via paved roadways.
- Gravel ramps will be provided at the tire cleaning area.
- All unpaved exits from the construction site will be graveled or treated to reduce track-out to public roadways.
- All construction vehicles will enter the construction site through the treated entrance roadways, unless an alternative route has been provided.

- Construction areas adjacent to any paved roadway will be provided with sandbags or other similar measures as specified in the construction SWPPP to prevent runoff to roadways.
- All paved roads within the construction site will be cleaned on a periodic basis (or less during periods of precipitation), to prevent the accumulation of dirt and debris.
- The first 500 feet of any public roadway exiting the construction site will be cleaned on a periodic basis (or less during periods of precipitation), using wet sweepers or air-filtered dry vacuum sweepers, when construction activity occurs or on any day when dirt or runoff from the construction site is visible on the public roadways.
- Any soil storage piles and/or disturbed areas that remain inactive for longer than 10 days will be covered, or shall be treated with appropriate dust suppressant compounds.
- All vehicles that are used to transport solid bulk material on public roadways and that have the potential to cause visible emissions will be covered, or the materials shall be sufficiently wetted and loaded onto the trucks in a manner to minimize fugitive dust emissions. A minimum freeboard height of 2 feet will be required on all bulk materials transport.
- Wind erosion control techniques (such as windbreaks, water, chemical dust suppressants, and/or vegetation) will be used on all construction areas that may be disturbed. Any windbreaks installed to comply with this condition will remain in place until the soil is stabilized or permanently covered with vegetation.
- Disturbed areas, which are presently vegetated, will be re-vegetated as soon as practical.

To mitigate exhaust emissions from construction equipment, the Applicant is proposing the following:

- The Applicant will work with the general contractor to utilize to the extent feasible, Environmental Protection Agency (EPA)/Air Resources Board Tier II/Tier III engine compliant equipment for equipment over 100 horsepower.
- Ensure periodic maintenance and inspections per the manufacturers specifications.
- Reduce idling time through equipment and construction scheduling.
- Use California low sulfur diesel fuels (<=15 ppmw Sulfur).

Based on the temporary nature and the time frame for construction, the Applicant believes that these measures will reduce construction emissions and effects to levels that are less than significant. Use of these mitigation measures and control strategies will ensure that the site does not cause any violations of existing air quality standards as a result of construction-related activities. Appendix 5.1E, Air Quality Data, presents the evaluation of construction related emissions as well as data on the construction related ambient air quality effects.

Table 5.1-10, BAAQMD CEQA Significance Thresholds, presents data on the regional air quality significance thresholds currently being implemented by the BAAQMD. The specific construction and operational thresholds were derived from the BAAQMD California Environmental Quality Act (CEQA) guidance.

TABLE 5.1-10
BAAQMD CEQA Significance Thresholds

Pollutant	Annual Operations Thresholds	Daily Operations Thresholds
NO_x	15 tpy	80 lbs/day
CO	—	—
POCs	15 tpy	80 lbs/day
SO_x	—	—
PM_{10}	15 tpy	80 lbs/day
$PM_{2.5}$	—	—

Note: The BAAQMD has not established numerical thresholds for construction activities, but rather the BAAQMD relies upon a set of feasible control measures to mitigate emissions. The construction mitigation measures as proposed above and in Appendix 5.1E meet the Districts CEQA guidelines.

Source: BAAQMD CEQA Manual, 12/99.

In addition to the local and regional significance criteria, the following general conformity analysis thresholds are as follows in accordance with Code of Federal Regulations (40 CFR Parts 6 and 51):

- NO_x – 100 tons per year
- POCs – 100 tons per year
- CO – 100 tons per year
- SO_x – 100 tons per year
- PM_{10} – 70 tons per year
- $PM_{2.5}$ – no value available (use 100 tpy based on PM_{10} moderate NA area value)

Emissions from the construction phase are not estimated to exceed the conformity levels noted above. Emissions from the operational phase are subject to the BAAQMD NSR and general permitting provisions, and as such, are exempt from a conformity determination or analysis.

5.1.4 Best Available Control Technology Evaluation

5.1.4.1 Current Facility Control Technologies

Table 5.1-11, BACT Values for Combustion Turbines/HRSGs, summarizes the control technologies currently proposed for use on the combustion turbines/HRSGs.

TABLE 5.1-11
BACT Values for Combustion Turbines/HRSGs

Pollutant	BACT Emissions Range*	Proposed BACT
NO_x	2.0 – 2.5 ppmvd	2.0 ppmvd
CO	3.0 – 6.0 ppmvd	2.0 ppmvd
POCs	2.0 ppmvd	1.0 ppmvd
SO_x	1.0 gr S/100 scf (short term)	1.0 gr S/100 scf (short term)

TABLE 5.1-11
BACT Values for Combustion Turbines/HRSGs

Pollutant	BACT Emissions Range*	Proposed BACT
Natural Gas	0.33 gr S/100 scf (long term)	0.25 gr S/100 scf (long term)
TSP, $PM_{10}/PM_{2.5}$	7.5 – 18 lb/hr	7.5 lb/hr

*Source: CARB, BAAQMD, SDAPCD, SJVUAPCD, and BAAQMD BACT Guidelines.
Source: Radback-CCGS Team, 2009.

5.1.4.2 Proposed Best Available Control Technology

Table 5.1-12, Proposed BACT for the Combustion Turbines/HRSGs, presents the proposed BACT for the combustion turbines/HRSGs.

TABLE 5.1-12
Proposed BACT for the Combustion Turbines/HRSGs

Pollutant	Proposed BACT Emissions Level	Proposed BACT System(s)	Meets Current BACT Requirements
NO_x	2.0 ppmvd	DLN (turbine) with SCR	Yes
CO	2.0 ppmvd	Oxidation Catalyst	Yes
POCs	1.0 ppmvd	Oxidation Catalyst	Yes
SO_x	1.0 gr S/100 scf (short term) 0.25 gr S/100 scf (long term)	Natural Gas	Yes
TSP, $PM_{10}/PM_{2.5}$	≤ 7.50 lbs/hr	Natural Gas	Yes
NH_3	5.0 ppmvd	Reagent for SCR System 29.4% aqueous ammonia	Yes

Note: HRSGs are unfired.
Source: CARB, BAAQMD, SDAPCD, SJVUAPCD, and BAAQMD BACT Guidelines.

5.1.4.2.1 Evaporative Fluid Cooler BACT

BAAQMD Regulation 2, Rule 1, section 128.4 exempts the evaporative fluid cooler from the permit process and is, therefore, not subject to the BACT requirements of Regulation 13. Additionally, Regulation 2, Rule 1, section 319 exempts a source from permitting if the emissions are less than five (5) tpy. CCGS emissions of $PM_{10/2.5}$ are less than 200 lbs/year. BACT is referenced here for the CEC. BACT for the evaporative fluid cooler will be high efficiency drift eliminators rated at 0.00003 drift fraction (0.003 percent) of the circulating water flow. Due to the small size of the evaporative fluid cooler, BACT at 0.003% is proposed.

5.1.4.2.2 Auxiliary Boiler BACT

The proposed auxiliary boiler is rated at 50.6 MMBtu/hr (HHV), and will be used for a maximum of 24 hours per day and 4,324 hours per year. The auxiliary boiler will be fired exclusively on natural gas and will be equipped with SCR and a CO Catalyst. Exhaust concentrations of NOx and CO will be limited to 9 and 50 ppmvd at 3% O_2, respectively. POC emissions will be controlled to a level of 5 ppmvd while PM_{10} emissions are estimated to be 0.007 lb/MMBtu (HHV). These emissions levels meet the BAAQMD BACT limits for limited use small boilers firing clean fuels such as natural gas.

5.1.4.2.3 Fire Pump Engine BACT

The fire pump engine will be fired exclusively on California certified ultra low sulfur diesel fuel and will meet all the emissions standards as specified in: (1) CARB ATCM, (2) EPA/CARB Tier III, and (3) NSPS Subpart IIII. Due to the low use rate of the engine for testing and maintenance, as well as its intended use for emergency fire protection, the engine meets the current BACT requirements of the BAAQMD.

5.1.5 Air Quality Impact Analysis

This section describes the results, in both magnitude and spatial extent, of ground level concentrations resulting from emissions from the project site. The maximum modeled facility concentrations were added to the maximum background concentrations to calculate a total impact when appropriate (e.g., for comparison to ambient air quality standards).

Potential air quality impacts were evaluated based on air quality dispersion modeling, as described herein and presented in the Air Quality Modeling Protocol previously submitted and approved by the BAAQMD and the CEC. A copy of the Air Quality Modeling Protocol is included in Appendix 5.1, Air Quality Data. All input and output modeling files are contained on a CD-ROM disk provided to the BAAQMD and CEC Staff under separate cover. All modeling analyses were performed using the techniques and methods as discussed with the BAAQMD and CEC through development of the Air Quality Modeling Protocol.

5.1.5.1 Dispersion Modeling

For modeling the potential impact of the project site in terrain that is both below and above stack top (defined as simple terrain when the terrain is below stack top and complex terrain when it is above stack top) the USEPA guideline model AERMOD (version 07026) was used as well as the latest versions of the AERMOD preprocessors to determine surface characteristics (AERSURFACE version 08009), to process meteorological data (AERMET version 06341), and to determine receptor slope factors (AERMAP version 09040). The purpose of the AERMOD modeling analysis was to evaluate compliance with the California and federal air quality standards.

The nearest representative surface data set in the general area of the proposed project site is the PG&E database collected at the Contra Costa Power Plant (CCP), located approximately 1.5 km northwest of the project site. This surface meteorological data set was provided by the BAAQMD for the years 2001-2002 and 2004-2006 and, for each of the listed years, data recovery exceeds 90 percent. The corresponding upper air data was collected at the Oakland International Airport for the same time periods. The CCP meteorological data provided were already processed for input to AERMOD by BAAQMD for the surface characteristics based on the meteorological monitoring location. Due to the slight differences in surface roughness between the meteorological monitoring location and the project site, the merged data files provided by BAAQMD were re-processed with Stage 3 of AERMET for the surface characteristics of the project site location. AERSURFACE was executed for the project site using the BAAQMD-recommended sectors (76° – 147°, 147° – 277°, 277° – 355°, and 355° –

76°) and moisture conditions determined by BAAQMD for each month of every year of the original CCP dataset using Antioch Pump Plant 3 meteorological station precipitation data and the percentile method specified in the AERSURFACE User's Guide. Months were assigned to each season according to BAAQMD defaults as follows: spring—February and March; summer—April through July; autumn—August through October; and winter—November through January. Both sets of meteorological data will be used to model the facility in the screening analysis and the worst-case from either set of screening runs will be used in the refined modeling analyses. Albedo, Bowen ratio, and surface roughness were classified for the CCP meteorological monitoring location by the BAAQMD. These parameters were also determined for the project site to prepare a second set of modeling files for the screening analysis (as noted above, these surface characteristics are relatively consistent throughout the area, including the locations of the meteorological monitoring site and project site). The AERSURFACE program (version 08009) was used to generate the surface characteristics for the project site as specified in EPA's January 2009 AERMOD Guidance Document and AERSURFACE User's Guide using default settings where appropriate. Surface roughness was determined by AERSURFACE for the sectors determined by BAAQMD for each location (see Figure 2 in the Air Quality Modeling Protocol). These AERSURFACE inputs/outputs are listed below in Table 5.1-13, AERSURFACE Inputs/Outputs for Use in AERMET.

TABLE 5.1-13
AERSURFACE Inputs/Outputs for Use in AERMET

Month	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Oct	Nov	Dec
Seasonal Assignments and Other Assumptions for Both Meteorological Datasets:												
Season	**Winter**	**Spring**	**Spring**	**Summer**	**Summer**	**Summer**	**Summer**	**Autumn**	**Autumn**	**Autumn**	**Winter**	**Winter**
Snow	No	—	—	—	—	—	—	—	—	—	No	No
Arid	No	No	No	No	No	No	No	No	No	No	No	No
Airport	No	No	No	No	No	No	No	No	No	No	No	No
Bowen Ratio Classification for each Month/Year based on Antioch Pump Plant 3:												
2001	Avg	Wet	Dry	Avg	Avg	Wet	Dry	Wet	Dry	Dry	Avg	Wet
2002	Dry	Dry	Avg	Dry	Dry	Dry	Dry	Dry	Dry	Dry	Avg	Wet
2004	Avg	Wet	Dry	Dry	Avg	Dry	Dry	Dry	Dry	Wet	Avg	Wet
2005	Wet	Avg	Wet	Avg	Avg	Wet	Dry	Dry	Dry	Dry	Dry	Wet
2006	Avg	Avg	Wet	Wet	Dry	Dry	Dry	Dry	Dry	Avg	Dry	Avg
SURFACE CHARACTERISTICS FOR THE CCP METEOROLOGICAL DATA LOCATION (608644, 4208274 meters, UTM Zone 10, NAD83) Surface Roughness (meters) for Sectors 1 (62°-150°) / 2 (150°-182°) / 3 (182°-243°) / 4 (243°-274°) / 5 (274°-62°):												
Sector 1	0.437	0.493	0.493	0.550	0.550	0.550	0.550	0.550	0.550	0.550	0.437	0.437
Sector 2	0.317	0.397	0.397	0.460	0.460	0.460	0.460	0.460	0.460	0.460	0.317	0.317
Sector 3	0.433	0.488	0.488	0.534	0.534	0.534	0.534	0.534	0.534	0.534	0.433	0.433
Sector 4	0.609	0.634	0.634	0.651	0.651	0.651	0.651	0.651	0.651	0.651	0.609	0.609
Sector 5	0.041	0.042	0.042	0.042	0.042	0.042	0.042	0.042	0.042	0.042	0.041	0.041
Albedo	0.16	0.15	0.15	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Bowen Ratio by surface moisture (surface moisture classification for each month/year given at the top of this table):												
Avg	0.49	0.34	0.34	0.42	0.42	0.42	0.42	0.49	0.49	0.49	0.49	0.49
Wet	0.33	0.27	0.27	0.30	0.30	0.30	0.30	0.33	0.33	0.33	0.33	0.33
Dry	0.94	0.70	0.70	0.83	0.83	0.83	0.83	0.94	0.94	0.94	0.94	0.94

TABLE 5.1-13
AERSURFACE Inputs/Outputs for Use in AERMET

Month	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Oct	Nov	Dec
SURFACE CHARACTERISTICS FOR THE PROJECT SITE LOCATION (610176.8, 4207394.7 meters, UTM Zone 10, NAD27) Surface Roughness (meters) for Sectors 1 (76º-147º) / 2 (147º-277º) / 3 (277º-355º) / 4 (355º-76º):												
Sector 1	0.121	0.195	0.195	0.299	0.299	0.299	0.299	0.299	0.299	0.299	0.121	0.121
Sector 2	0.233	0.320	0.320	0.399	0.399	0.399	0.399	0.399	0.399	0.399	0.233	0.233
Sector 3	0.217	0.311	0.311	0.409	0.409	0.409	0.409	0.409	0.409	0.409	0.217	0.217
Sector 4	0.253	0.343	0.343	0.415	0.415	0.415	0.415	0.415	0.415	0.415	0.253	0.253
Albedo	0.16	0.15	0.15	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Bowen Ratio by surface moisture (surface moisture classification for each month/year given at the top of this table):												
Avg	0.52	0.34	0.34	0.43	0.43	0.43	0.43	0.51	0.51	0.51	0.52	0.52
Wet	0.34	0.26	0.26	0.30	0.30	0.30	0.30	0.34	0.34	0.34	0.34	0.34
Dry	1.00	0.71	0.71	0.88	0.88	0.88	0.88	1.00	1.00	1.00	1.00	1.00

Source: Modeling Protocol, 2009.

AERMOD input data options are listed below. Use of these options follows the USEPA's modeling guidance. Default model option[1] for temperature gradients, wind profile exponents, and calm processing, which includes final plume rise, stack-tip downwash, and elevated receptor terrain heights option, and all sources were modeled as rural sources.

5.1.5.2 Model Selection

Several other USEPA models and programs were used to quantify pollutant impacts on the surrounding environment based on the emission sources operating parameters and their locations. The models used were Building Profile Input Program for PRIME (BPIP-PRIME, current version 04274), the HARP On-Ramp preprocessor, and the SCREEN3 (version 96043) dispersion model for fumigation impacts. These models, along with options for their use and how they are used, are discussed below.

- Comparison of impacts to significant impact levels.
- Compliance with state and federal ambient air quality standards (AAQS).
- Calculation of health risk impacts through the use of the HARP On-Ramp program.

5.1.5.3 Good Engineering Practice Stack Height Analysis

The Good Engineering Practice (GEP) stack height was calculated at 310 feet based on existing onsite and offsite structure dimensions (i.e., the air-cooled condenser) for all onsite stacks (i.e., turbines, fire pump, and wet cells). The design stack heights are less than GEP stack height, thus downwash impacts were included in the modeling analysis.

BPIP-PRIME was used to generate the wind-direction-specific building dimensions for input into AERMOD. All on-site were included for analysis with BPIP-PRIME. The building location plan, located in Appendix 5.1, Air Quality Data, shows the buildings included in the downwash analysis.

---

[1]To reduce run times for the area source modeled for fugitive dust and the large number of point sources modeled for mobile combustion source equipment, the TOXICS keyword was used for modeling construction impacts.

5.1.5.4 Receptor Grid Selection and Coverage

Receptor and source base elevations were determined from the U.S. Geological Survey (USGS) Digital Elevation Model (DEM) data using 10-meter spacing between grid nodes. All coordinates were referenced to UTM North American Datum 1927 (NAD27), Zone 10. The receptor locations and elevations from the DEM files will be placed exactly on the DEM nodes. Every effort was made to maintain receptor spacing across DEM file boundaries.

Cartesian coordinate receptor grids are used to provide adequate spatial coverage surrounding the project area for assessing ground-level pollution concentrations, to identify the extent of significant impacts, and to identify maximum impacts locations. The receptor grids used in this analysis are listed below.

- 10-meter resolution from the project site fenceline and extending outwards in all directions 500-meters. This is called the downwash grid. In addition, receptors were placed at 10-meter intervals or less along the project site fenceline.
- 50-meter resolution that extends outwards from the edge of the downwash grid to 2 kilometers in all directions. This is referred to as the intermediate grid.
- 200-meter resolution that extends outwards from the edge of the intermediate grid to about 10 kilometers in all directions (and more if necessary to calculate the extent of any significant impact area(s)). This is referred to as the coarse grid.
- 10-meter resolution around any location on the coarse and intermediate grids where a maximum impact is modeled that is above the concentrations on the downwash grid.
- For the HARP On-Ramp program, the minimum receptor spacing was changed to 100 meter resolution due to the limitation of the number of receptors On-Ramp can use.

Concentrations within the facility fence-line will not be calculated. The receptor grid figure, located in Appendix 5.1, Air Quality Data, displays the receptors grids used in the modeling assessment. A facility boundary figure is also presented in Appendix 5.1, Air Quality Data.

5.1.5.5 Meteorological Data Selection

The use of the five years of meteorological data collected at CCP, which were also reprocessed to include surface characteristics for the project site location and included in the modeling analyses, satisfies the definition of on-site data. Detailed discussions of the representativeness of the meteorological data and comparisons of the CCP and project site locations (including aerial photo figures) are contained in the Air Quality Modeling Protocol (included in Appendix 5.1, Air Quality Data) that was previously submitted and approved by the BAAQMD and the CEC.

A graphical wind rose for 2001-2006 period is attached to the Air Quality Modeling Protocol included in Appendix 5.1, Air Quality Data. Five-year quarterly wind roses for the modeling data set are also provided in Appendix 5.1, Air Quality Data.

The area surrounding the project site, within 3 kilometers, can be characterized as mostly rural in accordance with the Auer land use classification methodology (USEPA's "*Guideline on Air Quality Models*"), with the water of the San Joaquin River to the north and open/undeveloped areas, commercial/industrial areas, and residential areas surrounding the project site. Therefore, in the modeling analyses supporting the permitting of the facility, all emissions were modeled as rural sources. Aerial photos and a Auer land use classification of the project site are contained in the Air Quality Modeling Protocol included in Appendix 5.1, Air Quality Data

5.1.5.6 Background Air Quality

In 1970, the United States Congress instructed the USEPA to establish standards for air pollutants, which were of nationwide concern. This directive resulted from the concern of the effects of air pollutants on the health and welfare of the public. The resulting Clean Air Act (CAA) set forth air quality standards to protect the health and welfare of the public. Two levels of standards were promulgated—primary standards and secondary standards. Primary national ambient air quality standards (NAAQS) are "those which, in the judgment of the administrator [of the USEPA], based on air quality criteria and allowing an adequate margin of safety, are requisite to protect the public health (state of general health of community or population)." The secondary NAAQS are "those which in the judgment of the administrator [of the USEPA], based on air quality criteria, are requisite to protect the public welfare and ecosystems associated with the presence of air pollutants in the ambient air." To date, NAAQS have been established for seven criteria pollutants as follows: SO_2, CO, ozone, NO_2, PM_{10}, $PM_{2.5}$, and lead.

The criteria pollutants are those that have been demonstrated historically to be widespread and have a potential to cause adverse health effects. USEPA developed comprehensive documents detailing the basis of, or criteria for, the standards that limit the ambient concentrations of these pollutants. The State of California has also established AAQS that further limit the allowable concentrations of certain criteria pollutants. Review of the established air quality standards is undertaken by both USEPA and the State of California on a periodic basis. As a result of the periodic reviews, the standards have been updated and amended over the years following adoption.

Each federal or state AAQS is comprised of two basic elements: (1) a numerical limit expressed as an allowable concentration, and (2) an averaging time which specifies the period over which the concentration value is to be measured. Table 5.1-14, State and Federal Ambient Air Quality Standards, presents the current federal and state AAQS.

TABLE 5.1-14
State and Federal Ambient Air Quality Standards

Pollutant	Averaging Time	California Standards Concentration	National Standards Concentration
Ozone	1-hour	0.09 ppm (180 μg/m^3)	—
	8-hour	0.07 ppm (137 μg/m^3)	0.075 ppm (147 μg/m^3) (3-year average of annual 4th-highest daily maximum)
Carbon Monoxide	8-hour	9.0 ppm (10,000 μg/m^3)	9 ppm (10,000 μg/m^3)
	1-hour	20 ppm (23,000 μg/m^3)	35 ppm (40,000 μg/m^3)
Nitrogen dioxide	Annual Average	0.030 ppm (57 μg/m^3)	0.053 ppm (100 μg/m^3)
	1-hour	0.18 ppm (339 μg/m^3)	—

TABLE 5.1-14
State and Federal Ambient Air Quality Standards

Pollutant	Averaging Time	California Standards Concentration	National Standards Concentration
Sulfur dioxide	Annual Average	—	0.030 ppm (80 μg/m^3)
	24-hour	0.04 ppm (105 μg/m^3)	0.14 ppm (365 μg/m^3)
	3-hour	—	0.5 ppm (1,300 μg/m^3)
	1-hour	0.25 ppm (655 μg/m^3)	—
Respirable particulate matter (10 micron)	24-hour	50 μg/m^3	150 μg/m^3
	Annual Arithmetic Mean	20 μg/m^3	—
Fine particulate matter (2.5 micron)	Annual Arithmetic Mean	12 μg/m^3	15.0 μg/m^3 (3-year average)
	24-hour	—	35 μg/m^3 (3-year average of 98th percentiles)
Sulfates	24-hour	25 μg/m^3	—
Lead	30-day	1.5 μg/m^3	—
	3 Month Rolling Average	—	0.15 μg/m^3

Source: CARB website, table updated 11/17/08

μg/m^3 = micrograms per cubic meter
ppm = parts per million

Brief descriptions of health effects for the main criteria pollutants are as follows.

Ozone—Ozone is a reactive pollutant that is not emitted directly into the atmosphere, but rather is a secondary air pollutant produced in the atmosphere through a complex series of photochemical reactions involving precursor organic compounds (POC) and NO_x. POC and NO_x are therefore known as precursor compounds for ozone. Significant ozone production generally requires ozone precursors to be present in a stable atmosphere with strong sunlight for approximately three hours. Ozone is a regional air pollutant because it is not emitted directly by sources, but is formed downwind of sources of POC and NO_x under the influence of wind and sunlight. Short-term exposure to ozone can irritate the eyes and cause constriction of the airways. In addition to causing shortness of breath, ozone can aggravate existing respiratory diseases such as asthma, bronchitis, and emphysema.

Carbon Monoxide—CO is a non-reactive pollutant that is a product of incomplete combustion. Ambient CO concentrations generally follow the spatial and temporal distributions of vehicular traffic and are also influenced by meteorological factors such as wind speed and atmospheric mixing. Under inversion conditions, CO concentrations may be distributed more uniformly over an area out to some distance from vehicular sources. When inhaled at high concentrations, CO combines with hemoglobin in the blood and reduces the oxygen-carrying capacity of the blood. This results in reduced oxygen reaching the brain, heart, and other body tissues. This condition is especially critical for people with cardiovascular diseases, chronic lung disease or anemia, as well as fetuses.

Particulate Matter (PM_{10} and $PM_{2.5}$)—PM_{10} consists of particulate matter that is 10 microns or less in diameter (a micron is 1 millionth of a meter), and fine particulate matter, $PM_{2.5}$, consists of particulate matter 2.5 microns or less in diameter. Both PM_{10} and $PM_{2.5}$ represent fractions of particulate matter, which can be inhaled into the air passages and the lungs and can cause adverse health effects. Particulate matter in the atmosphere results from many kinds of dust- and fume-producing industrial and agricultural operations, combustion, and atmospheric photochemical reactions. Some of these operations, such as demolition and construction activities, contribute to increases in local PM_{10} concentrations, while others, such as vehicular traffic, affect regional PM_{10} concentrations.

Several studies that the USEPA relied on for its staff report have shown an association between exposure to particulate matter, both PM_{10} and $PM_{2.5}$, and respiratory ailments or cardiovascular disease. Other studies have related particulate matter to increases in asthma attacks. In general, these studies have shown that short-term and long-term exposure to particulate matter can cause acute and chronic health effects. $PM_{2.5}$, which can penetrate deep into the lungs, causes more serious respiratory ailments.

Nitrogen Dioxide and Sulfur Dioxide—NO_2 and SO_2 are two gaseous compounds within a larger group of compounds, NO_x and SO_x, respectively, which are products of the combustion of fuel. NO_x and SO_x emission sources can elevate local NO_2 and SO_2 concentrations, and both are regional precursor compounds to particulate matter. As described above, NO_x is also an ozone precursor compound and can affect regional visibility. (NO_2 is the "whiskey brown-colored" gas readily visible during periods of heavy air pollution.) Elevated concentrations of these compounds are associated with increased risk of acute and chronic respiratory disease.

SO_2 and NO_2 emissions can be oxidized in the atmosphere to eventually form sulfates and nitrates, which contribute to acid rain. Large power facilities with high emissions of these substances from the use of coal or oil are subject to emissions reductions under the Phase I Acid Rain Program of Title IV of the 1990 CAA Amendments. Power facilities, with individual equipment capacity of 25 MW or greater that use natural gas or other fuels with low sulfur content, are subject to the Phase II Program of Title IV. The Phase II program requires facilities to install Continuous Monitoring Systems (CMS) in accordance with 40 CFR Part 75 and report annual emissions of SO_x and NO_x. Thus, the acid rain program provisions will apply to the project site. The project site will participate in the Acid Rain allowance program through the purchase of SO_2 allowances. Sufficient quantities of SO_2 allowances are available for use on this project site.

Lead—Gasoline-powered automobile engines used to be the major source of airborne lead in urban areas. Excessive exposure to lead concentrations can result in gastrointestinal disturbances, anemia, and kidney disease, and, in severe cases, neuromuscular and neurological dysfunction. The use of lead additives in motor vehicle fuel has been eliminated in California and lead concentrations have declined substantially as a result.

The nearest criteria pollutant air quality monitoring sites to the project site would be the stations located at Bethel Island, Pittsburg, and Concord. Ambient monitoring data for these sites for the most recent three-year period is summarized in Table 5.1-16, Summary of Air Quality Monitoring Data for the Most Recent 3 Year Period. Data from these sites is estimated to present a reasonable representation of background air quality for the project site and the facility's impact area.

Table 5.1-15, BAAQMD Attainment Status Table, presents the BAAQMD attainment status.

TABLE 5.1-15
BAAQMD Attainment Status

Pollutant	Averaging Time	Federal Status	State Status
Ozone	1-hr	NA	NA
Ozone	8-hr	NA	NA
NO_2	All	UNC/ATT	ATT
CO	All	ATT	ATT
SO_2	All	ATT	ATT
PM_{10}	All	UNC	NA
$PM_{2.5}$	All	UNC/ATT	NA

ATT = attainment
NA = non-attainment
UNC = unclassified

Source: BAAQMD Website, 2008 and 40 CFR 81.305.

TABLE 5.1-16
Summary of Air Quality Monitoring Data for Most Recent 3-Year Period

Pollutant	Site	Avg. Time	2006	2007	2008
Ozone, ppm	Bethel Isl.	1-Hr Max	.116	.093	.109
	Pittsburg		.105	.100	.106
	Bethel Isl.	8-Hr Max	.085	.071	.076
	Pittsburg		.079	.067	.067
PM_{10}, µg/m^3	Bethel Isl.	24-Hr Max	82	47	78
	Pittsburg		58	56	74
	Bethel Isl.	Annual AM	19.4	18.8	24
	Pittsburg		19.9	19.4	20
$PM_{2.5}$, µg/m^3	Concord	24-Hr 98th Percentile	38.8	45	38
	Concord	Annual AM	19.0	8.7	10.2
CO, ppm	Bethel Isl.	1-Hr Max	1.3	1.1	1.0
	Pittsburg		3.3	2.8	2.8
	Bethel Isl.	8-Hr Max	1.0	.8	.8
	Pittsburg		1.9	1.5	1.4
NO_2, ppm	Bethel Isl.	1-Hr Max	.044	.048	.03
	Pittsburg		.052	.051	.044
	Bethel Isl.	Annual AM	.008	.008	.006
	Pittsburg		.011	.01	.009

TABLE 5.1-16
Summary of Air Quality Monitoring Data for Most Recent 3-Year Period

Pollutant	Site	Avg. Time	2006	2007	2008
SO_2, ppm	Bethel Isl.	1-Hr Max	.017	.018	.012
		3-Hr Max	.011	.013	.009
		24-Hr Max	.007	.005	.004
		Annual AM	.002	.002	.002
	Pittsburg	1-Hr Max	.045	.047	.023
		3-Hr Max	.025	.024	.015
		24-Hr Max	.009	.007	.006
		Annual AM	.003	.002	.002

Source: AQMD website, Air Quality Monitoring Summaries for 2006-2008. EPA AIRS Data System, EPA Website, 2009.

Table 5.1-17, Background Air Quality Values, shows the background air quality values (converted to μg/m^3 when appropriate) based upon the data presented in Table 5.1-16, Summary of Air Quality Monitoring Data for the Most Recent 3-Year Period. The background values represent the highest values reported for any site during any single year of the most recent three-year period. Appendix 5.1, Air Quality Data, presents the background air quality data summaries.

TABLE 5.1-17
Background Air Quality Values

Pollutant and Averaging Time	Background Value, μg/m^3
Ozone – 1-hr	227
Ozone – 8-hr	166.5
PM_{10} – 24-hr	82
PM_{10} – Annual	24
$PM_{2.5}$ – 24-hr	35*
$PM_{2.5}$ – Annual	9[a]
CO – 1-hr	3,771
CO – 8-hr	2,171
NO_2 – 1-hr	98.1
NO_2 – Annual	20.8
SO_2 – 1-hr	122.2
SO_2 – 3-hr	65.0
SO_2 – 24-hr	23.4
SO_2 – Annual	7.8
Sulfate, 24-hr	Nd

*Regulatory-defined background for project vicinity based on the 2006-2008 98th percentiles (February 26, 2009 BAAQMD guidance).

5.1.5.6.1 Impacts on Class II Areas

Operational characteristics of the combustion turbine such as emission rate, exit velocity, and exit temperature vary by operating load and ambient temperature. The project site will be operated over a variety of these temperature ranges. Thus, the air quality analysis considered the range of operational characteristics over a variety of ambient temperatures. The screening modeling analysis, using AERMOD and the five-year set of hourly meteorology (i.e., years 2001-2002 and 2004-2006 of the CCP meteorological dataset prepared by BAAQMD for AERMOD and the same dataset reprocessed to include the surface characteristics Albedo, Bowen ratio, and surface roughness for the project site) was performed for various load conditions in order to determine the combustion turbine operating condition that will result in the highest modeled concentrations for averaging periods of 24 hours or less. These conditions were considered for following ambient temperature conditions: 34°F (a cold day), 59°F (average conditions), and 104°F (a hot day). The 59°F condition was assumed to represent annual average conditions. As such, no screening analyses were performed for annual average concentrations, which were modeled for the 59°F case at 100 percent load (combustion turbine inlet air evaporative cooling on), which is the typical operating scenario.

The results of the load screening analysis are listed in Appendix 5.1, Air Quality Data. The screening analysis shows that the worst-case load and ambient temperature condition is 80 percent load at 34°F for all short-term impacts. In addition, the CCP meteorological data processed with the project site surface characteristics produced higher turbine screening impacts for all pollutants and averaging times. Therefore, the CCP meteorological data processed with the project site surface characteristics were used for the refined analysis and construction impacts modeling.

5.1.5.7 Refined Analysis

All facility sources were modeled in the analysis for comparisons with Significant Impact Levels (SILs) and California Ambient Air Quality Standards (CAAQS)/National Ambient Air Quality Standards (NAAQS), as necessary.

The project will use GE’s Rapid Response technology which will limit all startup/shutdown periods to one (1) hour or less. Since AERMOD is based on one (1) hour steady state conditions, the startup/shutdown emission rate used for modeling assumed the remaining time periods were at full load operation. For example, to model the one (1) hour cold start condition of 45 minutes, the remaining 15 minutes in the hour were set to full load operation emissions after adjusting the full load emission by the time (0.25). For the two (2) proposed turbines, start-up/shutdown emissions were also accounted for in the refined analysis for all short-term (24-hours or less) and long-term (annual) averages in the air quality modeling. For short-term averaging times, the highest one-hour emissions during the start-up of the combustion turbines (cold start) were used for determining one-hour NO_x and CO impacts. For the eight-hour CO modeling during startup, one cold start (1-hour), one shutdown (1-hour) and six (6) hours of base load operation were assumed. Annual emission estimates already include emissions from start-up, shutdown, and maintenance activities. Detailed emission calculations for all averaging periods are included in Appendix 5.1, Air Quality Data. The modeling assumptions included the following:

- Auxiliary boiler operation is 2 hours per day during turbine operation and 4,324 hours per year
- Fire pump operates 1 hour per day, 53 hours per year

- Evaporative fluid cooler operates 24 hours per day and 1,500 hours per year
- Turbine operates 24 hours per day
- Worst-case annual emissions: 8,424 hours base load, 51 warm/hot starts, 1 cold starts, 52 shutdowns = 8,449 hours
- Cold start is 45 minutes which is the worst case start plus 15 minutes of base load emissions
- CO 8-hour impacts calculated as 1 cold start + one shutdown + 6 hours base load
- Fire pump not tested during 1 hour start cycle
- Aux boiler assumed to operate two hours for 8-hour CO startup modeling

The worst-case modeling input information for each pollutant and averaging period are shown in Table 5.1-18, Stack Parameters and Emission Rates for the Modeled Sources, for normal operating conditions and combustion turbine startup/shutdown conditions. As discussed above, the combustion turbine stack parameters used in modeling the impacts for each pollutant and averaging period reflected the worst-case operating condition for that pollutant and averaging period identified in the load screening analysis. Stack parameters associated with operation at 80 the percent load case and evaporative cooler off were modeled for all short-term averaging times while the 100 percent load case with evaporative cooler on at the average temperature of 59°F were used in modeling annual average impacts.

TABLE 5.1-18
Stack Parameters and Emission Rates for Each of the Modeled Sources

	Stack Height (m)	Stack Temp. (deg K)	Exit Vel. (m/s)	Stack Diam. (m)	Emission Rates (g/s)			
					NO_x	SO_2	CO	$PM_{10/2.5}$
Averaging Period: 1-hour for Normal Operating Conditions								
Each Turbine/HRSG	47.396	358.0	19.26	5.5992	1.956	0.756	1.191	—
Fire Pump	4.877	714.26	32.22	0.2032	2.901E-1	5.040E-4	0.093	—
Auxiliary Boiler	15.240	416.48	15.08	0.7620	6.930E-2	1.764E-2	0.233	—
Averaging Period: 3-hours for Normal Operating Conditions								
Each Turbine/HRSG	47.396	358.0	19.26	5.5992	—	0.756	-	—
Fire Pump	4.877	714.26	32.22	0.2032	—	1.680E-4	-	—
Auxiliary Boiler	15.240	416.48	15.08	0.7620	—	1.764E-2	-	—
Averaging Period: 8-hours for Normal Operating Conditions								
Each Turbine/HRSG	47.396	358.0	19.26	5.5992	—	—	1.191	—
Fire Pump	4.877	714.26	32.22	0.2032	—	—	1.167E-2	—
Auxiliary Boiler	15.240	416.48	15.08	0.7620	—	—	0.233	—

TABLE 5.1-18
Stack Parameters and Emission Rates for Each of the Modeled Sources

	Stack Height (m)	Stack Temp. (deg K)	Exit Vel. (m/s)	Stack Diam. (m)	Emission Rates (g/s)			
					NO_x	SO_2	CO	$PM_{10/2.5}$
Averaging Period: 24-hours for Normal Operating Conditions								
Each Turbine/HRSG	47.396	358.0	19.26	5.5992	—	0.756	—	0.396
Fire Pump	4.877	714.26	32.22	0.2032	—	2.100E-5	—	4.778E-4
Auxiliary Boiler	15.240	416.48	15.08	0.7620	—	5.880E-3	—	9.576E-3
Each Evap. Cooler Cell	7.010	304.21	10.19	3.353	—	—	—	2.541E-3
Averaging Period: Annual for Normal Operating Conditions								
Each Turbine/HRSG	47.396	361.4	22.04	5.5992	1.424	0.176	—	0.595
Fire Pump	4.877	714.26	32.22	0.2032	1.655E-3	3.103E-6	—	6.532E-5
Auxiliary Boiler	15.240	416.48	15.08	0.7620	3.163E-3	8.190E-4	—	1.069E-2
Each Evap. Cooler Cell	7.010	304.21	10.19	3.353	—	—	—	9.493E-4
Averaging Period: 1-hour for Start-up/Shutdown Conditions								
Each Turbine/HRSG	47.396	358.0	19.26	5.5992	12.585	—	68.338	—
Fire Pump	4.877	714.26	32.22	0.2032	—	—	—	—
Auxiliary Boiler	15.240	416.48	15.08	0.7620	6.930E-2	—	0.233	—
Averaging Period: 8-hours for Start-up/Shutdown Conditions								
Each Turbine/HRSG	47.396	358.0	19.26	5.5992	—	—	12.794	—
Fire Pump	4.877	714.26	32.22	0.2032	—	—	1.167E-2	—
Auxiliary Boiler	15.240	416.48	15.08	0.7620	—	—	0.058	—

Source: Radback-CCGS Team, 2009.

5.1.5.8 Normal Operations Impact Analysis

In order to determine the magnitude and location of the maximum impacts for each pollutant and averaging period, the AERMOD model was used. Table 5.1-19 summarizes maximum modeled concentrations for each criteria pollutant and associated averaging periods. In order to assess the significance of the modeled concentrations, they were compared to the Class II PSD and BAAQMD SILs. All modeled facility pollutant concentrations are less than the SILs for those pollutants.

Maximum impacts for 24-hour and annual averages for SO_2, NO_X, and $PM_{10/2.5}$ occurred in the 50-meter spaced intermediate grid. Therefore, additional 10-meter spaced refined receptor grids were modeled for these pollutants and averaging times. Additionally, the 8-hour CO startup was also modeled with the additional 10-meter spaced grid. The maximum impacts for the other pollutants and averaging times (i.e., NO_2 1-hour averages, CO 1-hour and 8-hour averages, and SO_2 1-hour and 3-hour averages) occurred in the immediate vicinity of the facility either on the fenceline or within the downwash grid in the 10-meter-spaced receptor areas. Therefore, no additional 10-meter-spaced receptor grids in the coarse or intermediate receptor grid areas were required for these pollutants/averaging times. Again, it should be noted that the refined modeling analyses was performed with the CCP meteorological data processed with the project site surface characteristics based on the results of the turbine screening analyses.

The maximum modeled impacts for all pollutants and averaging times are less than all applicable significance impact levels with the exception of 1-hour NO_2. Therefore, the project site would not significantly affect the attainment status of any pollutant and facility impacts are considered to not be discernable from or significantly increase existing background pollutant concentrations. Facility impacts are also less than the 1-hour NO_2 CAAQS. Total concentrations (maximum modeled impacts plus maximum background concentrations) only exceed CAAQS/NAAQS for those pollutants and averaging times where background concentrations already equal or exceed the standards (i.e., the 24-hour and annual PM_{10} CAAQS and the 24-hour $PM_{2.5}$ NAAQS).

TABLE 5.1-19
Air Quality Impact Results for Refined Modeling Analysis of Project

Pollutant	Avg. Period	Maximum Concentration (µg/m³)	Background (µg/m³)	Total (µg/m³)	Class II Significance Level (µg/m³)	Ambient Air Quality CAAQS/NAAQS (µg/m³)	(µg/m³)
Normal Operating Conditions							
NO_2	1-hour	177.5	98.1	275.6	19	339	-
	Annual	0.59	20.8	21.4	1	57	100
CO	1-hour	65.497	3771	3836.5	2,000	23,000	40,000
	8-hour	33.6	2171	2204.6	500	10,000	10,000
SO_2	1-hour	10.1	122.2	132.3	-	655	-
	3-hour	7.5	65.0	72.5	25	-	1,300
	24-hour	2.0	23.4	25.4	5	105	365
	Annual	0.07	7.8	7.9	1	-	80
PM_{10}	24-hour	1.196	82	83.2	5	50	150
	Annual	0.29	24	24.3	1	20	-
$PM_{2.5}$	24-hour	1.196	35	36.2	1.2	-	35
	Annual	0.29	9	9.3	0.3	12	15.0
Start-up/Shutdown Periods							
NO_2	1-hour	162.86	98.1	260.96	19	339	-
CO	1-hour	881.45	3771	4652.45	2,000	23,000	40,000
	8-hour	92.0	2171	2263	500	10,000	10,000
Commissioning Activities							
NO_2	1-hour	148.62	98.1	246.72	19	339	-
CO	1-hour	234.37	3771	4005.37	2,000	23,000	40,000
	8-hour	127.61	2171	2298.61	500	10,000	10,000

Source: Radback-CCGS Team, 2009.

There are several scenarios that are possible during commissioning which are expected to result in NO_x, CO and POC emissions that are greater than during normal operations. During commissioning, SO_2 and $PM_{10/2.5}$ emissions are expected to be no greater than full load operations. Typically, these commissioning activities occur prior to the installation of the abatement equipment, e.g., SCR and oxidation catalyst, while the combustion turbines are being tuned to achieve optimum performance. During combustion turbine tuning, NO_x and CO emission control systems would not be functioning.

For the purposes of air quality modeling, NO_2 and CO impacts could be higher during commissioning than under other operating conditions already evaluated. The commissioning activities for the combustion turbine are expected to consist of several phases. Though precise emission values during the phases of commissioning cannot be provided given the consideration for contingencies during shakedown, the worst case short-term emissions profile during expected commissioning-period operating loads are summarized in Table 5.1-20, Estimated Maximum Hourly Emissions Rates.

TABLE 5.1-20
Estimated Maximum Hourly Emissions Rates During Commissioning*

		NO_X	CO	POC	$PM_{10/2.5}$	SO_x
Emission Rate	lb/hr	126	593	72	7.5	6.0

* Turbines only
Source: Radback-CCGS Team, 2009.

The new combustion turbine's commissioning period (prior to SCR and CO catalyst loading), with an estimated duration of 583 operating hours total, is expected to consist of the following processes and time periods as delineated in Table 5.1-21, Commissioning Schedule.

TABLE 5.1-21
Commissioning Schedule

Stage	Activities	Emissions Controls	Duration (time, hours)
1	1) Combustion turbine first fire 2) Combustion turbine full speed/no load testing	DLN: None SCR/CO: None/None	72 hours per turbine 144 hours both turbines
2	1) Steam blow 2) Combustion turbine tuning and part load testing	DLN: Partial SCR/CO: None/None	144 hours per turbine 288 hours total
3	1) Combustion turbine full load testing 2) Combustion turbine tuning	DLN: Partial SCR/CO: None/None	48 hours per turbine 96 hours total
4	1) Full load testing with catalyst 2) SCR system tuning	DLN: Full SCR/CO: Partial/Partial	24 hours per turbine 48 hours total

Source: Radback-CCGS Team, 2009.

The emissions during the 583 hours of commissioning activities are expected to be as follows:

- NO_x – 29.63 tons
- CO – 22.87 tons
- POC – 2.28 tons
- TSP, $PM_{10/2.5}$ – 2.19 tons
- SO_x – 1.27 tons

Only one turbine will be commissioned at a time. Appendix 5.1, Air Quality Data, lists the specific emissions during each phase of the commissioning activity.

The modeling presented in Table 5.1-19 summarizes the results of the commissioning assessment and assumes one turbine is in commissioning phase with the other turbine in full load operation.

Fumigation analyses with the USEPA Model SCREEN3 (version 96043) were conducted based on USEPA guidance given in *"Screening Procedures for Estimating the Air Quality Impact of Stationary Sources, Revised"* (EPA-454/R-92-019) and BAAQMD guidance contained in *"Permit Modeling Guidance"* (June 2007). Stack parameters for the worst-case 1-hour source configuration from the AERMOD screening analysis were used for the fumigation analysis. The site is classified as a rural source location based on the Auer land use classification methodology. Therefore, only rural dispersion conditions were considered since there is no need to adjust fumigation impacts for urban dispersion conditions.

The inversion breakup fumigation impact of 1.243 micrograms/cubic meter ($\mu g/m^3$) for a unitized emission rate (1 gram/second, [g/s]) was predicted to occur 16,055 meters (m) from the turbines for a single turbine stack. This result is predicted to occur by SCREEN3 for rural conditions of F stability and 2.5 m/s wind speed at the stack release height. At the inversion breakup fumigation distance for the turbines, the maximum auxiliary boiler and fire pump impacts were 8.469 and 11.10 $\mu g/m^3$, respectively, for a 1 g/s emission rate for each stack under rural conditions for all SCREEN3 meteorological combinations. No inversion breakup fumigation impacts are predicted to occur by SCREEN3 for the auxiliary boiler or fire pump stacks.

These unitized impacts were used to calculate 1-hour inversion breakup impacts for all pollutants by multiplying the unitized impacts by the pollutant emission rates (in g/s). The fumigation impacts from the two proposed turbines are added to the SCREEN3 fire pump and auxiliary boiler impacts at the same location to obtain combined pollutant impacts for the entire facility. The maximum fumigation impact is compared to the maximum 1-hour impacts from the refined AERMOD analyses in the following table.

TABLE 5.1-22
Inversion Breakup Fumigation Impacts

Pollutant/Avg. Time	Impacts (µg/m3) at Inversion Breakup Location				Maximum refined Impacts from AERMOD
	Fumigation impacts for Two (2) Turbines	Aux. Blr Impacts	Fire Pump Impacts	Total Impacts	
NO_x 1-hour	4.863	3.220	2.797	7.660	177.5
SO_2 1-hour	0.763	1.879	0.196	0.006	10.1
CO 1-hour	1.636	2.961	2.586	1.032	65

As shown above, the maximum 1-hour inversion breakup fumigation impacts are less than maximum 1-hour facility impacts predicted by AERMOD to occur under normal dispersion conditions. (The maximum fumigation impacts are also less than the SCREEN3 maxima predicted to occur under normal dispersion conditions as shown in the model output files provided to the agency.) Therefore, no further analysis of fumigation impacts for additional short-term averaging times (3-hours, 8-hours, or 24-hours) is required as described in Section 4.5.3 of *"Screening Procedures for Estimating the Air Quality Impact of Stationary Sources, Revised"* (EPA-454/R-92-019).

Shoreline fumigation impacts were also assessed since the nearest distance to the shoreline of the San Joaquin River is less than 3000 meters from the turbine stacks. Like the inversion breakup fumigation analysis, the SCREEN3 model was also used to perform the shoreline fumigation analysis. The default Thermal Internal Boundary Layer (TIBL) factor in the SCREEN3 model is set to a value of 6.0. Shoreline fumigation for TIBL factors from 2 to 6 were also calculated as required by the BAAQMD Modeling Guidance by revising and recompiling SCREEN3 for TIBL factors of 2.0, 3.0, 4.0, and 5.0. The final effective plume centerline height for the turbine stacks is 165 meters for rural conditions of F stability and 2.5 meter/second (m/s) wind speeds at the turbine stack release height. TIBL heights at the nearest turbine stack to the shoreline of the San Francisco Bay (a distance of about 950 meters) range from 62 to 154 meters for TIBL factors from 2.0 to 5.0 (for a 6.0 TIBL factor, the TIBL height at the turbine stack location is greater than the final effective plume centerline height, so no shoreline fumigation impacts would occur for a 6.0 TIBL factor). No shoreline fumigation impacts are predicted to occur by SCREEN3 for either the fire pump or auxiliary boiler stacks for any TIBL factor modeled from 2.0 to 6.0. Like the inversion breakup fumigation analysis, SCREEN3 was used to assess impacts at the shoreline fumigation location for these other facility sources using rural dispersion conditions with all SCREEN3 meteorological combinations and ignoring terrain at the distance of the maximum fumigation concentration.

The highest turbine shoreline fumigation impact from varying the TIBL factor was 8.730 µg/m^3 for a unitized emission rate of 1.0 g/s/turbine for a 5.0 TIBL factor at a distance of 1347 meters from the turbine stack. At this distance, the maximum auxiliary boiler and fire pump impacts were 56.85 and 76.96 µg/m^3, respectively, for a 1 g/s emission rate for each stack under rural conditions for all SCREEN3 meteorological combinations. These unitized impacts were used to calculate total 1-hour impacts for the entire facility by multiplying the unitized impacts by the pollutant emission rates (in g/s) and adding the impacts together. These 1-hour pollutant impacts are shown in the following table.

TABLE 5.1-23
Shoreline Fumigation Impacts

Pollutant/Avg. Time	Impacts ($\mu g/m^3$) at Inversion Breakup Location				Maximum refined Impacts from AERMOD
	Fumigation impacts for Two (2) Turbines	Aux. Blr Impacts	Fire Pump Impacts	Total Impacts	
NO_x 1-hour	34.152	22.326	19.394	75.872	177.5
SO_2 1-hour	13.200	1.358	0.039	14.597	10.1
CO 1-hour	20.795	17.932	7.157	45.884	65
PM 1-hour	15.095	2.211	0.882	18.185	20.116

As shown above, the maximum 1-hour inversion breakup fumigation impacts are less than maximum 1-hour facility impacts predicted by AERMOD (or SCREEN3) to occur under normal dispersion conditions for all pollutants other than SO_2. (The maximum fumigation impacts are also less than the SCREEN3 maxima predicted to occur under normal dispersion conditions for all pollutants other than SO_2 as shown in the model output files provided to the agency.) Therefore, no further analysis of fumigation impacts for additional short-term averaging times (3-hours, 8-hours, or 24-hours) is required for NOx, CO, and PM. For SO_2, impacts for other short-term averaging times were calculated as described in Section 4.5.3 of *"Screening Procedures for Estimating the Air Quality Impact of Stationary Sources, Revised"* (EPA-454/R-92-019). These SO_2 impacts are shown below compared to the significance levels and ambient air quality standards.

TABLE 5.1-24
SO_2 Impact Results for Shoreline Fumigation

Pollutant	Avg. Period	Maximum Concentration ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total ($\mu g/m^3$)	Class II Significance Level ($\mu g/m^3$)	Ambient Air Quality CAAQS/NAAQS ($\mu g/m^3$)	($\mu g/m^3$)
Normal Operating Conditions							
	1-hour	14.6	122.2	136.8	—	655	—
SO_2	3-hour	8.2	65.0	73.2	25	—	1,300
	24-hour	0.7	23.4	24.1	5	105	365

A comparison to Table 5.1-24 shows that the 1-hour and 3-hour SO_2 shoreline fumigation impacts are greater than the maximum refined AERMOD results. However, like the

AERMOD results, all of these facility impacts are less than the applicable significance levels and total facility impacts plus background concentrations are far less than the ambient air quality standards. Therefore, the fumigation impacts do not change the conclusions of the refined AERMOD analyses.

Based upon emissions data provided to the Federal Land Managers (FLMs), specifically the United States Park Service (Dee Moris), the FLMs did not require a Class I air quality related values (AQRV) analyses to either deposition or visibility at the closest Class I areas which are Pinnacles National Monument and Point Reyes. A copy of the National Park Service letter exempting this project from a Class I ARQV analysis is included in Appendix 5.1C. However, the Class I areas were modeled for comparisons to the Federal Class I significance levels for increment analysis.

The projected impacts from all proposed criteria pollutant emissions were modeled at both Class I areas with AERMOD. As listed in Table 5.2-25, all impacts are well below the Significant Impact Levels (SIL) for all criteria pollutants and averaging periods.

TABLE 5.2-25
Criteria Pollutant Class I SILs and Increments

Pollutant	Averaging Interval	Pinnacles ($\mu g/m^3$)	Point Reyes ($\mu g/m^3$)	Class I Significant Impact Level ($\mu g/m^3$)	Class I PSD Increment ($\mu g/m^3$)
NO_2	Annual	0.00201	0.00467	0.1	2.5
SO_2	3-Hour	0.02018	0.18858	1.0	25
	24-Hour	0.00766	0.04213	0.2	5
	Annual	0.00025	0.00058	0.1	2
PM10/2.5	24-Hour	0.00406	0.02213	0.3	10
	Annual	0.00084	0.00196	0.2	5

5.1.5.9 Impacts on Soils, Visibility, Vegetation, and Sensitive Species (Class I and Class II)

Impacts on soils, vegetation, and sensitive species were determined to be "insignificant" for the following reasons:

- No soils, vegetation, or sensitive species were identified in the project area, which are recognized to have any known sensitivity to the types or amounts of air pollutants expected to be emitted by the facility. A more complete summary is presented in the Biology Section of the AFC.
- The facility emissions are expected to be in compliance with all applicable air quality rules and regulations.

- The facility impacts are not predicted to result in violations of existing air quality standards, nor will the emissions cause an exacerbation of an existing violation of any quality standard.
- No animal species were identified in the project area, which are recognized to have any known sensitivity to the types or amounts of air pollutants emitted by the proposed facility.

  The AERMOD modeling results were compared against the thresholds in "A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals" (EPA-450/2-81-078, Table 3). The results of this analysis are listed below in Table 5.2-26.

TABLE 5.2-26
Soils and Vegetation Screening Results

Pollutant	Screening Concentration (µg/m^3)	Modeled Maximum (µg/m^3)	Model Averaging Time Used
SO_2 1-Hour	917	10.1	1 hour
SO_2 3-Hour	786	7.5	3 hour
SO_2 Annual	18	0.07	annual
NO_2 4-Hours	3,760	177.5	1 hour
NO_2 1-Month	564	177.5	1 hour
NO_2 Annual	94	0.59	annual
CO Weekly	1,800,000	92.0	8 hour

5.1.6 Laws, Ordinances, Regulations, and Statutes (LORS)

Table 5.1-27 presents a summary of federal, state, and local air quality LORS deemed applicable to the project site.

TABLE 5.1-27
Applicable Laws, Ordinances, Regulations, and Standards for Protection of Air Quality

LORS	Purpose	Regulating Agency	Applicability/Compliance Strategy
Federal			
Title 40 CFR Part 50	Establishes AAQS for criteria pollutants.	EPA Region IX	CCGS will conduct a dispersion modeling analysis to determine if the project will exceed the state or federal AAQS. Dispersion modeling indicates the CCGS will not exceed the state or federal AAQS for the attainment pollutants. Non-attainment pollutant emissions will be mitigated through the surrendering of emission reduction credits consistent with the BAAQMD's SIP-Approved New Source Review program.
Title 40 CFR Part 51, NSR (BAAQMD Reg 2 Rule 2)	Requires pre-construction review and permitting of new or modified stationary sources of air pollution to allow industrial growth without interfering with the attainment and maintenance of ambient air quality standards.	EPA Region IX	Requires NSR facility permitting for construction or modification of specified stationary sources. The NSR requirements are implemented at the local level with EPA oversight (BAAQMD Reg 2 Rule 2). Because the CCGS will exceed the 10 lb/day trigger for at least one of the regulated pollutants, an ATC and PTO application will be obtained from the BAAQMD prior to construction of the project site. As a result, the compliance requirements of 40 CFR, Part 51.165 will be met.
Title 40 CFR Part 52, PSD	The PSD program allows new sources of air pollution to be constructed or existing sources to be modified in areas classified as attainment, while preserving the existing ambient air quality levels, protecting public health and welfare, and protecting Class I Areas (e.g., national parks and wilderness areas).	EPA Region IX	The PSD requirements apply on a pollutant-specific basis to any project that is a new major stationary source or a major modification to an existing major stationary source. BAAQMD classifies an unlisted source (which is not in the specified 28 source categories) that emits or has the potential to emit 250 tons per year (tpy) of any pollutant regulated by the Act as a major stationary source. For listed sources, the threshold is 100 tpy. NO_x or SO_x emissions from a modified major source are subject to PSD if the cumulative emission increases for either pollutant exceeds 40 tpy. In addition, a modification at a non-major source is subject to PSD if the modification itself would be considered a major source. Because the CCGS is a combined-cycle project, it would be considered one of the 28 source categories. Therefore, the emission rates were compared to the 100 ton per year threshold. As shown in Table 5.1-9, the emission increase in CO is greater than 100 tons per year, and the emissions rates for NOx and PM10/2.5 are greater than the significant emissions thresholds. Therefore, CCGS would be subject to PSD analysis requirements.

TABLE 5.1-27
Applicable Laws, Ordinances, Regulations, and Standards for Protection of Air Quality

LORS	Purpose	Regulating Agency	Applicability/Compliance Strategy
Title 40 CFR, Part 60	Establishes national standards of performance for new or modified facilities in specific source categories.	BAAQMD with EPA Region IX oversight	**Turbines:** 40 CFR Part 60 Subpart KKKK – NO_x Emission Limits for New Stationary Combustion Turbines applies to all new combustion turbines that commence construction, modification, or reconstruction after February 18, 2005. The rule requires natural-gas-fired turbines greater than or equal to 30 MW to meet a NO_x emission limit of 50 nanograms per Joule (ng/J) (0.39 pounds per megawatt-hour [lb/MW-hr]), and an SO_2 limit of 73 ng/J (0.58 lb/MW-hr). Alternatively, a fuel sulfur limit of 500 parts per million by weight (ppmw) could be met. Stationary combustion turbines regulated under this subpart would be exempt from the requirements of Subpart GG. The proposed turbines will utilize low NO_x combustors along with an SCR system, pipeline-quality natural gas, and will comply with both the NO_x and SO_2 limits. The certified NO_x Continuous Emission Monitoring System (CEMS) will ensure compliance with the standard. Records of natural gas usage and fuel sulfur content will ensure compliance with the SO_2 limit.
Title 40 CFR, Part 60	Establishes national standards of performance for new or modified facilities in specific source categories.	BAAQMD with EPA Region IX oversight	**Fire Pump:** 40 CFR Part 60 Subpart IIII (Standards of Performance for Stationary Compression Ignition Internal Combustion Engines) would apply to the diesel fire pump. The NMHC+NO_x emission limit for a model year 2009 fire pump between 175 and 300 hp would be 3.0 g/bhp, the CO emission limit would be 2.6 g/bhp, and the PM_{10} emission limit would be 0.15 g/bhp. The proposed CI ICE used to operate the emergency fire pump would be a Tier III, 200 bhp ICE. Therefore, the engine would meet the NMHC+NO_x, CO, and PM_{10} emission standards.

TABLE 5.1-27
Applicable Laws, Ordinances, Regulations, and Standards for Protection of Air Quality

LORS	Purpose	Regulating Agency	Applicability/Compliance Strategy
Title 40 CFR, Part 63	Establishes national emission standards to limit emissions of hazardous air pollutants (HAPs, or air pollutants identified by EPA as causing or contributing to the adverse health effects of air pollution but for which NAAQS have not been established) from facilities in specific categories.	BAAQMD with EPA Region IX oversight	Title 40, Code of Federal Regulations, Part 63—National Emission Standards for Hazardous Air Pollutants for Source Categories, establishes emission standards to limit emissions of hazardous air pollutants from specific source categories for Major HAP sources. Sources subject to Part 63 requirements must either use the maximum achievable control technology (MACT), be exempted under Part 63, or comply with published emission limitations. The potential NESHAPS applicable to the project are Subpart YYYY, which sets a formaldehyde emission limit or an operational limit of 91 parts per billion by volume (ppbv) for the turbines and subpart ZZZZ the NESHAPS for Stationary Reciprocating Internal Combustion Engines (RICE). CCGS would be subject to the Subpart YYYY requirements if the HAP PTE is greater or equal to 25 tpy for combined HAPs and 10 tpy for individual HAPs, i.e., major source of HAPs. As shown in Section 5.9 (Public Health), CCGS will not exceed the major source thresholds for HAPs (10 tpy for any one pollutant or 25 tpy for all HAPs combined). Therefore, CCGS will not be subject to Subpart YYYY. Subpart ZZZZ applies to area (minor) sources as well as major sources. Therefore, CCGS will be subject to Subpart ZZZZ for the fire pump engine.

TABLE 5.1-27
Applicable Laws, Ordinances, Regulations, and Standards for Protection of Air Quality

LORS	Purpose	Regulating Agency	Applicability/Compliance Strategy
Title 40 CFR Part 64 (CAM Rule)	Establishes onsite monitoring requirements for emission control systems.	BAAQMD with EPA Region IX oversight	Title 40, Code of Federal Regulations, Part 64—Compliance Assurance Monitoring (CAM), requires facilities to monitor the operation and maintenance of emissions control systems and report any control system malfunctions to the appropriate regulatory agency. If an emission control system is not working properly, the CAM rule also requires a facility to take action to correct the control system malfunction. The CAM rule applies to emissions units with uncontrolled potential to emit levels greater than applicable major source thresholds. Emission control systems governed by Title V operating permits requiring continuous compliance determination methods are generally exempt from the CAM rule. CCGS would have an emission control systems for NO_x and CO (SCR and oxidation catalyst). However, emissions of NO_x and CO would be directly measured by a continuous monitoring system. Therefore, CCGS would not be subject to the CAM provisions.
Title 40 CRF part 70 (BAAQMD Reg 2, Rule 6)	CAA Title V Operating Permit Program	BAAQMD with EPA Region IX oversight	Title 40, Code of Federal Regulations, Part 70—Operating Permits Program, requires the issuance of operating permits that identify all applicable federal performance, operating, monitoring, recordkeeping, and reporting requirements. The requirements of 40 CFR, Part 70 apply to facilities that are subject to NSPS requirements and are implemented at the local level through BAAQMD Reg 2, Rule 6. According to Reg 2, Rule 6, a facility would be considered a Major Facility if the facility had a potential to emit greater than 100 tpy on a pollutant specific basis or the HAP PTE is greater or equal to 25 tpy for combined HAPs and 10 tpy for individual HAPs.

TABLE 5.1-27
Applicable Laws, Ordinances, Regulations, and Standards for Protection of Air Quality

LORS	Purpose	Regulating Agency	Applicability/Compliance Strategy
Title 40 CFR part 72 (BAAQMD Reg 2, Rule 7)	CAA Acid Rain Program	BAAQMD with EPA Region IX oversight	Title 40, Code of Federal Regulations, Part 72—Acid Rain Program, establishes emission standards for SO_2 and NO_x emissions from electric generating units through the use of market incentives, requires sources to monitor and report acid gas emissions, and requires the acquisition of SO_2 allowances sufficient to offset SO_2 emissions on an annual basis. This program is implemented through BAAQMD's Reg 2, Rule 7. An acid rain facility, such as CCGS, must also obtain an acid rain permit as mandated by Title IV of the Clean Air Act. A permit application must be submitted to the BAAQMD at least 24 months before operation of the new units commences. The application must present all relevant sources at the facility, a compliance plan for each unit, applicable standards, and estimated commencement date of operation. The necessary Title IV applications will be included during the CEC licensing proceeding.
State			
California Code of Regulations, Section 41700	Prohibits emissions in quantities that adversely affect public health, other businesses, or property.	BAAQMD with ARB oversight	The CEC conditions of exemption and the air quality management district (AQMD) ATC processes are developed to ensure no adverse public health affects or public nuisances result from operation of the project site.
California Code of Regulations Sections 93115 (Diesel ATCM)	The purpose of the airborne toxics control measure (ATCM) is to reduce diesel particulate emissions from stationary diesel fired compression engines.	BAAQMD with ARB oversight	The diesel ATCM applies to stationary compression engines with a rating of greater than 50 brake horsepower and requires the use of ARB-certified diesel fuel or equivalent, and limits emissions from the operation of compression engines. The proposed fire pump would be greater than 50 bhp. However, the fire pump would meet the Tier III emission standards and non-emergency hours of operation would be limited to 50 hours or less per year. Therefore, the project site would comply with the diesel ATCM.
California Assembly Bill 32 – Global Warming Solutions Act of 2006 (AB32)	The purpose is to reduce carbon emissions within the state by approximately 25% by the year 2020.	BAAQMD with ARB oversight	There are currently no applicable facility-specific greenhouse gas emission limits or caps. Therefore, greenhouse gas emissions have been estimated for CCGS for informational purposes at this time.

Local			
BAAQMD Reg 1, Section 301 (Public Nuisance)	Prohibits the emissions of air contaminants or other material which create a public nuisance.	BAAQMD	The CEC conditions of exemption and the BAAQMD ATC process is designed to ensure that the operation of the project site will not cause a public nuisance.
BAAQMD Regulation 2, Rule 2 (Permits – NSR)	Purpose of this Rule is to provide for the review of new and modified sources and provide mechanisms, including the use of Best Available Control Technology (BACT), Best Available Control Technology for Toxics (TBACT), and emission offsets, by which authorities to construct such sources may be granted.	BAAQMD	Applicability: As part of the NSR permit approval process, an air quality dispersion analysis must be conducted using a mass emissions-based analysis contained in the rule or an approved dispersion model, to evaluate impacts of increased criteria pollutant emissions from any new or modified facility on ambient air quality. Compliance: An air quality dispersion analysis was conducted, using a mass emissions-based analysis contained in the rule and the AERMOD dispersion model. Applicability: The PSD requirements apply on a pollutant-specific in areas attaining the state and federal AAQS to any project that is a new major stationary source or a major modification to an existing major stationary source. (See Title 40 CFR Part 51 and Part 52 discussion for thresholds). Applicability: BACT shall be applied to all new and modified sources with a potential to emit 10 pounds or more of any of the following: POC, NPOC, NOx, SO_2, PM_{10} or CO. (BAAQMD 2-2-301). Compliance: Based on the BACT thresholds, a BACT analysis was conducted for the following: POC, NOx, PM_{10} and CO. Applicability: A source shall be exempt from MACT requirements if the combined potential to emit from all related sources in a proposed modification is less than 10 tpy of any HAP and less than 25 tpy of any combination of HAPs. (BAAQMD 2-2-114). Compliance: The CCGS does not exceed the major source thresholds for HAPs (10 tpy for any one pollutant or 25 tpy for all HAPs combined). Applicability: Offsets for NOx are required at a 1.0 to 1.15 ratio if a modification to the permit causes a cumulative increase greater than 35 tpy. Offsets for PM_{10} and SO_x are required for a Major Facility at a 1.0 to 1.0 ratio if a modification to the permit causes a cumulative increase of 100 tpy. (BAAQMD 2-2-302 and 2-2-303). See Appendix 5.1G for offset strategy. Applicability: A visibility, soils, and vegetation analysis is required if the proposed project is subject to PSD requirements and is within 10 kilometers of a Class I Area. (BAAQMD 2-2-417).

TABLE 5.1-27
Applicable Laws, Ordinances, Regulations, and Standards for Protection of Air Quality

LORS	Purpose	Regulating Agency	Applicability/Compliance Strategy
BAAQMD Regulation 2, Rule 3 (Permits – ATC and Permit to Operate [PTO] for Power Plants)	The purpose of this rule is to outline the special permitting provisions for the construction of power plants within the District.	BAAQMD	In conjunction with the submittal of the AFC to the CEC, CCGS will work with the BAAQMD to provide the information needed for the issuance of a ATC. As stated in this rule, the review will be conducted as outlined in Regulation 2, Rule 2.
BAAQMD Regulation 2, Rule 5 (Permits – Toxics NSR)	The purpose of this rule is to provide for the review of new and modified sources of TAC emissions in order to evaluate potential public exposure and health risk, to mitigate potentially significant health risks resulting from these exposures, and to provide net health risk benefits by improving the level of control when existing sources are modified or replaced.	BAAQMD	TBACT shall be applied to any new or modified source of TACs where the source risk is a cancer risk greater than 1.0 in a million (10^{-6}), and/or a chronic hazard index greater than 0.20. An ATC or PTO will be denied if the facility cancer risk exceeds 10 in a million, or the facility chronic hazard index exceeds 1.0, or the facility acute hazard index exceeds 1.0. Section 5.9 and Appendix 5.1D present the results of the facility risk assessment, which shows compliance with all applicable AQMD significance values.
BAAQMD Regulation 2, Rule 6 (Permits – Title V)	The purpose of this rule is to implement the operating permit requirements of Title V of the CAA as amended in 1990.	BAAQMD with EPA Oversight	See Federal, Title 40 CFR, Part 70 to review applicability and the compliance assessment.
BAAQMD Regulation 2, Rule 7 (Permits – Acid Rain)	The purpose of this rule is to incorporate by reference the provisions of 40 CFR Part 72 for purposes of implementing an acid rain program that meets the requirements of Title IV of the CAA.	BAAQMD with EPA Oversight	See Federal, Title 40 CFR, Part 72 to review applicability and the compliance assessment.
BAAQMD Regulation 6 (Particulate Matter and Visible Emissions)	Purpose of this Regulation is to limit the quantity of particulate matter in the atmosphere through the establishment of limitations on emission rates, concentration, visible emissions, and opacity.	BAAQMD	Exhaust emissions shall not be darker than No. 1 when compared to the Ringleman Chart for any period(s) aggregating 3 minutes in any hour, exceed the opacity standard of not greater than 20 percent for a period or periods aggregating 3 minutes in any hour, or exceed the 0.15 grains per dry standard cubic feet of exhaust gas volume. The use of clean fuels (natural gas and California certified low sulfur diesel fuel will insure compliance with these limits.

TABLE 5.1-27
Applicable Laws, Ordinances, Regulations, and Standards for Protection of Air Quality

LORS	Purpose	Regulating Agency	Applicability/Compliance Strategy
BAAQMD Regulation 7 (Odorous Substances)	The purpose of this regulation is to place general limitations on odorous substances and specific emission limitations on certain odorous compounds.	BAAQMD	Emissions of odorous substances shall not remain odorous after dilution with odor-free air at a rate of 1,000 volumes of odor-free air per volume of source sample. The maximum emissions of ammonia shall not exceed 5,000 ppm. Ammonia emissions from the SCR catalyst will be less than [number] ppmv. Therefore, maximum emissions will be below the 5,000 ppm limit, and odors from the CCGS are expected to be less than significant.
BAAQMD Regulation 9, Rule 1	Establishes emission limits for sulfur dioxide from all sources and limits ground-level concentrations of SO_2	BAAQMD	Dispersion modeling will be conducted to determine if off-property SO_2 ground level concentrations are less than 0.5 ppm for 3 consecutive minutes, 0.25 ppm averaged over 60 consecutive minutes, or 0.05 ppm averaged over 24 hours. Sulfur contents in the fuel will be less than 0.5% and gas stream concentrations will be less than 300 ppm (dry).
BAAQMD Regulation 9, Rule 9	Purpose of this rule is to limit emissions of NO_x from stationary gas turbines.	BAAQMD	For turbines with a heat input rating greater than 500 million British thermal units per hour (MMBtu/hr) (40+ MW), NO_x emission levels shall not exceed 0.72 lb/MW-hr or 25 ppmv. BACT levels of less than 2.5 ppmv for NO_x will be applied to the project site; therefore, the NO_x emission levels for the project site will not exceed the 25 ppmv level.
BAAQMD Regulation 10 (40 CFR Part 60)	Establishes national standards of performance for new or modified facilities in specific source categories.	BAAQMD	See Federal, Title 40 CFR, Part 60 to review applicability and the compliance assessment.

5.1.7 Agencies and Agency Contacts

Table 5.1-26 presents data on the following: (1) air quality agencies that may or will exercise jurisdiction over air quality issues resulting from the power facility, (2) the most appropriate agency contact for the project site, (3) contact address and phone information, and (4) the agency involvement in required permits or approvals.

TABLE 5.1-26
Agencies, Contacts, Jurisdictional Involvement, Required Permits For Air Quality

Agency	Contact	Jurisdictional Area	Permit Status
California Energy Commission (CEC)	Assigned Project Manager 1516 Ninth St. Sacramento, CA 95814	Primary reviewing and certification agency.	Will certify the facility under the energy siting regulations and CEQA. Certification will contain a variety of conditions pertaining to emissions and operation.
Bay Area AQMD	Brian Bateman Dir. Engineering Div. 939 Ellis St. San Francisco, CA 94109 (415) 771-4653	Prepares Determination of Compliance (DOC) for CEC, Issues BAAQMD Authority to Construct (ATC) and Permit to Operate (PTO), Primary air regulatory and enforcement agency.	DOC will be prepared subsequent to AFC submittal. AFC plus District permit forms in Appendix 5.1I comprise the required District application.
California Air Resources Board (CARB)	Mike Tollstrup Chief, Project Assessment Branch 1001 I St., 6th Floor Sacramento, CA 95814 (916) 322-6026	Oversight of AQMD stationary source permitting and enforcement program	CARB staff will provide comments on applicable AFC sections affecting air quality and public health. CARB staff will also have opportunity to comment on draft PTC.
Environmental Protection Agency, Region IX	Gerardo Rios Chief, Permits Section USEPA-Region 9 75 Hawthorne St. San Francisco, CA 94105 (415) 947-3974	Oversight of all AQMD programs, including permitting and enforcement programs	USEPA Region 9 staff will receive a copy of the DOC. USEPA Region 9 staff will have opportunity to comment on draft PTC

5.1.8 Permits and Permit Schedule

An ATC application is required in accordance with the BAAQMD rules. Appendix 5.1-I contains the BAAQMD permitting application forms. These forms in conjunction with the AFC in its entirety, but specifically Section 2.0, Project Description; Section 5.1, Air Quality; Section 5.9, Public Health' and Appendixes 5.1-A through 5.1-I constitute the required Authority to Construct application pursuant to the District rules.

5.1.9 References

BAAQMD (Air Quality Management District) website. June 2009. http://www.baaqmd.gov/.

BAAQMD (Bay Area Air Quality Management District). 1999. CEQA Air Quality Handbook. December 1999.

CARB (California Air Resources Board). 1999. Guidance for Power Plant Siting and Best Available Control Technology, PAB-SSD. July.

CARB (California Air Resources Board). 2008. Best Available Control Technology Clearinghouse Program, http://www.arb.ca.gov/bact/bact.htm. August.

CARB (California Air Resources Board). 2009. California Air Quality Data Statistics, 2006-2008 Data, ADAM Database, http://www.arb.ca.gov/adam, Air Quality Data Branch, Sacramento, California. June.

CARB (California Air Resources Board). 2009. The 2009 California Almanac of Emissions and Air Quality. CARB, Technical Support Division.

CEC (California Energy Commission). 2008. Energy Facilities Siting/Licensing Process Web Site. http://www.energy.ca.gov/sitingcases/index.html.

Holzworth, G.C. 1972. Mixing Heights, Wind Speeds, and Potential for Urban Air Pollution throughout the Contiguous United States. January.

Lee and Atkinson 1992. Procedures for Substituting Values for Missing NWS Meteorological Data for Use in Regulatory Air Quality Models, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina 2771 July.

Midwest Research Institute. 1996. Improvement of Specific Emission Factors (BACM Project No. 1), Final Report. Prepared by Midwest Research Institute for South Coast AQMD. March.

Nappo et. al. 1982. The Workshop on the Representativeness of Meteorological Observations, Bull. Am. Meteorological Society, 63, 761-764.

NWS (National Weather Service). 2009. California Climate data — Normals, Means, and Extremes for the Antioch Pump Station #040232.

Radback Energy – Contra Costa Project Team. 2009. Fieldwork, observations, and research.

U.S. Department of Agriculture Forest Service. 2002. USDA Forest Service Class I Area Information. http://www.fs.fed.us/r6/aq/natarm/r5/. August.

USEPA (U.S. Environmental Protection Agency). 1985. Guideline for Determination of Good Engineering Stack Height (Technical Support Document for the Stack Height Regulation) (Revised), EPA-450/4-80-023R. Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina 27711. June.

USEPA (U.S. Environmental Protection Agency). 1989. 40 CFR Part 51, Appendix W: Guideline on Air Quality Models and CARB (Reference Document for California Statewide Modeling Guideline. April.

USEPA (U.S. Environmental Protection Agency). 1991. Nonroad Engine and Vehicle Emission Study — Report, 21A-2001, Office of Mobile Sources, Washington, D.C. 20460. November.

USEPA (U.S. Environmental Protection Agency). 1992. Workbook for Plume Visual Impact Screening and Analysis (Revised), EPA-454/R-92-023, Office of Air and Radiation, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina 27711. October.

USEPA (U.S. Environmental Protection Agency). 1995. Compilation of Air Pollution Emission Factors, Volume I, Fifth Edition; AP-42.

USEPA (U.S. Environmental Protection Agency). 1995. Onsite Meteorological Program Guidance for Regulatory Model Applications, EPA-450/4-87-013, August.

USEPA (U.S. Environmental Protection Agency). 1995. User's Guide for the Industrial Source Complex (ISC3) Dispersion Models, EPA-454/B-95-003a, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina 27711. September.

USEPA (U.S. Environmental Protection Agency). 1995. User's Guide to the Building Profile Input Program (Revised), EPA-454/R-93-038, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina 27711. February.

USEPA (U.S. Environmental Protection Agency). 2005. User's Guide for the AERMOD Model, EPA-454/B-03-001, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina 27711. September.

Oil Water Separator Form

DATA FORM G
General Air Pollution Source

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street San Francisco, CA 94109 (415) 749-4990 FAX (415) 749-5030 www.baaqmd.gov

Form G is for general air pollution sources. Use specific forms when applicable. If this source burns fuel, then also complete Form C.

1. Business Name: RADBACK ENERGY - CCGS Plant No: ______ (if unknown, leave blank)
2. SIC No.: 4911 Date of Initial Operation ______
3. Name or Description: OIL/WATER SEPARATOR Source No.: S- 6
4. Make, Model, and Rated Capacity of Equipment: ______
5. Process Code[1] 5017 Material Code[2] 427 Usage Unit[2] 1000 GALS.
6. Total throughput, last 12 mos. Ø usage units[2] Maximum operating rate: 0.12 usage units[2] /hr
7. Typical % of total throughput: Dec-Feb 25 % Mar-May 25 % Jun-Aug 25 % Sep-Nov 25 %
8. Typical operating times: 24 hrs/day 7 days/week 52 weeks/year
9. For batch or cyclic processes: N/A minutes/cycle N/A minutes between cycles
10. Exhaust gases from source: (at maximum operation) Wet gas flowrate N/A cfm at N/A °F
    Approximate water vapor content N/A volume%

EMISSION FACTORS *(at maximum operating rate)*

If this form is being submitted as part of an application for an **authority to construct**, completion of the following table is mandatory. If not, and the Source is *already in operation*, completion of the table is requested but not required.

If this source also burns fuel, do not include those combustion products in the emission factors below; they are accounted for on Form C. If source test or other data are available for composite emissions only, estimate from those data the emissions attributable to just the general process and show below.

☐ Check box if factors apply to emissions *after* Abatement Device(s).

	Emission Factors lb/Usage Unit [2]	*Basis Code* [3]
11. Particulate		
12. Organics	0.2	6 (AP-42, SECTION 5.1, 1/95.) TABLE 5.1-2
13. Nitrogen Oxides (as NO_2)		
14. Sulfur Dioxide		
15. Carbon Monoxide		
16. Other: ______		
17. Other: ______		

18. With regard to air pollutant flow from this source, what sources(s), abatement device(s) and/or emission point(s) are **immediately** downstream?

S- ______ **S-** ______ **S-** ______ **A** ______ **A-** ______ **A-** ______
P- ______ **P-** ______ **P-** ______ **P-** ______ **P-** ______

[1]See Tables G-1 through G-7 for code
[3]See Basis Code Table below
[2]See Table G5 or the Material Codes Table (available upon request)

Person completing this form: GREG DARVIN	Date: 8-27-09

Form G – 5/07

Revised Air Emissions Workbook

Contra Costa Generating Station 2x1

Cover Page

Contra Costa Generating Station 2x1

BAAQMD Fees

	Combustion Sources	Miscellaneous Sources
Filing Fee		
Filing Fee, per source	$ 337.00	
Initial Fee		
Initial Fee, per MMBtu/hr	$ 42.35	
Minimum Initial Fee, per source	$ 226.00	$ 328.00
Maximum Initial Fee, per source	$ 79,018.00	
Risk Screening Fee (RSF)		
RSF, for first toxic air contaminant (TAC) source (fixed portion)	$ 337.00	$ 665.00
RSF, for first TAC source (variable portion), per MMBtu/hr	$ 42.35	
Minimum RSF, for first TAC source	$ 563.00	
RSF for each add'l TAC source, per MMBtu/hr *	$ 42.35	$ 328.00
Minimmum RSF, for each add'l TAC source *	$ 226.00	
Maximum RSF, per source	$ 79,018.00	
* - RSF for add'l TAC sources only applicable to those sources that eimt one or more TACs at a rate that *exceeds a trigger level listed in Table 2-5-1.*		
Permit to Operate (PTO) Fee		
PTO Fee, per MMBtu/hr	$ 21.17	
Minimum PTO Fee, per source	$ 161.00	$ 237.00
Maximum PTO Fee, per source	$ 39,508.00	
Toxic Surcharge		
Toxic Surcharge, % of PTO Fee	10%	10%

	Combustion Turbine No. 1	Combustion Turbine No. 2	Auxiliary Boiler	Fire Pump	Evaporative Fluid Cooler	Total
Maximum Fuel Input, MMBtu/hr HHV	2,150.0	2,150.0	50.6	2.8		
Filing Fee	$ 337.00	$ 337.00	$ 337.00	$ 337.00	$ 337.00	$ 1,685.00
Initial Fee	$ 79,018.00	$ 79,018.00	$ 2,143.46	$ 226.00	$ 328.00	$ 160,733.00
Risk Screening Fee	$ 79,018.00	$ 79,018.00	$ 2,143.46	$ 226.00	$ 328.00	$ 160,733.00
Total Application Fee	$ 158,373.00	$ 158,373.00	$ 4,623.91	$ 789.00	$ 993.00	$ 323,151.00
Permit to Operate Fee	$ 39,508.00	$ 39,508.00	$ 1,071.48	$ 161.00	$ 237.00	$ 80,485.00
Toxic Surcharge	$ 3,950.80	$ 3,950.80	$ 107.15	$ 16.10	$ 23.70	$ 8,049.00
Total Permit to Operate Fee	$ 43,458.80	$ 43,458.80	$ 1,178.62	$ 177.10	$ 260.70	$ 88,534.00
Total All Fees	$ 201,831.80	$ 201,831.80	$ 5,802.54	$ 966.10	$ 1,253.70	$ 411,685.00

Contra Costa Generating Station 2x1

Annual Emissions - PG&E Specification - 300 Starts (25 of which are cold)

Plant Dispatch		Proposed Limits
Combustion Turbines/HRSGs (per unit unless noted)		
Number of Turbines/HRSGs	**2**	
Minimum Load Hours - Natural Gas	**-**	
Base Load ISO Hours - Natural Gas	**3,657**	
Base Load Peak July Hours - Natural Gas	**1,500**	
Total Hot Starts - Natural Gas	**275**	
Total Warm Starts - Natural Gas	**-**	
Total Cold Starts - Natural Gas	**25**	
Total Shutdowns - Natural Gas	300	
Startup/Shutdown Hours	153	
Total Hours of Operation	5,310	
Offline Hours	3,450	
Annual Fuel Use, MMBtu (HHV) (all units)	22,144,470	35,338,987
Auxiliary Boiler		
Margin	**20%**	
Operating Hours	4,324	
Evaporative Fluid Cooler		
Operating Hours	**1,500**	
Fire Pump		
Duration of Periodic Tests, mins	**60**	
Frequency of Tests, tests/year	**53**	
Load During Testing, %	**100%**	
Operating Hours	53	
Annual Fuel Use, gals/yr	1,060	

Contra Costa Generating Station 2x1

Annual Emissions - PG&E Specification - 300 Starts (25 of which are cold)

Combustion Turbine/HRSG Emissions		Proposed Limits
Minimum Load - Natural Gas		
NO_x, tons as NO_2	-	
CO, tons	-	
POC, tons as CH_4	-	
PM_{10}, tons	-	
SO_2, tons	-	
CO_2, tons	-	
Base Load ISO - Natural Gas		
NO_x, tons as NO_2	20.8	
CO, tons	16.9	
POC, tons as CH_4	4.8	
PM_{10}, tons	13.7	
SO_2, tons	2.7	
CO_2, tons	450,985.6	
Base Load Peak July - Natural Gas		
NO_x, tons as NO_2	8.3	
CO, tons	6.7	
POC, tons as CH_4	1.9	
PM_{10}, tons	5.6	
SO_2, tons	1.1	
CO_2, tons	179,825.6	
Startups/Shutdowns - Natural Gas		
NO_x, tons as NO_2	10.1	
CO, tons	56.6	
POC, tons as CH_4	7.7	
PM_{10}, tons	0.6	
SO_2, tons	0.1	
CO_2, tons	36,996	
Total Emissions (each unit)		
NO_x, tons as NO_2	39.2	
CO, tons	80.2	
POC, tons as CH_4	14.4	
PM_{10}, tons	19.9	
SO_2, tons	3.9	
CO_2, tons	667,808	

Contra Costa Generating Station 2x1

Annual Emissions - PG&E Specification - 300 Starts (25 of which are cold)

Cooling Tower Emissions		Permit Limits
PM_{10}, tons	-	
Auxiliary Boiler		**Proposed Limits**
NO_x, tons as NO_2	1.180	
CO, tons	3.990	
POC, tons as CH_4	0.229	
PM_{10}, tons	0.766	
SO_2, tons	0.305	
CO_2, tons	12,786	
Evaporative Fluid Cooler		**Proposed Limits**
PM_{10}, tons	0.099	
Fire Pump Emissions		**Proposed Limits**
NO_x, tons as NO_2	0.0610	
CO, tons	0.0196	
POC, tons as CH_4	0.0024	
PM_{10}, tons	0.0024	
SO_2, tons	0.0001	
Total Plant Emissions		**Proposed Limits**
NO_x, tons as NO_2	79.6	98.8
CO, tons	164.5	164.5
POC, tons as CH_4	29.1	29.5
PM_{10}, tons	40.7	63.5
SO_2, tons	8.0	12.5
CO_2, tons (excluding fire pump)	1,348,401	2,081,421

Contra Costa Generating Station 2x1

Annual Emissions - 6x16 with 1,500 Hours at Peak July

Plant Dispatch		Proposed Limits
Combustion Turbines/HRSGs (per unit unless noted)		
Number of Turbines/HRSGs	**2**	
Minimum Load Hours - Natural Gas	**-**	
Base Load ISO Hours - Natural Gas	**3,933**	
Base Load Peak July Hours - Natural Gas	**1,500**	
Total Hot Starts - Natural Gas	**260**	
Total Warm Starts - Natural Gas	**51**	
Total Cold Starts - Natural Gas	**1**	
Total Shutdowns - Natural Gas	312	
Startup/Shutdown Hours	146	
Total Hours of Operation	5,579	
Offline Hours	3,181	
Annual Fuel Use, MMBtu (HHV) (all units)	23,276,077	35,338,987
Auxiliary Boiler		
Margin	**20%**	
Operating Hours	3,992	
Evaporative Fluid Cooler		
Operating Hours	**1,500**	
Fire Pump		
Duration of Periodic Tests, mins	**60**	
Frequency of Tests, tests/year	**53**	
Load During Testing, %	**100%**	
Operating Hours	53	
Annual Fuel Use, gals/yr	1,060	

Contra Costa Generating Station 2x1

Annual Emissions - 6x16 with 1,500 Hours at Peak July

Combustion Turbine/HRSG Emissions		Proposed Limits
Minimum Load - Natural Gas		
NO_x, tons as NO_2	-	
CO, tons	-	
POC, tons as CH_4	-	
PM_{10}, tons	-	
SO_2, tons	-	
CO_2, tons	-	
Base Load ISO - Natural Gas		
NO_x, tons as NO_2	22.4	
CO, tons	18.2	
POC, tons as CH_4	5.2	
PM_{10}, tons	14.7	
SO_2, tons	2.9	
CO_2, tons	485,022.3	
Base Load Peak July - Natural Gas		
NO_x, tons as NO_2	8.3	
CO, tons	6.7	
POC, tons as CH_4	1.9	
PM_{10}, tons	5.6	
SO_2, tons	1.1	
CO_2, tons	179,825.6	
Startups/Shutdowns - Natural Gas		
NO_x, tons as NO_2	9.6	
CO, tons	53.9	
POC, tons as CH_4	7.5	
PM_{10}, tons	0.5	
SO_2, tons	0.1	
CO_2, tons	38,476	
Total Emissions (each unit)		
NO_x, tons as NO_2	40.2	
CO, tons	78.8	
POC, tons as CH_4	14.6	
PM_{10}, tons	20.9	
SO_2, tons	4.1	
CO_2, tons	703,324	

Contra Costa Generating Station 2x1

Annual Emissions - 6x16 with 1,500 Hours at Peak July

Auxiliary Boiler		Proposed Limits
NO_x, tons as NO_2	1.089	
CO, tons	3.685	
POC, tons as CH_4	0.211	
PM_{10}, tons	0.707	
SO_2, tons	0.282	
CO_2, tons	11,807	
Evaporative Fluid Cooler		**Proposed Limits**
PM_{10}, tons	0.099	
Fire Pump Emissions		**Proposed Limits**
NO_x, tons as NO_2	0.0610	
CO, tons	0.0196	
POC, tons as CH_4	0.0024	
PM_{10}, tons	0.0024	
SO_2, tons	0.0001	
Total Plant Emissions		**Proposed Limits**
NO_x, tons as NO_2	81.6	98.8
CO, tons	161.2	164.5
POC, tons as CH_4	29.5	29.5
PM_{10}, tons	42.7	63.5
SO_2, tons	8.4	12.5
CO_2, tons (excluding fire pump)	1,418,455	2,081,421

Contra Costa Generating Station 2x1

Annual Emissions - 6x24/1x18 with 1,500 Hours at Peak July

Plant Dispatch		Proposed Limits
Combustion Turbines/HRSGs (per unit unless noted)		
Number of Turbines/HRSGs	**2**	
Minimum Load Hours - Natural Gas	**-**	
Base Load ISO Hours - Natural Gas	**6,924**	
Base Load Peak July Hours - Natural Gas	**1,500**	
Total Hot Starts - Natural Gas	**51**	
Total Warm Starts - Natural Gas	**-**	
Total Cold Starts - Natural Gas	**1**	
Total Shutdowns - Natural Gas	52	
Startup/Shutdown Hours	25	
Total Hours of Operation	8,449	
Offline Hours	311	
Annual Fuel Use, MMBtu (HHV) (all units)	35,338,987	35,338,987
Auxiliary Boiler		
Margin	**20%**	
Operating Hours	403	
Evaporative Fluid Cooler		
Operating Hours	**1,500**	
Fire Pump		
Duration of Periodic Tests, mins	**60**	
Frequency of Tests, tests/year	**53**	
Load During Testing, %	**100%**	
Operating Hours	53	
Annual Fuel Use, gals/yr	1,060	

Contra Costa Generating Station 2x1

Annual Emissions - 6x24/1x18 with 1,500 Hours at Peak July

Combustion Turbine/HRSG Emissions		Proposed Limits
Minimum Load - Natural Gas		
NO_x, tons as NO_2	-	
CO, tons	-	
POC, tons as CH_4	-	
PM_{10}, tons	-	
SO_2, tons	-	
CO_2, tons	-	
Base Load ISO - Natural Gas		
NO_x, tons as NO_2	39.4	
CO, tons	32.0	
POC, tons as CH_4	9.2	
PM_{10}, tons	26.0	
SO_2, tons	5.2	
CO_2, tons	853,876.0	
Base Load Peak July - Natural Gas		
NO_x, tons as NO_2	8.3	
CO, tons	6.7	
POC, tons as CH_4	1.9	
PM_{10}, tons	5.6	
SO_2, tons	1.1	
CO_2, tons	179,825.6	
Startups/Shutdowns - Natural Gas		
NO_x, tons as NO_2	1.6	
CO, tons	9.1	
POC, tons as CH_4	1.3	
PM_{10}, tons	0.1	
SO_2, tons	0.0	
CO_2, tons	6,413	
Total Emissions (each unit)		
NO_x, tons as NO_2	49.3	
CO, tons	47.9	
POC, tons as CH_4	12.4	
PM_{10}, tons	31.7	
SO_2, tons	6.3	
CO_2, tons	1,040,114	

Contra Costa Generating Station 2x1

Annual Emissions - 6x24/1x18 with 1,500 Hours at Peak July

Auxiliary Boiler		Proposed Limits
NO_x, tons as NO_2	0.110	
CO, tons	0.372	
POC, tons as CH_4	0.021	
PM_{10}, tons	0.071	
SO_2, tons	0.028	
CO_2, tons	1,192	
Evaporative Fluid Cooler		**Proposed Limits**
PM_{10}, tons	0.099	
Fire Pump Emissions		**Proposed Limits**
NO_x, tons as NO_2	0.0610	
CO, tons	0.0196	
POC, tons as CH_4	0.0024	
PM_{10}, tons	0.0024	
SO_2, tons	0.0001	
Total Plant Emissions		**Proposed Limits**
NO_x, tons as NO_2	98.8	98.8
CO, tons	96.1	164.5
POC, tons as CH_4	24.7	29.5
PM_{10}, tons	63.5	63.5
SO_2, tons	12.5	12.5
CO_2, tons (excluding fire pump)	2,081,421	2,081,421

Contra Costa Generating Station 2x1
Maximum Annual Emissions

Annual Emissions					
Case Number	1	2	3	Maximum for Air Permit	Maximum for ERC's or Mitigation
Description	PG&E Spec. 275 Hot Starts 25 Cold Starts	6x16 1,500 hrs at Peak July	6x24/1x18 1,500 hrs of Peak July		
Include in ERC Calc.?	Yes	Yes	No		
NO_X, tons as NO_2	79.6	81.6	98.8	98.8	81.6
CO, tons	164.5	161.2	96.1	164.5	164.5
VOC, tons as CH_4	29.1	29.5	24.7	29.5	29.5
PM_{10}, tons	40.7	42.7	63.5	63.5	42.7
SO_2, tons	8.0	8.4	12.5	12.5	8.4
CO_2, tons	1,348,401.3	1,418,454.9	2,081,420.9	2,081,421	1,418,454.9
Total Fuel, MMBtu/hr	22,144,469.6	23,276,076.8	35,338,987.2	35,338,987	23,276,076.8

Contra Costa Generating Station 2x1
Short-Term Emissions

Maximum Hour Excluding Startups		Notes
Combustion Turbines (each unit)		
NO_x, lbs as NO_2	15.52	**Cold day @ base load**
CO, lbs	9.45	**Cold day @ base load**
POC, lbs as CH_4	2.71	**Cold day @ base load**
PM_{10}, lbs	7.50	**Cold day @ base load**
SO_2, lbs	6.00	**Cold day @ base load, maximum S content**
Auxiliary Boiler		
NO_x, lbs as NO_2	0.55	**Maximum firing rate**
CO, lbs	1.85	**Maximum firing rate**
POC, lbs as CH_4	0.11	**Maximum firing rate**
PM_{10}, lbs	0.35	**Maximum firing rate**
SO_2, lbs	0.14	**Maximum firing rate, maximum S content**
Fire Pump		
NO_x, lbs as NO_2	2.302	**Full load test**
CO, lbs	0.741	**Full load test**
POC, lbs as CH_4	0.092	**Full load test**
PM_{10}, lbs	0.091	**Full load test**
SO_2, lbs	0.004	**Full load test**
Evaporative Fluid Cooler		
PM_{10}, lbs	0.13	
Total		
NO_x, lbs as NO_2	33.35	**Two CTs @ base load & fire pump**
CO, lbs	20.75	**Two CTs @ base load & auxiliary boiler**
POC, lbs as CH_4	5.52	**Two CTs @ base load & auxiliary boiler**
PM_{10}, lbs	15.49	**Two CTs @ base load, auxiliary boiler, and evaporative fluid cooler**
SO_2, lbs	12.14	**Two CTs @ base load & auxiliary boiler, maximum S content**

Contra Costa Generating Station 2x1
Short-Term Emissions

Maximum Hour Including Startups		Notes
Combustion Turbines (each unit)		
NO_x, lbs as NO_2	99.88	**Cold start (45 min) & cold day @ base load (15 min)**
CO, lbs	542.36	**Cold start (45 min) & cold day @ base load (15 min)**
POC, lbs as CH_4	67.68	**Cold start (45 min) & cold day @ base load (15 min)**
PM_{10}, lbs	7.50	**Cold day @ base load**
SO_2, lbs	6.00	**Cold day @ base load, maximum S content**
Auxiliary Boiler		
NO_x, lbs as NO_2	0.55	**Maximum firing rate**
CO, lbs	1.85	**Maximum firing rate**
POC, lbs as CH_4	0.11	**Maximum firing rate**
PM_{10}, lbs	0.35	**Maximum firing rate**
SO_2, lbs	0.14	**Maximum firing rate, maximum S content**
Fire Pump		
NO_x, lbs as NO_2	2.302	**Full load test**
CO, lbs	0.741	**Full load test**
POC, lbs as CH_4	0.092	**Full load test**
PM_{10}, lbs	0.091	**Full load test**
SO_2, lbs	0.004	**Full load test**
Evaporative Fluid Cooler		
PM_{10}, lbs	0.13	
Total		
NO_x, lbs as NO_2	200.31	**Two CTs in startup (45 min)/cold day @ base load (15 min) & auxiliary boiler**
CO, lbs	1,086.57	**Two CTs in startup (45 min)/cold day @ base load (15 min) & auxiliary boiler**
POC, lbs as CH_4	135.46	**Two CTs in startup (45 min)/cold day @ base load (15 min) & auxiliary boiler**
PM_{10}, lbs	15.49	**Two CTs @ base load, auxiliary boiler & evaporative fluid cooler**
SO_2, lbs	12.14	**Two CTs @ base load & auxiliary boiler, maximum S content**
Maximum 3-Hours Including Startups		**Notes**
Combustion Turbines (each unit)		
SO_2, lbs	18.00	**Cold day with duct firing, maximum S content**
Auxiliary Boiler		
SO_2, lbs	0.28	**Maximum firing rate (2 hrs), maximum S content**
Fire Pump		
SO_2, lbs	0.004	**Full load test (test limited to 1 hour)**
Total		
SO_2, lbs	36.28	**Two CTs @ base load & auxiliary boiler (2 hrs), maximum S content**

Contra Costa Generating Station 2x1
Short-Term Emissions

Maximum 8-Hours Including Startups		Notes
Combustion Turbines (each unit)		
CO, lbs	812.31	**Cold start (45 min), shutdown (14 min) & cold day @ base load (7 hrs 1 min)**
Auxiliary Boiler		
CO, lbs	3.69	**Maximum firing rate (2 hrs)**
Fire Pump		
CO, lbs	0.741	**Full load test (test limited to 1 hour)**
Total		
CO, lbs	1,628.31	**Two CTs cold start & shutdown w/ remaining hrs cold day @ base load & auxiliary boiler (2 hrs)**
Maximum 24-Hours Including Startups		**Notes**
Combustion Turbines (each unit)		
NO_x, lbs as NO_2	492.26	**Cold start (45 min), shutdown (14 min) & cold day @ base load (23 hrs 1 min)**
CO, lbs	963.52	**Cold start (45 min), shutdown (14 min) & cold day @ base load (23 hrs 1 min)**
POC, lbs as CH_4	146.29	**Cold start (45 min), shutdown (14 min) & cold day @ base load (23 hrs 1 min)**
PM_{10}, lbs	180.00	**Cold day @ base load**
SO_2, lbs	144.00	**Cold day @ base load, maximum S content**
Auxiliary Boiler		
NO_x, lbs as NO_2	1.091	**Maximum firing rate (2 hrs)**
CO, lbs	3.692	**Maximum firing rate (2 hrs)**
POC, lbs as CH_4	0.211	**Maximum firing rate (2 hrs)**
PM_{10}, lbs	0.709	**Maximum firing rate (2 hrs)**
SO_2, lbs	0.282	**Maximum firing rate (2 hrs), maximum S content**
Fire Pump		
NO_x, lbs as NO_2	2.302	**Full load test (test limited to 1 hour)**
CO, lbs	0.741	**Full load test (test limited to 1 hour)**
POC, lbs as CH_4	0.092	**Full load test (test limited to 1 hour)**
PM_{10}, lbs	0.091	**Full load test (test limited to 1 hour)**
SO_2, lbs	0.004	**Full load test (test limited to 1 hour)**
Evaporative Fluid Cooler		
PM_{10}, lbs	3.17	
Total		
NO_x, lbs as NO_2	987.92	**Two combustion turbines, auxiliary boiler, fire pump, & evaporative fluid cooler**
CO, lbs	1,931.47	**Two combustion turbines, auxiliary boiler, fire pump, & evaporative fluid cooler**
POC, lbs as CH_4	292.89	**Two combustion turbines, auxiliary boiler, fire pump, & evaporative fluid cooler**
PM_{10}, lbs	363.97	**Two combustion turbines, auxiliary boiler, fire pump, & evaporative fluid cooler**
SO_2, lbs	288.29	**Two combustion turbines, auxiliary boiler, fire pump, & evaporative fluid cooler**

Contra Costa Generating Station 2x1

HRSG Stack Sizing

Stack Diameter, ft	
Exhaust Flow, lb/hr	4,162,310
Stack Temperature, deg. F	192
Exhaust Molecular Weight	28.43
Site Elevation, ft	**17.5**
Ambient Pressure, psia	14.69
Maximum Velocity, fps	**75.0**
Minimum Stack Diameter, ft	18.13
Selected Stack Diameter, ft	**18.37**
Actual Velocity, fps	73.0
Stack Height	
Finished Grade to Top of Foundation, ft	**0.5**
Top of Foundation to Top of Breeching, ft	**89.0**
Stack Damper, ft	**10.0**
Stack Silencer, ft	**10.0**
Last Disturbance to Test Ports, diameters	**2.0**
Test Ports to Stack Outlet, diameter	**0.5**
Minimum Stack Height, ft (above top of foundation)	154.9
Selected Stack Height, ft (above top of foundation)	**155.0**
Selected Stack Height, ft (above finshed grade)	155.5
Top of Stack Elevation, ft	173.0
Stack Height to HRSG Height Ratio	1.7

Contra Costa Generating Station 2x1
CTG/HRSG Assumptions

Plant Design Parameters		
Combustion Turbine Manufacturer	**GE**	
Combustion Turbine Model	**7FA**	
Stack Diameter, ft	18.37	
Stack Height, ft	155	
Sulfate Particulate Molecular Weight	**134**	
Sulfate Particulate Conversion Rate in CTG	**5%**	
Duct Burner Emissions		
	Without PAG	**With PAG**
NOx, lb/MMBtu as NO_2 (HHV)	**0.080**	**0.080**
CO, lb/MMBtu (HHV)	**0.100**	**0.250**
POC, lb/MMBtu as CH4 (HHV)	**0.020**	**0.050**
PM_{10}, lb/MMBtu (HHV)	**0.015**	**0.015**
Sulfate Particulate Conversion Rate in Duct Burner	**0%**	**0%**
CO Catalyst Design Parameters		
CO Catalyst Required? (Yes/No)	**Yes**	
Design Outlet CO with Duct Firing, ppmvd @ 15% O_2	**2.0**	
Design Outlet CO without Duct Firing, ppmvd @ 15% O_3	**2.0**	
Design Outlet POC with Duct Firing, ppmvd as CH4 @ 15% O3	**1.0**	
Design Outlet POC, ppmvd as CH4 @ 15% O2	**1.0**	
Minimum POC Reduction across CO Catalyst	**0%**	
Sulfate Particulate Conversion Rate across CO Catalyst	**80%**	
NO_x Catalyst Design Parameters		
NO_x Catalyst Required? (Yes/No)	**Yes**	
Design Outlet NO_x, ppmvd @ 15% O_2	**1.5**	
Ammonia Slip, ppmvd @ 15% O_2	**5**	
Sulfate Particulate Conversion Rate across SCR Catalyst	**10%**	
CT PM_{10} Assumptions		
Natural Gas - lbs/MMBtu (HHV)	**0.0087**	

Contra Costa Generating Station 2x1
Operating Emissions

		ISO Conditions			Peak July Conditions			Minimum Ambient		
		Case B	Case D	Case R	Case H	Case J	Case X	Case 01C	Case 01F	Case 01E
		Max	Med Output	Min Output	Max	Med Output	Min Output	Max	Med Output	Min Output
		All Units	All Units	One Unit	All Units	All Units	One Unit	All Units	All Units	One Unit
Operating Conditions										
Ambient Dry Bulb Temp.	deg. F	59	59	59	104	104	104	34	34	34
Ambient Wet Bulb Temp.	deg. F	51	51	51	70	70	70	32	32	32
Relative Humidity	%	60%	60%	60%	18%	18%	18%	83%	83%	83%
Elevation	ft	21	21	21	21	21	21	21	21	21
Ambient Pressure	psia	14.68	14.68	14.68	14.68	14.68	14.68	14.68	14.68	14.68
Combustion Turbine Load	%	100%	80%	49%	100%	80%	52%	100%	80%	49%
Combustion Turbines Operating		2	2	1	2	2	1	2	2	1
Evap Cooling or Fogging? (Yes/No)		Yes	No	No	Yes	No	No	No	No	No
Evap Cooling/Fogging Effectiveness	%	85%	%	85%	85%	85%	85%	85%	85%	85%
Duct Firing? (Yes/No)		No	No	No	No	No	No	No	No	No
Steam or Water Injection? (Yes/No)		No	No	No	No	No	No	No	No	No
Fuel Input (each CT)										
Fuel Type		Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CT Fuel (LHV)	MMBtu/hr	1,896	1,562	1,208	1,843	1,433	1,157	1,940	1,734	1,239
HRSG Fuel (LHV)	MMBtu/hr	0	0	0	0	0	0	0	0	0
Total Fuel (LHV)	MMBtu/hr	1,896	1,562	1,208	1,843	1,433	1,157	1,940	1,734	1,239
HHV/LHV =		1.1085	1.1085	1.1085	1.1085	1.1085	1.1085	1.1085	1.1085	1.1085
CT Fuel (HHV)	MMBtu/hr	2,102	1,731	1,339	2,043	1,589	1,283	2,150	1,923	1,373
HRSG Fuel (HHV)	MMBtu/hr	0	0	0	0	0	0	0	0	0
Total Fuel (HHV)	MMBtu/hr	2,102	1,731	1,339	2,043	1,589	1,283	2,150	1,923	1,373
CT Fuel	lb/hr	90,871	74,840	57,896	88,330	68,681	55,452	92,955	83,126	59,382
HRSG Fuel	lb/hr	0	0	0	0	0	0	0	0	0
Total Fuel	lb/hr	90,871	74,840	57,896	88,330	68,681	55,452	92,955	83,126	59,382
Inlet Air (each CT)										
N_2	mole % dry	78.04%	78.04%	78.04%	78.04%	78.04%	78.04%	78.04%	78.04%	78.04%
O_2	mole % dry	20.99%	20.99%	20.99%	20.99%	20.99%	20.99%	20.99%	20.99%	20.99%
CO_2	mole % dry	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%
Ar	mole % dry	0.94%	0.94%	0.94%	0.94%	0.94%	0.94%	0.94%	0.94%	0.94%
Total		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Molecular Weight, dry air		28.97	28.97	28.97	28.97	28.97	28.97	28.97	28.97	28.97
Dry Bulb Temperature	deg. F	53.5	59.0	59.0	75.5	104.4	104.4	34.0	34.0	34.0
Moisture Content of Ambient Air	lb $H_2$0/lb air	0.0064	0.0064	0.0064	0.0082	0.0082	0.0082	0.0034	0.0034	0.0034
Moisture Content of Inlet Air	lb $H_2$0/lb air	0.0076	0.0064	0.0064	0.0149	0.0082	0.0082	0.0034	0.0034	0.0034
Relative Humidity of Inlet Air	%	88%	60%	60%	78%	18%	18%	83%	83%	83%
Moisture Content	moles $H_2$0/mole air	0.012	0.010	0.010	0.024	0.013	0.013	0.005	0.005	0.005
N_2	mole %	77.09%	77.25%	77.25%	76.22%	77.02%	77.02%	77.61%	77.61%	77.61%
O_2	mole %	20.74%	20.78%	20.78%	20.50%	20.72%	20.72%	20.88%	20.88%	20.88%
CO_2	mole %	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%
H_2O	mole %	1.21%	1.01%	1.01%	2.34%	1.30%	1.30%	0.55%	0.55%	0.55%
Ar	mole %	0.93%	0.93%	0.93%	0.92%	0.93%	0.93%	0.93%	0.93%	0.93%
Total		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Molecular Weight		28.83	28.86	28.86	28.71	28.82	28.82	28.91	28.91	28.91
Inlet Air Flow	lb/hr	4,025,259	3,241,369	2,687,064	3,984,360	3,087,806	2,713,728	4,069,355	3,554,946	2,675,348
Pagging/Injection Steam/Water (each CT)										
Steam or Water/Fuel Ratio		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Steam or Water Injection Flow	lb/hr	0	0	0	0	0	0	0	0	0
Combustion Turbine Exhaust (each CT)										
Excess Combustion Air	%	163.8%	158.3%	176.7%	166.7%	167.6%	191.3%	161.8%	155.8%	169.4%
N_2	lb/hr	3,016,114	2,431,819	2,015,898	2,964,181	2,312,374	2,032,170	3,061,989	2,674,949	2,013,044
O_2	lb/hr	575,145	457,642	395,396	569,015	444,768	409,850	581,175	500,285	388,772
CO_2	lb/hr	246,642	203,099	157,200	239,767	186,434	150,625	252,287	225,572	161,202
H_2O	lb/hr	226,443	181,896	141,853	248,832	173,208	141,642	214,285	191,339	137,148
Ar	lb/hr	51,786	41,753	34,613	50,894	39,703	34,893	52,573	45,927	34,564
Total Exhaust Flow	lb/hr	4,116,130	3,316,209	2,744,960	4,072,690	3,156,487	2,769,180	4,162,310	3,638,072	2,734,730
Manufacturer's Exhaust Flow	lb/hr	4,116,130	3,316,209	2,744,960	4,072,690	3,156,487	2,769,180	4,162,310	3,638,072	2,734,730
N_2	mass %	73.28%	73.33%	73.44%	72.78%	73.26%	73.39%	73.56%	73.53%	73.61%
O_2	mass %	13.97%	13.80%	14.40%	13.97%	14.09%	14.80%	13.96%	13.75%	14.22%
CO_2	mass %	5.99%	6.12%	5.73%	5.89%	5.91%	5.44%	6.06%	6.20%	5.89%
H_2O	mass %	5.50%	5.49%	5.17%	6.11%	5.49%	5.11%	5.15%	5.26%	5.02%
Ar	mass %	1.26%	1.26%	1.26%	1.25%	1.26%	1.26%	1.26%	1.26%	1.26%
Total		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
N_2	moles/hr	107,667	86,809	71,962	105,813	82,545	72,543	109,304	95,488	71,860
O_2	moles/hr	17,974	14,302	12,357	17,782	13,899	12,808	18,162	15,634	12,150
CO_2	moles/hr	5,620	4,628	3,582	5,463	4,248	3,432	5,749	5,140	3,673
H_2O	moles/hr	12,569	10,097	7,874	13,812	9,614	7,862	11,895	10,621	7,613
Ar	moles/hr	1,296	1,045	866	1,274	994	873	1,316	1,150	865
Total	moles/hr	145,126	116,881	96,641	144,145	111,301	97,519	146,426	128,033	96,161
N_2	mole %	74.19%	74.27%	74.46%	73.41%	74.16%	74.39%	74.65%	74.58%	74.73%
O_2	mole %	12.38%	12.24%	12.79%	12.34%	12.49%	13.13%	12.40%	12.21%	12.63%
CO_2	mole %	3.87%	3.96%	3.71%	3.79%	3.82%	3.52%	3.93%	4.01%	3.82%
H_2O	mole %	8.66%	8.64%	8.15%	9.58%	8.64%	8.06%	8.12%	8.30%	7.92%
Ar	mole %	0.89%	0.89%	0.90%	0.88%	0.89%	0.90%	0.90%	0.90%	0.90%
Total		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Molecular Weight		28.37	28.38	28.41	28.26	28.36	28.40	28.43	28.42	28.44
CT Emissions (each CT) - Expected										
NO_X, @ 15% O_2	ppmvd	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
CO	ppmvd	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
POC	ppmvw	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
NO_X, as NO_2	lb/hr	68.3	56.2	43.5	66.4	51.6	41.6	69.8	62.5	44.6
CO	lb/hr	33.4	26.9	22.4	32.9	25.6	22.6	33.9	29.6	22.3
POC, as CH_4	lb/hr	3.3	2.6	2.2	3.2	2.5	2.2	3.3	2.9	2.2
PM_{10}	lb/hr	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
Portion of PM_{10} from Sulfur Particulates	lb/hr	0.61	0.51	0.39	0.60	0.46	0.37	0.63	0.56	0.40
Portion of PM_{10} from Soot/Ash	lb/hr	8.4	8.5	8.6	8.4	8.5	8.6	8.4	8.4	8.6
Maximum SO_2	lb/hr	5.9	4.8	3.7	5.7	4.4	3.6	6.0	5.4	3.8
Annual Average SO_2	lb/hr	1.5	1.2	0.9	1.4	1.1	0.9	1.5	1.3	1.0

Radback Energy

Contra Costa Generating Station 2x1

Operating Emissions

		ISO Conditions			Peak July Conditions			Minimum Ambient		
		Case B	Case D	Case R	Case H	Case J	Case X	Case 01C	Case 01F	Case 01E
		Max	Med Output	Min Output	Max	Med Output	Min Output	Max	Med Output	Min Output
		All Units	All Units	One Unit	All Units	All Units	One Unit	All Units	All Units	One Unit
Duct Burner Emissions (each CT) - Expected										
NO_x, as NO_2	lb/hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO	lb/hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
POC, as CH_4	lb/hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PM_{10}	lb/hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Portion of PM_{10} from Sulfur Particulates	lb/hr	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Portion of PM_{10} from Soot/Ash	lb/hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Maximum SO_2	lb/hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Annual Average SO_2	lb/hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Emissions Upstream of Catalyst (each CT)										
NO_x, as NO_2	lb/hr	68.3	56.2	43.5	66.4	51.6	41.6	69.8	62.5	44.6
CO	lb/hr	33.4	26.9	22.4	32.9	25.6	22.6	33.9	29.6	22.3
POC, as CH_4	lb/hr	3.3	2.6	2.2	3.2	2.5	2.2	3.3	2.9	2.2
PM_{10}	lb/hr	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
Portion of PM_{10} from Sulfur Particulates	lb/hr	0.6	0.5	0.4	0.6	0.5	0.4	0.6	0.6	0.4
Portion of PM_{10} from Soot/Ash	lb/hr	8.4	8.5	8.6	8.4	8.5	8.6	8.4	8.4	8.6
SO_2 Converted to PM_{10} w/in CT & HRSG	lb/hr	0.29	0.24	0.19	0.28	0.22	0.18	0.30	0.27	0.19
Maximum SO_2	lb/hr	5.9	4.8	3.7	5.7	4.4	3.6	6.0	5.4	3.8
Annual Average SO_2	lb/hr	1.5	1.2	0.9	1.4	1.1	0.9	1.5	1.3	1.0
CO Catalyst Performance (each CT)										
Required CO Reduction	lb/hr	24.2	19.3	16.5	23.9	18.6	17.0	24.5	21.1	16.3
Required CO Reduction (mass basis)	%	72%	72%	74%	73%	73%	75%	72%	71%	73%
Required POC Reduction	lb/hr	0.6	0.4	0.5	0.7	0.5	0.6	0.6	0.5	0.4
Required POC Reduction (mass basis)	%	19%	17%	22%	21%	20%	26%	18%	16%	20%
PM_{10} Increase from Sulfur Particulates	lb/hr	9.3	7.7	5.9	9.1	7.0	5.7	9.5	8.5	6.1
SO_2 Converted to PM_{10} w/in CO Catalyst	lb/hr	4.46	3.67	2.84	4.33	3.37	2.72	4.56	4.08	2.91
NOx Catalyst Performance (each CT)										
Required NO_x Reduction, as NO_2	lb/hr	56.9	46.9	36.2	55.3	43.0	34.7	58.2	52.1	37.2
Required NO_x Reduction (mass basis)	%	83%	83%	83%	83%	83%	83%	83%	83%	83%
PM_{10} Increase from Sulfur Particulates	lb/hr	0.23	0.19	0.15	0.23	0.18	0.14	0.24	0.21	0.15
NH_3 Slip	lb/hr	14.0	11.6	8.9	13.6	10.6	8.6	14.4	12.8	9.2
NH_3 Reacted	lb/hr	22.1	18.2	14.1	21.5	16.7	13.5	22.6	20.2	14.4
Total NH_3 Added	lb/hr	36.2	29.8	23.0	35.1	27.3	22.0	37.0	33.1	23.6
Stack Exhaust Analysis (each CT)										
N_2	lb/hr	3,016,114	2,431,819	2,015,898	2,964,181	2,312,374	2,032,170	3,061,989	2,674,949	2,013,044
O_2	lb/hr	575,145	457,642	395,396	569,015	444,768	409,850	581,175	500,285	388,772
CO_2	lb/hr	246,642	203,099	157,200	239,767	186,434	150,625	252,287	225,572	161,202
H_2O	lb/hr	226,443	181,896	141,853	248,832	173,208	141,642	214,285	191,339	137,148
Ar	lb/hr	51,786	41,753	34,613	50,894	39,703	34,893	52,573	45,927	34,564
Total	lb/hr	4,116,130	3,316,209	2,744,960	4,072,690	3,156,487	2,769,180	4,162,310	3,638,072	2,734,730
N_2	mass %	73.3%	73.3%	73.4%	72.8%	73.3%	73.4%	73.6%	73.5%	73.6%
O_2	mass %	14.0%	13.8%	14.4%	14.0%	14.1%	14.8%	14.0%	13.8%	14.2%
CO_2	mass %	6.0%	6.1%	5.7%	5.9%	5.9%	5.4%	6.1%	6.2%	5.9%
H_2O	mass %	5.5%	5.5%	5.2%	6.1%	5.5%	5.1%	5.1%	5.3%	5.0%
Ar	mass %	1.3%	1.3%	1.3%	1.2%	1.3%	1.3%	1.3%	1.3%	1.3%
Total	mass %	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
N_2	moles/hr	107,649	86,794	71,950	105,796	82,532	72,532	109,286	95,472	71,848
O_2	moles/hr	17,971	14,299	12,355	17,779	13,897	12,806	18,159	15,632	12,148
CO_2	moles/hr	5,619	4,627	3,581	5,462	4,247	3,432	5,748	5,139	3,672
H_2O	moles/hr	12,567	10,095	7,873	13,810	9,613	7,861	11,893	10,619	7,612
Ar	moles/hr	1,296	1,045	866	1,274	994	873	1,316	1,149	865
Total	moles/hr	145,102	116,861	96,625	144,121	111,283	97,504	146,401	128,011	96,145
N_2	mole%	74.2%	74.3%	74.5%	73.4%	74.2%	74.4%	74.6%	74.6%	74.7%
O_2	mole%	12.4%	12.2%	12.8%	12.3%	12.5%	13.1%	12.4%	12.2%	12.6%
CO_2	mole%	3.9%	4.0%	3.7%	3.8%	3.8%	3.5%	3.9%	4.0%	3.8%
H_2O	mole%	8.7%	8.6%	8.1%	9.6%	8.6%	8.1%	8.1%	8.3%	7.9%
Ar	mole%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%
Total	mole%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Molecular Weight		28.37	28.38	28.41	28.26	28.36	28.40	28.43	28.42	28.44
Stack Temperature	deg. F	191	180	171	213	196	180	192	185	171
Stack Temperature	deg. K	361.43	355.22	350.59	373.59	364.46	355.21	361.82	358.03	350.54
Stack Flow	cf/hr	69,006,000	54,620,000	44,575,000	70,845,000	53,366,000	45,572,000	69,698,000	60,306,000	44,346,000
Stack Velocity	ft/sec	72.3	57.2	46.7	74.3	55.9	47.8	73.0	63.2	46.5
Stack Velocity	m/sec	22.0	17.4	14.2	22.6	17.0	14.6	22.3	19.3	14.2
Calculated Stack Emissions (each CT)										
NO_x, @ 15% O_2	ppmvd	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
CO, @ 15% O_2	ppmvd	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
POC, as CH_4 @ 15% O2	ppmvd	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
NH_3 slip, @ 15% O_2	ppmvd	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
NO_x, as NO_2	lb/hr	11.4	9.4	7.2	11.1	8.6	6.9	11.6	10.4	7.4
CO	lb/hr	9.2	7.6	5.9	9.0	7.0	5.6	9.5	8.5	6.0
POC, as CH_4	lb/hr	2.6	2.2	1.7	2.6	2.0	1.6	2.7	2.4	1.7
Total PM_{10} from Sulfur Particulates	lb/hr	9.8	8.1	6.3	9.6	7.4	6.0	10.1	9.0	6.4
Total PM_{10}	lb/hr	**18.6**	**16.9**	**15.1**	**18.3**	**16.2**	**14.8**	**18.8**	**17.7**	**15.2**
NH_3	lb/hr	14.0	11.6	8.9	13.6	10.6	8.6	14.4	12.8	9.2
Maximum SO_2	lb/hr	5.9	4.8	3.7	5.7	4.4	3.6	6.0	5.4	3.8
Annual Average SO_2	lb/hr	1.5	1.2	0.9	1.4	1.1	0.9	1.5	1.3	1.0

Contra Costa Generating Station 2x1
Operating Emissions

		ISO Conditions			Peak July Conditions			Minimum Ambient		
		Case B	Case D	Case R	Case H	Case J	Case X	Case 01C	Case 01F	Case 01E
		Max All Units	Med Output All Units	Min Output One Unit	Max All Units	Med Output All Units	Min Output One Unit	Max All Units	Med Output All Units	Min Output One Unit
Permitted Stack Emissions (each CT)										
NO_X, @ 15% O_2	ppmvd	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**
CO, @ 15% O_2	ppmvd	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**
POC, as CH_4 @ 15% O2	ppmvd	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**
NH_3 Slip, @ 15% O_2	ppmvd	**5.0**	**5.0**	**5.0**	**5.0**	**5.0**	**5.0**	**5.0**	**5.0**	**5.0**
NO_X, as NO_2	lb/hr	15.17	12.50	9.66	14.75	11.47	9.25	15.52	13.88	9.91
CO	lb/hr	9.24	7.61	5.88	8.98	6.98	5.63	9.45	8.45	6.04
POC, as CH_4	lb/hr	2.65	2.18	1.68	2.57	2.00	1.61	2.71	2.42	1.73
Total PM_{10}	lb/hr	**7.50**	**7.50**	**7.50**	**7.50**	**7.50**	**7.50**	**7.50**	**7.50**	**7.50**
NH_3	lb/hr	14.04	11.57	8.94	13.65	10.61	8.56	14.36	12.85	9.17
Maximum SO_2	lb/hr	5.90	4.80	3.70	5.70	4.40	3.60	6.00	5.40	3.80
Annual Average SO_2	lb/hr	1.50	1.20	0.90	1.40	1.10	0.90	1.50	1.30	1.00
NO_X, as NO_2	lb/MMBtu(HHV)	0.00722	0.00722	0.00721	0.00722	0.00722	0.00721	0.00722	0.00722	0.00722
CO	lb/MMBtu(HHV)	0.00440	0.00440	0.00439	0.00439	0.00439	0.00439	0.00440	0.00440	0.00439
POC, as CH_4	lb/MMBtu(HHV)	0.00126	0.00126	0.00126	0.00126	0.00126	0.00126	0.00126	0.00126	0.00126
		0.00455	0.00455	0.00455	0.00455	0.00455	0.00455	0.00455	0.00455	0.00455
Total PM_{10}	lb/MMBtu(HHV)	0.00357	0.00433	0.00560	0.00367	0.00472	0.00585	0.00349	0.00390	0.00546
Maximum SO_2	lb/MMBtu(HHV)	0.00281	0.00277	0.00276	0.00279	0.00277	0.00281	0.00279	0.00281	0.00277
Annual Maximum SO_2	lb/MMBtu(HHV)	0.00071	0.00069	0.00067	0.00069	0.00069	0.00070	0.00070	0.00068	0.00073
CO_2	lb/MMBtu(HHV)	117.35	117.33	117.39	117.36	117.36	117.44	117.34	117.32	117.37

Contra Costa Generating Station 2x1

Startup Emissions Summary

Calculated Values		Proposed Limits
Hot Start		
Start Duration, minutes	14.0	**14.0**
Total per Start (per turbine)		
NO_x, lbs	22.0	**22.0**
CO, lbs	138.0	**138.0**
POC, lbs	31.0	**31.0**
PM_{10}, lbs	1.8	
SO_2, lbs (maximum)	0.9	
SO_2, lbs (annual average)	0.2	
Warm Start		
Start Duration, minutes	14.0	**14.0**
Total per Start (per turbine)		
NO_x, lbs	22.0	**22.0**
CO, lbs	138.0	**138.0**
POC, lbs	31.0	**31.0**
PM_{10}, lbs	1.8	
SO_2, lbs (maximum)	0.9	
SO_2, lbs (annual average)	0.2	
Cold Start		
Start Duration, minutes	45.0	**45.0**
Total per Start (per turbine)	5.0	
NO_x, lbs	96.0	**96.0**
CO, lbs	540.0	**540.0**
POC, lbs	67.0	**67.0**
PM_{10}, lbs	5.6	
SO_2, lbs (maximum)	2.9	
SO_2, lbs (annual average)	0.8	
Shutdown		
Shutdown Duration, minutes	14.0	**14.0**
Total per Shutdown (per turbine)		
NO_x, lbs	39.0	**39.0**
CO, lbs	206.0	**206.0**
POC, lbs	17.0	**17.0**
PM_{10}, lbs	1.8	
SO_2, lbs (maximum)	0.9	
SO_2, lbs (annual average)	0.2	

Contra Costa Generating Station 2x1

Combustion Turbine Commissioning

Operating Mode	No.	Hours	Hourly Emissions (lbs/hr or lbs/start or shutdown)					Total Emissions (lbs)				
			NO_x	CO	POC	PM_{10}	SO_2	NO_x	CO	POC	PM_{10}	SO_2
CTG/HRSG 1 - No Load[1]		**72**	120.0	210.0	20.0	7.5	3.8	8,640	15,120	1,440	540	274
CTG/HRSG 2 - No Load[1]		**72**	120.0	210.0	20.0	7.5	3.8	8,640	15,120	1,440	540	274
CTG/HRSG 1 - 49% Load[2]		**144**	113.0	22.0	2.0	7.5	3.8	16,272	3,168	288	1,080	547
CTG/HRSG 2 - 49% Load[2]		**144**	113.0	22.0	2.0	7.5	3.8	16,272	3,168	288	1,080	547
CTG/HRSG 1 - Full Load - No SCR[3]		**48**	68.3	33.4	3.3	7.5	6.0	3,277	1,604	156	360	288
CTG/HRSG 2 - Full Load - No SCR[3]		**48**	68.3	33.4	3.3	7.5	6.0	3,277	1,604	156	360	288
CTG/HRSG 1 - Full Load - Partial SCR[4]		**24**	41.7	21.3	3.0	7.5	6.0	1,001	512	71	180	144
CTG/HRSG 2 - Full Load - Partial SCR[4]		**24**	41.7	21.3	3.0	7.5	6.0	1,001	512	71	180	144
CTG/HRSG 1 - Full Load - Full SCR[5,6]		**336**	15.2	9.2	2.6	7.5	6.0	5,098	3,104	889	2,520	2,016
CTG/HRSG 2 - Full Load - Full SCR[5]		**24**	15.2	9.2	2.6	7.5	6.0	364	222	63	180	144
CTG/HRSG 1 - Cold Starts	**1**	0.75	96.0	540.0	67.0	5.6	2.9	96	540	67	6	3
CTG/HRSG 2 - Cold Starts	**1**	0.75	96.0	540.0	67.0	5.6	2.9	96	540	67	6	3
CTG/HRSG 1 - Hot Starts	**5**	1.17	22.0	138.0	31.0	1.8	0.9	110	690	155	9	4
CTG/HRSG 2 - Hot Starts	**5**	1.17	22.0	138.0	31.0	1.8	0.9	110	690	155	9	4
CTG/HRSG 1 - Shutdowns	6	1.40	39.0	206.0	17.0	1.8	0.9	234	1,236	102	11	5
CTG/HRSG 2 - Shutdowns	6	1.40	39.0	206.0	17.0	1.8	0.9	234	1,236	102	11	5
Total		943						64,723	49,065	5,511	7,070	4,691
Maximum Hour (each CTG/HRSG)			126.0	592.5	72.0	7.5	6.0					
CTG/HRSG 1 - Total Commissioning Time[7]		291										
CTG/HRSG 2 - Total Commissioning Time[7]		291										
Total Commissioning Duration		583										

Notes:

1. Full speed, no load tests including ignition system, synchronization, and overspeed checks.
2. Part load tests, combustor tuning, steam blows.
3. Full load tests with no catalyst installed, combustor tuning.
4. Full load tests with catalyst installed, SCR system tuning.
5. Full load operation with catalyst installed and operating as specified.
6. Assumes startup of second unit starts when catalyst is loaded on first unit and allows 2 days for catalyst installation.
7. Includes all time with uncontrolled emissions, including no load, 49% load, 100% load without SCR, and 100% load with partial SCR.

Operating Mode	Fuel MMBtu/hr	Hourly Emissions (lbs/MMBtu HHV)				
		NO_x	CO	POC	PM_{10}	SO_2
CTG/HRSG 1 - No Load[1]	863	0.1391	0.2435	0.0232	0.0087	0.0044
CTG/HRSG 2 - No Load[1]	863	0.1391	0.2435	0.0232	0.0087	0.0044
CTG/HRSG 1 - 49% Load[2]	1,339	0.0844	0.0164	0.0015	0.0056	0.0028
CTG/HRSG 2 - 49% Load[2]	1,339	0.0844	0.0164	0.0015	0.0056	0.0028
CTG/HRSG 1 - Full Load - No SCR[3]	2,102	0.0325	0.0159	0.0016	0.0036	0.0029
CTG/HRSG 2 - Full Load - No SCR[3]	2,102	0.0325	0.0159	0.0016	0.0036	0.0029
CTG/HRSG 1 - Full Load - Partial SCR[4]	2,102	0.0199	0.0101	0.0014	0.0036	0.0029
CTG/HRSG 2 - Full Load - Partial SCR[4]	2,102	0.0199	0.0101	0.0014	0.0036	0.0029
CTG/HRSG 1 - Full Load - Full SCR[5,6]	2,102	0.0072	0.0044	0.0013	0.0036	0.0029
CTG/HRSG 2 - Full Load - Full SCR[5]	2,102	0.0072	0.0044	0.0013	0.0036	0.0029

Contra Costa Generating Station 2x1
Evaporative Fluid Cooler

Operating Conditions		Peak July Conditions Case H
Ambient Dry Bulb Temp.	deg. F	104.4
Ambient Wet Bulb Temp.	deg. F	70.4
Relative Humidity	%	18%
Elevation	ft	21.0
Ambient Pressure	psia	14.68
Combustion Turbine Load	%	100%
Combustion Turbines Operating		2
Evaporative Cooling or Fogging? (Yes/No)		Yes
Duct Firing? (Yes/No)		No
Steam or Water Injection? (Yes/No)		No
Evaporative Fluid Cooler Performance		
Allowance to WB Temp to Account for Recirculation	deg. F	-
EFC Design Wet Bulb Temperature	deg. F	70.4
Closed Loop Cooling Water Flow	gpm	**5,610**
EFC Circulating Flow	gpm	**5,880**
Heat Rejected from Closed Loop Cooling Water	MMBtu/hr	43.2
Closed Loop Cooling Water Outlet Temperature	deg. F	105.0
Closed Loop Cooling Water Inlet Temperature	deg. F	120.4
Require Approach Temperature	deg. F	34.6
Makeup Water Temperature	deg. F	**70.0**
Number of Cells		**3**
Number of Fans Operating		**3**
Fan Stack Diameter	ft	**11.00**
Leaving Air Flow/Fan	acfm	**190,600**
Total Leaving Air Flow	acfm	571,800
Stack Velocity	ft/sec	33.4
Wet Bulb Temperature of Leaving Air	deg. F	**87.91**
Enthalpy of Leaving Air	Btu/lb	53.1
Moisture Content of Leaving Air	grains/lb dry air	204
Humidity Ratio of Leaving Air	lb water/lb dry air	0.0291
Density of Leaving Air	lbs/cf	0.0712
Total Dry Air Flow	lb/min	39,537
L/G Ratio		1.239
Enthalpy of Entering Air	Btu/lb	34.1
Moisture Content of Entering Air	grains/lb dry air	57
Humidity Ratio of Entering Air	lb water/lb dry air	0.0082
Heat Removed by Air	MMBtu/hr	43
Qair/Qcw		100%
Evaporation	gpm	99
Drift, percent of circulating water flow	%	**0.0030%**
Drift	gpm	0.18
Drift	lb/hr	0.17
EFC Circulating Water TDS	mg/l	**1,500**
% PM_{10} Emissions	% of total	**100%**
PM_{10} Emissions	lbs/hr	0.132

RADBACK ENERGY

Contra Costa Generating Station 2x1

Expected Auxiliary Boiler Emissions Assumptions

Plant Design Parameters	
Ambient Pressure, psia	14.68
Stack Diameter, ft	2.5
Stack Height, ft	50
Stack Temperature, deg F	290
Auxiliary Steam Demands	
Steam Turbine Seals, lb/hr	13,500
Condenser Hotwell Sparging, lb/hr	13,500
Gas Turbine Dewpoint Fuel Heating, lb/hr	0
SJAE, lb/hr	0
HRSG Sparging, lb/hr	0
Total Auxiliary Steam Demand	27,000
Boiler Net Output, lb/hr	30,062
Steam Pressure, psig	285
Steam Temperature, deg. F	417
Superheated Steam, Yes/No	No
Steam Enthalpy, Btu/lb	1,203.5
Makeup Water Temperature, deg. F	100
Makeup Water Enthalpy, Btu/lb	68.8
Boiler Feedwater Temperature, deg. F	228
Deaerator Pressure, psig	5.3
Deaerator Vent Steam, % of Inlet Steam	2%
Deaerator Vent Steam Enthalpy, Btu/lb	1,156.3
Boiler Feedwater Enthalpy, Btu/lb	196.3
Boiler Thermal Efficiency	75.0%
Deaerator Steam, lb/hr	3,938
Boiler Gross Output, lb/hr	**34,000**
Sulfate Particulate Molecular Weight	134
Sulfate Particulate Conversion Rate in Boiler	5%
CO Catalyst Design Parameters	
CO Catalyst Required? (Yes/No)	Yes
Design Outlet CO, ppmvd @ 3% O_2	50.0
Design Outlet POC, ppmvd @ 3% O2	5.0
Minimum POC Reduction across CO Catalyst	0%
Sulfate Particulate Conversion Rate across CO Catalyst	80%
NO_x Catalyst Design Parameters	
NO_x Catalyst Required? (Yes/No)	Yes
Design Outlet NO_x, ppmvd @ 3% O_2	9.0
Ammonia Slip, ppmvd @ 3% O_2	5
Sulfate Particulate Conversion Rate across SCR Catalyst	10%

Contra Costa Generating Station 2x1

Expected Auxiliary Boiler Emissions

Auxiliary Boiler		
Operating Conditions		
Ambient Dry Bulb Temp.	deg. F	59.0
Ambient Wet Bulb Temp.	deg. F	51.5
Relative Humidity	%	60%
Elevation	ft	21.0
Ambient Pressure	psia	14.68
Auxiliary Boiler Firing Rate	%	**100%**
Fuel Input		
Fuel (LHV)	MMBtu/hr	45.7
HHV/LHV =	1.1085	
Fuel (HHV)	MMBtu/hr	50.6
Fuel	lb/hr	2,188
Combustion Air		
N_2	mole % dry	78.04%
O_2	mole % dry	20.99%
CO_2	mole % dry	0.03%
Ar	mole % dry	0.94%
Total		100.00%
Molecular Weight, dry air		28.97
Inlet Air Dry Bulb Temperature	deg. F	59.0
Moisture Content of Inlet Air	lb H_20/lb air	0.0064
Moisture Content	moles H_20/mole air	0.010
N_2	mole %	77.25%
O_2	mole %	20.78%
CO_2	mole %	0.03%
H_2O	mole %	1.01%
Ar	mole %	0.93%
Total		100.00%
Molecular Weight		28.86
Inlet Air Flow	lb/hr	42,208
Boiler Exhaust		
Excess Combustion Air	%	**15.0%**
N_2	lb/hr	31,683
O_2	lb/hr	1,270
CO_2	lb/hr	5,915
H_2O	lb/hr	4,985
Ar	lb/hr	544

Contra Costa Generating Station 2x1

Expected Auxiliary Boiler Emissions

Auxiliary Boiler		
Total Exhaust Flow	lb/hr	44,396
Manufacturer's Exhaust Flow	lb/hr	**44,396**
N_2	mass %	71.36%
O_2	mass %	2.86%
CO_2	mass %	13.32%
H_2O	mass %	11.23%
Ar	mass %	1.22%
Total		100.00%
N_2	moles/hr	1,131
O_2	moles/hr	40
CO_2	moles/hr	135
H_2O	moles/hr	277
Ar	moles/hr	14
Total	moles/hr	1,596
N_2	mole %	70.87%
O_2	mole %	2.49%
CO_2	mole %	8.45%
H_2O	mole %	17.34%
Ar	mole %	0.85%
Total		100.00%
Molecular Weight		27.83
Boiler Emissions Upstream of Catalyst		
NO_x, @ 3% O_2	ppmvd	**83.0**
CO, @ 3% O_2	ppmvd	**50.0**
POC, @ 3% O_2	ppmvd	**0.24**
NO_x, as NO_2	lb/hr	5.0
CO	lb/hr	1.8
POC, as CH_4	lb/hr	0.0051
PM_{10}	lb/hr	**0.52**
PM_{10} Increase from Sulfur Particulates	lb/hr	0.01
SO_2 Converted to PM_{10} within Boiler	lb/hr	0.01
SO_2	lb/hr	0.14
CO Catalyst Performance		
Required CO Reduction	lb/hr	0.0
Required CO Reduction (mass basis)	%	0%
Required POC Reduction	lb/hr	0.0
Required POC Reduction (mass basis)	%	0%
PM_{10} Increase from Sulfur Particulates	lb/hr	0.2

RADBACK ENERGY

Contra Costa Generating Station 2x1

Expected Auxiliary Boiler Emissions

Auxiliary Boiler		
SO_2 Converted to PM_{10} within CO Catalyst	lb/hr	0.1
NO_x Catalyst Performance		
Required NO_x Reduction, as NO_2	lb/hr	4.5
Required NO_x Reduction (mass basis)	%	89%
PM_{10} Increase from Sulfur Particulates	lb/hr	0.01
NH_3 Slip	lb/hr	0.1
NH_3 Reacted	lb/hr	1.7
Total NH_3 Added	lb/hr	1.9
Boiler Stack Exhaust Analysis		
N_2	lb/hr	31,683
O_2	lb/hr	1,270
CO_2	lb/hr	5,915
H_2O	lb/hr	4,985
Ar	lb/hr	544
Total	lb/hr	44,396
N_2	mass %	71.4%
O_2	mass %	2.9%
CO_2	mass %	13.3%
H_2O	mass %	11.2%
Ar	mass %	1.2%
Total	mass %	100.0%
N_2	moles/hr	1,131
O_2	moles/hr	40
CO_2	moles/hr	135
H_2O	moles/hr	277
Ar	moles/hr	14
Total	moles/hr	1,595
N_2	mole%	70.9%
O_2	mole%	2.5%
CO_2	mole%	8.4%
H_2O	mole%	17.3%
Ar	mole%	0.9%
Total	mole%	100.0%
Molecular Weight		27.83
Stack Temperature	deg. F	**290**
Stack Temperature	deg. K	416
Stack Flow	acfh	874,000
Stack Flow	acfm	14,566.67

Contra Costa Generating Station 2x1

Expected Auxiliary Boiler Emissions

Auxiliary Boiler		
Stack Velocity	ft/sec	49.46
Stack Velocity	m/sec	15.08
Calculated Boiler Stack Emissions		
NO_x, @ 3% O_2	ppmvd	9.0
CO, @ 3% O_2	ppmvd	50.0
POC, as CH_4 @ 3% O2	ppmvd	0.24
NH_3 slip, @ 3% O_2	ppmvd	5.0
NOx, as NO_2	lb/hr	0.5
CO	lb/hr	1.8
POC, as CH_4	lb/hr	0.0051
Total PM_{10} from Sulfur Particulates	lb/hr	0.23
Total PM_{10}	lb/hr	0.75
NH_3	lb/hr	0.11
SO_2	lb/hr	0.14
Permitted Boiler Stack Emissions		
NO_x, @ 3% O_2	ppmvd	**9.0**
CO, @ 3% O_2	ppmvd	**50.0**
POC, as CH_4 @ 3% O2	ppmvd	**5.0**
Total PM_{10}	lbs/MMBtu HHV	**0.0070**
NH_3 Slip, @ 3% O_2	ppmvd	**5.0**
NO_x, as NO_2	lb/hr	0.55
CO	lb/hr	1.85
POC, as CH_4	lb/hr	0.11
Total PM_{10}	lb/hr	0.35
Total PM_{10}	lbs/MMscf	7.2
NH_3	lb/hr	0.11
SO_2	lb/hr	0.14
SO_2	lbs/MMscf	2.85
NO_x, as NO_2	g/s	0.069
CO	g/s	0.233
POC, as CH4	g/s	0.013
Total PM_{10}	g/s	0.045
NH_3	g/s	0.014
SO_2	g/s	0.018

Contra Costa Generating Station 2x1

Expected Emergency Fire Pump Engine Emissions

Engine		
Manufacturer		**Clarke**
Model		**JW6H-UFAD80**
Rated Horsepower	hp	**400**
Speed	rpm	**2,100**
Fuel		**No. 2 fuel oil**
Fuel Specific Gravity		**0.863**
Fuel Sulfur Content	mass %	**0.0015%**
Fuel Consumption	gph	**20.0**
Fuel Consumption	MMBtu/hr (HHV)	2.79
Exhaust Flow	cfm	**2,214**
Exhaust Temperature	deg. F	**826**
Exhaust Pipe Diameter	in	**8**
Exhaust Stack Height	ft	**16**
Pump		
Capacity	gpm	**2,500**
Discharge Pressure	psig	**125**
Pump Efficiency	%	**65.0%**
Brake Horsepower	bhp	280
Emissions		
Exhaust Velocity	ft/sec	106
NO_x	g/hp-hr	**2.61**
CO	g/hp-hr	**0.84**
POC	g/hp-hr	**0.10**
Particulates	g/hp-hr	**0.10**
SO_2	g/hp-hr	0.0049
NO_x	lb/hr	2.302
CO	lb/hr	0.741
HC	lb/hr	0.092
Particulates	lb/hr	0.091
SO_2	lb/hr	0.004

Tier 3 Emissions Data - John Deere Power Systems

Nameplate Rating Information	
Clarke Model	JW6H-UFAD80
Power Rating (BHP / kW)	400 / 298
Certified Speed (RPM)	2100

Certificate Data	
John Deere Engine Rating	6090HFC47B
Engine Model Year *	2009
EPA Family Name	9JDXL09.0114
EPA Certificate Number	JDX-NRCI-09-23
CARB Executive Order Number	U-R-004-0369
Emissions Label Part Number	R528939

* The Engine Model Year is listed on the emissions label.

Emissions Data **		
Units	g/hp-hr	g/kW-hr
CO	0.84	1.12
Pm	0.103	0.138
NOx	2.61	3.5
HC	0.104	0.14
NOx + HC	2.71	3.64
Test Engine	RG6090L015278	

** The emission data listed is measured from the calibration engine under laboratory test conditions. It is intended to represent an "average" engine but is not a guarantee that all engines meet these values.

JOHN DEERE

John Deere Power Systems
3801 W. Ridgeway Ave., PO Box 5100
Waterloo, Iowa USA 50704-5100

JDPS 2/19/2009

CLARKE

Fire Protection Products

JW6H-UFAD80
INSTALLATION & OPERATION DATA

Basic Engine Description

Engine Manufacturer	John Deere Co.
Ignition Type	Compression (Diesel)
Number of Cylinders	6
Bore and Stroke - in.(mm)	4.66 (118) X 5.35 (136)
Displacement - in^3 (L)	496 (8.1)
Compression Ratio	16.0:1
Valves per cylinder - Intake	2
Exhaust	2
Combustion System	Direct Injection
Engine Type	In-Line, 4 Stroke Cycle
Aspiration	Turbocharged
Firing Order (CW Rotation)	1-5-3-6-2-4
Charge Air Cooling Type	Raw Water Cooled
Rotation (Viewed from Front) - Clockwise	Standard
Counter-Clockwise	Not Available
Engine Crankcase Vent System	Open
Installation Drawing	D-628
Weight - lb (kg)	2094 (948)

Cooling System

	1760	2100
Engine H_2O Heat -Btu/sec.(kW)	97.2 (103)	97.6 (102)
Engine Radiated Heat - Btu/sec.(kW)	96 (101)	90.5 (95)
Heat Exchanger Minimum Flow		
60°F (15°C) Raw H_2O - gal/min. (L/min.)	38 (144)	40 (151)
95°F (35°C) Raw H_2O - gal/min. (L/min.)	47 (178)	50 (189)
Heat Exchanger Maximum Cooling H_2O		
Inlet Pressure - bar (lb./in^2) (kPa)	4 (60) (400)	
Flow - gal./min (L/min.)	80 (302)	
Thermostat, Start to Open - °F (°C)	180 (82)	
Fully Opened - °F (°C)	201 (94)	
Engine Coolant Capacity - qt. (L)	22 (20.8)	
Coolant Pressure Cap - lb./in^2(kPa)	15 (103)	
Maximum Engine H_20 Temperature - °F (°C)	221 (105)	
Minimum Engine H_20 Temperature - °F (°C)	160 (71)	

Electric System - DC

System Voltage (Nominal)	12 (Standard)	24 (Optional)
Battery Capacity for Ambients Above 32°F (0°C)		
Voltage (Nominal)	12	12
Qty. per Battery Bank	1	2
SAE size per J537	8D-900	8D-900
CCA @ 0°F (-18°C)	900	900
Reserve Capacity - Minutes	430	430
Battery Cable Circuit*, Max Resistance - ohm	0.0017	0.0017
Battery Cable Minimum Size		
0 -120 in. Circuit* Length	00	00
121 - 160 in. Circuit* Length	000	000
161 - 200 in. Circuit* Length	0000	0000
Charging Alternator Output - Amp	40	40
Starter Cranking Amps - @ 60°F (15°C)	495	326

**Positive and Negative Cables Combined Length*

NOTE: This engine is Intendend For Indoor Installation Or In A Weatherproof Enclosure. *(Continued)*

JW6H-UFAD80
INSTALLATION & OPERATION DATA (Continued)

Exhaust System	1760	2100
Exhaust Flow - ft.^{3}/min. (m^3/min.)	2048 (58)	2214 (62.7)
Exhaust Temperature - °F (°C)	891 (477)	826 (441)
Maximum Allowable Back Pressure - in. H_20 (kPa)	30 (7.5)	30 (7.5)
Minimum Exhaust Pipe Dia. - in. (mm)**	6 (152)	

Fuel System		
Fuel Consumption - gal./hr. (L/hr.)	20 (75.6)	20 (75.6)
Fuel Return - gal./hr. (L/hr.)		
Total Supply Fuel Flow - gal./hr. (L/hr.)		
Fuel Pressure - lb./in.^{2} (kPa)		
Minimum Line Size - Supply - (in.)	.50 Schedule 40 Steel Pipe	
Pipe Outer Diameter in. (mm)	.848 (0.33)	
Minimum Line Size - Return - (in.)	.375 Schedule 40 Steel Pipe	
Pipe Outer Diameter in. (mm)	.675 (0.26)	
Maximum Allowable Fuel Pump Suction		
With Clean Filter - in. H_20 (mH_20)	80 (2.0)	
Maximum Allowable Fuel Head above Fuel pump, Supply or Retrun - ft.(m)	6.6 (2.0)	
Fuel Filter Micron Size	2 (Secondary)	

Heater System	
Jacket Water Heater	Standard
Wattage (Nominal)	2500
Voltage - AC, 1P	230 (+5%, -10%)
Optional Voltage - AC, 1P	115 (+5%, -10%)
Lube Oil Heater Wattage	
(Required Option When Ambient is Below 40°F (4°C)	150

Induction Air System		
Air Cleaner Type	Indoors Service Only - Washable	
Air Intake Restriction Maximum Limit		
Dirty Air Cleaner - in. H_20 (kPa)	25 (6.25)	25 (6.25)
Clean Air Cleaner - in. H_20 (kPa)	15 (3.75)	15 (3.75)
Engine Air Flow - ft.^{3}/min. (m^3/min.)	848 (24)	971 (27.5)
Maximum Allowable Temperature (Air To Engine Inlet) - °F (°C)***	130 (54)	

Lubrication System		
Oil Pressure - normal - lb./in.^{2} (kPa)	37 (255)	41 (280)
In Pan Oil Temperature - °F (°C)	190-220 (88-104)	
Oil Pan Capacity - High - qt. (L)	48 (45)	
- Low - qt. (L)	39 (43)	
Total Oil Capacity with Filter - qt. (L)	41 (46)	

Performance		
BMEP - lb./in.^{2} (kPa)	346 (2386)	274 (1892)
Piston Speed - ft./min. (m/min.)	1570 (479)	1874 (571)
Mechanical Noise - dB(A) @ 1M	Consult Factory	
Power Curve	C132616	

*** Based On Nominal System. Flow Analysis Must Be Done To Assure Adherance To System Limitations. (Minimum Exhaust pipe Diameter is based on 15 feet of pipe, one elbow, and a silencer pressure drop no greter than one half the max. allowable back pressure.)*

**** Review For Power Deration If Air Entering Engine Exceeds °77F (25°C)*

C132906 revA
DSP 10DEC08

Contra Costa Generating Station 2x1

Fuel Gas Analysis

		Fuel Gas Composition (mole %)	Mole % x Molecular Weight	Fuel Gas Composition (mass %)	Molecular Weight	Density (lbs/scf)	Specific Gravity	Heat of Combustion		Lb/lb Fuel									
								Btu/lb		Required for Combustion					Exhaust Products				
								Gross	Net	N2	O2	CO2	Ar	Dry Air	N2	CO2	SO2	H2O	Ar
Methane	CH_4	**95.619%**	15.340	91.4%	16.043	0.0422	0.5558	23,879	21,520	11.86	3.64	0.01	0.20	15.72	11.86	2.51	0.00	2.05	0.20
Ethane	C_2H_6	**2.647%**	0.796	4.7%	30.070	0.0792	1.0418	22,320	20,432	0.57	0.18	0.00	0.01	0.76	0.57	0.14	0.00	0.09	0.01
Propane	C_3H_8	**0.300%**	0.132	0.8%	44.097	0.1161	1.5277	21,661	19,944	0.09	0.03	0.00	0.00	0.12	0.09	0.02	0.00	0.01	0.00
n -Butane	C_4H_{10}	**0.043%**	0.025	0.1%	58.124	0.1530	2.0137	21,308	19,680	0.02	0.01	0.00	0.00	0.02	0.02	0.00	0.00	0.00	0.00
Isobutane	C_4H_{10}	**0.033%**	0.019	0.1%	58.124	0.1530	2.0137	21,257	19,629	0.01	0.00	0.00	0.00	0.02	0.01	0.00	0.00	0.00	0.00
n -Pentane	C_5H_{12}	**0.008%**	0.006	0.0%	72.151	0.1900	2.4997	21,091	19,517	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00
Isopentane	C_5H_{12}	**0.011%**	0.008	0.0%	72.151	0.1900	2.4997	21,052	19,478	0.01	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00
Neopentane	C_5H_{12}	**0.000%**	0.000	0.0%	72.151	0.1900	2.4997	20,970	19,396	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
n -Hexane	C_6H_{14}	**0.008%**	0.007	0.0%	86.178	0.2269	2.9856	20,940	19,403	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00
Ethylene	C_2H_4	**0.000%**	0.000	0.0%	28.054	0.0739	0.9719	21,644	20,295	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Propylene	C_3H_6	**0.000%**	0.000	0.0%	42.081	0.1108	1.4579	21,041	19,691	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
n -Butene	C_4H_8	**0.000%**	0.000	0.0%	56.108	0.1477	1.9439	20,840	19,496	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Isobutene	C_4H_8	**0.000%**	0.000	0.0%	56.108	0.1477	1.9439	20,730	19,382	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
n -Pentene	C_5H_{10}	**0.000%**	0.000	0.0%	70.135	0.1847	2.4298	20,712	19,363	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Benzene	C_6H_6	**0.000%**	0.000	0.0%	78.115	0.2057	2.7063	18,210	17,480	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Toluene	C_7H_8	**0.000%**	0.000	0.0%	92.142	0.2426	3.1922	18,440	17,620	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Xylene	C_8H_{10}	**0.000%**	0.000	0.0%	106.169	0.2795	3.6782	18,650	17,760	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Acetylene	C_2H_2	**0.000%**	0.000	0.0%	26.038	0.0686	0.9021	21,500	20,776	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Napthalene	$C_{10}H_8$	**0.000%**	0.000	0.0%	128.175	0.3375	4.4406	17,298	16,708	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Methly alcohol	CH_3OH	**0.000%**	0.000	0.0%	32.042	0.0844	1.1101	10,259	9,078	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ethyl alcohol	C_2H_5OH	**0.000%**	0.000	0.0%	46.070	0.1213	1.5961	13,161	11,929	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ammonia	NH_3	**0.000%**	0.000	0.0%	17.031	0.0448	0.5900	9,668	8,001	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hydrogen	H_2	**0.000%**	0.000	0.0%	2.016	0.0053	0.0698	61,100	51,623	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nitrogen	N_2	**0.815%**	0.228	1.4%	28.013	0.0738	0.9712	0	0	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00
Carbon Dioxide	CO_2	**0.516%**	0.227	1.4%	44.010	0.1159	1.5247	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00
Total		100.0%		100.0%	16.789	0.0442	0.5820	23,130	20,865	12.58	3.86	0.01	0.22	16.66	12.59	2.70	0.00	2.16	0.22
Sulfur Compounds										**N2**	**O2**	**CO2**	**Ar**	**Dry Air**	**N2**	**CO2**	**SO2**	**H2O**	**Ar**
Maximum Sulfur	S	**1.00**	grains/100scf	0.00323%	32.060	N/A	N/A	3,983	3,983	1.0E-04	3.2E-05	6.3E-08	1.8E-06	1.4E-04	1.0E-04	6.3E-08	6.5E-05	0.0E+00	1.8E-06
Annual Average Sulfur	S	**0.25**	grains/100scf	0.00081%	32.060	N/A	N/A	3,983	3,983	2.6E-05	8.1E-06	1.6E-08	4.5E-07	3.5E-05	2.6E-05	1.6E-08	1.6E-05	0.0E+00	4.5E-07
Hydrogen Sulfide	H_2S	**0**	ppmv	0.000%	34.076	0.0897	1.1806	7,100	6,545	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
Maximum Total				0.00323%						1.0E-04	3.2E-05	6.3E-08	1.8E-06	1.4E-04	1.0E-04	6.3E-08	6.5E-05	0.0E+00	1.8E-06
Annual Average Total				0.00081%						2.6E-05	8.1E-06	1.6E-08	4.5E-07	3.5E-05	2.6E-05	1.6E-08	1.6E-05	0.0E+00	4.5E-07

Contra Costa Generating Station 2x1

Assumed Ambient Air Analysis

Ambient Air				
	Mole % (dry)	Mole % x Molecular Weight	Mass % (dry)	Molecular Weight
N_2	**78.04%**	21.862	75.47%	28.013
O_2	**20.99%**	6.717	23.19%	31.999
CO_2	**0.03%**	0.013	0.05%	44.010
Ar	**0.94%**	0.376	1.30%	39.948
Total	100.00%		100.00%	28.967

National Park Service Letter

United States Department of the Interior
NATIONAL PARK SERVICE
Air Resources Division
P.O. Box 25287
Denver, CO 80225

TAKE PRIDE IN AMERICA

IN REPLY REFER TO:

August 4, 2009

Gregory Darvin
Atmospheric Dynamics, Inc.
2925 Puesta del Sol
Santa Barbara, California 93105

Dear Mr. Darvin:

We have reviewed the information you provided in your July 30, 2009, email message regarding the Contra Costa Generating Station (CCGS). The proposed CCGS facility is located approximately 105 kilometers east of Point Reyes National Seashore, approximately 160 kilometers northwest of Yosemite National Park, and approximately 170 kilometers northeast of Pinnacles National Monument, all are Class I air quality areas administered by the National Park Service. Based on your information, emissions from the facility will be 99 tons per year (TPY) of nitrogen oxide, 63 TPY of particulate matter (PM/PM_{10}), 31 TPY of volatile organic compounds, and 12 TPY of sulfur dioxide. Based on the emission rates and distances from the National Park Service Class I areas, the National Park Service anticipates that modeling would not show any significant additional impacts to air quality related values (AQRV) at the Class I areas. Therefore, we are not requesting that a Class I AQRV analysis be included in the Prevention of Significant Deterioration permit application. Our screening of this analysis does not indicate agreement with any AQRV analysis protocols or conclusions applicants may make independent of Federal Land Manager review. Please note that we are specifically addressing the need for an AQRV analysis for Class I areas managed by the National Park Service.

The state and/or the Environmental Protection Agency may have a different opinion regarding the need for a Class I increment analysis. Should the emissions or the nature of the CCGS project change significantly, please contact me so that I might re-evaluate the revised proposed project.

Thank you for keeping me informed and involving the National Park Service in the review of the CCGS project.

Sincerely,

Darwin W. Morse
Environmental Protection Specialist

ATTACHMENT DR4-1

Annual Emissions Scenario 1

Oakley Generating Station 2x1

Annual Emissions - PG&E Specification - 300 Starts (25 of which are cold)

Plant Dispatch		Proposed Limits
Combustion Turbines/HRSGs (per unit unless noted)		
Number of Turbines/HRSGs	**2**	
Minimum Load Hours - Natural Gas	**-**	
Base Load ISO Hours - Natural Gas	**3,657**	
Base Load Peak July Hours - Natural Gas	**1,500**	
Total Hot Starts - Natural Gas	**275**	
Total Warm Starts - Natural Gas	**-**	
Total Cold Starts - Natural Gas	**25**	
Total Shutdowns - Natural Gas	300	
Startup/Shutdown Hours	233	
Total Hours of Operation	5,390	
Offline Hours	3,370	
Annual Fuel Use, MMBtu (HHV) (all units)	22,480,757	35,397,277
Auxiliary Boiler		
Margin	**20%**	
Operating Hours	4,324	
Evaporative Fluid Cooler		
Operating Hours	**1,500**	
Fire Pump		
Duration of Periodic Tests, mins	**45**	
Frequency of Tests, tests/year	**53**	
Load During Testing, %	**100%**	
Operating Hours	40	
Annual Fuel Use, gals/yr	795	

Oakley Generating Station 2x1

Annual Emissions - PG&E Specification - 300 Starts (25 of which are cold)

Combustion Turbine/HRSG Emissions		Proposed Limits
Minimum Load - Natural Gas		
NO_x, tons as NO_2	-	
CO, tons	-	
POC, tons as CH_4	-	
PM_{10}, tons	-	
SO_2, tons	-	
CO_2, tons	-	
Base Load ISO - Natural Gas		
NO_x, tons as NO_2	20.8	
CO, tons	8.4	
POC, tons as CH_4	4.8	
PM_{10}, tons	16.5	
SO_2, tons	2.7	
CO_2, tons	450,985.6	
Base Load Peak July - Natural Gas		
NO_x, tons as NO_2	8.3	
CO, tons	3.4	
POC, tons as CH_4	1.9	
PM_{10}, tons	6.8	
SO_2, tons	1.1	
CO_2, tons	179,825.6	
Startups/Shutdowns - Natural Gas		
NO_x, tons as NO_2	10.1	
CO, tons	37.2	
POC, tons as CH_4	7.7	
PM_{10}, tons	1.0	
SO_2, tons	0.1	
CO_2, tons	36,996	
Total Emissions (each unit)		
NO_x, tons as NO_2	39.2	
CO, tons	49.0	
POC, tons as CH_4	14.4	
PM_{10}, tons	24.3	
SO_2, tons	3.9	

Oakley Generating Station 2x1

Annual Emissions - PG&E Specification - 300 Starts (25 of which are cold)

CO_2, tons	667,808	

Oakley Generating Station 2x1

Annual Emissions - PG&E Specification - 300 Starts (25 of which are cold)

Auxiliary Boiler		Proposed Limits
NO_x, tons as NO_2	1.180	
CO, tons	0.798	
POC, tons as CH_4	0.229	
PM_{10}, tons	0.766	
SO_2, tons	0.305	
CO_2, tons	12,786	
Evaporative Fluid Cooler		**Proposed Limits**
PM_{10}, tons	0.099	
Fire Pump Emissions		**Proposed Limits**
NO_x, tons as NO_2	0.0457	
CO, tons	0.0147	
POC, tons as CH_4	0.0018	
PM_{10}, tons	0.0018	
SO_2, tons	0.0001	
Total Plant Emissions		**Proposed Limits**
NO_x, tons as NO_2	79.6	98.8
CO, tons	98.8	98.8
POC, tons as CH_4	29.1	29.5
PM_{10}, tons	49.4	76.3
SO_2, tons	8.1	12.6
CO_2, tons (excluding fire pump)	1,348,401	2,081,421

ATTACHMENT DR4-2

Annual Emissions Scenario 2

RADBACK ENERGY

Oakley Generating Station 2x1

Annual Emissions - 6x16 with 1,500 Hours at Peak July

Plant Dispatch		Proposed Limits
Combustion Turbines/HRSGs (per unit unless noted)		
Number of Turbines/HRSGs	**2**	
Minimum Load Hours - Natural Gas	**-**	
Base Load ISO Hours - Natural Gas	**3,933**	
Base Load Peak July Hours - Natural Gas	**1,500**	
Total Hot Starts - Natural Gas	**260**	
Total Warm Starts - Natural Gas	**51**	
Total Cold Starts - Natural Gas	**1**	
Total Shutdowns - Natural Gas	312	
Startup/Shutdown Hours	229	
Total Hours of Operation	5,662	
Offline Hours	3,098	
Annual Fuel Use, MMBtu (HHV) (all units)	23,625,816	35,397,277
Auxiliary Boiler		
Margin	**20%**	
Operating Hours	3,992	
Evaporative Fluid Cooler		
Operating Hours	**1,500**	
Fire Pump		
Duration of Periodic Tests, mins	**45**	
Frequency of Tests, tests/year	**53**	
Load During Testing, %	**100%**	
Operating Hours	40	
Annual Fuel Use, gals/yr	795	

Oakley Generating Station 2x1

Annual Emissions - 6x16 with 1,500 Hours at Peak July

Combustion Turbine/HRSG Emissions		Proposed Limits
Minimum Load - Natural Gas		
NO_x, tons as NO_2	-	
CO, tons	-	
POC, tons as CH_4	-	
PM_{10}, tons	-	
SO_2, tons	-	
CO_2, tons	-	
Base Load ISO - Natural Gas		
NO_x, tons as NO_2	22.4	
CO, tons	9.1	
POC, tons as CH_4	5.2	
PM_{10}, tons	17.7	
SO_2, tons	2.9	
CO_2, tons	485,022.3	
Base Load Peak July - Natural Gas		
NO_x, tons as NO_2	8.3	
CO, tons	3.4	
POC, tons as CH_4	1.9	
PM_{10}, tons	6.8	
SO_2, tons	1.1	
CO_2, tons	179,825.6	
Startups/Shutdowns - Natural Gas		
NO_x, tons as NO_2	9.6	
CO, tons	35.2	
POC, tons as CH_4	7.5	
PM_{10}, tons	1.0	
SO_2, tons	0.1	
CO_2, tons	38,476	
Total Emissions (each unit)		
NO_x, tons as NO_2	40.2	
CO, tons	47.7	
POC, tons as CH_4	14.6	
PM_{10}, tons	25.5	
SO_2, tons	4.1	

Oakley Generating Station 2x1

Annual Emissions - 6x16 with 1,500 Hours at Peak July

CO_2, tons	703,324	

Oakley Generating Station 2x1

Annual Emissions - 6x16 with 1,500 Hours at Peak July

Auxiliary Boiler		Proposed Limits
NO_x, tons as NO_2	1.089	
CO, tons	0.737	
POC, tons as CH_4	0.211	
PM_{10}, tons	0.707	
SO_2, tons	0.282	
CO_2, tons	11,807	
Evaporative Fluid Cooler		**Proposed Limits**
PM_{10}, tons	0.099	
Fire Pump Emissions		**Proposed Limits**
NO_x, tons as NO_2	0.0457	
CO, tons	0.0147	
POC, tons as CH_4	0.0018	
PM_{10}, tons	0.0018	
SO_2, tons	0.0001	
Total Plant Emissions		**Proposed Limits**
NO_x, tons as NO_2	81.6	98.8
CO, tons	96.1	98.8
POC, tons as CH_4	29.5	29.5
PM_{10}, tons	51.8	76.3
SO_2, tons	8.5	12.6
CO_2, tons (excluding fire pump)	1,418,455	2,081,421

ATTACHMENT DR4-3

Annual Emissions Scenario 3

Oakley Generating Station 2x1

Annual Emissions - 6x24/1x18 with 1,500 Hours at Peak July

Plant Dispatch		Proposed Limits
Combustion Turbines/HRSGs (per unit unless noted)		
Number of Turbines/HRSGs	2	
Minimum Load Hours - Natural Gas	-	
Base Load ISO Hours - Natural Gas	6,924	
Base Load Peak July Hours - Natural Gas	1,500	
Total Hot Starts - Natural Gas	51	
Total Warm Starts - Natural Gas	-	
Total Cold Starts - Natural Gas	1	
Total Shutdowns - Natural Gas	52	
Startup/Shutdown Hours	39	
Total Hours of Operation	8,463	
Offline Hours	297	
Annual Fuel Use, MMBtu (HHV) (all units)	35,397,277	35,397,277
Auxiliary Boiler		
Margin	20%	
Operating Hours	403	
Evaporative Fluid Cooler		
Operating Hours	1,500	
Fire Pump		
Duration of Periodic Tests, mins	45	
Frequency of Tests, tests/year	53	
Load During Testing, %	100%	
Operating Hours	40	
Annual Fuel Use, gals/yr	795	

Oakley Generating Station 2x1

Annual Emissions - 6x24/1x18 with 1,500 Hours at Peak July

Combustion Turbine/HRSG Emissions		Proposed Limits
Minimum Load - Natural Gas		
NO_x, tons as NO_2	-	
CO, tons	-	
POC, tons as CH_4	-	
PM_{10}, tons	-	
SO_2, tons	-	
CO_2, tons	-	
Base Load ISO - Natural Gas		
NO_x, tons as NO_2	39.4	
CO, tons	16.0	
POC, tons as CH_4	9.2	
PM_{10}, tons	31.2	
SO_2, tons	5.2	
CO_2, tons	853,876.0	
Base Load Peak July - Natural Gas		
NO_x, tons as NO_2	8.3	
CO, tons	3.4	
POC, tons as CH_4	1.9	
PM_{10}, tons	6.8	
SO_2, tons	1.1	
CO_2, tons	179,825.6	
Startups/Shutdowns - Natural Gas		
NO_x, tons as NO_2	1.6	
CO, tons	6.0	
POC, tons as CH_4	1.3	
PM_{10}, tons	0.2	
SO_2, tons	0.0	
CO_2, tons	6,413	
Total Emissions (each unit)		
NO_x, tons as NO_2	49.3	
CO, tons	25.3	
POC, tons as CH_4	12.4	
PM_{10}, tons	38.1	
SO_2, tons	6.3	

Oakley Generating Station 2x1

Annual Emissions - 6x24/1x18 with 1,500 Hours at Peak July

CO_2, tons	1,040,114	

Oakley Generating Station 2x1

Annual Emissions - 6x24/1x18 with 1,500 Hours at Peak July

Auxiliary Boiler		Proposed Limits
NO_x, tons as NO_2	0.110	
CO, tons	0.074	
POC, tons as CH_4	0.021	
PM_{10}, tons	0.071	
SO_2, tons	0.028	
CO_2, tons	1,192	
Evaporative Fluid Cooler		**Proposed Limits**
PM_{10}, tons	0.099	
Fire Pump Emissions		**Proposed Limits**
NO_x, tons as NO_2	0.0457	
CO, tons	0.0147	
POC, tons as CH_4	0.0018	
PM_{10}, tons	0.0018	
SO_2, tons	0.0001	
Total Plant Emissions		**Proposed Limits**
NO_x, tons as NO_2	98.8	98.8
CO, tons	50.8	98.8
POC, tons as CH_4	24.7	29.5
PM_{10}, tons	76.3	76.3
SO_2, tons	12.6	12.6
CO_2, tons (excluding fire pump)	2,081,421	2,081,421

ATTACHMENT DR20-1

AERMOD Turbine Screening Results

Table 5.1B4A

OGS AERMOD Turbine Screening Results

Regular Receptor Grids

155.5' Stack Height

Case	B	D	R	H	J	X	1E	1F	1G
Evap Cooling	**Yes**	**Off**	**Off**	**On**	**Off**	**Off**	**Off**	**Off**	**Off**
Load %	**100**	**80**	**49**	**100**	**80**	**52**	**100**	**80**	**49**
Duct Firing	**No**	**No**	**No**	**No**	**No**	**No**	**No**	**No**	**No**
Ambient Temp, °F	59	59	59	104	104	104	34	34	34
Stack Exit Temp (deg.F)	190.900	179.720	171.400	212.800	196.360	179.700	191.600	184.790	171.300
Volumetric Flowrate ACFM	1,150,000	910,000	743,000	1,181,000	889,000	760,000	1,162,000	1,005,000	739,000
Stack Inside Diameter (ft)	18.37	18.37	18.37	18.37	18.37	18.37	18.37	18.37	18.37
Stack Height (m)	47.396	47.396	47.396	47.396	47.396	47.396	47.396	47.396	47.396
Stack Exit Temp (deg.K)	361.4	355.2	350.6	373.6	364.5	355.2	361.8	358.0	350.5
Stack Exit Velocity (m/s)	22.04	17.44	14.24	22.64	17.04	14.57	22.27	19.26	14.16
Stack Inside Diameter (m)	5.5992	5.5992	5.5992	5.5992	5.5992	5.5992	5.5992	5.5992	5.5992
Normal Operations - Short-term Emissions									
NOx(lb/hr/turbine)	15.17	12.50	9.66	14.75	11.47	9.25	15.52	13.88	9.91
CO(lb/hr/turbine)	9.24	7.61	5.88	8.98	6.98	5.63	9.45	8.45	6.04
SO2(lb/hr/turbine)	5.90	4.80	3.70	5.70	4.40	3.60	6.00	5.40	3.80
PM10(lb/hr/turbine)	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00
1-Hr Unitized Conc (ug/m3)	5.62463	7.05599	8.31072	5.00969	6.68256	7.90813	5.56412	6.44339	8.33895
3-Hr Unitized Conc (ug/m3)	4.27351	5.32345	6.42166	3.84959	5.04008	6.08899	4.22494	4.80076	6.44604
8-Hr Unitized Conc (ug/m3)	3.18504	3.92533	4.62115	2.69903	3.72586	4.40545	3.14595	3.57729	4.63869
24-Hr Unitized Conc (ug/m3)	1.16360	1.45696	1.76917	0.98469	1.37628	1.64297	1.14878	1.32026	1.77658
Normal Operations - Short-term Emissions									
NOx(g/s/turbine)	1.912	1.575	1.217	1.858	1.445	1.165	1.956	1.749	1.249
CO(g/s/turbine)	1.164	0.959	0.741	1.131	0.880	0.709	1.191	1.065	0.760
SO2(g/s/turbine)	0.743	0.605	0.466	0.718	0.554	0.454	0.756	0.680	0.479
PM10(g/s/turbine)	1.134	1.134	1.134	1.134	1.134	1.134	1.134	1.134	1.134
1-Hour NOx(ug/m3)	21.509	22.226	20.228	18.616	**19.313**	18.426	21.767	22.539	20.831
1-Hour CO(ug/m3)	13.094	13.533	12.316	11.332	**11.761**	11.214	13.254	13.724	12.675
8-Hour CO(ug/m3)	4.733	4.750	4.307	3.876	**4.128**	4.000	4.757	4.865	4.444
1-Hour SO2(ug/m3)	8.358	8.538	7.746	7.194	**7.404**	7.181	8.413	8.763	7.989
3-Hour SO2(ug/m3)	16.342	16.769	15.630	14.305	**14.566**	14.187	16.528	16.793	16.102
24-Hour SO2(ug/m3)	1.729	1.763	1.649	1.414	**1.525**	1.492	1.737	1.796	1.702
24-Hour PM10 at 24 hours op	2.639	3.304	4.012	2.233	**3.121**	3.726	2.605	2.994	4.029
24-Hour PM10(ug/m3)	2.639	**3.304**	4.012	2.233	**3.121**	3.726	2.605	2.994	4.029
Commissioning									
NOx(lb/hr) - 1-Hour	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00
CO(lb/hr) - 1-Hour	1500.0	1500.0	1500.0	1500.0	1500.0	1500.0	1500.0	1500.0	1500.0
CO(lb/hr) - 8-Hours	1500.0	1500.0	1500.0	1500.0	1500.0	1500.0	1500.0	1500.0	1500.0
1-Hr NOx(ug/m3)	212.611	266.716	314.145	189.366	**252.601**	298.927	210.324	243.560	315.212
1-Hr CO(ug/m3)	1063.055	1333.582	1570.726	946.831	**1263.004**	1494.637	1051.619	1217.801	1576.062
8-Hr CO(ug/m3)	601.973	741.887	873.397	510.117	**704.188**	832.630	594.585	676.108	876.712

Worst-Case Operating Scenarios are **bolded**.

**Based on USEPA Ambient Ratio Method (ARM)=75% of NOx impact

ATTACHMENT DR27-1

Greenhouse Gas Emissions Calculations

Table 5.2A-8a Aux Boiler
Calculation of Criteria Pollutant Emissions for Boilers Firing Gaseous Fuels

Boiler Operation Mode: Normal firing mode — # of Units: 1
Ops Hr/Day: 24 Worst Case — Fuel Type: Nat Gas
Ops Hr/Yr: 4324

Calculation of Criteria Pollutant Emissions from Each Identical Unit

						All Units			
Compound	Emission Factor, lb/MMscf (1)	Maximum Hourly Emissions, lb/hr (2)	Maximum Daily Emissions, lb/day	Maximum Annual Emissions, lbs/yr	Annual Emissions, ton/yr (3)	Maximum Hourly Emissions, lb/hr	Maximum Daily Emissions, lb/day	Maximum Annual Emissions, lbs/yr	Annual Emissions, ton/yr
NOx	1.11E+01	5.50E-01	1.32E+01	2.38E+03	1.19E+00	5.50E-01	1.32E+01	2.38E+03	1.19E+00
CO	3.74E+01	1.85E+00	4.44E+01	8.00E+03	4.00E+00	1.85E+00	4.44E+01	8.00E+03	4.00E+00
VOC	2.14E+00	1.06E-01	2.54E+00	4.58E+02	2.29E-01	1.06E-01	2.54E+00	4.58E+02	2.29E-01
SOx	2.83E+00	1.40E-01	3.36E+00	6.05E+02	3.03E-01	1.40E-01	3.36E+00	6.05E+02	3.03E-01
PM10	7.17E+00	3.55E-01	8.52E+00	1.53E+03	7.67E-01	3.55E-01	8.52E+00	1.53E+03	7.67E-01
PM2.5	7.17E+00	3.55E-01	8.52E+00	1.53E+03	7.67E-01	3.55E-01	8.52E+00	1.53E+03	7.67E-01
NH3	2.22E+00	1.10E-01	2.64E+00	4.76E+02	2.38E-01	1.10E-01	2.64E+00	4.76E+02	2.38E-01
	lbs/mscf								
CO2	1.21E+02	5.97E+03	1.43E+05	2.58E+07	1.29E+04	5.97E+03	1.43E+05	2.58E+07	1.29E+04
Methane	1.98E-04	9.82E-03	2.36E-01	4.25E+01	2.12E-02	9.82E-03	2.36E-01	4.25E+01	2.12E-02
N2O	1.98E-04	9.82E-03	2.36E-01	4.25E+01	2.12E-02	9.82E-03	2.36E-01	4.25E+01	2.12E-02
CO2e									1.29E+04
								metric tons	11741.1

Notes:
(1) natural gas criteria pollutant EF factors
(2) Based on maximum hourly boiler fuel use of 50.6 MMBtu/hr/boiler
and fuel HHV of 1022 Btu/scf gives 0.0495 MMscf/hr/boiler.
(3) Based on maximum annual boiler fuel use of 218,794 MMBtu/yr/boiler
and fuel HHV of 1022 Btu/scf gives 214.0845 MMscf/yr/boiler.
(4) APCs per AFC Section 5.1
(5) PM2.5 = PM10

Refs:
(1) EFs from Radback Energy
(2) GHG EFs and GWP factors, BAAQMD Fact Sheet, Tables 1 and 2, 2-5-08.

Table 5.2A-8b Aux Boiler

Calculation of Criteria Pollutant Emissions for Boilers Firing Gaseous Fuels

Boiler Operation Mode: Normal firing mode

Ops Hr/Day: 24 Typical Case

Ops Hr/Yr: 403

# of Units: 1

Fuel Type: Nat Gas

Calculation of Criteria Pollutant Emissions from Each Identical Unit

Compound	Emission Factor, lb/MMscf (1)	Maximum Hourly Emissions, lb/hr (2)	Maximum Daily Emissions, lb/day	Maximum Annual Emissions, lbs/yr	Annual Emissions, ton/yr (3)	All Units Maximum Hourly Emissions, lb/hr	Maximum Daily Emissions, lb/day	Maximum Annual Emissions, lbs/yr	Annual Emissions, ton/yr
NOx	1.11E+01	5.50E-01	1.32E+01	2.22E+02	1.11E-01	5.50E-01	1.32E+01	2.22E+02	1.11E-01
CO	3.74E+01	1.85E+00	4.44E+01	7.46E+02	3.73E-01	1.85E+00	4.44E+01	7.46E+02	3.73E-01
VOC	2.14E+00	1.06E-01	2.54E+00	4.27E+01	2.13E-02	1.06E-01	2.54E+00	4.27E+01	2.13E-02
SOx	2.83E+00	1.40E-01	3.36E+00	5.64E+01	2.82E-02	1.40E-01	3.36E+00	5.64E+01	2.82E-02
PM10	7.17E+00	3.55E-01	8.52E+00	1.43E+02	7.15E-02	3.55E-01	8.52E+00	1.43E+02	7.15E-02
PM2.5	7.17E+00	3.55E-01	8.52E+00	1.43E+02	7.15E-02	3.55E-01	8.52E+00	1.43E+02	7.15E-02
NH3	2.22E+00	1.10E-01	2.64E+00	4.43E+01	2.22E-02	1.10E-01	2.64E+00	4.43E+01	2.22E-02
	lbs/mscf								
CO2	1.21E+02	5.97E+03	1.43E+05	2.41E+06	1.20E+03	5.97E+03	1.43E+05	2.41E+06	1.20E+03
Methane	1.98E-04	9.82E-03	2.36E-01	3.96E+00	1.98E-03	9.82E-03	2.36E-01	3.96E+00	1.98E-03
N2O	1.98E-04	9.82E-03	2.36E-01	3.96E+00	1.98E-03	9.82E-03	2.36E-01	3.96E+00	1.98E-03
CO2e									1.20E+03
								metric tons	*1094.3*

Notes:

(1) natural gas criteria pollutant EF factors

(2) Based on maximum hourly boiler fuel use of 50.6 MMBtu/hr/boiler
and fuel HHV of 1022 Btu/scf gives 0.0495 MMscf/hr/boiler.

(3) Based on maximum annual boiler fuel use of 20,392 MMBtu/yr/boiler
and fuel HHV of 1022 Btu/scf gives 19.9528 MMscf/yr/boiler.

(4) APCs per AFC Section 5.1

(5) PM2.5 = PM10

Refs:

(1) EFs from Radback Energy

(2) GHG EFs and GWP factors, BAAQMD Fact Sheet, Tables 1 and 2, 2-5-08.

Table 5.2A-12 EXPECTED INTERNAL COMBUSTION ENGINE EMISSIONS

Liquid Fuel

Emergency Fire Pump

Liquid Fuel			# of Identical Engines:	1	
Mfg:	Clarke		Stack Data		
Engine #:	JW6H-UFAD80		Height:	16	Ft.
Kw	0	approx.	Diameter:	0.67	Ft.
BHP:	400		Temp:	826	deg F
RPM:	-		ACFM:	2214	
Fuel:	#2 Diesel		input the mfg ACFM or calculate per Exhaust sheet)		
Fuel Use:	20	Gph (1)	Area:	0.353	Sq.Ft.
FuelHHV:	139000	Btu/gal	Velocity:	105	Ft/Sec
mmbtu/hr:	2.78	HHV	Max Daily Op Hrs:	1	
EPA/CARB Tier #:	3		Max Annual Op Hrs:	53	

Fuel Wt:	7	Lbs/gal
Fuel S:	0.0015	% wt.
Fuel S:	0.105	Lbs/1000 gal
SO2:	0.21	Lbs/1000 gal

			Single Engine				*All Engines*			
EFs (g/bhp-hr)			**Lb/Hr**	**Lb/Day**	**Lbs/Yr**	**Tons/Yr**	***Lb/Hr***	***Lb/Day***	***Lbs/Yr***	***Tons/Yr***
NOx	2.61		2.30	2.30	121.88	0.061	*2.30*	*2.30*	*121.88*	*0.06*
CO	0.84		0.74	0.74	39.22	0.020	*0.74*	*0.74*	*39.22*	*0.02*
VOC	0.104		0.09	0.09	4.86	0.002	*0.09*	*0.09*	*4.86*	*0.002*
PM10	0.103		0.09	0.09	4.81	0.002	*0.09*	*0.09*	*4.81*	*0.002*
SOx	NA		0.0042	0.0042	0.22	0.0001	*0.0042*	*0.0042*	*0.22*	*0.0001*
	lbs/gal									
CO2	22.38		448	448	23723	11.86	*448*	*448*	*23723*	*11.86*
Methane	0.000529		0.01	0.01	0.56	0.000	*0.01*	*0.01*	*0.56*	*0.000*
N2O	0.000198		0.00	0.00	0.21	0.0001	*0.00*	*0.00*	*0.21*	*0.0001*
CO2e						11.9				*11.90*
CO2e	21.7	Ref 5	434	434	23002	11.50	*434*	*434*	*23002*	*11.50*
									metric tons	*10.5*

Notes:

1. fuel consumption based on 0.055 gal/hp-hr (avg EPA and SCAQMD values) if no value given by mfg for specific engine.
2. PM10 equals PM2.5.
3. PM10 used in HRA to represent DPM emissions.
4. GHG EFs and GWP values from BAAQMD, Fact Sheet, Tables 1 and 2, 2-5-08.
5. Statement of Basis, Russell City Energy Center, BAAQMD, 8-3-09.

Greenhouse Gas Emissions Calculator

Combustion Turbines-Gaseous Fuels Emissions Analysis Period: Annual

Facility Name: Radback-Oakley Generating Station Gas Type: Natural Gas

Turbine Device ID: SW 501s w/HRSG Op Hours: 8463

Turbine Heat Rating: 4300 mmbtu/hr

Gas Btu Content: 1022 btu/scf Ref 1, Table C.5

Carbon Content: 14.47 kg/mmbtu
Frac Oxidized: 0.995
CO2/C Ratio: 3.6667

Annual Gas Usage: 35608 mmscf
36390900 mmbtu/yr

Emissions Factors:

CO2	118.9	lb/mmbtu	Ref 1
CH4	0.002	lb/mmbtu	Ref 1
N2O	0.00022	lb/mmbtu	Ref 1

	lbs/yr	kg/yr	Emissions metric tons/yr	IPCC GWP/SAR		CO2e metric tons/yr
CO2	4.327E+09	1.963E+09	1962672	1	Ref 2	1962672
CH4	7.278E+04	3.301E+04	33.01382	25	Ref 2	825
N2O	8.006E+03	3.632E+03	3.631521	298	Ref 2	1082

Total **1964579** **CO2e metric tons**

Source Specific Emissions Factor References, Data Notes, or Calculation Notes:

1. Statement of Basis, Russell City Energy Center, BAAQMD, 8-3-09.
2. Fact Sheet, BAAQMD Proposed GHG Fee Schedule, 2-5-08.
3. ***
4. ***

Greenhouse Gas Emissions Calculator

SF6-Direct Fugitive Emissions
Electrical Equipment Used by Utilities

Emissions Analysis Period: Annual

System ID: CCGS Circuit Breakers

Total capacity of system identified (lbs):	200	=	90.72	kg			
Calculated losses of SF6 (lbs) for the device and reporting period:*			(1)	1	=	0.45	kg
IPCC 2007 GWP Factor:			22800	(2)			
Total Annual Emissions of SF6:				**10.3**	**CO2e metric tons**		

* estimated loss rate from circuit breakers is 0.5% per year.
Ref (1) Statement of Basis, Russell City Energy Center, BAAQMD, 8-3-09.
Ref (2) BAAQMD Fact Sheet, Proposed GHG Fee Schedule, 2-5-08.

ATTACHMENT DR28-1

Operations Mobile Vehicle Emissions

Operations Mobile Vehicle Emissions

Ref: SFAB, Emfac 2007, V2.3, Nov 2006
On-Road Heavy Duty Diesels (1967-2011)
HD Gasoline Trucks (1967-2011)

Operations Site Delivery Emissions

Deliveries per Avg Month:	60	
Per delivery roundtrip VMT:	20	
Total monthly VMT:	1200	
Total annual VMT:	14400	
Fraction annual VMT (gasoline):	0.5	
Fraction annual VMT (diesel):	0.5	Daily VMT*
Annual gasoline VMT:	7200	28
Annual diesel VMT:	7200	28

*Daily VMT based on 260 days/year.

Emissions Factors (lbs/vmt)

NOx	CO	VOC	SOx	PM10	CO2	
0.025066	0.007002	0.001418	0.000036	0.000955	3.785	HDD
0.012557	0.091005	0.007343	0.00002	0.00008	1.572139	HD Gas

Daily Emissions (lbs)

NOx	**CO**	**VOC**	**SOx**	**PM10**	**CO2**	**PM2.5**	
0.6941	0.1939	0.0393	0.0010	0.0264	104.8154	0.0262	Diesel
0.3477	2.5201	0.2033	0.0006	0.0022	43.5362	0.0022	Gasoline

Annual Emissions, tons

0.0902	0.0252	0.0051	0.0001	0.0034	13.6260	0.0034	Diesel
0.0452	0.3276	0.0264	0.0001	0.0003	5.6597	0.0003	Gasoline

See support table for K.1-7 for mielage and delivery rate data.

Employee Commute

Ref: SFAB, Emfac 2007, V2.3, Nov 2006
On Road Vehicles (1967-2011)
LDP/LDT Weighted Avg Efs

Avg # employees:	22	Commuting to site per day
Avg commute distance:	20	roundtrip VMT
Total daily VMT:	440	
Total Annual VMT:	114400	

Emissions Factors, lbs/VMT

NOx	CO	VOC	Sox	PM10	CO2	PM2.5
0.00081	0.00864	0.00091	0.000001	0.00008	0.96325	
Daily Emissions, lbs						
0.36	3.80	0.40	0.0004	0.04	423.83	0.03
Annual Emissions, tons						
0.05	0.49	0.05	0.00006	0.00	55.10	0.005

Notes:
1. employee commute based on 260 days/year

ATTACHMENT DR32-1

Emissions Factors
Construction Greenhouse Gases

Table 5.1E-7

EMFAC Composite Emissions Factor Conversion — EMFAC 2007, V2.3, Nov 2006

County: SFAB (BAAQMD)
Year: 2011
Model Years: 1967-2011

EMFAC Burden Output

	LDP(gas)	LDP(diesel)	LDT(gas)	LDT(diesel)	MDT(gas)	MDT(diesel)	HDT(gas)	HDT(diesel)	Buses	Motorcycles
Daily VMT/1000	91371	183	55777	651	14393	1047	1005	5570	614	1347
Daily VMT	91371000	183000	55777000	651000	14393000	1047000	1005000	5570000	614000	1347000
ROG, tpd	36.5	0.04	30.57	0.06	8.1	0.25	3.69	3.95	0.68	7.15
CO, tpd	336.27	0.16	299.05	0.45	77.88	1.27	45.73	19.5	4.37	59.48
NOx, tpd	28.44	0.3	30.89	1.09	11.96	4.98	6.31	69.81	11.78	1.98
CO2, tpd (x 1000) >	40290	70	30580	250	11500	600	790	10540	1640	240
PM10, tpd	3.3	0.03	2.72	0.05	0.75	0.09	0.04	2.66	0.21	0.07
SOx, tpd	0.001	0.39	0.001	0.3	0.001	0.12	0.01	0.1	0.02	0.001

Composite Efs

	LDP(gas)	LDP(diesel)	LDT(gas)	LDT(diesel)	MDT(gas)	MDT(diesel)	HDT(gas)	HDT(diesel)	Buses	Motorcycles
	g/VMT	g/VMT	g/VMT	g/VMT	g/VMT	g/VMT	g/VMT	g/VMT	g/VMT	g/VMT
ROG	0.36	0.00	0.50	0.0010	0.51	0.00	3.33	0.64	1.00	4.82
CO	3.34	0.00	4.86	0.0073	4.91	0.01	41.28	3.18	6.46	40.06
NOx	0.28	0.00	0.50	0.0177	0.75	0.05	5.70	11.37	17.40	1.33
CO2	400.02	0.69	497.37	4.0661	724.84	5.96	713.11	1716.64	2423.09	161.64
PM10	0.03	0.00	0.04	0.0008	0.05	0.00	0.04	0.43	0.31	0.05
SOx	0.0000	0.0039	0.0000	0.0049	0.0001	0.0012	0.0090	0.0163	0.0295	0.0007

Composite Efs

	LDP(gas)	LDP(diesel)	LDT(gas)	LDT(diesel)	MDT(gas)	MDT(diesel)	HDT(gas)	HDT(diesel)	Buses	Motorcycles
	lb/VMT	lb/VMT	lb/VMT	lb/VMT	lb/VMT	lb/VMT	lb/VMT	lb/VMT	lb/VMT	lb/VMT
ROG	0.000799	0.000001	0.001096	0.000002	0.001126	0.000005	0.007343	0.001418	0.002215	0.010616
CO	0.007361	0.000004	0.010723	0.000016	0.010822	0.000028	0.091005	0.007002	0.014235	0.088315
NOx	0.000623	0.000007	0.001108	0.000039	0.001662	0.000109	0.012557	0.025066	0.038371	0.002940
CO2	0.881899	0.001532	1.096509	0.008964	1.597999	0.013133	1.572139	3.784560	5.342020	0.356347
PM10	0.000072	0.000001	0.000098	0.000002	0.000104	0.000002	0.000080	0.000955	0.000684	0.000104
SOx	0.000000	0.000009	0.000000	0.000011	0.000000	0.000003	0.000020	0.000036	0.000065	0.000001

Weighted Avg LDP/LDT Gasoline

	g/VMT	lb/VMT		
ROG	0.413	0.00091	Calc 1	0.379
CO	3.917	0.00864	Calc 2	0.621
NOx	0.366	0.00081		
CO2	436.9	0.96325		
PM10	0.037	0.00008		
SOx	0.000	0.00000		

	LDP(gas)	LDP(diesel)	LDT(gas)	LDT(diesel)	MDT(gas)	MDT(diesel)	HDT(gas)	HDT(diesel)	Buses	Motorcycles
Annual VMT	3.34E+10	6.68E+07	2.04E+10	2.38E+08	5.25E+09	3.82E+08	3.67E+08	2.03E+09	2.24E+08	4.92E+08
Daily Fuel Use, 10^3 gal	4184.69	6.51	3183.39	22.46	1190.83	54.19	89.21	948.85	149.14	35.91
Daily Fuel Use, gals	4184690	6510	3183390	22460	1190830	54190	89210	948850	149140	35910
Annual Fuel Use, gals	1527411850	2376150	1161937350	8197900	434652950	19779350	32561650	346330250	54436100	13107150
Average Miles/gallon	21.8	28.1	17.5	29.0	12.1	19.3	11.3	5.9	4.1	37.5

ATTACHMENT DR33-1

Locomotive Emissions

Locomotive Emissions Associated with Construction Phase Deliveries

Oakley Generating Station Project

Ref: USEPA, OTAQ, EPA-420-F-09-025, Emissions Factors for Locomotives, April 2009.

Revised Standards per 40 CFR Part 1033

Ref: CCAR General Protocol, Version 3.1, January 2009.

Input Data, Assumptions, and Calculations

Estimated Tier Standard Level:	1+	Engines manufactured during 2002-2004.
Line Haul Emission Factors Used:	Yes	
Conversion Factor:	20.8	g/bhp-hr to g/gal fuel consumed (per EPA)
Conversion Factor:	400	g/gal fuel to g/ton-mile (per EPA)

Emissions Factors: (for Tier specified above)

Pollutant	g/bhp-hr	g/gal fuel	g/ton-mile	lbs/ton-mile
PM10	0.200	4.16	0.010	0.000023
PM2.5	0.194	4.04	0.010	0.000022
NOx	6.700	139.36	0.348	0.000768
CO	1.280	26.62	0.067	0.000147
HC	0.290	6.03	0.015	0.000033
VOC	0.305	6.35	0.016	0.000035
SOx	0.0071	lbs/gal		

Other Emissions Factors (diesel fuel):

CO2	21.96	lbs/gal		
Methane	0.000051	frac of CO2	0.00112	lbs/gal
N2O	0.000032	frac of CO2	0.00070	lbs/gal

Assumed sulfur content of fuel:	0.05	% wt
	0.0005	wt fraction

Fuel weight: 7.05 lbs/gal

Rail transport travel distance, miles:	10	(one way distance within the agency boundary)***
Avg weight of loaded railcar, tons:	220	
Avg # of railcars per day:	4	
Total tonnage per day:	880	
Total ton-miles/day:	8800	
Estimated # of const days that will experience rail deliveries:	200	
Total ton-miles/const period:	1760000	
EPA fuel consumption value:	1	gal/400 ton-miles
Daily fuel consumption, gals:	22	
Period fuel consumption, gals:	4400	

Estimated Emissions

	PM10	PM2.5	NOx	CO	VOC	SOx	CO2	Methane	N2O
lbs/day	0.202	0.196	6.759	1.291	0.308	0.155	483.1	0.025	0.015
lbs/period	40.35	39.14	1351.85	258.26	61.61	31.02	96624	4.93	3.09
tons/period	0.020	0.020	0.676	0.129	0.031	0.016	48.3	0.002	0.002

CO2e (short tons):	48.8
CO2e (metric tons):	44.0

*** AT&SF/Southern Pacific line from eastern boundary of Contra Costa County to Oakley siding.

Geological Hazards and Resources (34)

Clay Soils

34. *Please provide supporting documentation to support the statement that clay soils with a PI between 15 and 32 exhibit low expansion potential.*

Response: The Preliminary Geotechnical Report for the Contra Costa Generating Station, LLC, in Oakley, California was prepared by Black and Veatch (B&V, June 1, 2009). B&V reported encountering low expansive clay layers in the three borings, BV-1 to BV-3.

Specifically, based on the boring logs in Appendix A of the report, groundwater was reported at 14 to 15 feet below the ground surface (bgs). Also, B&V encountered the following depths of clay:

- In Boring BV-1, the clay was encountered from 13 to 43 feet bgs.
- In Boring BV-2, the clay was encountered from 7 to 23 feet bgs.
- In Boring BV-3, the clay was encountered from 7 to 30 feet bgs.

The plastic indices (PI) for the clay ranged from 4 to 20 in all the samples, except for Boring BV-2 between 18 and 32 feet bgs. At a depth between 18 and 32 feet bgs in BV-2, the PI was 34. According to O'Neill and Poormoayed (1980), a PI less than 25 has a low swell potential. According to the same reference, a plastic index between 25 and 35 has marginal swell potential. However, because the PI of 34 was encountered below the groundwater table, the clay is already saturated and not expected to swell. For this reasoning, all the clay samples exhibited low swelling potential.

Reference

O'Neill, M.W., and A.M. Poormoayed (1980). "Methodology for Foundation on Expansive Clays." ASCE, Journal of the Geotechnical Engineering Division, ASCE, 106, 1345-1367.

Land Use (35-39)

General Plan and Zoning Ordinance Consistency

35. *Please provide the city of Oakley's position on the proposed project's overall consistency with its General Plan and Zoning Ordinance.*

Response: According to City of Oakley officials, the OGS project is consistent with the Oakley General Plan (Personal communication, Rebecca Willis, City of Oakley Director of Community Development, January 28, 2010). The City's General Plan designates the project site for a land use of Utility Energy, which "Allows for power plant uses involved in the clean production of electricity utilizing the best available combustion turbine technology."

When the City of Oakley incorporated in 1999, it initially adopted the General Plan and zoning districts of Contra Costa County. In December 2002, the City adopted its own general plan and followed with the Oakley Municipal Code. Oakley proceeded to develop and designate its own zoning districts and, in April 2009, adopted zoning of the remaining "carry-over" properties that had not been rezoned at that time and still retained the zoning they had previously had under County zoning. At that time, the OGS property was designated SP-3, indicating that specific zoning and land use specifications would be developed under a future Specific Plan.

There is currently no Specific Plan approved for the property. The DuPont Bridgehead Road Specific Plan was proposed for the larger DuPont property including the OGS site in 2007, but work on the Specific Plan has been suspended due to the economic downturn and is in a holding pattern at this time. The OGS is consistent with the SP-3 zoning designation, therefore, because there is no approved Specific Plan. Development of a combustion turbine power plant on this parcel is consistent with the Utility Energy General Plan Land Use Designation, which contemplated just such uses in this specific location. The City has, in fact, enacted a Utility Energy zoning district, which would be compatible zoning in a location designated for Utility Energy land use in the General Plan.

If not for a Specific Plan or revised zoning designation, the underlying parcel zoning would be Heavy Industry (H-I). This zoning designation permits: "Heavy industrial manufacturing uses of all kinds, including, but not limited to, the manufacturing or processing of petroleum, lumber, steel, chemicals, explosives, fertilizers, gas, rubber, paper, cement, sugar, and all other industrial or manufacturing products shall be permitted in the H-I district" (Contra Costa County Code 84-62.402). This zoning designation is consistent with electrical power generation. For example, the proposed Marsh Landing Generating Station and the PG&E Gateway Generating Station, are located unincorporated Contra Costa County in the H-I district and have been found consistent with that zoning designation.

DuPont Specific Plan

36. Please discuss is the current status of the Draft DuPont Specific Plan.

Response: In 2007, the City of Oakley and DuPont prepared a draft specific plan document for the DuPont property, called the DuPont Bridgehead Road Specific Plan, which envisioned industrial, office, and research and development land uses on this property. The City hired LSA Associates to prepare the Environmental Impact Report (EIR) for the specific plan project. LSA Associates completed the preliminary steps for the preparation of the Draft EIR and is standing by for authorization to proceed with the completion of this document. DuPont requested a pause in the preparation of the Draft EIR due to the change in the economic and market conditions since 2007. The City and DuPont are working cooperatively to reevaluate potential land uses and specific plan concepts for the site and DuPont has optioned the OGS site parcel, formerly part of the DuPont Bridgehead Road Specific Plan area, to Contra Costa Generating Station LLC (CCGS) for the OGS. The City has discussed with DuPont the possibility of removing the area proposed for the OGS from any future version of the DuPont Bridgehead Road Specific Plan (Personal communication, Rebecca Willis, City of Oakley Director of Community Development, January 29, 2010).

Rezoning Request

37. Please submit a request to the city of Oakley regarding rezoning the site to UE.

Response: Because the Specific Plan zoning is consistent with the use of the project parcel as a power generation site and the General Plan land use designation of Utility Energy is also consistent with the OGS, the project is currently compliant with land use LORS and a rezone would not be required with CEC certification. The project parcel is currently zoned SP-3 (future Specific Plan) and there is no approved specific plan for the parcel, therefore, the underlying applicable zoning designation would be Heavy Industry (H-I). This zoning is compatible with power plant development.

Conditional Use Permit Findings and Conditions

38. Please provide information from the city of Oakley regarding the Conditional Use Permit (CUP) findings it would make for the Project, but for the exclusive authority of the Energy Commission, and the conditions the city would attach to this Project, were it the permitting agency. Any conditions recommended by the city as part of a CUP would be considered by Energy Commission staff for inclusion in the conditions of certification for the Project.

Response: The following are the Findings that the City of Oakley would have to make in approving Conditional Use Permit per Section 9.1.1602(f) of the Zoning Code, but for the exclusive authority of the CEC:

1. That the site for the proposed use is adequate in size and shape to accommodate the use and all yards, spaces, walls and fences, parking, loading, landscaping and other features required by law to adapt the use with land and uses in the neighborhood;
2. That the site for the proposed use relates to streets and highways adequate in width and pavement type to carry the quantity and kind of traffic generated by the proposed use;
3. The proposed use will be arranged, designed, constructed, operated and maintained so as to be compatible with the intended character of the area and shall not change the

essential character of the area from that intended by the general plan and the applicable zoning ordinances;

4. That the proposed use provides for the continued growth and orderly development of the community and is consistent with the various elements and objectives of the general plan;
5. That the proposed use, including any conditions attached thereto, will be established in compliance with the applicable provisions of the California Environmental Quality Act.

The Conditions of Certification recommended by the City are being prepared by the City separately and will be relayed to the CEC under separate cover.

LORS and Conditions

39 Energy Commission staff will write a letter to the city of Oakley requesting detailed information regarding the proposed project's compliance with the city's applicable LORS and the conditions the city would attach to this Project, were it the permitting agency. Please provide Project information to the city of Oakley, with a copy to Commission staff, to facilitate their input regarding LORS conformance, conditions, and the required rezone of the Project site.

Response: The Applicant has met with the City and discussed the Staff's information needs to complete the AFC LORS conformance analysis. The City's response is found partly in the response to Data Request #38. The City has indicated that they will provide a letter to the Staff that will provide the information that Staff requests.

Paleontological Resources (40)

Field Survey Report

40. *Please provide supporting information with respect to field survey that was performed. Such information would include, but not necessarily be limited to, a letter from the paleontologist that performed the work that describes the work performed and summarizes the results of the work.*

Response: The paleontological resources field review performed for this project was conducted by the Paleontological Resources Specialist, Dr. W. Geoffrey Spaulding on April 22, 2009. Survey and reconnaissance methodology were both employed depending on ground visibility and extent of disturbance and development and were reported in Section 5.8 of the AFC.

Ground visibility of the proposed generation station site was good owing to the fact that it was primarily recently tilled vineyard. A shallow borrow pit was also located at the eastern end of the site. This area was crossed by subparallel pedestrian transects to assure that all surfaces with exposed native sediment had been examined. The surface sediment consisted of fine to medium reddish-brown sand comprising two subdued topographic highs that are likely relict sand dunes. No marked change in lithology was evident in the shallow borrow pit at the eastern margin of the site. No paleontological material or other indictors of possible paleontological potential (e.g., carbonate casts, paleosols, etc.) were found here.

Surface visibility elsewhere along the project linears was poor due to development, vegetation, and recontouring, especially in the immediate vicinity of roadways and drainages. The right-of-way for the transmission line was therefore subject to reconnaissance-level survey, which consisted of following the proposed right-of-way by foot and by car, and stopping to inspect areas where native soil appeared exposed, and in the vicinity of planned tower locations. Frequently the stop was restricted to the time it took to confirm that no native soil was exposed. In a few cases, such as west of Oakley Road and east of the western terminus of the transmission line, the right-of-way was subject to survey-level protocol because more native sediment appeared exposed. In all cases, however, surface sediment appeared to be recent fill combined with varying proportions of disturbed late Holocene colluvium. No paleontological resources would be expected near the surface in these settings.

Transmission System Engineering (41-43)

Contra Costa Substation Layout

41. *Provide a detailed physical layout drawing of the Contra Costa Substation with the proposed OGS. Show all major equipment, ratings, and transmission outlets.*

Response: As discussed in the Applicant's Supplement in Response to CEC Staff's Data Adequacy Review of the AFC, the Applicant requested such detailed information from PG&E. PG&E responded, however, that it could not provide additional detail "without running into confidentiality and propriety issues". In lieu of a physical layout drawing, the Applicant has provided Figure DR41-1, which is an aerial photograph of the Contra Costa Substation showing the existing 230 kV buses, transformer bank outlets, and transmission line outlets.

Substation 230 kV Bus

42. *To accommodate the OGS into the Contra Costa Substation, the existing 230 kV bus requires extension.*

a. Please address whether the bus extension would occur inside the Contra Costa Substation fence line.

Response: Extension of the existing buses for interconnection of the OGS generator tie-line would be a relatively straightforward process. However, in the Transition Cluster Group 1 Phase I Interconnection Study Report, CAISO/PG&E proposes more significant modifications to the Contra Costa Substation, including converting the substation to a breaker-and-a-half (BAAH) design and looping the existing Contra Costa to Moraga 230 kV Line No. 1 into the Contra Costa Substation. While these improvements may result in expansion of the substation beyond the existing substation fence line, PG&E advises that the improvements will still be confined to PG&E's existing property (see Figure DR42-1, which shows the relationship of the existing substation fence line to the overall parcel).

b. Discuss whether any additional bus sectionalized breakers in the drawing will be required.

Response: The existing Contra Costa Substation, in its single breaker/double bus configuration, has a total of six breakers, with one of the six breakers serving as a tie breaker between the two buses. The Applicant's proposed design would have added a single breaker for the OGS generator tie-line and no bus sectionalizing breakers. With CAISO/PG&E's proposed improvements, which include converting the substation to a BAAH configuration, bus sectionalizing breakers would not appear to be necessary due to the functionality and size of the BAAH design.

c. Provide detailed information and a physical layout drawing of the proposed changes. Show all major equipment, ratings, and transmission outlets.

Response: The requested level of detail is not available at this time. The improvements at Contra Costa Substation extend well beyond those required for the interconnection of the

OGS and include network upgrades for the benefit of the entire Group 1 cluster. PG&E is not expected to begin detailed design of the substation improvements until such time that the Group 1 interconnection customers execute their respective Large Generator Interconnection Agreements. Given the schedule included in the CAISO's tariff, the Applicant estimates that this will occur in the first quarter of 2011.

CAISO Phase I Interconnection Study

43. *Provide the California ISO Phase I Interconnection Study of the proposed 624 MW OGS to the California ISO control grid. The Study should analyze the system impacts with and without the project during peak and off-peak system conditions, and demonstrate conformance or non-conformance with the utility reliability and planning criteria with the following provisions:*

Response: The CAISO Transition Cluster Group 1 Phase I Interconnection Study Report for the Applicant's initial interconnection request is included as Attachment DR43-1. The Applicant's initial interconnection request, submitted on September 11, 2007, was for 520 MW. A supplemental interconnection request for an additional 131 MW was submitted on July 31, 2009, bringing the total to 631 MW. The Applicant's Supplement in Response to Data Adequacy Review of the AFC indicated that the Phase I Interconnection Study for the supplemental interconnection request was expected to be received on or before April 1, 2010. On November 17, 2009, the Federal Energy Regulatory Commission approved amendments CAISO had proposed to their Large Generation Interconnection Procedures. One of these amendments was to allow projects in the Transition Cluster to increase the MW value above the Generating Facility Capacity set forth in the Interconnection Request, not to exceed 30 percent of the original amount (i.e. not to exceed 130 percent of the Generation Facility Capacity set forth in the original Interconnection Request). As such, the Applicant has chosen to withdraw the supplemental interconnection request and instead add 131 MW of additional generation to the original interconnection request. The increase in output was communicated to the CAISO in the form of Appendix B to the Large Generator Interconnection Study Process Agreement (included here as Attachment DR43-2).

Since the time that the CAISO Transition Cluster Group 1 Phase I Interconnection Study Report was published, the generation included in Group 1 has been significantly reduced. Table DR43-1 provides a listing of the Group 1 projects as included in the CAISO Transition Cluster Group 1 Phase I Interconnection Study Report. This group includes 12 projects totaling 4,706.9 MW of generation.

TABLE DR43-1
Transition Cluster Group 1 Generation Interconnection Projects from Interconnection Study Report

Queue	MW	Point of Interconnection	Online Date
171	500	Vaca-Tesla 500 kV Line	12/31/2011
222	60	Birds Landing Substation 230 kV Bus	12/31/2010
257	575	Loop Ignacio-Sobrante and Lakeville-Sobrante #2 230 kV Lines	6/1/2/2011
258	520	Contra Costa Substation 230 kV Bus	2/1/2012
269	371.3	Tesla Substation 230 kV Bus	4/15/2012

TABLE DR43-1
Transition Cluster Group 1 Generation Interconnection Projects from Interconnection Study Report

Queue	MW	Point of Interconnection	Online Date
275	630	Loop Vaca Dixon-Peabody and Vaca-Lambie 230 kV Lines	9/1/2012
305	611	Contra Costa Power Plant 230 kV Switchyard	7/30/2012
320	476	Contra Costa Power Plant 230 kV Switchyard	4/29/2011
322	611	Pittsburg Power Plant 230 kV Switchyard	9/30/2012
334	193.6	Kelso Substation 230 kV Bus	6/1/2012
378	123	Los Esteros Substation 115 kV Bus	6/1/2011
417	36	Pittsburg-Tesla 230 kV Line	9/30/2010
Total	4706.9		

Table DR43-2 provides a listing of the same Group 1 projects as reflected in the January 8, 2010 CAISO Queue (included as Attachment DR43-3). Projects that have been withdrawn from the queue are shown in strikeout font. MW revisions (increases and decreases) to projects remaining in the queue are shown in bold font.

TABLE DR43-2
Transition Cluster Group 1 Generation Interconnection Projects from Interconnection Study Report (as of January 8, 2010

Queue	MW	Point of Interconnection	Online Date
~~171~~	~~500~~	~~Vaca-Tesla 500 kV Line~~	~~12/31/2011~~
222	**78**	Birds Landing Substation 230 kV Bus	12/31/2010
~~257~~	~~575~~	~~Loop Ignacio-Sobrante and Lakeville-Sobrante #2 230 kV Lines~~	~~6/1/2/2011~~
258	**651**	Contra Costa Substation 230 kV Bus	2/1/2012
~~269~~	~~371.3~~	~~Tesla Substation 230 kV Bus~~	~~4/15/2012~~
~~275~~	~~630~~	~~Loop Vaca Dixon-Peabody and Vaca-Lambie 230 kV Lines~~	~~9/1/2012~~
~~305~~	~~611~~	~~Contra Costa Power Plant 230 kV Switchyard~~	~~7/30/2012~~
320	**100**	Contra Costa Power Plant 230 kV Switchyard	4/29/2011
~~322~~	~~611~~	~~Pittsburg Power Plant 230 kV Switchyard~~	~~9/30/2012~~
334	**195.9**	Kelso Substation 230 kV Bus	6/1/2012
378	**120**	Los Esteros Substation 115 kV Bus	6/1/2011
417	**14**	Pittsburg-Tesla 230 kV Line	9/30/2010
Total	1158.9		

Six projects with a total generation of 1158.9 MW remain in Group 1. This represents a decrease of 75 percent from the generation for Group 1 that was included in the Phase I Interconnection Study. In addition, the CAISO has confirmed that Contra Costa No. 6 and 7, representing a total of 680 MW of generation in the immediate proximity of the proposed OGS, have been removed from the base case for the Phase II Interconnection Study. While the OGS queue generation is increasing from 520 MW to 631 MW, because of the significant reduction in the total generation for Group 1 and also the reduction in nearby existing generation, the Applicant believes that the results from the Phase I study represent a very conservative worst case scenario for the network upgrades attributable to the OGS.

a. *Identify major assumptions in the base cases including imports to the system, major generation and load changes in the system and queue generation.*

Response: The base cases are discussed in general terms in Section 4 of the report and in more detail in Appendix B. The following two base cases were evaluated:

- **2013 Summer Peak Full Loop Base Case**—This base case was developed from PG&E's 2008 base case series. It has a 1-in-10 year heat wave load forecast for PG&E's Greater Bay Area.
- 2**013 Summer Off-Peak Full Loop Base Case**—This base case evaluates the potential congestion on transmission facilities during the lightest loading conditions during the year. The summer 2013 off peak loads are about 50 percent of the summer peak loads.

Table 3-1 of the report lists the queue generation included in Group 1, and identifies the generation in MW and interconnection location for each proposed project. Import capabilities into the system are listed in Table 10-1 of the report. Table B-1 in Appendix B lists the existing generation and proposed generation with senior queue positions modeled in the base cases. Table B-2 in Appendix B lists the network upgrades associated with senior queue projects (operational by 2013) modeled in the base cases. Table B-3 in Appendix B lists the approved PG&E transmission projects (operational by 2013) modeled in the base cases.

b. *Analyze the system for N-0, important N-1 and critical N-2 contingency conditions and provide a list of criteria violations in a table showing the loadings before and after adding the new generation.*

Response: The steady state power flow study criteria used by CAISO is discussed in Section 5 of the report. Section 6 lists the contingencies analyzed and summarizes the study results. CAISO's Category "A" contingency addresses all facilities in operation under normal conditions (N-0 contingency). CAISO's Category "B" contingencies address all single generator outages, all single transmission circuit outages, and all single transformer outages (i.e. N-1 contingencies) as well as selected overlapping single generator and transmission circuit outages for the transmission lines and generators. CASIO's Category "C" contingencies include combinations of two-generation/transmission line/transformer outages (i.e. N-2 contingencies) as well as various single line-to-ground fault scenarios. As it is impractical to study every Category "C" contingency, the CAISO selected critical Category "C" contingencies for evaluation in the study. The pre- and post-project loadings are showing in Table 6-2-1 for Category "A" normal violations, Table 6-2-2 for Category "B" emergency overloads, and Table 6-2-3 for Category "C" emergency overloads.

c. *Analyze short circuit duties.*

Response: Short circuit duties are discussed in Section 7 of the report. The results are presented in Appendix H.

d. *Analyze system for Transient Stability and Post-transient voltage conditions under critical N-1 and N-2 contingencies, and provide related plots, switching data and a list for voltage violations in the studies.*

Response: Section 9 of the report discusses the Dynamic Stability Evaluation for critical Category "B" and Category "C" contingencies. The results in the form of plots are included in Appendix F. Switching data can be obtained from the appropriate power flow diagrams found in Appendix D. The study concluded that the project would not cause the transmission system to go unstable under Category "B" and Category "C" outages.

e. *Provide a list of contingencies evaluated for each study.*

Response: Appendix C includes the Category "B" and Category "C" contingencies evaluated in the Steady State Power Flow Study. The Category "B" and Category "C" contingencies analyzed in the Dynamic Stability Evaluation are listed in Section 9.1 of the report.

f. *List mitigation measures considered and those selected for all criteria violations.*

Response: The measures considered for mitigation of overloads and the selected solutions are listed in Section 11 of the report.

g. *Provide electronic copies of *.sav and *.drw PSLF files.*

Response: The Applicant does not possess the PLSF files. The CAISO does not provide these files with the study results as they consider the files to be confidential and proprietary. To obtain these files, the Applicant would be required to execute a non-disclosure agreement with the CAISO which, in turn, would prohibit the Applicant from disclosing these files to the CEC.

h. *Provide power flow diagrams (MW, % loading & P. U. voltage) for base cases with and without the project. Power flow diagrams must also be provided for all N-0, N-1 and N-2 studies where overloads or voltage violations appear. Provide the pre and post project diagrams only for an elements largest overload.*

Response: Steady state power flow diagrams are provided in Appendix D.

FIGURE DR41-1
CONTRA COSTA SUBSTATION 230 KV BUS
OAKLEY GENERATING STATION RESPONSE TO DATA REQUESTS
OAKLEY, CALIFORNIA

FIGURE DR42-1
CONTRA COSTA SUBSTATION PARCEL
OAKLEY GENERATING STATION RESPONSE TO DATA REQUESTS
OAKLEY, CALIFORNIA

ATTACHMENT DR43-2

Appendix B to the Large Generator Interconnection Study Process Agreement

Appendix B

Large Generator Interconnection Study Process Agreement

DATA FORM TO BE PROVIDED BY THE INTERCONNECTION CUSTOMER PRIOR TO COMMENCEMENT OF THE PHASE II INTERCONNECTION STUDY

Generating Facility size (MW): **<u>651</u>**

Provide two copies of this completed form and other required plans and diagrams in accordance with Section 7.1 of the LGIP.

Provide location plan and one-line diagram of the plant and station facilities. For staged projects, please indicate future generation, transmission circuits, etc.

One set of metering is required for each generation connection to the new bus or existing CAISO Controlled Grid station. Number of generation connections: **<u>One (1)</u>**

On the one line indicate the generation capacity attached at each metering location. (Maximum load on CT/PT)

On the one line indicate the location of auxiliary power. (Minimum load on CT/PT)

Will an alternate source of auxiliary power be available during CT/PT maintenance?
☒ Yes ☐ No

Will a transfer bus on the generation side of the metering require that each meter set be designed for the total plant generation? ☒ Yes ☐ No

(Please indicate on one line).

What type of control system or PLC will be located at the Interconnection Customer's Large Generating Facility?
<u>GE Mark VIe</u>

What protocol does the control system or PLC use?
<u>QNX</u>

Please provide a 7.5-minute quadrangle of the site. Sketch the plant, station, transmission line, and property line.

Physical dimensions of the proposed interconnection station:

<u>The Contra Costa Generating Station will have three small switchyards (one for each generator). The dimensions of the three switchyards will be approximately 160' x 115' (15,510 sf), 176' x 82' (14,060 sf), 172' x 89' (11,780 sf).</u>

Bus length from generation to interconnection station:

The bus length from each of the three generators to the corresponding step-up transformer will be from approximately 160 to 175 feet. The bus length from each step-up transforer to the common bus will be approximately 120 to 130 feet (including high-side circuit breaker).

Line length from interconnection station to the Participating TO's transmission line.

The length of the generation tie line from the Contra Costa Generating Station switchyard to the Contra Costa Substation is approximately 2.4 miles.

Tower number observed in the field. (Painted on tower leg)*

N/A - Interconnection will be made at the Contra Costa Substation 230 kV bus.

Number of third party easements required for transmission lines*:

None - Generation tie line will utilize an existing corridor presently occupied by the DuPont-Contra Costa 60 kV line.

* To be completed in coordination with the Participating TO or CAISO.

Is the Large Generating Facility in the Participating TO's service area?

☒ Yes ☐ No

Local service provider for auxiliary and other power: **PG&E**

Please provide proposed schedule dates:

Environmental survey start:		**1/1/2009**
Environmental impact report submittal:		**6/30/2009**
Procurement of project equipment:		**5/10/2011**
Begin Construction	Date:	**5/23/2011**
Generator step-up transformer receives back feed power	Date:	**10/18/2012**
Generation Testing	Date:	**7/2/2013**
Commercial Operation Date	Date:	**12/1/2013**

Level of Deliverability: Choose one of the following:

- ☐ Energy Only
- ☒ Full Capacity

ATTACHMENT DR43-3

CAISO-Controlled Grid Generation Queue as of January 8, 2010

The California ISO Controlled Grid Generation Queue
as of: January 8, 2010

				Generating Facility		Maximum MWs		Deliverability Status	Location		Point of Interconnection				Study Availability				
Queue Position	Interconnection Request Receive Date	Queue Date	Application Status	Type	Fuel	Summer	Winter	Full Capacity or Energy Only (FC/EO)	County	State	Utility	Station or Transmission Line	Proposed On-line Date (as filed with IR)	Current On-line Date	Feasibility Study (IFS)	System Impact Study *or* Phase I Cluster Study	Facilities Study (FAS) *or* Phase II Cluster Study	Optional Study (OS)	Interconnection Agreement Status
1	9/30/1998	9/30/1998	Active - A39	WT	W	16.5			Riverside	CA	SCE	Devers-Garnet 115 kV line (Tap)	3/1/1999	12/31/2010	NA	Complete	Complete		IFA
1A	11/1/1999	11/1/1999	Complete	CC	NG	550	550		San Diego	CA	SDGE	Miguel Substation	3/1/2002	10/3/2009	N/A	Complete	Complete		IA Executed
2	8/10/1999	2/3/2000	Complete	CC	NG	590			Contra Costa	CA	PGE	Contra Costa Power Plant 230 kV bus	11/28/2007	1/7/2009	N/A	Complete	Complete		GSFA Executed
3	4/21/2000	6/14/2000	Active	CT	NG	850			Riverside	CA	SCE	Devers Substation 230 kV Bus	1/1/2004	6/1/2010	NA	Complete	Re-study Complete	Complete	Executed
4	8/8/2000	8/8/2000	Complete	CC	NG	521	545		San Diego	CA	SDGE	Palomar 230 kV	6/1/2001	10/15/2005	NA	Complete	Complete		Executed
~~5~~	~~8/9/2000~~	~~8/9/2000~~	Withdrawn 9/14/06	~~CC~~	~~NG~~	~~900~~			~~San Diego~~	~~CA~~	~~SDGE~~	~~Encina Power Plant Switchyard~~	~~6/30/2003~~	~~6/1/2008~~	~~NA~~	~~Complete~~	~~In Progress~~		
6	8/23/2000	8/23/2000	Active - Serial	CC	NG	1156			San Joaquin	CA	PGE	Tesla Substation 230 kV Bus E	6/1/2008	11/30/2014	NA	Re-Study Complete	Complete	Complete	In Progress
7	8/16/2000	10/6/2000	Active - Serial	CC	NG	630			Los Angeles	CA	SCE	El Segundo 220 kV Bus	8/1/2009	6/1/2013	NA	Complete	Complete	Complete	Executed
8	11/28/2000	11/28/2000	Active - Serial	CC	NG	750			San Diego	CA	SDGE	Sycamore Canyon Substation	6/1/2004	12/31/2010	NA	Complete	Re-Study Complete		In Progress
~~9~~	~~12/1/2000~~	~~12/1/2000~~	Withdrawn 9/20/08	~~CC~~	~~NG~~	~~1200~~			~~San Luis Obispo~~	~~CA~~	~~PGE~~	~~Morro Bay Substation~~	~~1/1/2008~~	~~1/1/2008~~	~~NA~~	~~Complete~~	~~Complete~~		~~GSFA Executed~~
~~10~~	~~5/2/2001~~	~~5/2/2001~~	Withdrawn 5/24/07	~~CC~~	~~NG~~	~~620~~			~~Kings~~	~~CA~~	~~PGE~~	~~Gates Substation (Arco - Gates 230 kV line)~~	~~1/1/2009~~	~~7/1/2009~~	~~NA~~	~~Complete~~	~~Complete~~		~~GSFA Executed~~
~~11~~	~~10/14/2002~~	~~10/23/2002~~	Withdrawn 8/21/09	~~WT~~	~~W~~	~~63~~			~~San Bernardino~~	~~CA~~	~~SCE~~	~~Wheaton Substation~~	~~12/1/2004~~	~~3/1/2008~~	~~NA~~	~~Complete~~	~~Complete~~		~~IFA Executed~~
11A	7/26/2002	7/26/2002	Active	CC	NG	520			Riverside	CA	SCE	Julian Hinds Substation 230kV	6/1/2005	8/1/2010	NA	Complete	Complete		Executed
12	12/16/2002	12/16/2002	Complete	WT	W	150			Solano	CA	PGE	Birds Landing Substation 230kV	10/31/2005	3/30/2006	NA	Complete	Complete		GSFA Executed
13	1/3/2003	1/3/2003	Active	H	WTR	40			San Diego	CA	SDGE	Escondido	7/1/2007	7/31/2010	NA	Complete	Complete		Executed
14	1/7/2003	1/7/2003	Complete	CC	NG	65			San Diego	CA	SDGE	Miguel-Tijuana	12/31/2004	10/3/2009	NA	Complete	Complete		IA Tendered
~~15~~	~~12/31/2002~~	~~1/17/2003~~	Withdrawn 7/13/07	~~WT~~	~~W~~	~~50~~			~~San Bernardino~~	~~CA~~	~~SCE~~	~~Mountain Pass~~	~~9/1/2004~~	~~1/1/2010~~	~~NA~~	~~Complete~~	~~Complete~~		
16	3/11/2003	3/11/2003	Active	WT	W	120			Santa Barbara	CA	PGE	Cabrillo	6/1/2006	12/31/2011	NA	Complete	Complete		GSFA Executed
17	3/18/2003	3/18/2003	Active - Serial	CC	NG	520			Riverside	CA	SCE	Devers-Palo Verde 500 kV line near Blythe	1/1/2006	8/1/2010	NA	Complete	Complete		In Progress
~~18~~	~~4/15/2003~~	~~4/15/2003~~	Withdrawn 6/20/06	~~WT~~	~~W~~	~~200~~			~~Los Angeles~~	~~CA~~	~~SCE~~	~~Antelope~~	~~12/31/2005~~	~~12/12/2007~~	~~NA~~	~~Complete~~	~~Complete~~		~~Tendered~~
19	6/4/2003	6/18/2003	Complete	WT	W	46			San Diego	CA	SDGE	Crestwood	12/31/2005	10/1/2005	NA	Complete	Complete		Executed
20	8/19/2003	9/4/2003	Active - Serial	WT	W	300			Kern	CA	SCE	Antelope	12/31/2006	10/31/2011	NA	Re-Study Complete	Re-study in Progress		
21	10/3/2003	10/23/2003	Complete	WT	W	37.55			Byron	CA	PGE	Windmaster/Buena Vista Sub	7/1/2004	12/29/2006	NA	NA	NA		Executed
22	11/18/2003	11/18/2003	Active	WT	W	38			Solano	CA	PGE	New Birds Lndng Sw Sta near Contra Costa PP Sub	6/30/2005	12/31/2010	NA	Complete	Complete		GSFA Executed
23	11/17/2003	11/24/2003	Complete	CC	NG	72			San Bernardino	CA	SCE	San Bernardino 220+M127 kV	11/1/2004	10/1/2005	NA	Complete	Complete		IFA Executed
24	1/30/2004	1/30/2004	Complete	WT	W	150			Solano	CA	PGE	High Winds/Contra Costa PP	12/31/2006	1/27/2009	NA	Complete	Complete		GSFA Executed
~~25~~	~~2/5/2004~~	~~2/5/2004~~	Withdrawn 6/11/07	~~WT~~	~~W~~	~~117~~			~~San Diego~~	~~CA~~	~~SDGE~~	~~Crestwood~~	~~6/6/2005~~	~~6/1/2007~~	~~NA~~	~~In Progess~~			
~~26~~	~~2/12/2004~~	~~2/12/2004~~	Withdrawn 8/23/07	~~WT~~	~~W~~	~~36~~			~~San Diego~~	~~CA~~	~~SDGE~~	~~Crestwood~~	~~4/1/2006~~	~~1/1/2008~~	~~NA~~	~~In Progress~~			
~~27~~	~~2/23/2004~~	~~2/23/2004~~	Withdrawn 10/19/07	~~CC~~	~~NG~~	~~650~~			~~San Diego~~	~~CA~~	~~SDGE~~	~~230/138/69 kV South Bay (650 MW CC)~~	~~1/1/2010~~	~~1/1/2010~~	~~NA~~	~~Complete~~	~~Complete~~		~~In Progress~~
~~28~~	~~2/25/2004~~	~~2/25/2004~~	Withdrawn 7/22/08	~~CT~~	~~NG~~	~~145.1~~			~~San Francisco~~	~~CA~~	~~PGE~~	~~Potrero 115 kV Sub~~	~~12/1/2006~~	~~6/1/2008~~	~~NA~~	~~Complete~~	~~Complete~~		~~Executed~~
~~29~~	~~3/8/2004~~	~~3/29/2004~~	Withdrawn 7/11/08	~~WT~~	~~W~~	~~201~~			~~Lake & Sonoma~~	~~CA~~	~~PGE~~	~~Collector Substation at Geysers #17 & Fulton 230 kV line~~	~~12/1/2006~~	~~7/1/2009~~	~~NA~~	~~Complete~~	~~Re-study in Progress~~		~~In Progress~~
~~30~~	~~4/26/2004~~	~~4/26/2004~~	Withdrawn 7/22/08	~~CT~~	~~NG~~	~~48.7~~			~~San Francisco~~	~~CA~~	~~PGE~~	~~SF Airport Substation~~	~~6/1/2006~~	~~6/1/2008~~	~~NA~~	~~Complete~~	~~Complete~~		~~GSFA Executed~~
~~31~~	~~4/12/2004~~	~~5/11/2004~~	Withdrawn 4/18/08	~~WT~~	~~W~~	~~201~~			~~Kern~~	~~CA~~	~~SCE~~	~~Monolith Substation~~	~~12/31/2007~~	~~6/1/2010~~	~~NA~~	~~Complete~~	~~In Progress~~		
32	5/12/2004	5/24/2004	Active - Serial	WT	W	201			San Diego	CA	SDGE	Boulevard Substation 138kV	9/1/2007	11/1/2012	NA	Complete	Complete		In Progress
33	7/9/2004	7/12/2004	Complete	ST	G	10			Churchill	NV	SCE	Bishop Control Sub	7/14/1988	5/31/2006	NA	Complete	Complete		LGIA Executed
~~34~~	~~7/19/2004~~	~~7/19/2004~~	Withdrawn 4/18/08	~~WT~~	~~W~~	~~300~~			~~Kern~~	~~CA~~	~~SCE~~	~~Monolith Substation~~	~~7/1/2007~~	~~7/1/2011~~	~~NA~~	~~Complete~~	~~In Progress~~		
~~35~~	~~10/25/2004~~	~~10/25/2004~~	Withdrawn 4/12/07	~~CT~~	~~NG~~	~~49.9~~			~~Fresno~~	~~CA~~	~~PGE~~	~~115 KV Panoche Sub~~	~~5/31/2006~~	~~5/31/2006~~	~~NA~~	~~Complete~~	~~Complete~~		~~Tendered~~
~~36~~	~~11/1/2004~~	~~11/1/2004~~	Withdrawn 2/8/07	~~CT~~	~~NG~~	~~99.9~~			~~Stanislaus~~	~~CA~~	~~PGE~~	~~115 kV Tesla - Stockton Cogen Trans. Line.~~	~~5/31/2006~~	~~5/31/2006~~	~~NA~~	~~Complete~~	~~Complete~~		~~Tendered~~
37	11/8/2004	11/8/2004	Active	CT	NG	74.9			San Joaquin	CA	PGE	Tesla Substation	1/1/2007	12/31/2011	NA	Complete	Complete		Executed
38	10/19/2004	11/11/2004	Active - Serial	IC	NG	146.4			Humboldt	CA	PGE	Humboldt Power Plant Substation	8/1/2008	7/15/2010	NA	Complete	Complete		LGIA Executed
39	11/11/2004	11/11/2004	Active	WT	W	200			Solano	CA	PGE	New Birds Lndng Sw Sta near Contra Costa PP Sub	12/31/2008	12/22/2009	NA	Complete	Complete		Executed
~~40~~	~~10/19/2004~~	~~11/11/2004~~	Withdrawn 4/20/09	~~IC~~	~~NG~~	~~118~~			~~Alameda~~	~~CA~~	~~PGE~~	~~Eastshore Substation~~	~~5/1/2007~~	~~10/1/2009~~	~~NA~~	~~Complete~~	~~Complete~~		~~Executed~~
41	11/9/2004	11/18/2004	Active - A39	CT	NG	157			Kern	CA	SCE	Pastoria Substation	7/31/2006	6/1/2011	NA	Complete	Complete		
42	11/24/2004	11/26/2004	Active	CT	NG	300			Fresno	CA	PGE	McCall Substation	5/31/2007	3/31/2013	NA	Complete	Complete		Executed
~~43~~	~~11/29/2004~~	~~11/29/2004~~	Withdrawn 6/27/06	~~IC~~	~~NG~~	~~168.7~~			~~San Joaquin~~	~~CA~~	~~PGE~~	~~Tesla-Bellota 230 kV line~~	~~1/1/2008~~	~~10/1/2007~~	~~NA~~	~~Complete~~			~~Tendered~~
~~44~~	~~11/29/2004~~	~~11/29/2004~~	Withdrawn 3/30/06	~~IC~~	~~NG~~	~~126.5~~			~~Madera~~	~~CA~~	~~PGE~~	~~Borden Substation 230 kV Bus~~	~~1/1/2008~~	~~10/1/2007~~	~~NA~~	~~Complete~~	~~Complete~~		
45	12/1/2004	12/1/2004	Active	CT	NG	361			Alameda	CA	PGE	Eastshore substation	7/31/2006	6/1/2012	NA	Complete	Re-study Complete		Executed
~~46~~	~~12/1/2004~~	~~12/1/2004~~	Withdrawn 5/11/07	~~CT~~	~~NG~~	~~531~~			~~Contra Costa~~	~~CA~~	~~PGE~~	~~Tesla-Tracy #1 230 kV Line - Tracy Sub~~	~~7/31/2006~~	~~7/31/2008~~	~~NA~~	~~Complete~~	~~Complete~~		
~~47~~	~~12/1/2004~~	~~12/1/2004~~	Withdrawn 2/26/08	~~CT~~	~~NG~~	~~200.6~~			~~Fresno~~	~~CA~~	~~PGE~~	~~Herndon - Kearney 230 kV line~~	~~6/30/2008~~	~~6/30/2008~~	~~NA~~	~~Complete~~	~~Complete~~		~~In Progress~~
~~48~~	~~12/1/2004~~	~~12/1/2004~~	Withdrawn 4/6/06	~~5~~	~~NG~~	~~590~~			~~Contra Costa~~	~~CA~~	~~PGE~~	~~Contra Costa Power Plant 230 kV Substation~~	~~1/1/2008~~	~~10/1/2008~~	~~NA~~	~~Complete~~	~~Complete~~		~~Tendered~~
49	12/14/2004	12/14/2004	Active - Serial	WT	W	100.5			Riverside	CA	SCE	Devers Substation	12/1/2006	7/31/2011	NA	Re-Study Complete	Re-study Complete		
50	12/21/2004	12/21/2004	Active	CC	NG	810			Riverside	CA	SCE	SCE Valley Substation	5/31/2008	8/4/2008	NA	Complete	Complete		IA Executed
51	12/20/2004	12/21/2004	Complete	IC	NG	0.55			Fresno	CA	PGE	70 kV Kerman-Helm transmission line	4/30/2005	5/31/2006	NA	NA	NA		GSFA Executed
52	12/1/2004	12/21/2004	Complete	CT	NG	401			Fresno	CA	PGE	Panoche Sub Station	6/30/2008	5/28/2009	NA	Re-Study Complete	Re-study Complete		Executed
~~53~~	~~12/1/2004~~	~~12/22/2004~~	Withdrawn 7/24/06	~~CT~~	~~NG~~	~~116.8~~			~~Placer~~	~~CA~~	~~PGE~~	~~Pleasant Grove Sub Station~~	~~6/1/2008~~	~~6/1/2008~~	~~NA~~	~~Complete~~	~~Complete~~		~~Tendered~~
54	11/11/2004	1/12/2005	Complete	CT	NG	119.9			Fresno	CA	PGE	Panoche Substation	6/1/2008	5/4/2009	NA	Complete	Re-study Complete		Executed
~~55~~	~~12/1/2004~~	~~1/13/2005~~	Withdrawn 11/13/07	~~CC~~	~~NG~~	~~673~~			~~Fresno~~	~~CA~~	~~PGE~~	~~Helm substation~~	~~7/31/2008~~	~~7/31/2008~~	~~NA~~	~~Re-Study Complete~~	~~Tendered~~		
~~56~~	~~12/21/2004~~	~~1/25/2005~~	Withdrawn 5/31/07	~~CC~~	~~NG~~	~~634~~			~~Clark~~	~~NV~~	~~SCE~~	~~El Dorado 230 kV Substation~~	~~6/1/2007~~	~~8/1/2009~~	~~NA~~	~~Complete~~	~~Complete~~		
57	12/1/2004	2/8/2005	Active	CC	NG	715			Colusa	CA	PGE	Between Cottonwood and Vaca-Dixon	1/1/2010	5/1/2010	NA	Complete	Complete		Executed
58	1/25/2005	2/22/2005	Active - Serial	ST	G	62			Mineral	NV	SCE	Control 115kV Substation	10/7/2007	2/1/2012	NA	Complete	Complete	TAS II Completed	Filed Unexecuted
~~59~~	~~3/25/2005~~	~~3/28/2005~~	Withdrawn 8/2/06	~~CT~~	~~NG~~	~~97.2~~			~~Kings~~	~~CA~~	~~PGE~~	~~Henrietta Substantion 70 kV~~	~~1/1/2008~~	~~1/1/2008~~	~~NA~~	~~Complete~~	~~Complete~~		~~Tendered~~
60	3/28/2005	3/28/2005	Active	CT	NG	94			Kern	CA	PGE	Kern Oil Substation 115 kV	3/31/2007	3/31/2013	NA	Complete	Complete		Executed
61	3/28/2005	3/30/2005	Complete	ST	NG	73.27			Fresno	CA	PGE	70kV Helm-Kerman	5/31/2006	3/29/2007	NA	Complete	Complete		Executed
~~62~~	~~3/28/2005~~	~~4/13/2005~~	Withdrawn 2/21/06	~~CC~~	~~NG~~	~~166.5~~			~~Humboldt~~	~~CA~~	~~PGE~~	~~Humboldt Bay-Humboldt #1 115 kV~~	~~5/31/2007~~	~~6/1/2007~~	~~NA~~		~~Tendered~~		
~~63~~	~~3/25/2005~~	~~4/18/2005~~	Withdrawn 1/4/07	~~CC~~	~~NG~~	~~158~~			~~Contra Costa~~	~~CA~~	~~PGE~~	~~Contra Costa (230 kV)~~	~~1/1/2008~~	~~1/1/2008~~	~~NA~~	~~Complete~~	~~Re-study in Progress~~		~~Tendered~~
~~64~~	~~3/30/2005~~	~~4/28/2005~~	Withdrawn 1/13/06	~~CT~~	~~NG~~	~~147~~			~~Humboldt~~	~~CA~~	~~PGE~~	~~Humboldt Bay Power Plant Sub~~	~~5/1/2008~~	~~3/1/2008~~	~~NA~~	~~Complete~~			
~~65~~	~~5/6/2005~~	~~5/6/2005~~	Withdrawn 4/11/07	~~CT~~	~~NG~~	~~424.8~~			~~Los Angeles~~	~~CA~~	~~SCE~~	~~Long Beach Gen Station 220kv switchyard~~	~~1/1/2007~~	~~6/1/2010~~	~~NA~~	~~Complete~~	~~Complete~~		
66	5/6/2005	5/6/2005	Active	CT	NG	500.5			Los Angeles	CA	SCE	Walnut Substation	9/1/2007	3/5/2011	NA	Re-Study Complete	Complete		Executed
67	3/28/2005	5/9/2005	Active	CC	NG	245			Alameda	CA	PGE	Eastshore Substation	7/31/2008	6/1/2012	NA	Complete	Re-study Complete		Executed
68	3/30/2005	5/11/2005	Active - Serial	Other	S	850			San Bernadino	CA	SCE	Pisgah 230 kV Substation	12/31/2009	12/31/2009	Waived	Re-Study Complete	Complete	Optional Study	In Progress
~~69~~	~~5/6/2005~~	~~6/7/2005~~	Withdrawn 5/17/06	~~CT~~	~~NG~~	~~527~~			~~San Bernardino~~	~~CA~~	~~SCE~~	~~Etiwanda 230kV Substation~~	~~8/1/2008~~	~~8/1/2008~~	~~NA~~	~~Complete~~			
70	5/9/2005	6/14/2005	Complete	IC	LFG	12.6			San Mateo	CA	PGE	Hillsdale Junction-Half Moon Bay 60 kV line	12/23/2005	4/1/2009	NA	Complete	Complete		GSFA Executed
~~71~~	~~5/6/2005~~	~~6/15/2005~~	Withdrawn 1/11/06	~~CC~~	~~NG~~	~~591~~			~~Clark~~	~~NV~~	~~SCE~~	~~Eldorado 500/230kV Substation~~	~~2/28/2007~~	~~1/31/2007~~	~~Complete~~	~~Tendered~~			

				Generating Facility		Maximum MWs		Deliverability Status	Location		Point of Interconnection				Study Availability				
Queue Position	Interconnection Request Receive Date	Queue Date	Application Status	Type	Fuel	Summer	Winter	Full Capacity or Energy Only (FC/EO)	County	State	Utility	Station or Transmission Line	Proposed On-line Date (as filed with IR)	Current On-line Date	Feasibility Study (IFS)	System Impact Study *or* Phase I Cluster Study	Facilities Study (FAS) *or* Phase II Cluster Study	Optional Study (OS)	Interconnection Agreement Status
72	4/26/2005	6/21/2005	Active - Serial	H	WTR	500			Riverside	CA	SCE/SDGE	Proposed Lee Lake Substation	12/31/2008	5/23/2012	NA	Complete	Complete		In Progress
73	6/6/2005	6/27/2005	Active - Serial	WT	W	250			Kern	CA	SCE	Whirlwind Substation 230kV bus	12/31/2007	10/31/2010	NA	Complete	In Progress		
74	7/12/2005	7/12/2005	Active - Serial	WT	W	102			Shasta	CA	PGE	230kV line btn Pit#3 & Round Mtn	12/15/2007	12/15/2010	Complete	Complete	Re-study Complete		Executed
75	**4/28/2005**	**7/15/2005**	**Complete**	**ST**	**B**	**10.5**			**Madera**	**CA**	**PGE**	**Le Grand-Chowcilla 115 kV**	**12/31/2005**	**5/20/2009**	**NA**	**Complete**	**Complete**		**GSFA Executed**
76	**4/28/2005**	**7/15/2005**	**Complete**	**ST**	**B**	**10.5**			**Merced**	**CA**	**PGE**	**PG&E Merced #1 70 kV circuit**	**7/1/2006**	**5/19/2009**	**NA**	**Complete**	**Complete**		**GSFA Executed**
~~77~~	~~8/19/2005~~	~~8/22/2005~~	Withdrawn 6/26/06	~~WT~~	~~W~~	~~300~~			~~Kern~~	~~CA~~	~~SCE/PG&E~~	~~TBD Bakersfiled~~	~~11/30/2007~~	~~11/30/2007~~	~~Complete~~	~~Tendered~~			
78	8/31/2005	8/31/2005	Active	Other	S	300			Imperial	CA	SDGE	Imperial Valley Substation	12/31/2009	12/1/2010	Waived	Complete	Complete		Executed
79	5/24/2005	9/7/2005	Active - Serial	WT	W	51			Kern	CA	SCE	Windhub Substation 66kV bus	6/1/2006	3/31/2010	Complete	Complete	Complete		In Progress
~~80~~	~~9/12/2005~~	~~9/12/2005~~	Withdrawn 9/28/09	~~CC~~	~~NG~~	~~610~~			~~Los Angeles~~	~~CA~~	~~SCE~~	~~Laguna Bell Substation 230 kV~~	~~7/31/2008~~	~~5/31/2012~~	~~Waived~~	~~Re-Study Complete~~	~~Re-study Complete~~		~~In Progress~~
81	**9/13/2005**	**9/13/2005**	**Complete**	**ST**	**G**	**55**			**Lake**	**CA**	**PGE**	**Geysers #17 - Fulton 230 kV Line**	**9/1/2006**	**11/1/2007**	**Waived**	**Complete**	**Complete**		**Executed**
~~82~~	~~6/10/2005~~	~~9/14/2005~~	Withdrawn 8/16/06	~~ST~~	~~B~~	~~6.8~~			~~Humboldt~~	~~CA~~	~~PGE~~	~~Rio Dell Substation 60 KV~~	~~1/1/2006~~	~~1/1/2006~~	~~Waived~~	~~Complete~~	~~Waived~~		
~~83~~	~~9/16/2005~~	~~9/16/2005~~	Withdrawn 10/8/08	~~WT~~	~~W~~	~~60~~			~~San Bernardino~~	~~CA~~	~~SCE~~	~~Lugo-Pisgah No. 2 230 kV tran line~~	~~12/31/2008~~	~~6/1/2010~~	~~Complete~~	~~Complete~~	~~Tendered~~	~~Tendered~~	
84	11/22/2005	12/1/2005	Active - Serial	WT	W	340			Kern	CA	SCE	Whirlwind Substation 230kV	12/31/2009	12/31/2011	NA	Complete	Complete		In Progress
~~85~~	~~12/28/2005~~	~~12/28/2005~~	Withdrawn 3/26/08	~~WT~~	~~W~~	~~120~~			~~Kern~~	~~CA~~	~~SCE~~	~~Segment 3 230 Collector Loop Tehachapi~~	~~12/31/2007~~	~~12/31/2009~~	~~NA~~	~~Complete~~	~~Tendered~~		
~~86~~	~~12/30/2005~~	~~12/30/2005~~	Withdrawn 4/7/06	~~CT~~	~~NG~~	~~49.9~~			~~Kern~~	~~CA~~	~~PGE~~	~~Kern Oil-Vedder 115 kV Line~~	~~3/1/2008~~	~~3/1/2008~~					
86A	1/20/2006	1/20/2006	Active - Serial	WT	W	33.1			Kern	CA	SCE	Vincent Substation	1/1/2008	10/1/2009	NA	Complete	Complete		In Progress
86B	1/20/2006	1/20/2006	Active - Serial	WT	W	34			Kern	CA	SCE	Canwind Substation	1/1/2008	10/1/2009	NA	Complete	In Progress		
~~87~~	~~2/3/2006~~	~~2/3/2006~~	Withdrawn 3/9/06	~~ST~~	~~NU~~	~~28~~			~~San Luis Obispo~~	~~CA~~	~~PGE~~	~~Diablo Canyon Substation Circuit Breakers 532 and 632~~	~~12/8/2005~~	~~12/8/2005~~					
~~88~~	~~2/10/2006~~	~~2/10/2006~~	Withdrawn 2/14/08	~~CC~~	~~NG~~	~~613.5~~			~~Los Angeles~~	~~CA~~	~~SCE~~	~~Hinson Substation 230 kV bus~~	~~7/1/2011~~	~~7/1/2011~~	~~Complete~~	~~Re-Study Complete~~	~~Tendered~~		
89	2/13/2006	2/13/2006	Active - Serial	CC	NG	570			San Bernardino	CA	SCE	Victorville Substation	7/1/2009	4/1/2010	Waived	Complete	Complete		
~~90~~	~~2/16/2006~~	~~2/16/2006~~	Withdrawn - 10/26/09	~~CT~~	~~NG~~	~~93~~			~~San Diego~~	~~CA~~	~~SDGE~~	~~Existing radial 69kV gen-tie line to TL6929~~	~~6/1/2007~~	~~6/1/2009~~	~~Complete~~	~~Complete~~	~~Complete~~		~~In Progress~~
91	2/22/2006	2/22/2006	Active - Serial	WT	W	51			Kern	CA	SCE	Windhub Substation 66kV bus	3/31/2010	3/31/2010	NA	Complete	Complete		In Progress
92	2/23/2006	2/23/2006	Active - Serial	CC	NG	570			Los Angeles	CA	SCE	Vincent 230 kV	7/1/2009	8/1/2010	NA	Complete	Complete		
93	2/15/2006	3/1/2006	Active - Serial	WT	W	220			Kern	CA	SCE	Tehachapi Conceptual Substation #1	12/31/2008	12/31/2012	NA	Complete	Complete		
94	3/1/2006	3/1/2006	Active - Serial	WT	W	180			Kern	CA	SCE	Highwind Substation 220kV	12/31/2008	12/31/2011	NA	Complete	Complete		
95	3/1/2006	3/1/2006	Active - Serial	WT	W	550			Kern	CA	SCE	Tehachapi Conceptual Substation #1	12/31/2009	12/31/2011	NA	Complete	Complete		In Progress
96	3/1/2006	3/1/2006	Active - Serial	WT	W	600			Kern	CA	SCE	Tehachapi Conceptual Substation #1	12/31/2009	12/31/2010	NA	Complete	Complete		In Progress
97	3/1/2006	3/1/2006	Active - Serial	WT	W	160			Kern	CA	SCE	Whirlwind Substation 220kV bus	12/31/2009	12/31/2013	NA	Complete	Complete		
98	**3/9/2006**	**3/9/2006**	**Complete**	**ST**	**NU**	**37**			**San Luis Obispo**	**CA**	**PGE**	**Diablo Canyon Substation Circuit Breakers 532 and 632**	**12/8/2005**	**1/1/2006**	**NA**	**Complete**	**NA**		**NA**
99	**3/29/2006**	**3/29/2006**	**Complete**	**ST**	**NU**	**45**			**San Luis Obispo**	**CA**	**PGE**	**Diablo Canyon Substation Circuit Breakers 542 and 642**	**6/8/2006**	**6/8/2006**	**NA**	**Complete**	**NA**		**NA**
100	4/5/2006	4/5/2006	Active - Serial	WT	W	120			Kern	CA	SCE	Vincent Substation through Sagebrush 230 kV line	12/31/2007	12/31/2012	NA	Complete	Complete		LGIA Executed
~~101~~	~~4/7/2006~~	~~4/7/2006~~	Withdrawn 10/17/06	~~CT~~	~~NG~~	~~100~~			~~Kern~~	~~CA~~	~~PGE~~	~~PG&E Kern Oil-Vedder 115 kV line~~	~~3/1/2008~~	~~3/1/2008~~	~~Complete~~	~~Tendered~~			
~~102~~	~~4/19/2006~~	~~4/19/2006~~	Withdrawn 1/17/08	~~WT~~	~~W~~	~~210~~			~~Monterey~~	~~CA~~	~~PGE~~	~~PG&E Coburn 230 kV Sub~~	~~11/30/2008~~	~~11/30/2008~~	~~Complete~~	~~Complete~~	~~Complete~~		~~In Progress~~
~~102A~~	~~4/21/2006~~	~~4/21/2006~~	Withdrawn 6/26/06	~~WT~~	~~W~~	~~100~~			~~Santa Barbara~~	~~CA~~	~~PGE~~	~~PG&E #2 Cabrillo-Divide 115 kV line~~	~~12/31/2009~~	~~12/31/2009~~	~~Tendered~~				
103	5/2/2006	5/2/2006	Active - Serial	ST	B	27			San Diego	CA	SDGE	Border Substation 69 kV	12/1/2008	2/15/2010	Complete	Complete	Complete		In Progress
~~104~~	~~4/14/2006~~	~~5/3/2006~~	Withdrawn 9/28/09	~~CT~~	~~NG~~	~~304~~			~~Los Angeles~~	~~CA~~	~~SCE~~	~~Laguna Bell 230 kV Substation~~	~~7/31/2009~~	~~7/31/2009~~	~~Waived~~	~~Re-Study Complete~~	~~Re-study Complete~~		~~In Progress~~
~~105~~	~~5/4/2006~~	~~5/4/2006~~	Withdrawn 6/29/06	~~WT~~	~~W~~	~~100~~			~~Humboldt~~	~~CA~~	~~PGE~~	~~Between Rio Del Junction and Bridgeville~~	~~10/30/2009~~	~~10/30/2009~~					
~~106~~	~~5/26/2006~~	~~5/26/2006~~	Withdrawn 10/13/08	~~ST~~	~~S~~	~~635~~			~~San Bernardino~~	~~CA~~	~~SCE~~	~~Mohave 500 kV Switchyard~~	~~12/31/2009~~	~~12/31/2010~~	~~Complete~~	~~Tendered~~			
106A	5/1/2006	6/6/2006	Active - Serial	WT	W	160			San Diego	CA	SDGE	Boulevard Substation 138kV	6/30/2008	6/30/2012	Complete	Complete	In Progress		
~~107~~	~~6/9/2006~~	~~6/9/2006~~	Withdrawn 11/17/06	~~WT~~	~~W~~	~~128~~			~~Solano~~	~~CA~~	~~PGE~~	~~Brighton-Contra Costa 115 kV~~	~~3/1/2011~~	~~3/1/2011~~	~~Complete~~				
108	6/9/2006	6/9/2006	Active - Serial	WT	W	128			Solano	CA	PGE	Lambie-Contra Costa 230 kV	3/1/2011	3/5/2012	Complete	Complete	Complete	Complete	Executed
~~108A~~	~~6/14/2006~~	~~6/14/2006~~	Withdrawn 11/16/06	~~Other~~	~~S~~	~~300~~			~~San Luis Obispo~~	~~CA~~	~~PGE~~	~~Morro Bay-Midway 230 kV circuit~~	~~3/1/2010~~	~~3/1/2010~~	~~Tendered~~				
~~109~~	~~6/14/2006~~	~~6/16/2006~~	Withdrawn 12/4/09	~~Other~~	~~S~~	~~550~~		~~EO~~	~~San Bernardino~~	~~CA~~	~~SCE~~	~~Pisgah Substation~~	~~3/1/2011~~	~~3/1/2011~~	~~Complete~~	~~Complete~~			
~~110~~	~~6/14/2006~~	~~6/16/2006~~	Withdrawn 12/4/09	~~Other~~	~~S~~	~~1400~~		~~EO~~	~~San Bernardino~~	~~CA~~	~~SCE~~	~~Pisgah Substation~~	~~3/1/2013~~	~~3/1/2013~~	~~Complete~~	~~Complete~~			
111	6/23/2006	6/26/2006	Active - A39	ST	B	16			Kern	CA	PGE	Tap of Chevron 70kv tran line	8/31/2009	12/15/2012	NA	Complete	Complete		GSFA Executed
~~112~~	~~6/28/2006~~	~~6/28/2006~~	Withdrawn 5/1/09	~~WT~~	~~W~~	~~300~~			~~San Diego~~	~~CA~~	~~SDGE~~	~~500 kV Imperial Valley-Miguel trans line~~	~~10/31/2008~~	~~10/31/2008~~	~~Complete~~	~~Complete~~	~~In Progress~~		
113	6/29/2006	6/30/2006	Active - Serial	WT	W	30			Solano	CA	PGE	Birds Landing	4/1/2009	4/1/2012	Complete	Complete	Waived		LGIA Executed
~~114~~	~~6/29/2006~~	~~7/12/2006~~	Withdrawn 11/26/08	~~WT~~	~~W~~	~~150~~			~~San Bernardino~~	~~CA~~	~~SCE~~	~~Victor 230 kV~~	~~7/1/2008~~	~~7/1/2008~~	~~Complete~~	~~In Progress~~			
~~115~~	~~6/29/2006~~	~~7/12/2006~~	Withdrawn 11/26/08	~~WT~~	~~W~~	~~150~~			~~San Bernardino~~	~~CA~~	~~SCE~~	~~Lugo-Pisgah 230kV line~~	~~7/1/2008~~	~~7/1/2008~~	~~Complete~~	~~In Progress~~			
~~116~~	~~6/29/2006~~	~~7/12/2006~~	Withdrawn 11/26/08	~~WT~~	~~W~~	~~50~~			~~San Bernardino~~	~~CA~~	~~SCE~~	~~Lugo-Pisgah 230kV line~~	~~7/1/2008~~	~~7/1/2008~~	~~Complete~~	~~In Progress~~			
~~117~~	~~7/7/2006~~	~~7/20/2006~~	Withdrawn 5/9/07	~~WT~~	~~W~~	~~70~~			~~Humboldt~~	~~CA~~	~~PGE~~	~~Bridgeville 115kV Substation~~	~~10/30/2009~~	~~10/30/2009~~	~~Complete~~	~~In Progress~~			
~~118~~	~~8/2/2006~~	~~8/4/2006~~	Withdrawn 11/28/07	~~CC~~	~~NG~~	~~550~~			~~Mohave~~	~~AZ~~	~~SCE~~	~~SCE Mojave Substation~~	~~1/8/2009~~	~~1/8/2009~~	~~Re-study Complete~~	~~Tendered~~			
119	8/8/2006	8/8/2006	Active - Serial	WT	W	500			Kern	CA	SCE	Windhub Substation 230kV	12/31/2010	12/31/2013	Complete	Complete	In Progress		
~~120~~	~~8/9/2006~~	~~8/9/2006~~	Withdrawn 11/26/08	~~Other~~	~~S~~	~~1200~~			~~San Bernardino~~	~~CA~~	~~SCE~~	~~Mojave 500 kV Switchyard~~	~~3/1/2011~~	~~3/1/2011~~	~~In Progress~~				
121	**8/16/2006**	**8/17/2006**	**Complete**	**CT**	**NG**	**49**			**San Diego**	**CA**	**SDGE**	**SDG&E Miramar GT Substation**	**3/31/2009**	**8/8/2009**	**Waived**	**Complete**	**Complete**		**Executed**
~~122~~	~~8/16/2006~~	~~8/17/2006~~	Withdrawn 1/16/07	~~CT~~	~~NG~~	~~99~~			~~Orange~~	~~CA~~	~~SDGE~~	~~SDG&E Margarita Substation~~	~~3/31/2009~~	~~6/30/2008~~	~~Waived~~	~~In Progress~~			
~~123~~	~~8/16/2006~~	~~8/17/2006~~	Withdrawn 1/16/07	~~CT~~	~~NG~~	~~99~~			~~San Diego~~	~~CA~~	~~SDGE~~	~~SDG&E Pala Substation~~	~~3/31/2009~~	~~6/30/2008~~	~~Waived~~	~~In Progress~~			
124	8/22/2006	8/22/2006	Active - Serial	Other	S	600			Imperial	CA	SDGE	Imperial Valley Substation	3/1/2011	3/1/2011	Waived	Complete	Complete		Executed
125	8/22/2006	8/22/2006	Active - Serial	ST	S	250			San Bernardino	CA	SCE	Coolwater-Kramer 230kv line	8/1/2010	8/1/2010	Complete	Complete	In Progress		
126	8/31/2006	8/31/2006	Active - Serial	WT	W	1500			Clark	NV	SCE	Eldorado Substation	12/31/2011	12/31/2011	Complete	Complete	In Progress		
~~127~~	~~8/22/2006~~	~~9/1/2006~~	Withdrawn 7/11/07	~~Other~~	~~HR~~	~~27.2~~			~~Contra Costa~~	~~CA~~	~~PG&E~~	~~115kV Oleum Switchyard~~	~~8/1/2008~~	~~8/1/2008~~	~~Waived~~	~~Complete~~	~~Tendered~~		
~~128~~	~~9/1/2006~~	~~9/1/2006~~	Withdrawn 8/6/09	~~CT~~	~~NG~~	~~565~~	~~600~~		~~Fresno~~	~~CA~~	~~PGE~~	~~McCall Substation~~	~~12/1/2010~~	~~12/1/2012~~	~~Complete~~	~~Re-Study Complete~~	~~Re-Study In Progress~~		
~~129~~	~~9/13/2006~~	~~9/13/2006~~	Withdrawn 10/24/06	~~WT~~	~~W~~	~~400~~			~~San Bernardino~~	~~CA~~	~~SCE~~	~~Pisgah 230kV Substation~~	~~3/1/2010~~	~~3/1/2010~~					
~~130~~	~~9/13/2006~~	~~9/13/2006~~	Withdrawn 4/1/08	~~Other~~	~~S~~	~~565~~			~~San Bernardino~~	~~CA~~	~~SCE~~	~~Mohave Generating Station~~	~~12/31/2010~~	~~12/31/2010~~	~~In Progress~~				
131	9/25/2006	9/25/2006	Active - Serial	ST	S	100			San Bernardino	CA	SCE	Loop new sub connecting to Eldorado-Mtn Pass 115kV line	6/30/2010	6/30/2010	Complete	Complete	Complete		In Progress
132	9/27/2006	9/27/2006	Active - Serial	WT	W	297			Kern	CA	SCE	Highwind Substation 230kV bus	12/31/2009	12/31/2010	Complete	Complete	Complete		In Progress
~~133~~	~~10/3/2006~~	~~10/3/2006~~	Withdrawn 12/21/06	~~WT~~	~~W~~	~~140~~			~~San Bernardino~~	~~CA~~	~~SCE~~	~~Pisgah-Lugo 230kV~~	~~3/1/2010~~	~~3/1/2010~~	~~Tendered~~				
~~134~~	~~10/9/2006~~	~~10/9/2006~~	Withdrawn 1/31/07	~~CT~~	~~NG~~	~~200~~			~~Kern~~	~~CA~~	~~SCE~~	~~Pastoria Substation~~	~~5/31/2010~~	~~5/31/2010~~					
135	10/10/2006	10/10/2006	Active - Serial	WT	W	60			San Bernardino	CA	SCE	Lugo-Pisgah 230kV line	9/30/2008	3/31/2011	Complete	Complete	In Progress		
136	10/16/2006	10/16/2006	Active - Serial	CT	NG	300			San Bernardino	CA	SCE	Etiwanda 230kV Substation	1/1/2010	1/1/2010	Waived	Complete	Complete		In Progress
137	10/11/2006	10/17/2006	Active - Serial	CC	NG	300			San Diego	CA	SDGE	Encina Substation 230kV bus	8/1/2008	3/1/2013	Waived	Complete	Complete		Executed
138	10/23/2006	10/23/2006	Active - Serial	WT	W	150			Riverside	CA	SCE	Devers-Vista 230kV #1	12/31/2008	3/1/2012	Waived	Complete	Complete		
139	10/24/2006	10/24/2006	Active - Serial	CC	NG	698			San Bernardino	CA	SCE	SCE Rancho Vista 500kV Sub	6/1/2010	6/1/2010	Waived	Complete	Complete		In Progress
~~140~~	~~10/31/2006~~	~~10/31/2006~~	Withdrawn 2/26/07	~~ST~~	~~G~~	~~75~~			~~Inyo~~	~~CA~~	~~SCE~~	~~Coso-Kramer 230 kV~~	~~8/18/2011~~	~~8/18/2011~~	~~Tendered~~				
~~141~~	~~11/3/2006~~	~~11/3/2006~~	Withdrawn 8/24/07	~~CT~~	~~NG~~	~~504~~			~~San Bernardino~~	~~CA~~	~~SCE~~	~~SCE Rancho Vista 500kV Sub~~	~~6/1/2010~~	~~6/1/2010~~	~~Waived~~	~~Complete~~	~~Tendered~~		
142	11/6/2006	11/6/2006	Active - Serial	ST	S	80			San Bernardino	CA	SCE	Kramer Substation	12/31/2009	12/31/2009	Complete	Complete	In Progress		
~~143~~	~~11/6/2006~~	~~11/6/2006~~	Withdrawn 11/26/08	~~ST~~	~~S~~	~~80~~			~~San Bernardino~~	~~CA~~	~~SCE~~	~~Kramer Substation~~	~~12/31/2009~~	~~12/31/2009~~	~~Complete~~	~~In Progress~~			
~~144~~	~~11/6/2006~~	~~11/6/2006~~	Withdrawn 12/7/09	~~ST~~	~~S~~	~~320~~		~~FC~~	~~San Bernardino~~	~~CA~~	~~SCE~~	~~Kramer Substation~~	~~12/31/2009~~	~~12/31/2009~~	~~Complete~~	~~Complete~~			
~~145~~	~~11/8/2006~~	~~11/8/2006~~	Withdrawn 10/23/08	~~CC~~	~~HR~~	~~591~~			~~Clark~~	~~NV~~	~~SCE~~	~~Eldorado 500 kV Substation~~	~~6/1/2010~~	~~6/1/2010~~	~~Complete~~	~~In Progress~~			

				Generating Facility		Maximum MWs		Deliverability Status	Location		Point of Interconnection				Study Availability				
Queue Position	Interconnection Request Receive Date	Queue Date	Application Status	Type	Fuel	Summer	Winter	Full Capacity or Energy Only (FC/EO)	County	State	Utility	Station or Transmission Line	Proposed On-line Date (as filed with IR)	Current On-line Date	Feasibility Study (IFS)	System Impact Study *or* Phase I Cluster Study	Facilities Study (FAS) *or* Phase II Cluster Study	Optional Study (OS)	Interconnection Agreement Status
146	11/16/2006	11/16/2006	Active - Serial	PV	S	150			Riverside	CA	SCE	Eagle Mountain Substation	12/1/2008	12/31/2009	Complete	Complete	In Progress		In Progress
147	11/16/2006	11/16/2006	Active - Serial	PV	S	400			Riverside	CA	SCE	Red Bluff Substation 230kV switchyard	2/1/2010	2/1/2010	Complete	Complete	In Progress		In Progress
148	11/16/2006	11/16/2006	Withdrawn 2/1/07	ST	G	90			Churchill	NV	SCE	Oxbow 230kV Substation	10/1/2011	10/1/2011					
149	11/16/2006	11/16/2006	Withdrawn 10/20/08	WT	W	362			Kern	CA	SCE	SCE Highwind Sub #2 (proposed) 230 kV	12/31/2009	12/31/2010	In Progress				
150	11/16/2006	11/16/2006	Active - Serial	CT	NG	43			San Diego	CA	SDGE	Border Substation	5/31/2008	5/15/2011	Complete	Re-Study Complete	In Progress		
151	11/17/2006	11/17/2006	Withdrawn 12/11/06	CT	NG	510			San Bernardino	CA	SCE	Chino Substation 230kV Line	5/1/2011	5/1/2011					
152	11/22/2006	11/22/2006	Withdrawn 10/29/08	WT	W	105			Santa Barbara	CA	PGE	Mesa-Divide #1 115kV line	12/31/2009	12/31/2009	Complete	Complete	Tendered		
153	11/22/2006	11/22/2006	Active - Serial	WT	W	100			Kern	CA	SCE	Whirlwind Substation 230kV	5/30/2008	12/31/2012	Waived	Complete	In Progress		
154	**11/28/2006**	**11/30/2006**	**Transition Cluster**	**ST**	**S**	**250**		**FC**	**Kern**	**CA**	**SCE**	**Kramer 230 kV Substion**	**12/31/2009**	**6/1/2015**	Complete	**Complete**	**In Progress**		
155	12/1/2006	12/1/2006	Withdrawn 1/2/09	CT	NG	300			Alameda	CA	PGE	Oakland C 115kV substation	5/31/2010	5/31/2012	Complete	Re-Study Complete	Tendered		
156	12/5/2006	12/5/2006	Active - Serial	WT	W	201			San Bernardino	CA	SCE	Lugo-Pisgah 230kV line	3/1/2009	3/1/2012	Waived	Complete	In Progress		
157	12/15/2006	12/15/2006	Withdrawn 11/26/08	WT	W	100			Kern	CA	SCE	66kV Rosamond-Antelope line	5/30/2008	12/31/2014	In Progress				
158	12/15/2006	12/15/2006	Withdrawn 11/26/08	WT	W	100			Kern	CA	SCE	66kV Rosamond-Delsur line	5/30/2008	12/31/2013	In Progress				
159	12/15/2006	12/15/2006	Withdrawn 12/14/09	WT	W	100		FC	Kern	CA	SCE	Antelope-Magunden #1 220kV line	5/30/2008	12/31/2013	In Progress	Complete			
159A	12/6/2006	12/22/2006	Active - Serial	WT	W	400			La Rumorosa, Baja CA	Mexico	SDGE	500kV Imperial Valley-Miguel transmission line	6/1/2009	5/31/2013	Complete	Complete	In Progress		
160	12/2/2006	12/29/2006	Withdrawn 9/17/07	ST	S	220			San Bernardino	CA	SCE	Kramer	1/1/2009	1/1/2009	In Progress				
161	12/27/2006	1/4/2007	Active - Serial	CT	NG	202			Los Angeles	CA	SCE	Harborgen Substation	5/1/2009	3/1/2012	Waived	Re-Study Complete	In Progress		
162	1/5/2007	1/5/2007	Active - Serial	ST	S	114			San Bernardino	CA	SCE	Loop new sub connecting Eldorado-Mtn Pass 115kV line	6/30/2010	6/30/2010	Waived	Complete	In Progress		
163	**1/9/2007**	**1/9/2007**	**Transition Cluster**	**PV**	**S**	**300**		**FC**	**San Bernardino**	**CA**	**SCE**	**Mountain Pass Substation 115kV**	**12/31/2010**	**12/31/2015**	In Progress	**Complete**	**In Progress**		
164	1/12/2007	1/12/2007	Withdrawn 11/19/08	WT	W	1000			La Rumorosa, Baja C	Mexico	SDGE	Imperial Valley 230kV switchyard	10/1/2010	10/1/2010	Complete	In Progress			
165	1/16/2007	1/16/2007	Active - Serial	ST	S	400			San Bernardino	CA	SCE	Pisgah 230kV Substation bus	6/30/2011	6/30/2011	Waived	Complete	In Progress		
166	1/23/2007	1/23/2007	Active - Serial	PV	S	210			San Luis Obispo	CA	PGE	Midway-Morrow Bay 230kV line	12/31/2010	12/31/2013	Complete	Complete	Complete		Executed
167	1/25/2007	1/25/2007	Withdrawn 5/16/07	CC	NG	700			Riverside	CA	SCE	500kV line to Midpoint Switching Station	6/1/2012	6/1/2012	Tendered				
168	2/2/2007	2/2/2007	Withdrawn 12/14/09	WT	W	1000		EO	a Rumorosa, Baja C	Mexico	SDGE	Imperial Valley 500kV bus	12/31/2011	12/31/2011	Complete	Complete			
169	2/2/2007	2/2/2007	Withdrawn 11/26/08	ST	S	211.6			Imperial	CA	SDGE	Imperial Valley 230kV bus	12/31/2011	12/31/2011	Complete	In Progress			
170	2/2/2007	2/2/2007	Withdrawn 12/7/09	PV	S	150		FC	Kern	CA	SCE	Substation 5 (aka Whirlwind)	12/31/2011	7/31/2013	In Progress	Complete			
171	2/9/2007	2/9/2007	Withdrawn 12/7/09	WT	W	500		FC	Solano	CA	PGE	Vaca-Tesla 500kV line	12/31/2011	3/31/2011	In Progress	Complete			
172	2/8/2007	2/15/2007	Active - Serial	CC	NG	508			San Joaquin	CA	PGE	Tesla-Bellota 230kV lines	5/15/2011	5/1/2014	Complete	Complete	Complete		In Progress
173	2/16/2007	2/16/2007	Withdrawn 1/27/09	CT	NG	49.9			San Diego	CA	SDGE	Pala 69kV Substation	5/1/2008	5/1/2011	Waived	Complete	Complete		In Progress
174	2/16/2007	2/16/2007	Withdrawn 6/12/07	WT	W	30			Riverside	CA	SCE	Devers-Venwind 115kV line	12/1/2008	12/1/2008	Tendered				
175	**2/21/2007**	**2/21/2007**	**Transition Cluster**	**WT**	**W**	**650**		**FC**	**Kern**	**CA**	**SCE**	**SCE Proposed Whirlwind 230kV Substation**	**9/30/2008**	**12/31/2014**	In Progress	**Complete**	**In Progress**		
176	2/23/2007	2/23/2007	Withdrawn 8/14/09	CT	NG	49.9			San Diego	CA	SDGE	Margarita 138kV Substation	5/1/2008	6/15/2010	Waived	Complete	Complete		Executed
177	2/27/2007	2/28/2007	Withdrawn 1/21/09	WT	W	100			Contra Costa	CA	PGE	Bahia – Moraga 230 kV Line	12/31/2011	12/31/2011	Complete	Complete	In Progress		
178	2/27/2007	2/28/2007	Withdrawn 11/19/07	WT	W	100			Merced	CA	PGE	Los Banos 230kV bus near Pacheco Pass	12/31/2011	12/31/2011	Complete	In Progress			
178A	2/27/2007	2/28/2007	Withdrawn 11/24/08	WT	W	500			Mexicali/Ensenada/Tec	Mexico	SDGE	Miguel 230kV Bus	6/15/2010	7/1/2011	Complete	In Progress			
178B	2/27/2007	2/28/2007	Withdrawn 12/14/09	WT	W	500		FC	xicali/Ensenada/Tec	Mexico	SDGE	Imperial Valley 230kV Substation	6/15/2010	6/15/2010	Complete	Complete			
179	2/15/2007	3/1/2007	Withdrawn 11/26/08	ST	S	300			San Bernardino	CA	SCE	Julian Hinds 230kV Substation	12/31/2010	12/31/2010	In Progress				
180	3/2/2007	3/2/2007	Withdrawn 5/1/08	CC	NG	564			San Bernardino	CA	SCE	New 230kV Switchyard on the Mira Loma-Vista #2 line	5/1/2011	5/1/2011	Complete	Tendered			
181	3/2/2007	3/2/2007	Withdrawn 5/1/08	CT	NG	400			San Bernardino	CA	SCE	New 230kV switchyard on the Chino-Serrano line	3/1/2010	3/1/2010	Complete	Tendered			
182	3/5/2007	3/5/2007	Withdrawn 12/2/09	PV	S	500		FC	Kern	CA	SCE	Windhub Substation	12/31/2010	7/1/2015	In Progress	Complete			
183	**3/5/2007**	**3/5/2007**	**Transition Cluster**	**WT**	**W**	**300**		**EO**	**a Rumorosa, Baja C**	**Mexico**	**SDGE**	**500kV Imperial Valley-Miguel transmission line**	**11/1/2009**	**7/31/2010**	Complete	**Complete**	**In Progress**		
184	3/5/2007	3/5/2007	Active - Serial	ST	G	35			Sonoma	CA	PGE	Geysers #3 – Cloverdale 115 kV Line	1/1/2010	4/1/2010	Complete	Complete	Complete		Executed
185	3/6/2007	3/6/2007	Active - Serial	ST	G	150			Mineral	NV	SCE	Bishop, CA Control Sub	8/1/2011	1/1/2011	Waived	In Progress			
186	3/7/2007	3/7/2007	Withdrawn 11/28/07	CT	NG	211			San Joaquin	CA	PGE	Stockton"A" Lockeford-Bellota 115kV #1&#2 lines & Tesla Tracy 115kV line	12/31/2009	12/31/2009	Complete				
187	3/14/2007	3/14/2007	Withdrawn 6/6/08	ST	G	50			Sonoma	CA	PGE	Geysers-Fulton 230kV transmission line	1/1/2011	1/1/2011	Waived	Complete	In Progress		
188	**3/23/2007**	**3/23/2007**	**Transition Cluster**	**WT**	**W**	**200**		**EO**	**Kern**	**CA**	**SCE**	**Windhub Substation 230kV**	**12/15/2013**	**12/1/2012**	In Progress	**Complete**	**In Progress**		
189	3/30/2007	3/30/2007	Active - Serial	CC	NG	280			San Diego	CA	SDGE	Encina 138kV Substation	5/1/2010	3/1/2013	Waived	Complete	Complete		Executed
190	3/30/2007	3/30/2007	Active - Serial	CT	NG	330			San Diego	CA	SDGE	Proposed Otay Mesa Energy Center 230kV Substation	3/1/2011	3/1/2011	Complete	Complete	Complete		In Progress
191	4/2/2007	4/2/2007	Withdrawn 10/1/07	CT	NG	315			San Diego	CA	SDGE	Penasquistos-Old Town 230kV transmission line	3/1/2010	3/1/2010	Complete	Tendered			
192	4/2/2007	4/2/2007	Withdrawn 10/1/07	CT	NG	315			San Diego	CA	SDGE	San Luis Rey-Mission 230kV transmission line	3/1/2010	3/1/2010	Complete	Tendered			
193	**3/19/2007**	**4/4/2007**	**Transition Cluster**	**ST**	**S**	**500**		**FC**	**Riverside**	**CA**	**SCE**	**Colorado River Substation**	**12/31/2010**	**7/1/2013**	In Progress	**Complete**	**In Progress**		
194	4/5/2007	4/5/2007	Active - Serial	ST	S	190			San Luis Obispo	CA	PGE	230kV lines near Carrizo Plain Substation	12/31/2010	9/1/2012	Complete	Complete	Complete		LGIA Executed
195	4/6/2007	4/6/2007	Withdrawn 9/21/07	CC	NG	725			Kern	CA	SCE	Springerville-Magunden 230kV line	1/1/2013	1/1/2013	Waived	In Progress			
196	4/13/2007	4/13/2007	Withdrawn 11/30/09	CT	NG	210		FC	Madera	CA	PGE	Borden Substation 230kV Bus	7/1/2011	6/15/2014	Complete	Complete			
197	4/16/2007	4/16/2007	Withdrawn 12/3/07	CT	NG	315			San Diego	CA	SDGE	Otay Mesa 230kV switchyard	12/1/2011	12/1/2011	Complete	Tendered			
198	4/18/2007	4/18/2007	Withdrawn 1/11/08	CT	NG	400			San Diego	CA	SDGE	OMEC interconnection substation	2/28/2010	2/28/2010	Complete	Tendered			
199	4/19/2007	4/19/2007	Withdrawn 3/3/08	CT	NG	50			San Joaquin	CA	PGE	60kV bus at Posdef QF facility	12/31/2009	12/31/2009	Waived	Complete	Tendered		
200	4/19/2007	4/19/2007	Withdrawn 5/14/07	CT	NG	200			Riverside	CA	SCE	Mira Loma Substation	5/31/2010	5/31/2010					
201	4/19/2007	4/19/2007	Active - Serial	CT	NG	99			San Diego	CA	SDGE	Pala Substation	5/31/2008	1/20/2010	Waived	Complete	Complete		Executed
202	4/19/2007	4/19/2007	Withdrawn 11/12/08	WT	W	198.65			San Bernardino	CA	SCE	Cool Water-Kramer #1 230kV line	11/15/2013	11/15/2013	In Progress				
203	4/19/2007	4/19/2007	Withdrawn 12/14/09	WT	W	198.65		FC	San Bernardino	CA	SCE	Cool Water-SEGS2-Tortilla 115kV line	12/15/2013	12/15/2013	In Progress	Complete			
204	4/19/2007	4/19/2007	Withdrawn 12/19/08	WT	W	149.4			San Bernardino	CA	SCE	Tortilla-Kramer 115 kV line	11/15/2013	11/15/2013	In Progress				
205	**4/20/2007**	**4/20/2007**	**Transition Cluster**	**ST**	**S**	**300**		**EO**	**Clark**	**NV**	**SCE**	**El Dorado 220kV Switchyard**	**12/31/2010**	**7/31/2010**	In Progress	**Complete**	**In Progress**		
206	4/23/2007	4/23/2007	Withdrawn 6/20/07	CC	S	200			Los Angeles	CA	SCE	El Segundo 230kV Switchyard	1/30/2013	1/30/2013					
207	4/26/2007	4/26/2007	Withdrawn 3/6/08	CC	NG	557			Los Angeles	CA	SCE	Long Beach 230kV Switchyard	2/28/2013	2/28/2013	Complete	Tendered			
208	4/20/2007	5/3/2007	Withdrawn 4/7/08	PV	S	2			Alameda	CA	PGE	Tracy-Herdlyn 69kV line	6/1/2008	9/1/2008	NA	Waived	In Progress		
209	5/2/2007	5/3/2007	Wihtdrawn 12/14/09	WT	W	400		FC	a Rumorosa, Baja C	Mexico	SDGE	New 230/500kV substation near the 500kV IV-ML line	12/31/2010	12/31/2010	Complete	Complete			
210	5/3/2007	5/3/2007	Withdrawn 12/2/09	PV	S	500		FC	Riverside	CA	SCE	Red Bluff Substation 230kV switchyard	12/31/2012	12/1/2016	In Progress	Complete			
211	4/23/2007	5/4/2007	Withdrawn 11/26/08	WT	W	201			Lassen	CA	PGE	Caribou 230kV Substation	10/31/2008	10/31/2008	Complete	Tendered			
212	5/9/2007	5/9/2007	Active - Serial	WT	W	50			Humboldt	CA	PGE	Rio Dell Substation 60kV	10/30/2010	10/30/2010	Complete	Complete	In Progress		
213	5/9/2007	5/9/2007	Withddrawn 11/26/08	WT	W	180			San Bernardino	CA	SCE	Coolwater 220kV bus	11/15/2010	11/15/2010	In Progress				
214	5/10/2007	5/10/2007	Withdrawn 11/12/08	WT	W	49.25			San Bernardino	CA	SCE	Coolwater-Kramer 115 kV line	12/15/2013	12/15/2013	In Progress				
215	**5/21/2007**	**5/21/2007**	**Transition Cluster**	**WT**	**W**	**420**		**EO**	**a Rumorosa, Baja C**	**Mexico**	**SDGE**	**Imperial Valley-Miguel 500kV**	**5/1/2011**	**12/31/2014**	Complete	**Complete**	**In Progress**		
216	5/22/2007	5/22/2007	Withdrawn 7/24/07	CT	NG	98.8			San Diego	CA	SDGE	Otay Mesa Energy Center	3/31/2010	3/31/2010					
217	5/22/2007	5/22/2007	Withdrawn 7/24/07	CT	NG	98.8			San Diego	CA	SDGE	San Luis Rey-Melrose 69kV	3/31/2010	3/31/2010					
218	5/22/2007	5/22/2007	Withdrawn 7/24/07	CT	NG	98.8			San Diego	CA	SDGE	Loop Talega-Escondido 230kV line	3/31/2010	3/31/2010					
219	5/7/2007	5/23/2007	Active - Serial	CT	NG	50			Riverside	CA	SCE	Midpoint Substation 500kV	6/1/2012	6/1/2012	Complete	Waived	Waived		In Progress
220	5/23/2007	5/23/2007	Withdrawn 12/2/09	PV	S	450		FC	San Bernardino	CA	SCE	BLM West-Kramer 230kV line	12/1/2011	10/1/2016	In Progress	Complete			
221	5/23/2007	5/23/2007	Withdrawn 12/2/09	PV	S	450		FC	San Bernardino	CA	SCE	Cool Water-Kramer #1 230kV line	12/1/2011	11/1/2015	In Progress	Complete			

				Generating Facility		Maximum MWs		Deliverability Status	Location		Point of Interconnection				Study Availability				
Queue Position	Interconnection Request Receive Date	Queue Date	Application Status	Type	Fuel	Summer	Winter	Full Capacity or Energy Only (FC/EO)	County	State	Utility	Station or Transmission Line	Proposed On-line Date (as filed with IR)	Current On-line Date	Feasibility Study (IFS)	System Impact Study or Phase I Cluster Study	Facilities Study (FAS) or Phase II Cluster Study	Optional Study (OS)	Interconnection Agreement Status
222	5/23/2007	5/23/2007	Transition Cluster	WT	W	78		FC	Solano	CA	PGE	Birds Landing Substation 230kV	12/31/2010	12/31/2011	Complete	Complete	In Progress		
223	5/29/2007	5/29/2007	Withdrawn 5/14/08	WT	W	170			San Bernardino	CA	SCE	Cool Water-Kramer #1 230kV line	12/31/2010	12/31/2010	In Progress				
224	5/23/2007	5/30/2007	Withdrawn 7/23/07	RE	NG	99			San Diego	CA	SDGE	69kV line next to Calpeak Border site	5/1/2010	5/1/2010					
225	5/23/2007	6/4/2007	Withdrawn 12/10/09	CC	NG	640		FC	Riverside	CA	SCE	500kV line to the new Midpoint switching station	6/1/2012	5/31/2015	In Progress	Complete			
226	5/16/2007	6/5/2007	Wtihdrawn 4/3/08	CC	NG	620			San Diego	CA	SDGE	New double circuit 230kV line into Escondido Substation	3/30/2012	3/30/2012	Complete	Tendered			
227	6/14/2007	6/14/2007	Withdrawn 3/10/08	WT	W	175			Marin	CA	PGE	Fulton-Ignacio 230kV #2 line	12/31/2010	12/31/2010	Complete	Tendered			
228	6/20/2007	6/20/2007	Withdrawn 10/22/07	CT	NG	630			Alameda	CA	PGE	Newark Substation 230kV bus	6/1/2011	6/1/2011	Tendered				
229	6/21/2007	6/21/2007	Withdrawn 12/2/09	PV	S	1000		FC	San Bernardino	CA	SCE	Devers Substation	12/31/2013	12/31/2016	In Progress	Complete			
230	6/21/2007	6/21/2007	Withdrawn 12/2/09	PV	S	1000		FC	San Bernardino	CA	SCE	Devers Substation	12/31/2013	12/31/2013	In Progress	Complete			
231	6/13/2007	6/25/2007	Withdrawn 11/26/08	WT	W	50			Riverside	CA	SCE	Venwind portion of Devers-Garnett-Venwind line	12/1/2009	12/1/2009	In Progress				
232	6/26/2007	6/26/2007	Withdrawn 8/6/07	RE	NG	99			San Diego	CA	SDGE	Talega-Escondido 230kV line	5/15/2010	5/15/2010					
233	6/27/2007	6/27/2007	Active - Serial	ST	S	200			San Bernardino	CA	SCE	Ivanpah Substation 230kV	6/30/2012	6/30/2012	Waived	Complete	In Progress		
234	6/27/2007	6/27/2007	Withdrawn 12/14/09	ST	S	400		FC	Clark	NV	SCE	Proposed Eldorado-Ivanpah 230kV line	6/30/2013	6/30/2013	In Progress	Complete			
235	6/29/2007	6/29/2007	Withdrawn 11/26/08	CT	NG	630			Contra Costa	CA	PGE	Tesla-Tracy #1 230kV line	6/1/2011	6/1/2011	In Progress				
236	6/29/2007	6/29/2007	Withdrawn 11/26/08	CT	NG	630			San Joaquin	CA	PGE	Tesla Substation 230kV bus	6/1/2011	6/1/2011	In Progress				
237	6/12/2007	7/2/2007	Withdrawn 11/24/08	CC	NG	634			Clark	NV	SCE	Eldorado 220kV switchyard	5/1/2011	5/1/2011	Waived	In Progress			
238	7/11/2007	7/11/2007	Withdrawn 11/26/08	PV	S	45			San Luis Obispo	CA	PGE	Temblor-San Luis Obispo 115kV line	12/1/2008	12/1/2008	In Progress				
239	7/11/2007	7/11/2007	Transition Cluster	PV	S	250		FC	San Luis Obispo	CA	PGE	Midway-Morro Bay 230kV line	12/1/2010	12/31/2011	In Progress	Complete	In Progress		
240	7/12/2007	7/12/2007	Active - Serial	ST	S	400			San Bernardino	CA	SCE	Pisgah Sub 230kV	6/30/2014	6/30/2014	Waived	Complete	In Progress		
241	7/12/2007	7/12/2007	Active - Serial	ST	S	400			San Bernardino	CA	SCE	Pisgah Sub 230kV	6/30/2015	6/30/2015	Waived	Complete	In Progress		
242	7/13/2007	7/13/2007	Transition Cluster	PV	S	150		FC	San Luis Obispo	CA	PGE	Morro Bay-Midway 230kV line	9/1/2012	12/31/2013	In Progress	Complete	In Progress		
243	7/16/2007	7/16/2007	Withdrawn 11/26/08	WT	W	429			San Bernardino	CA	SCE	Pisgah 230kV Substation	12/30/2010	12/30/2010	In Progress				
244	7/16/2007	7/16/2007	Withdrawn 11/26/08	WT	W	120			Kern and Inyo	CA	SCE	Control-Haiwee-Inyokern 115kV line	12/15/2010	12/15/2010	In Progress				
245	7/16/2007	7/16/2007	Withdrawn 11/26/08	WT	W	228			Riverside	CA	SCE	Devers-Mirage-Julian Hinds 230kV line	12/15/2010	12/15/2010	In Progress				
246	7/17/2007	7/17/2007	Withdrawn 11/26/08	WT	W	120			Kern	CA	SCE	Kramer-Inyokern-Randsburg #3 115kV line	12/15/2010	12/15/2010	In Progress				
247	7/30/2007	7/30/2007	Withdrawn 9/21/09	CC	NG	67		FC	Madera	CA	PGE	Borden Substation 230kV Bus	7/1/2011	4/15/2012	Waived	Complete			
248	7/30/2007	7/30/2007	Active - Serial	CC	NG	67			San Joaquin	CA	PGE	Tesla-Bellota 230kV line	5/15/2011	5/1/2014	Waived	Complete	Complete		In Progress
249	7/30/2007	7/30/2007	Withdrawn 11/26/08	WT	W	105			Monterey	CA	PGE	Moss Linding-Salinas-Soledad 115kV #1 and #2 lines	2/1/2010	11/1/2010	Complete	In Progress			
250	7/30/2007	7/30/2007	Transition Cluster	WT	W	66.2		FC	Lake and Colusa	CA	PGE	Redbud-Cortina 115kV line	8/1/2009	7/1/2013	Complete	Complete	In Progress		
251	8/1/2007	8/1/2007	Withdrawn 11/26/08	PV	S	200			Riverside	CA	SCE	Eagle Mountain-Blythe 161kV line	12/15/2009	12/15/2009	In Progress				
252	7/10/2007	8/6/2007	Active - Serial	ST	NG	25.96			Los Angeles	CA	SCE	Redondo Beach Generating Station 220kV switchyard	5/23/2007	5/23/2007	Waived	Complete	Complete		Complete
253	8/13/2007	8/13/2007	Withdrawn 11/26/08	WT	W	40			Santa Barbara	CA	PGE	Cabrillo Substation 115kV	12/31/2011	12/31/2011	Re-Study In Progress				
254	8/21/2007	8/21/2007	Transition Cluster	CC	NG	600		FC	Kings	CA	PGE	Gates Substation 230kV bus	6/1/2012	6/1/2012	Complete	Complete	In Progress		
255	8/23/2007	8/23/2007	Transition Cluster	ST	S	250		FC	Kern	CA	SCE	Inyokern Substation	12/28/2013	7/1/2013	In Progress	Complete	In Progress		
256	8/23/2007	8/23/2007	Withdrawn 9/18/07	PV	S	30			Fresno	CA	PGE	Mendota Biomass Substation	4/15/2009	4/15/2009					
257	9/10/2007	9/10/2007	Withdrawn 9/21/09	CC	NG	575		FC	Solano	CA	PGE	New Fairfield Substation 230kV bus	6/1/2011	6/1/2011	Re- Study In Progress	Complete			
258	9/12/2007	9/12/2007	Transition Cluster	CC	NG	651		FC	Contra Costa	CA	PGE	Contra Costa Substation 230kV bus	2/1/2012	12/1/2013	In Progress	Complete	In Progress		
259	9/12/2007	9/12/2007	Withdrawn 11/20/09	CC	NG	345		FC	Sutter	CA	PGE	Rio Oso Substation 115kV bus	2/1/2012	2/1/2012	In Progress	Complete			
260	9/12/2007	9/12/2007	Withdrawn 11/26/08	CC	NG	260			San Joaquin	CA	PGE	Loop Gold Hill-Eight Mile Road 230kV line	2/1/2012	2/1/2012	In Progress				
261	9/28/2007	9/28/2007	Withdrawn 11/26/08	CC	NG	104			Los Angeles	CA	SCE	Hinson Substation 220kV	10/1/2010	10/1/2010	In Progress				
261A	10/9/2007	10/9/2007	Active - A39	PV	S	5			Fresno	CA	PGE	Mendota-San Joaquin-Helm 70kV line	4/15/2009	4/15/2009	N/A	Complete	Waived		SGIA Executed
262	10/10/2007	10/10/2007	Withdrawn 6/3/08	RE	NG	390.6			Solano	CA	PGE	Birds Landing Substation 230 kV Bus	4/15/2012	4/15/2012	In Progress				
263	10/10/2007	10/10/2007	Withdrawn 2/13/08	CC	NG	634			Clark	NV	SCE	Eldorado Switchyard 220kV & NCP Merchant Substation 230kV	5/1/2011	5/1/2011	Waived	Tendered			
264	10/15/2007	10/15/2007	Withdrawn 12/11/09	WT	W	300		FC	San Bernardino	CA	SCE	Lugo-Mohave 500kV line	12/30/2010	12/30/2010	In Progress	Complete			
265	10/16/2007	10/16/2007	Withdrawn 12/5/07	PV	S	25			Riverside	CA	SCE	Eagle Mountain-Blythe 161kV line	12/1/2009	12/1/2009					
266	10/19/2007	10/19/2007	Withdrawn 11/26/08	CC	NG	325			Sutter	CA	PGE	Rio Oso Substation 230kV bus	2/1/2012	2/1/2012	In Progress				
267	10/23/2007	10/23/2007	Active - Serial	CC	NG	280			San Joaquin	CA	PGE	Gold Hill-Eight Mile 230kV lines	4/16/2012	4/16/2012	Waived	Waived	Complete		LGIA Executed
268	10/24/2007	10/24/2007	Active - Serial	ST	NG	145			San Joaquin	CA	PGE	Tesla-Manteca 115kV line via Schulte Switchyard	4/1/2013	4/1/2013	Waived	Complete	Complete	Complete	In Progress
269	10/30/2007	10/31/2007	Withdrawn 12/1/09	RE	NG	371.3		FC	San Joaquin	CA	PGE	Tesla-Westley 230 KV lines	4/15/2012	5/1/2015	Complete	Complete			
270	11/1/2007	11/1/2007	Withdrawn 12/2/09	PV	S	700		FC	Riverside	CA	SCE	Proposed Midpoint Substation 230kV	12/1/2011	12/1/2015	In Progress	Complete			
271	11/1/2007	11/1/2007	Withdrawn 12/2/09	PV	S	400		FC	San Bernardino	CA	SCE	Lugo-Pisgah 230kV line	12/1/2012	9/1/2016	In Progress	Complete			
272	11/1/2007	11/1/2007	Transition Cluster	CC/PV	S/NG	150		FC	Kings	CA	PGE	Henrietta Substation 70kV bus	6/1/2012	5/1/2013	In Progress	Complete	In Progress		
273	11/1/2007	11/1/2007	Withdrawn 1/31/08	CC/PV	NG/S	99.9			Kings	CA	PGE	Hanford Switchyard 115kV bus	5/1/2010	5/1/2010	Waived	Tendered			
274	11/5/2007	11/5/2007	Active - Serial	CC	NG	54			San Diego	CA	SDGE	Palomar Substation 230kV	6/1/2008	8/25/2008	Waived	Complete	Complete		Executed
275	11/7/2007	11/7/2007	Withdrawn 12/4/09	CT	NG	630		FC	Solano	CA	PGE	Loop Vaca Dixon-Peabody & Vaca Dixon-Lambie 230 kV line	9/1/2012	5/1/2013	In Progress	Complete			
276	11/9/2007	11/9/2007	Withdrawn 11/20/08	CC	NG	650			Contra Costa	CA	PGE	Contra Costa Switchyard 230kV bus	1/15/2012	1/15/2012	In Progress				
277	11/15/2007	11/15/2007	Withdrawn 3/6/08	WT	W	75			San Bernardino	CA	SCE	Coolwater-Dunn Siding 115kV line	11/15/2010	11/15/2010	Tendered				
278	11/26/2007	11/26/2007	Withdrawn 12/14/09	ST	S	565		FC	San Bernardino	CA	SCE	Pisgah Substation 230kV	1/1/2011	1/1/2011		Complete			
279	11/30/2007	11/30/2007	Withdrawn 2/29/08	H	WTR	40			Humboldt	CA	PGE	Fairhaven Substation 60kV bus	6/1/2012	6/1/2012	Tendered				
280	11/30/2007	11/30/2007	Withdrawn 11/20/08	H	WTR	40			Mendocino	CA	PGE	Fort Bragg Substation 60kV bus	6/1/2012	6/1/2012	In Progress				
281	12/3/2007	12/3/2007	Withdrawn 5/28/08	CC	NG	500			San Joaquin	CA	PGE	Loop Tesla-Stagg and Tesla-Eight Mile 230kV lines	12/31/2010	12/31/2010	In Progress				
282	12/11/2007	12/12/2007	Transition Cluster	ST	B	8		FC	Madera	CA	PGE	Tap Dairyland-Mendota 115 kV line	5/31/2008	12/31/2010	Waived	Complete	In Progress		
283	12/12/2007	12/12/2007	Withdrawn 12/11/09	ST	S/B	106.8		EO	Fresno	CA	PGE	Gates Substation 230kV bus	3/1/2010	9/30/2012	In Progress	Complete			
284	12/13/2007	12/13/2007	Withdrawn 11/26/08	RE	NG	115			Mendocino	CA	PGE	Ukiah Substation 115kV bus	4/15/2012	4/15/2012	In Progress				
285	12/13/2007	12/13/2007	Withdrawn 11/26/08	WT	W	150			San Bernardino	CA	SCE	Pisgah Substation 230kV	12/31/2011	12/31/2011	In Progress				
286	12/20/2007	12/20/2007	Withdrawn 5/7/08	ST	S	375			Imperial	CA	SDGE	Southwest Power Link 500kV line	7/1/2011	7/1/2012	Tendered				
287	12/21/2007	12/21/2007	Withdrawn 12/14/09	ST	S	231		FC	Kern	CA	SCE	Antelope-Magunden 230kV	4/1/2011	4/1/2011	In Progress	Complete			
288	12/20/2007	12/21/2007	Withdrawn 5/14/08	ST	S	375			San Luis Obispo	CA	PGE	Morro Bay-Midway #2 230kV line	7/1/2011	7/1/2012	Tendered				
289	12/20/2007	12/21/2007	Withdrawn 5/29/08	ST	S	375			San Bernardino	CA	SCE	El Dorado-Ivanpah 115kV line	7/1/2011	7/1/2011	Tendered				
290	12/27/2007	12/27/2007	Withdrawn 12/3/09	ST	S	750		FC	San Bernardino	CA	SCE	Pisgah Substation 230kV	6/1/2015	12/31/2012	In Progress	Complete			
291	12/27/2007	12/27/2007	Withdrawn 11/20/08	ST	S	250			San Bernardino	CA	SCE	Ivanpah Substation 230kV	6/1/2015	6/1/2015	In Progress				
292	12/27/2007	12/27/2007	Withdrawn 2/6/08	ST	S	250			Kern	CA	SCE	SCE portion of Kramer-BLM West 230 kV line	6/1/2014	6/1/2014					
293	1/3/2008	1/3/2008	Withdrawn 11/25/08	RE	B	5.2			Fresno	CA	PGE	Helm-Kerman 70kV line	6/1/2009	6/1/2009	In Progress				
294	1/15/2008	1/16/2008	Transition Cluster	ST	S	1000		FC	Riverside	CA	SCE	Midpoint Substation 500kV	6/1/2012	7/1/2013	In Progress	Complete	In Progress		
295	1/17/2008	1/17/2008	Withdrawn 12/7/09	ST	S	300		FC	San Bernardino	CA	SCE	Pisgah Substation 220kV	12/31/2011	12/31/2011	In Progress	Complete			
296	1/18/2008	1/18/2008	Withdrawn 5/23/08	ST	S	33			Los Angeles	CA	SCE	Antelope-Piute 66kV line	12/1/2009	12/1/2009	Waived	Tendered			
297	1/18/2008	1/18/2008	Transition Cluster	ST	S	66		FC	Los Angeles	CA	SCE	Neenach-Bailey 66kV line	12/1/2009	3/31/2012	Waived	Complete	In Progress		
298	1/23/2008	1/23/2008	Withdrawn 11/19/08	ST	S	140			Clark	NV	SCE	El Dorado 220kV switchyard	11/1/2011	11/1/2011	In Progress				
299	1/29/2008	1/29/2008	Transition Cluster	CC	NG	27		FC	Kings	CA	PGE	Hanford Switchyard 115kV bus	5/1/2010	5/1/2013	Waived	Complete	In Progress		

				Generating Facility		Maximum MWs		Deliverability Status	Location		Point of Interconnection				Study Availability				
Queue Position	Interconnection Request Receive Date	Queue Date	Application Status	Type	Fuel	Summer	Winter	Full Capacity or Energy Only (FC/EO)	County	State	Utility	Station or Transmission Line	Proposed On-line Date (as filed with IR)	Current On-line Date	Feasibility Study (IFS)	System Impact Study *or* Phase I Cluster Study	Facilities Study (FAS) *or* Phase II Cluster Study	Optional Study (OS)	Interconnection Agreement Status
300	1/29/2008	2/4/2008	Transition Cluster	CC	NG	400		FC	Kern	CA	PGE	Midway Substation 230kV bus	9/1/2014	9/1/2015	In Progress	Complete	In Progress		
301	2/8/2008	2/8/2008	Withdrawn 10/27/08	PV	S	500			San Bernardino	CA	SCE	Lugo-Pisgah 220kV line	1/1/2016	1/1/2016	In Progress				
302	2/19/2008	2/19/2008	Withdrawn 4/7/08	PV	S	200			San Bernardino	CA	SCE	Lugo-Pisgah 220kV line	2/1/2010	2/1/2010					
303	2/27/2008	2/27/2008	Withdrawn 10/27/08	WT	W	500			Baja California	Mexico	SDGE	Imperial Valley -Miguel 500kV line	12/31/2011	12/31/2011	In Progress				
304	2/28/2008	2/28/2008	Transition Cluster	PV	S	50		FC	Tulare	CA	PGE	Smyrna-Alpaugh 115kV line	5/3/2010	12/31/2012	In Progress	Complete	In Progress		
305	3/10/2008	3/10/2008	Withdrawn 11/23/09	CC	NG	611		FC	Contra Costa	CA	PGE	Contra Costa Substation 230kV switchyard	7/30/2012	7/30/2012					
306	3/11/2008	3/11/2008	Withdrawn 11/20/08	CT	NG	200			San Joaquin	CA	PGE	Tesla-Belota 230kV and Tesla-Webber 230kV lines	5/1/2012	5/1/2012					
307	3/11/2008	3/11/2008	Withdrawn 4/24/08	PV	S	100			Los Angeles	CA	SCE	Lancaster-Redman 66kV line	5/1/2009	5/1/2009					
308	3/11/2008	3/11/2008	Withdrawn 4/24/08	PV	S	100			Los Angeles	CA	SCE	Helijet-Little Rock-Palmdale-Rockair 66kV line	5/1/2009	5/1/2009					
309	3/11/2008	3/11/2008	Transition Cluster	PV	S	100		FC	Los Angeles	CA	SCE	Antelope Substation 66kV	5/1/2009	7/1/2013		Complete	In Progress		
310	3/11/2008	3/11/2008	Withdrawn 4/24/08	PV	S	100			Los Angeles	CA	SCE	Del- Sur-Lancaster-Rite Aid 66kV line	5/1/2009	5/1/2009					
311	3/11/2008	3/11/2008	Withdrawn 4/24/08	PV	S	100			Los Angeles	CA	SCE	Lancaster-Little Rock-Piute 66kV line	5/1/2009	5/1/2009					
312	3/11/2008	3/11/2008	Withdrawn 5/6/08	PV	S	100			Los Angeles	CA	SCE	Oasis-Tortoise 66kV line	5/1/2009	5/1/2009					
313	3/11/2008	3/11/2008	Withdrawn 4/24/08	PV	S	100			Los Angeles	CA	SCE	Piute-Redman 66kV line	5/1/2009	5/1/2009					
314	3/11/2008	3/11/2008	Withdrawn 4/24/08	PV	S	100			Los Angeles	CA	SCE	Lancaster-Little Rock-Piute 66kV line	5/1/2009	5/1/2009					
315	3/11/2008	3/11/2008	Withdrawn 4/24/08	PV	S	100			Los Angeles	CA	SCE	Helijet-Little Rock-Palmdale-Rockair 66kV line	5/1/2009	5/1/2009					
316	3/11/2008	3/11/2008	Withdrawn 4/24/08	PV	S	100			Los Angeles	CA	SCE	Antelope-Rosamond 66kV line	5/1/2009	5/1/2009					
317	3/11/2008	3/11/2008	Transition Cluster	PV	S	100		FC	Los Angeles	CA	SCE	Antelope Substation 66kV	5/1/2009	6/1/2013		Complete	In Progress		
318	3/11/2008	3/11/2008	Withdrawn 4/24/08	PV	S	100			Los Angeles	CA	SCE	Goldtown-Lancaster 66kV line	5/1/2009	5/1/2009					
319	3/11/2008	3/11/2008	Withdrawn 4/24/08	PV	S	100			Los Angeles	CA	SCE	Corum-Goldtown 66kV line	5/1/2009	5/1/2009					
320	3/12/2008	3/12/2008	Transition Cluster	CT	NG	100	214	FC	Contra Costa	CA	PGE	Contra Costa Substation 230kV switchyard	4/29/2011	5/1/2013		Complete	In Progress		
321	3/18/2008	3/18/2008	Withdrawn 12/11/09	WT	W	100		FC	Plumas	CA	PGE	Caribou Substation 230kV switchyard	12/15/2013	12/1/2013		Complete			
322	3/17/2008	3/18/2008	Withdrawn 11/23/09	CC	NG	611	554	FC	Contra Costa	CA	PGE	Pittsburg 230kV switchyard	9/30/2012	9/30/2012		Complete			
323	3/27/2008	3/27/2008	Withdrawn 4/24/08	PV	S	100			Kern	CA	SCE	Corum-Rosemond 66kV line	5/1/2009	5/1/2009					
324	3/27/2008	3/27/2008	Withdrawn 4/24/08	PV	S	250			San Bernardino	CA	SCE	Eldorado-Baker-Cook Water-Dunn Siding-Mountain Pass 115kV line	5/1/2009	5/1/2009					
325	3/27/2008	3/27/2008	Withdrawn 4/24/08	PV	S	100			Kern	CA	SCE	Kramer-Cool Water 115kV line	5/1/2009	5/1/2009					
326	3/27/2008	3/27/2008	Withdrawn 4/24/08	PV	S	100			Kern	CA	SCE	Kramer-Tortilla 115kV line	5/1/2009	5/1/2009					
327	3/27/2008	3/27/2008	Withdrawn 11/21/08	PV	S	100			Kern	CA	SCE	Kramer-Inyokern-Randsberg No. 1 115kV line	5/1/2009	5/1/2009					
328	3/27/2008	3/27/2008	Withdrawn 4/24/08	PV	S	100			Kern	CA	SCE	Kramer-Inyokern-Randsberg No. 3 115kV line	5/1/2009	5/1/2009					
329	3/31/2008	3/31/2008	Withdrawn 11/26/08	ST	S	264			Kern	CA	SCE	Whirlwind Substation 230kV	8/1/2012	8/1/2012					
330	3/31/2008	3/31/2008	Withdrawn 11/26/08	ST	S	33			Los Angeles	CA	SCE	Antelope-Calcement 66kV line	12/1/2009	12/1/2009					
331	3/31/2008	3/31/2008	Withdrawn 11/26/08	ST	S	231			Kern	CA	SCE	Windhub Substation	5/1/2010	5/1/2010					
332	3/31/2008	3/31/2008	Withdrawn 11/26/08	ST	S	264			Kern	CA	SCE	Windhub Substation	9/1/2011	9/1/2011					
333	3/31/2008	3/31/2008	Withdrawn 11/26/08	ST	S	33			San Bernardino	CA	SCE	Cool Water-Kramer 115kV line	7/1/2009	7/1/2009					
334	4/4/2008	4/4/2008	Transition Cluster	CT	NG	195.9		FC	Alameda	CA	PGE	Kelso Substation 230kV bus	6/1/2012	7/1/2012	In Progress	Complete	In Progress		
335	4/4/2008	4/4/2008	Withdrawn 5/5/08	RE	NG	99			Alameda	CA	PGE	Kelso Substation 230kV bus	6/1/2012	6/1/2012					
336	4/7/2008	4/7/2008	Withdrawn 11/21/08	PV	S	75			San Diego	CA	SDGE	Borrego Substation 69kV	12/31/2010	12/31/2010					
337	4/2/2008	4/18/2008	Transition Cluster	ST	S	26		FC	San Diego	CA	SDGE	Borrego Substation 69kV	4/1/2011	4/1/2012		Complete	In Progress		
338	4/17/2008	4/17/2008	Withdrawn 11/26/08	CC	NG	10			Fresno	CA	PGE	Kerman-Helms 70kV line	6/1/2010	6/1/2010					
339	4/18/2008	4/18/2008	Withdrawn 11/26/08	CT	NG	50			San Francisco	CA	PGE	Mission Substation	6/1/2011	6/1/2011					
340	4/2/2008	4/22/2008	Active - SGIP	PV	S	20			Tulare	CA	PGE	Smyrna-Alpaugh 115kV line	5/1/2010	4/1/2011	Waived	Complete	In Progress		
341	4/23/2008	4/23/2008	Withdrawn 11/26/08	CT	NG	525			Merced	CA	PGE	Wilson Substation 230kV bus	3/1/2012	3/1/2012					
342	4/25/2008	4/25/2008	Transition Cluster	PV	S	50		FC	Los Angeles	CA	SCE	Del Sur Substation 66kV	5/1/2011	7/1/2013		Complete	In Progress		
343	4/25/2008	4/25/2008	Withdrawn 11/21/08	PV	S	40			Los Angeles	CA	SCE	Piute-Redman 66kV line	5/1/2011	5/1/2011					
344	4/25/2008	4/25/2008	Withdrawn 12/7/09	PV	S	40		FC	Los Angeles	CA	SCE	Lancaster-Little Rock-Piute 66kV line	5/1/2011	5/1/2011		Complete			
345	4/25/2008	4/25/2008	Withdrawn 11/21/08	PV	S	40			Los Angeles	CA	SCE	Lancaster-Little Rock-Piute 66kV line	5/1/2011	5/1/2011					
346	4/25/2008	4/25/2008	Withdrawn 11/21/08	PV	S	30			Los Angeles	CA	SCE	Lancaster-Redman 66kV line	5/1/2011	5/1/2011					
347	4/25/2008	4/25/2008	Withdrawn 12/7/09	PV	S	50			Los Angeles	CA	SCE	Helijet-Little Rock-Palmdale-Rockair 66kV line	5/1/2011	5/1/2011		Complete			
348	4/25/2008	4/25/2008	Transition Cluster	PV	S	40		FC	Kern	CA	SCE	Corum-Goldtown 66kV line	5/1/2011	6/1/2013		Complete	In Progress		
349	4/25/2008	4/25/2008	Transition Cluster	PV	S	100		FC	Kern	CA	SCE	Goldtown Substation 66kV	5/1/2013	6/1/2013		Complete	In Progress		
350	4/25/2008	4/25/2008	Withdrawn 12/7/09	PV	S	80		FC	San Bernardino	CA	SCE	Eldorado-Baker-Coolwater-Dunn Siding-Mountain Pass 115k	5/1/2013	5/1/2013		Complete			
351	4/25/2008	4/25/2008	Withdrawn 11/25/08	CT	NG	49			Yolo	CA	PGE	Tap Vaca-Rio Oso 115kV line	7/1/2009	7/1/2009					
352	4/25/2008	4/25/2008	Withdrawn 11/25/08	CT	NG	49			Stanislaus	CA	PGE	Salado Substation 115kV	7/1/2009	7/1/2009					
353	4/25/2008	4/25/2008	Withdrawn 11/25/08	CT	NG	49			Fresno	CA	PGE	Panoche Substation 115kV bus	7/1/2009	7/1/2009					
354	4/25/2008	4/25/2008	Withdrawn 11/25/08	CT	NG	49			Fresno	CA	PGE	Tap Helm-Valley Nitrogen 70kV line	7/1/2009	7/1/2009					
355	4/28/2008	4/28/2008	Withdrawn 11/21/08	PV	S	100			San Luis Obispo	CA	PGE	San Luis Obispo-Temblor 115kV line	5/1/2011	5/1/2011					
356	4/28/2008	4/28/2008	Transition Cluster	PV	S	40		FC	Santa Barbara	CA	PGE	Taft-Cuyama #1 70kV line	5/1/2011	1/1/2013		Complete	In Progress		
357	4/28/2008	4/28/2008	Withdrawn 12/7/09	PV	S	100		FC	Kern	CA	PGE	Midway Substation via Midway-Sunset Gen-Tie 230kV line	5/1/2010	12/1/2013		Complete			
358	4/30/2008	4/30/2008	Withdrawn 11/21/08	PV	S	100			Kern	CA	PGE	Midway Substation via Midway-Sunset Gen-Tie 230kV line	5/1/2011	5/1/2011					
359	5/1/2008	5/1/2008	Withdrawn 11/26/08	PV	S	350			San Bernardino	CA	SCE	Eldorado-Baker-Cool Water-Dunn Siding-Mountain Pass 115kV line	3/1/2011	3/1/2011					
360	5/1/2008	5/1/2008	Withdrawn 7/11/08	CT	NG	200			Colusa	CA	PGE	Cortina Substation 230kV bus	6/1/2012	6/1/2012					
361	5/2/2008	5/2/2008	Withdrawn 11/26/08	ST	S	200			Riverside	CA	SCE	Blythe-Eagle Mountain 161kV line	8/30/2012	8/30/2012					
362	5/2/2008	5/2/2008	Withdrawn 11/26/08	ST	S	300			Riverside	CA	SCE	Midpoint Substation	8/30/2012	8/30/2012					
363	5/5/2008	5/6/2008	Withdrawn 12/7/09	PV	S	700		FC	Kern	CA	SCE	Windhub Substation 230kV	5/1/2013	5/1/2011		Complete			
364	5/5/2008	5/6/2008	Withdrawn 11/21/08	PV	S	700			Kern	CA	SCE	Windhub Substation 230kV	5/1/2014	5/1/2013					
365	5/6/2008	5/12/2008	Transition Cluster	ST	S	500		FC	Riverside	CA	SCE	Midpoint Substation	12/28/2013	7/1/2013		Complete	In Progress		
366	5/7/2008	5/12/2018	Withdrawn 10/30/08	RE	NG	115.5			Alameda	CA	PGE	Kelso Substation	6/1/2012	6/1/2012					
367	5/12/2008	5/12/2008	Withdrawn 11/26/08	PV	S	50			Santa Barbara	CA	PGE	69kV line proximate to Cuyama Substation	12/31/2009	12/31/2009					
368	5/9/2008	5/16/2008	Withdrawn 11/20/08	CT	NG	150			San Diego	CA	SDGE	Escondido Substation 69 kV	6/1/2010	6/1/2010					
369	5/16/2008	5/16/2008	Withdrawn 10/24/08	H	WTR	1300			Riverside	CA	SCE	Midpoint Substation 500kV	6/1/2014	6/1/2014					
370	5/1/2008	5/19/2008	Withdrawn 11/24/08	CT	NG	390.4			Solano	CA	PGE	Lambie-Contra Costa Substation 230kV bus	6/1/2012	6/1/2012					
371	5/9/2008	5/23/2008	Withdrawn 11/26/08	CC	NG	337.5			Fresno	CA	PGE	McCall-Kingsburg #1 & #2 115kV lines	12/1/2010	12/1/2010					
372	5/21/2008	5/21/2008	Active - SGIP	PV	S	20			Kings	CA	PGE	Jacobs Corner Substation 70kV bus	11/1/2010	11/1/2010	Waived	Complete	Complete		In Progress
373	5/27/2008	5/27/2008	Withdrawn 11/26/08	CT	NG	315			San Joaquin	CA	PGE	Loop Tesla-Stagg and Tesla-Eight Mile 230kV lines	7/1/2012	7/1/2012					
374	5/27/2008	5/27/2008	Withdrawn 11/25/08	CT	NG	49			Glenn	CA	PGE	Tap Cotonwood-Logan Creek-Vaca Dixon 230kV line	6/1/2010	6/1/2010					
375	5/28/2008	5/28/2008	Withdrawn 11/26/08	ST	NG	49.9			Kern	CA	PGE	Famoso Substation	6/2/2011	6/2/2011					
376	5/28/2008	5/28/2008	Withdrawn 12/19/08	ST	S	612			San Bernardino	CA	SCE	Pisgah-Lugo 230kV line	12/1/2012	12/1/2012					
377	5/28/2008	5/28/2008	Withdrawn 11/26/08	CT	NG	600			Alameda	CA	PGE	Tracy Substation 230kV	5/1/2013	5/1/2013					
378	5/28/2008	5/28/2008	Transition Cluster	CC	NG	120		FC	Santa Clara	CA	PGE	Los Esteros Substation 115kV bus	6/1/2011	6/1/2013		Complete	In Progress		

				Generating Facility		Maximum MWs		Deliverability Status	Location		Point of Interconnection				Study Availability				
Queue Position	Interconnection Request Receive Date	Queue Date	Application Status	Type	Fuel	Summer	Winter	Full Capacity or Energy Only (FC/EO)	County	State	Utility	Station or Transmission Line	Proposed On-line Date (as filed with IR)	Current On-line Date	Feasibility Study (IFS)	System Impact Study *or* Phase I Cluster Study	Facilities Study (FAS) *or* Phase II Cluster Study	Optional Study (OS)	Interconnection Agreement Status
379	5/28/2008	5/28/2008	Withdrawn 12/11/09	CC	NG	600		FC	Sutter	CA	PGE	Table Mountain-Tesla 500kV line	5/1/2012	1/1/2014		Complete			
380	5/21/2008	5/29/2008	Withdrawn 11/12/08	ST	S	145			San Bernardino	CA	SCE	Lugo-Mohave 500kV line	5/1/2013	5/1/2013					
381	5/21/2008	5/29/2008	Withdrawn 12/4/09	ST	S	240		FC	Clark	NV	SCE	Eldorado Substation 230kV	5/1/2013	5/1/2013		Complete			
382	5/21/2008	5/29/2008	Withdrawn 11/23/09	ST	S	290		FC	San Bernardino	CA	SCE	Lugo-Eldorado 500kV line	5/1/2013	5/1/2013		Complete			
383	5/29/2008	5/29/2008	Transition Cluster	CC	NG	85		FC	Los Angeles	CA	SCE	Arco Gen #1 & #2 230kV lines	5/31/2012	12/1/2012		Complete	In Progress		
384	5/29/2008	5/29/2008	Withdrawn 10/16/09	ST	S	900		EO	San Bernardino	CA	SCE	Lugo-Mohave 500kV line	2/1/2012	2/1/2015		Complete			
385	5/29/2008	5/29/2008	Withdrawn 10/16/09	ST	S	600		EO	San Bernardino	CA	SCE	Lugo-Mohave 500kV line	2/1/2011	2/1/2014		Complete			
386	5/29/2008	5/29/2008	Withdrawn 12/4/09	ST	S	600		EO	Imperial	CA	SDGE	New Substation on North Gila-Imperial Valley 500kV line	1/1/2012	10/1/2014		Complete			
387	5/29/2008	5/29/2008	Withdrawn 12/4/09	ST	S	900		EO	La Posa	AZ	SCE	Devers-Palo Verde 500kV line	2/1/2015	2/1/2015		Complete			
388	5/29/2008	5/29/2008	Withdrawn 12/4/09	ST	S	900		EO	La Paz/Maricopa	AZ	SCE	Devers-Palo Verde 500 kV line	6/1/2014	6/1/2014		Complete			
389	5/29/2008	5/29/2008	Withdrawn 12/4/09	ST	S	900		EO	Maricopa	AZ	SCE	Devers-Palo Verde 500 kV line	5/1/2015	5/1/2015		Complete			
390	5/29/2008	5/29/2008	Withdrawn 12/4/09	ST	S	300		EO	Maricopa	AZ	SDGE	North Gila-Hassayampa 500kV line	5/1/2011	3/1/2012		Complete			
391	5/29/2008	5/29/2008	Transition Cluster	ST	G	15		FC	Inyo	CA	SCE	Kramer Substation 230kV	1/11/2010	1/11/2010		Complete	In Progress		
392	5/29/2008	5/29/2008	Transition Cluster	ST	G	15		FC	Inyo	CA	SCE	BLM Substation 230kV	3/13/2019	1/11/2010		Complete	In Progress		
393	5/29/2008	5/29/2008	Transition Cluster	ST	G	15		FC	Inyo	CA	SCE	Inyokern Substation 115kV	8/19/2011	1/11/2010		Complete	In Progress		
394	5/29/2008	5/29/2008	Transition Cluster	ST	G	60.7		FC	Churchill	NV	SCE	Control Substation 115kV bus	12/1/2012	12/1/2015		Complete	In Progress		
395	5/29/2008	5/29/2008	Withdrawn 11/26/08	ST	G	52.5			Churchill	NV	SCE	Bishop Substation	12/1/2012	12/1/2012					
396	5/29/2008	5/29/2008	Transition Cluster	ST	G	60.7		FC	Churchill	NV	SCE	Control Substation 115kV bus	6/1/2013	6/1/2016		Complete	In Progress		
397	5/29/2008	5/29/2008	Withdrawn 11/26/08	ST	G	52.5			Churchill	NV	SCE	Bishop Substation	6/1/2013	6/1/2013					
398	5/29/2008	5/29/2008	Transition Cluster	ST	G	60.7		FC	Churchill	NV	SCE	Control Substation 115kV bus	6/1/2012	6/1/2012		Complete	In Progress		
399	5/29/2008	5/29/2008	Transition Cluster	ST	G	60.7		FC	Churchill	NV	SCE	Control Substation 115kV bus	6/1/2012	6/1/2013		Complete	In Progress		
400	5/30/2008	5/30/2008	Withdrawn 7/22/08	PV	S	700			Kern	CA	SCE	Windhub Substation	5/1/2011	5/1/2011					
401	5/30/2008	5/30/2008	Withdrawn 7/28/08	ST	NG	49.85			Los Angeles	CA	SCE	ChevGen Substation	9/1/2010	9/1/2010					
402	5/30/2008	5/30/2008	Withdrawn 8/19/08	CC	NG	600			Kern	CA	PGE	Midway Substation 230kV bus	6/1/2012	6/1/2012					
403	5/30/2008	5/30/2008	Withdrawn 12/14/09	PV	S	30		FC	Kern	CA	PGE	Midway Substation 230kV bus	6/1/2012	12/31/2011		Complete			
404	5/30/2008	5/30/2008	Withdrawn 8/19/08	CT	NG	450			Kern	CA	PGE	Midway Substation 230kV bus	6/1/2011	6/1/2011					
405	5/30/2008	5/30/2008	Withdrawn 11/26/08	ST	S	450			Imperial	CA	SDGE	Imperial Valley Substation	12/31/2012	12/31/2012					
406	5/30/2008	5/30/2008	Withdrawn 11/26/08	WT	W	130			San Diego	CA	SDGE	Boulevard Substation	6/1/2011	6/1/2011					
407	5/30/2008	5/30/2008	Transition Cluster	PV	S	325		FC	Kern	CA	SCE	Cottonwind-Whirlwind 230kV line	7/1/2012	12/1/2014		Complete	In Progress		
408	5/30/2008	5/30/2008	Transition Cluster	PV	S	325		FC	Kern	CA	SCE	Cottonwind-Whirlwind 230kV line	7/1/2012	12/1/2014		Complete	In Progress		
409	5/30/2008	5/30/2008	Transition Cluster	WT	W	150		EO	Kern	CA	SCE	Highwind Substation 230kV	10/1/2011	12/31/2012		Complete	In Progress		
410	5/30/2008	5/30/2008	Withdrawn 11/26/08	ST	S	49.5			Riverside	CA	SCE	Midpoint Substation 500kV	8/1/2012	8/1/2012					
411	5/30/2008	5/30/2008	Withdrawn 11/26/08	ST	S	49.5			Riverside	CA	SCE	Midpoint Substation 500kV	8/1/2012	8/1/2012					
412	5/30/2008	5/30/2008	Transition Cluster	PV	S	250		FC	Los Angeles	CA	SCE	Antelope-Magunden 230kV line	8/1/2012	12/1/2013		Complete	In Progress		
413	5/30/2008	5/30/2008	Withdrawn 11/21/08	ST	S	280			San Bernardino	CA	SCE	Pisgah Substation 230kV	8/1/2012	8/1/2012					
414	5/30/2008	5/30/2008	Withdrawn 11/21/08	ST	S	280			Imperial	CA	SDGE	Imperial Valley Substation 230kV bus	7/1/2012	7/1/2012					
415	5/30/2008	5/30/2008	Withdrawn 11/21/08	ST	S	280			Riverside	CA	SCE	Devers-Palo Verde 500kV line	8/1/2012	8/1/2012					
416	5/30/2008	5/30/2008	Withdrawn 11/21/08	ST	S	280			Riverside	CA	SCE	Midpoint Substation 230kV	8/1/2012	8/1/2012					
417	5/30/2008	5/30/2008	Transition Cluster	WT	W	14		FC	Contra Costa	CA	PGE	Pittsburg-Tesla 230kV line	9/30/2010	9/30/2010		Complete	In Progress		
418	5/30/2008	5/30/2008	Withdrawn 11/26/08	CT	NG	400			San Joaquin	CA	PGE	Tesla Substation 230kV bus	11/1/2012	11/1/2012					
419	5/30/2008	5/30/2008	Withdrawn 11/26/08	CT	NG	188			Fresno	CA	PGE	Panoche Substation 230kV	3/1/2011	3/1/2011					
420	5/30/2008	5/30/2008	Withdrawn 12/9/09	ST	S	49.5		FC	San Diego	CA	SDGE	Borrego Substation 69kV	2/1/2013	2/1/2013		Complete			
421	5/30/2008	5/30/2008	Transition Cluster	ST	S	49.5		FC	Riverside	CA	SCE	Eagle Mountain Substation	2/1/2012	2/1/2012		Complete	In Progress		
422	5/30/2008	5/30/2008	Withdrawn 11/26/08	ST	S	49.5			Riverside	CA	SCE	Camino-Iron Mountain 230kV line	2/1/2012	2/1/2012					
423	5/30/2008	5/30/2008	Withdrawn 11/26/08	ST	S	49.5			Riverside	CA	SCE	Camino-Iron Mountain 230kV line	2/1/2012	2/1/2012					
424	5/30/2008	5/30/2008	Withdrawn 11/26/08	ST	S	250			San Bernardino	CA	SCE	Mohave Switchyard	7/1/2014	7/1/2014					
425	5/30/2008	5/30/2008	Withdrawn 11/26/08	ST	S	250			Riverside	CA	SCE	Colorado River Substation	7/1/2014	7/1/2014					
426	5/30/2008	5/30/2008	Withdrawn 11/26/08	ST	S	250			Clark	NV	SCE	Mohave Switchyard	7/1/2014	7/1/2014					
427	5/30/2008	5/30/2008	Withdrawn 12/4/09	ST	S	250		FC	Kern	CA	SCE	Antelope Substation	7/1/2014	7/1/2014		Complete			
428	5/30/2008	5/30/2008	Withdrawn 11/26/08	ST	S	250			San Bernardino	CA	SCE	Eagle Mountain Substation	7/1/2014	7/1/2014					
429	5/30/2008	5/30/2008	Transition Cluster	ST	S	100		FC	Imperial	CA	SDGE	Imperial Valley Substation	7/1/2014	7/1/2014		Complete	In Progress		
430	5/30/2008	5/30/2008	Withdrawn 12/4/09	ST	S	250		FC	Kern	CA	SCE	Kramer Substation	7/1/2014	7/1/2014		Complete			
431	5/30/2008	5/30/2008	Transition Cluster	ST	S	150		FC	Riverside	CA	SCE	Midpoint Substation 220kV	7/1/2014	7/1/2014		Complete	In Progress		
432	5/30/2008	5/30/2008	Withdrawn 12/4/09	ST	S	250		FC	Riverside	CA	SCE	Colorado River Substation 230kV	7/1/2014	7/1/2014		Complete			
433	5/30/2008	5/30/2008	Withdrawn 11/26/08	ST	S	250			San Bernardino	CA	SCE	Iron Mountain Substation	5/29/2015	5/29/2015					
434	5/30/2008	5/30/2008	Withdrawn 11/26/08	ST	S	500			San Bernardino	CA	SCE	Mohave Switchyard	5/29/2015	5/29/2015					
435	5/30/2008	5/30/2008	Withdrawn 12/4/09	ST	S	250		FC	La Paz	AZ	SCE	Palo Verde-Devers #2 line	7/1/2014	7/1/2014		Complete			
436	5/30/2008	5/30/2008	Withdrawn 11/26/08	ST	S	250			Maricopa	AZ	SCE	Palo Verde-Devers #2 line	7/1/2014	7/1/2014					
437	5/30/2008	5/30/2008	Withdrawn 10/21/08	WT	W	350			Shasta	CA	PGE	Pit #3-Round Mountain 230kV line	6/1/2011	6/1/2011					
438	5/30/2008	5/30/2008	Withdrawn 11/26/08	WT	W	500			Kern	CA	SCE	Windhub Substation	12/31/2011	12/31/2011					
439	5/30/2008	5/30/2008	Withdrawn 11/26/08	ST	S	500			Riverside	CA	SCE	Midpoint Substation	12/31/2011	12/31/2011					
440	5/30/2008	5/30/2008	Withdrawn 11/26/08	ST	S	500			Kern	CA	SCE	Whirlwind Substation	12/31/2011	12/31/2011					
441	5/30/2008	5/30/2008	Withdrawn 11/26/08	ST	G	50			Lake	CA	PGE	Geysers 17-Fulton #2 230kV line	7/31/2012	7/31/2012					
442	5/30/2008	5/30/2008	Transition Cluster	ST	S	125		FC	Imperial	CA	SDGE	Imperial Valley 230kV	5/1/2013	3/1/2013		Complete	In Progress		
443	5/30/2008	5/30/2008	Withdrawn 11/25/08	CT	NG	49			San Diego	CA	SDGE	Talega-Escondido 230kV line	7/1/2009	7/1/2009					
444	5/30/2008	5/30/2008	Withdrawn 11/25/08	CT	NG	49			San Diego	CA	SDGE	Lilac-Rincon 69kV	7/1/2009	7/1/2009					
445	5/30/2008	5/30/2008	Withdrawn 11/25/08	CT	NG	49			San Diego	CA	SDGE	Pala-Lilac 69kV line	7/1/2009	7/1/2009					
446	5/30/2008	5/30/2008	Withdrawn 11/25/08	CT	NG	49			Orange	CA	SDGE	Talega-San Mateo 69kV line	7/1/2009	7/1/2009					
447	5/30/2008	5/30/2008	Withdrawn 11/25/08	CT	NG	49			San Diego	CA	SDGE	Ash-Valley Center 69kV line	7/1/2009	7/1/2009					
448	5/30/2008	5/30/2008	Withdrawn 11/25/08	CT	NG	49			San Diego	CA	SDGE	Border Substation 69kV	7/1/2009	7/1/2009					
449	5/30/2008	5/30/2008	Withdrawn 12/19/08	ST	S	250			Riverside	CA	SCE	Midpoint Substation 500kV	7/1/2012	7/1/2012					
450	5/30/2008	5/30/2008	Withdrawn 11/26/08	WT	W	1150			Los Angeles & Kern	CA	SCE	Whirlwind Substation 230kV	5/30/2013	5/30/2013					
451	5/30/2008	5/30/2008	Withdrawn 11/26/08	ST	S	1150			San Bernardino	CA	SCE	Pisgah Substation 230kV	5/30/2013	5/30/2013					
452	6/2/2008	6/2/2008	Withdrawn 11/24/08	CC	NG	730			Solano	CA	PGE	Loop Lakesville-Sobrante and Lakesville-Ignacio 230kV lines	6/15/2012	6/15/2012					
453	6/2/2008	6/2/2008	Withdrawn 11/26/08	ST	S	250			La Paz	AZ	SCE	Mohave Switchyard	7/1/2014	7/1/2014					
454	6/2/2008	6/2/2008	Withdrawn 11/26/08	ST	S	84			Imperial	CA	SDGE	Imperial Valley Substation 230kV	2/1/2011	2/1/2011					
455	6/2/2008	6/2/2008	Withdrawn 12/14/09	ST	S	141		FC	Los Angeles	CA	SCE	Whirlwind Substation 230kV	10/1/2013	10/1/2013		Complete			
456	6/2/2008	6/2/2008	Withdrawn 11/26/08	ST	S	840			Los Angeles	CA	SCE	Vincent Substation	9/1/2014	9/1/2014					
457	6/2/2008	6/2/2008	Withdrawn 11/26/08	PV	S	55			Riverside	CA	SCE	Victor Substation 115kV	6/15/2010	6/15/2010					

				Generating Facility		Maximum MWs		Deliverability Status	Location		Point of Interconnection				Study Availability				
Queue Position	Interconnection Request Receive Date	Queue Date	Application Status	Type	Fuel	Summer	Winter	Full Capacity or Energy Only (FC/EO)	County	State	Utility	Station or Transmission Line	Proposed On-line Date (as filed with IR)	Current On-line Date	Feasibility Study (IFS)	System Impact Study *or* Phase I Cluster Study	Facilities Study (FAS) *or* Phase II Cluster Study	Optional Study (OS)	Interconnection Agreement Status
~~458~~	~~6/2/2008~~	~~6/2/2008~~	Withdrawn 8/1/08	~~PV~~	~~S~~	~~50~~			~~Riverside~~	~~CA~~	~~SCE~~	~~Antelope-Cal Cement 69kV line~~	~~6/15/2010~~	~~6/15/2010~~					
~~459~~	~~6/2/2008~~	~~6/2/2008~~	Withdrawn 11/25/08	~~PV~~	~~S~~	~~50~~			~~San Diego~~	~~CA~~	~~SDGE~~	~~Cameron Substation 69kV~~	~~12/15/2009~~	~~12/15/2009~~					
~~460~~	~~6/2/2008~~	~~6/2/2008~~	Withdrawn 9/10/08	~~PV~~	~~S~~	~~40~~			~~Kern~~	~~CA~~	~~SCE~~	~~Inyokern Substation 115kV bus~~	~~12/1/2010~~	~~12/1/2010~~					
~~461~~	~~6/2/2008~~	~~6/2/2008~~	Withdrawn 9/10/08	~~PV~~	~~S~~	~~40~~			~~San Bernardino~~	~~CA~~	~~SCE~~	~~Dunn Siding-Cool Water 115kV line~~	~~12/1/2010~~	~~12/1/2010~~					
~~462~~	~~6/2/2008~~	~~6/2/2008~~	Withdrawn 11/25/08	~~PV~~	~~S~~	~~58.8~~			~~San Diego~~	~~CA~~	~~SDGE~~	~~Borrego Substation 69kV~~	~~6/15/2010~~	~~6/15/2010~~					
~~463~~	~~6/2/2008~~	~~6/2/2008~~	Withdrawn 11/25/08	~~PV~~	~~S~~	~~58.8~~			~~San Diego~~	~~CA~~	~~SDGE~~	~~Warner Substation 69kV~~	~~6/30/2010~~	~~6/30/2010~~					
~~464~~	~~6/2/2008~~	~~6/2/2008~~	Withdrawn 11/25/08	~~PV~~	~~S~~	~~40~~			~~Kern~~	~~CA~~	~~SCE~~	~~Redman Substation 69kV bus~~	~~12/1/2010~~	~~12/1/2010~~					
~~465~~	~~6/2/2008~~	~~6/2/2008~~	Withdrawn 11/25/08	~~PV~~	~~S~~	~~40~~			~~Kern~~	~~CA~~	~~SCE~~	~~Little Rock Substation 69kV bus~~	~~12/1/2010~~	~~12/1/2010~~					
~~466~~	~~6/2/2008~~	~~6/2/2008~~	Withdrawn 8/1/08	~~PV~~	~~S~~	~~100~~			~~Riverside~~	~~CA~~	~~SCE~~	~~Baker Substation 115kV~~	~~6/15/2010~~	~~6/15/2010~~					
467	**5/30/2008**	**6/2/2008**	**Transition Cluster**	**ST**	**S**	**230**		**FC**	**Clark**	**NV**	**SCE**	**Eldorado-Ivanpah 230kV line**	**8/1/2012**	**10/1/2015**		**Complete**	**In Progress**		
468	**5/30/2008**	**6/2/2008**	**Transition Cluster**	**ST**	**S**	**290**		**EO**	**Yuma**	**AZ**	**SDGE**	**Hassayampa-North Gila 500kV line**	**8/1/2012**	**6/15/2014**		**Complete**	**In Progress**		
~~469~~	~~7/14/2008~~	~~7/14/2008~~	Withdrawn 11/18/08	~~ST~~	~~B~~	~~16.3~~			~~Amador~~	~~CA~~	~~PGE~~	~~Valley Springs-Martel #2 60kV line~~	~~12/31/2008~~	~~12/31/2008~~					
470	7/30/2008	7/30/2008	Active - SGIP	PV	S	20			Kings	CA	PGE	Jacobs Corner Substation 70kV bus	3/1/2011	3/1/2011	Waived	Complete	Complete		In Progress
471	7/30/2008	7/30/2008	Active - SGIP	PV	S	20			Kings	CA	PGE	Jacobs Corner Substation 70kV bus	7/1/2011	7/1/2011	Waived	Complete	Complete		In Progress
472	8/4/2008	8/11/2008	Active - SGIP	ST	B	13.8			Humboldt	CA	PGE	Ultra Power 60kV tap	12/20/2008	7/10/2009	Waived	Waived	Complete		In Progress
473	9/3/2008	9/12/2008	Active - SGIP	PV	S	20			Tulare	CA	PGE	Smyrna-Alpaugh 115kV line	5/1/2010	7/1/2011	Waived	Complete	In Progress		
474	9/11/2008	9/15/2008	Active - SGIP	PV	S	19.9			San Bernardino	CA	SCE	Dunn Siding Substation	6/1/2011	6/1/2011	Waived	In Progress			
~~475~~	~~9/10/2008~~	~~10/8/2008~~	Withdrawn - 10/26/09	~~WT~~	~~W~~	~~20~~			~~Riverside~~	~~CA~~	~~SCE~~	~~Devers-Garnet-Venwind 115kV line~~	~~12/1/2009~~	~~12/1/2010~~	~~Waived~~	~~In Progress~~			
476	10/23/2008	10/23/2008	Active - SGIP	RE	LFG	10			Marin	CA	PGE	Tap Lakeville #2 60 kV line	5/29/2010	5/29/2010	Waived	In Progress			
477	2/2/2009	2/6/2009	Active - SGIP	RE	LFG	4			Butte	CA	PGE	Centerville-Table Mountain 60kV line	3/31/2010	4/17//11	Waived	Waived	In Progress		
478	2/17/2009	2/17/2009	Active - SGIP	PV	S	20			Kings	CA	PGE	Corcoran-Kingsburg 115kV line	11/1/2011	11/1/2011	Waived	In Progress			
479	3/13/2009	3/13/2009	Active - SGIP	PV	S	20			Tulare	CA	PGE	Smyrna-Alpaugh 115kV line	10/1/2011	10/1/2011	Waived	In Progress			
480	3/16/2009	3/16/2009	Active - SGIP	PV	S	20			San Diego	CA	SDGE	Borrego Substation 69kV switchyard	12/31/2010	12/31/2010	In Progress				
481	4/6/2009	4/20/2009	Active - SGIP	ST	B	18.4			Amador	CA	PGE	Valley Springs-Martel #2 60kV line	4/1/2010	4/1/2010	Waived	Complete	In Progress		
482	4/24/2009	4/24/2009	Active - SGIP	PV	S	20			Tulare	CA	PGE	Smyrna-Alpaugh 115kV line	4/1/2012	4/1/2012	Waived				
483	4/29/2009	4/29/2009	Active - SGIP	PV	S	10			Kern	CA	SCE	Vincent Substation	6/1/2010	6/1/2010	Waived	In Progress			
484	6/11/2009	6/11/2009	Active - SGIP	PV	S	20			Kern	CA	PGE	Blackwell Substation 70kV bus	9/30/2011	9/30/2011	Waived	In Progress			
485	6/3/2009	6/18/2009	Active - SGIP	WT	W	19.9			Kern	CA	SCE	Highwind Substation 230kV bus	6/30/2012	6/30/2012	In Progress				
486	6/29/2009	6/29/2009	Active - SGIP	PV	S	20			Kern	CA	SCE	Antelope-Neenach 66kV line	1/1/2012	1/1/2012					
487	7/30/2009	7/31/2009	Active - Cluster #1	PV	S	600		FC	Kern	CA	PGE	Midway-Wheeler Ridge 230kV double circuit line	12/1/2015	12/1/2015					
488	4/6/2009	7/31/2009	Active - Cluster #1	ST	S	92		FC	Clark	NV	SCE	Eldorado Substation 230kV	9/30/2012	9/30/2012					
489	5/26/2009	7/31/2009	Active - Cluster #1	WT	W	98.9		FC	Solano	CA	PGE	Birds Landing Substation 230kV	5/31/2011	5/31/2011					
490	6/3/2009	7/31/2009	Active - Cluster #1	ST	NU	48		FC	San Diego	CA	SCE	San Onofre Nuclear Generating Station 230kV switchyard	12/31/2012	12/31/2012					
491	6/4/2009	7/31/2009	Active - Cluster #1	PV	S	230		FC	San Bernardino	CA	SCE	Coolwater-Dunn Siding 115kV line	6/1/2014	6/1/2014					
~~492~~	~~7/6/2009~~	~~7/31/2009~~	Withdrawn 11/2/09	~~PV~~	~~S~~	~~350~~		~~FC~~	~~Kern~~	~~CA~~	~~SCE~~	~~Windhub Substation 230kV~~	~~12/1/2015~~	~~12/1/2015~~					
493	7/16/2009	7/31/2009	Active - Cluster #1	WT	W	547.9		FC	Imperial	CA	SDGE	Sunrise Powerlink 500kV line	12/31/2013	12/31/2013					
494	7/20/2009	7/31/2009	Active - Cluster #1	PV	S	350		FC	Kern	CA	SCE	Windhub Substation 230kV	12/1/2015	12/1/2015					
495	7/24/2009	7/31/2009	Active - Cluster #1	H	WTR	7.2		FC	Tuolumne	CA	PGE	Tulloch 115kV tap	10/1/2011	10/1/2011					
496	7/27/2009	7/31/2009	Active - Cluster #1	ST	S	960		FC	Yuma	AZ	SDGE	Agua Caliente Substation 500kV	1/1/2014	1/1/2014					
497	7/27/2009	7/31/2009	Active - Cluster #1	ST	S	6		FC	San Bernardino	CA	SCE	New Ivanpah Substation 115kV	3/31/2012	3/31/2012					
498	7/27/2009	7/31/2009	Active - Cluster #1	ST	S	20		FC	San Bernardino	CA	SCE	New Ivanpah Substation 115kV	9/30/2012	9/30/2012					
499	7/27/2009	7/31/2009	Active - Cluster #1	ST	S	40		FC	San Bernardino	CA	SCE	New Ivanpah Substation 115kV	3/31/2013	3/31/2013					
500	7/27/2009	7/31/2009	Active - Cluster #1	ST	S	960		FC	Lincoln	NV	SCE	Eldorado Substation 500kV	1/1/2014	1/1/2014					
501	7/28/2009	7/31/2009	Active - Cluster #1	PV	S	750		FC	Yuma	AZ	SDGE	Hassayampa-North Gila 500kV switching station	6/30/2015	6/30/2015					
502	7/28/2009	7/31/2009	Active - Cluster #1	PV	S	270		FC	Clark	NV	SCE	Eldorado-Ivanpah 230kV line	5/1/2016	5/1/2016					
503	7/28/2009	7/31/2009	Active - Cluster #1	PV	S	500		FC	Clark	NV	SCE	Eldorado Substation 230kV bus	1/1/2016	1/1/2016					
~~504~~	~~7/30/2009~~	~~7/31/2009~~	Withdrawn 10/20/09	~~WT~~	~~W~~	~~688~~		~~FC~~	~~Kern~~	~~CA~~	~~SCE~~	~~Highwind Substation 230kV bus~~	~~11/30/2012~~	~~11/30/2012~~					
505	7/30/2009	7/31/2009	Active - Cluster #1	WT/PV	W/S	1100		FC	Kern	CA	SCE	Highwind-Windhub 230kV line	11/30/2012	11/30/2012					
506	7/30/2009	7/31/2009	Active - Cluster #1	PV	S	300		EO	Kern	CA	SCE	Whirlwind Substation 230kV	7/31/2015	7/31/2015					
~~507~~	~~7/31/2009~~	~~7/31/2009~~	Withdrawn 12/4/09	~~CC~~	~~NG~~	~~131~~		~~FC~~	~~Contra Costa~~	~~CA~~	~~PGE~~	~~Contra Costa Substation 230kV bus~~	~~12/1/2013~~	~~12/1/2013~~					
508	7/31/2009	7/31/2009	Active - Cluster #1	CC	NG	10		FC	Fresno	CA	PGE	Sanger-Reedley 115kV line	3/15/2011	3/15/2011					
509	7/31/2009	7/31/2009	Active - Cluster #1	CT	NG	49.9		FC	San Diego	CA	SDGE	El Cajon-Los Coches 69kV line	6/15/2010	6/15/2010					
510	7/31/2009	7/31/2009	Active - Cluster #1	PV	S	200		FC	Imperial	CA	SDGE	Imperial Valley Substation 230kV bus	1/1/2012	1/1/2012					
~~511~~	~~7/31/2009~~	~~7/31/2009~~	Withdrawn 11/30/09	~~ST~~	~~S~~	~~92.6~~		~~FC~~	~~Kern~~	~~CA~~	~~SCE~~	~~Goldtown-Lancaster 66kV line~~	~~12/31/2012~~	~~12/31/2012~~					
512	7/31/2009	7/31/2009	Active - Cluster #1	PV	S	26		FC	Los Angeles	CA	SCE	Neenach Substation 66kV	2/15/2012	2/15/2012					
513	7/31/2009	7/31/2009	Active - Cluster #1	ST	S	141		FC	Los Angeles	CA	SCE	Whirlwind Substation 230kV	8/1/2013	8/1/2013					
~~513A~~	~~7/31/2009~~	~~7/31/2009~~	Withdrawn 10/8/09	~~CT~~	~~NG~~	~~190~~		~~FC~~	~~San Diego~~	~~CA~~	~~SDGE~~	~~Otay Mesa Energy Center Substation 230kV~~	~~5/1/2013~~	~~5/1/2013~~					
514	7/31/2009	7/31/2009	Active - SGIP	PV	S	20			Kern	CA	PGE	Arco Substation 69kV bus	12/15/2010	12/15/2010					
515	8/12/2009	8/12/2009	Active - SGIP	PV	S	20			Kern	CA	SCE	Kramer-Ransburg 115kV line	4/1/2011	4/1/2011					
516	8/12/2009	8/21/2009	Active - SGIP	PV	S	20			San Diego	CA	SDGE	Borrego Substation 69kV	1/1/2011	1/1/2011	In Progress				
517	8/19/2009	8/19/2009	Active - SGIP	PV	S	16			Kern	CA	PGE	Carnation Dairy-Old River 69kV line	12/31/2012	12/31/2012					
518	8/19/2009	8/19/2009	Active - SGIP	PV	S	19.9			Kern	CA	PGE	Kern-Old River 2 70kV line	12/31/2012	12/31/2012					
519	8/19/2009	8/19/2009	Active - SGIP	PV	S	20			Kern	CA	PGE	Elk Hills-Taft 69kV line	12/31/2014	12/31/2014					
520	8/19/2009	8/19/2009	Active - SGIP	PV	S	20			Kern	CA	PGE	Blackwell-Carneras 69kV line	12/31/2014	12/31/2014					
521	8/19/2009	8/19/2009	Active - SGIP	PV	S	19.9			Kern	CA	SCE	Goldtown-Corum 66kV line	12/31/2014	12/31/2014					
522	8/19/2009	8/19/2009	Active - SGIP	PV	S	19.9			Kern	CA	SCE	Goldtown-Lancaster 66kV line	12/31/2014	12/31/2014					
523	8/21/2009	8/21/2009	Active - SGIP	PV	S	20			Kings	CA	PGE	Arco Substation	10/30/2011	10/30/2011					
524	9/2/2009	9/2/2009	Active - SGIP	PV	S	20			San Bernardino	CA	SCE	Eldorado-Pisgah #2 230kV line	12/1/2011	12/1/2011					
525	9/8/2009	9/11/2009	Active - SGIP	PV	S	20			Kern	CA	PGE	Arco-Caneras 70kV line	4/30/2011	12/31/2010	Waived	In Progress			
526	9/11/2009	9/11/2009	Active - SGIP	PV	S	20			Fresno	CA	PGE	Schindler-Gates 69kV line	1/1/2012	1/1/2012					
527	9/23/2009	9/23/2009	Active - SGIP	PV	S	20			Kern	CA	SCE	Control-Haiwee-Inyokern #2 115kV line	6/1/2011	6/1/2011					
528	10/5/2009	10/5/2009	Active - SGIP	PV	S	20			Solano	CA	PGE	Birds Landing Substation	6/1/2011	6/1/2011					
529	10/19/2009	10/19/2009	Active - SGIP	PV	S	20			Kings	CA	PGE	Corcoran- Kingsburg #1 115kV line	8/1/2013	8/1/2013					
530	10/29/2009	10/29/2009	Active - SGIP	PV	S	16			Tulare	CA	PGE	Corcoran-Smyrna 115kV line	7/1/2011	7/1/2011					
531	10/29/2009	10/29/2009	Active - SGIP	PV	S	16			Tulare	CA	PGE	Corcoran-Smyrna 115kV line	7/1/2011	7/1/2011					
531A	10/29/2009	10/29/2009	Active - SGIP	PV	S	20			Los Angeles	CA	SCE	Antelope-Del Sur 69kV line	6/1/2011	6/1/2011					
531B	10/29/2009	10/29/2009	Active - SGIP	PV	S	20			Los Angeles	CA	SCE	Neenach Substation 69kV	6/1/2011	6/1/2011					
532	11/2/2009	11/2/2009	Active - SGIP	ST	S	16.3			Amador	CA	PGE	Schindler-Pleasant Valley 69kV line	1/1/2012	1/1/2012					
533	11/11/2009	11/11/2009	Active - SGIP	PV	S	20			Kern	CA	PGE	Semitropic-Midway #2 115kV line	1/1/2012	1/1/2012					

				Generating Facility		Maximum MWs		Deliverability Status	Location		Point of Interconnection				Study Availability				
Queue Position	Interconnection Request Receive Date	Queue Date	Application Status	Type	Fuel	Summer	Winter	Full Capacity or Energy Only (FC/EO)	County	State	Utility	Station or Transmission Line	Proposed On-line Date (as filed with IR)	Current On-line Date	Feasibility Study (IFS)	System Impact Study *or* Phase I Cluster Study	Facilities Study (FAS) *or* Phase II Cluster Study	Optional Study (OS)	Interconnection Agreement Status
534	8/4/2009	11/13/2009	Active - SGIP	PV	S	20			San Benito	CA	PGE	Moss Landing-Panoche #2 230kV line	6/30/2011	6/30/2011					
535	11/19/2009	11/19/2009	Active - SGIP	PV	S	20			Merced	CA	PGE	Mercy Springs Substation 70kV	10/31/2011	10/31/2011					
536	11/19/2009	11/19/2009	Active - SGIP	PV	S	20			Merced	CA	PGE	Mercy Springs 70kV line	12/31/2011	12/31/2011					
537	11/19/2009	11/19/2009	Active - SGIP	PV	S	20			Merced	CA	PGE	Mercy Springs-Oro Loma 70kV line	3/31/2012	3/31/2012					
538	12/16/2009	12/16/2009	Active - SGIP	PV	S	20			Fresno	CA	PGE	Oro Loma-Firebaugh 69kV line	1/1/2012	1/1/2012					
539	12/18/2009	12/18/2009	Active - SGIP	PV	S	20			Stanislaus	CA	PGE	Salado-Newman 60kV line	1/1/2011	1/1/2011					

Legend:

- **Application Status Key:** A39=Amendment 39 Procedures (Appendix W), Serial=Standard Large Generator Interconnection Procedures (Appendix U), Transition Cluster=Appendix 2 to Large Generator Interconnection Procedures in a Queue Cluster Window (Appendix Y), Numbered Clusters=Large Generator Interconnection Procedures in a Queue Cluster Window (Appendix Y), SGIP=Small Generator Interconnection Procedure (Appendix S), **Complete**=project is in Commercial Operation
- **Generator Type Key:** IC=Internal Combustion, ST=Steam Turbine, CT=Combustion Turbine, CC=Combined Cycle, H=Hydro, WT=Wind Turbine, PV=Photovoltaic, RE=Reciprocating Engine
- **Fuel Type Key:** W=Wind, NU=Nuclear, NG=Natural Gas, O=Oil, C=Coal, B=Biomass, S=Solar, LFG=Land Fill Gas, WTR=Water, G=Geothermal, HR=Heat Recovery

BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION OF THE STATE OF CALIFORNIA
1516 NINTH STREET, SACRAMENTO, CA 95814
1-800-822-6228 – WWW.ENERGY.CA.GOV

APPLICATION FOR CERTIFICATION FOR THE *OAKLEY GENERATING STATION*	**Docket No. 09-AFC-4** ***PROOF OF SERVICE*** **(Revised 2/4/2010)**

APPLICANT

Greg Lamberg, Sr. Vice President
RADBACK ENERGY
145 Town & Country Drive, #107
Danville, CA 94526
Greg.Lamberg@Radback.com

APPLICANT'S CONSULTANTS

Douglas Davy
CH2M HILL
2485 Natomas Park Drive, Suite 600
Sacramento, CA 95833
ddavy@ch2m.com

COUNSEL FOR APPLICANT

Scott Galati
Galati & Blek, LLP
455 Capitol Mall, Suite 350
Sacramento, CA 95814
sgalati@gb-llp.com

INTERESTED AGENCIES

California ISO e-recipient@caiso.com

INTERVENORS

ENERGY COMMISSION

JAMES D. BOYD
Vice Chair and Presiding Member
jboyd@energy.state.ca.us

***ROBERT B. WEISENMILLER**
Commissioner and Associate Member
rweisenm@energy.state.ca.us

Kourtney Vaccaro
Hearing Officer
KVaccaro@energy.state.ca.us

Joseph Douglas
Siting Project Manager
jdouglas@energy.state.ca.us

Kevin Bell
Staff Counsel
kbell@energy.state.ca.us

***Jennifer Jannings**
Public Adviser
publicadviser@energy.state.ca.us

*indicates change

DECLARATION OF SERVICE

I, Mary Finn, declare that on February 11, 2010, I served and filed copies of the attached Oakley Generation Station Project Response to Data Requests 1 through 43. The original document, filed with the Docket Unit, is accompanied by a copy of the most recent Proof of Service list, located on the web page for this project at: **[http://www.energy.ca.gov/sitingcases/contracosta/index.html].** The document has been sent to both the other parties in this proceeding (as shown on the Proof of Service list) and to the Commission's Docket Unit, in the following manner:

(*Check all that Apply*)

For service to all other parties:

____ sent electronically to all email addresses on the Proof of Service list;

__x__ by personal delivery or by depositing in the United States mail at Sacramento, California with first-class postage thereon fully prepaid and addressed as provided on the Proof of Service list above to those addresses **NOT** marked "email preferred."

AND

For filing with the Energy Commission:

_____ **sending an original paper copy and one electronic copy, mailed and emailed respectively, to the address below (preferred method);**

OR

___x__depositing in the mail an original and 12 paper copies, as follows:

CALIFORNIA ENERGY COMMISSION
Attn: Docket No. 09-AFC-4
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512
docket@energy.state.ca.us

I declare under penalty of perjury that the foregoing is true and correct.

Mary Finn