DOCKETED

Docket Number:	07-AFC-06C
Project Title:	Carlsbad Energy Center - Compliance
TN #:	202326
Document Title:	Application for an Authority to Construct, (ATC) Petition to Amend
Description:	N/A
Filer:	Dee Hutchinson
Organization:	Locke Lord LLP
Submitter Role:	Applicant Representative
Submission Date:	5/13/2014 9:29:00 AM
Docketed Date:	5/13/2014

Carlsbad Energy Center LLC.
5790 Fleet Street
Carlsbad, CA 92008
Phone: 760.710.2156
Fax: 760.710.2158

May 8, 2014

Jayne Hurley
Permit Processing Group
San Diego Air Pollution Control District
10124 Old Grove Road
San Diego, CA 92131

Subject: Application for an Authority To Construct, Carlsbad Energy Center Project Petition to Amend (07-AFC-06C)

Dear Ms. Hurley:

Please find enclosed an Application for an Authority to Construct (ATC) for the proposed Amended Carlsbad Energy Center Project (CECP). This ATC application package includes the relevant portions of the Petition to Amend (PTA) submitted to the California Energy Commission in April 2014 as well as San Diego APCD permit application forms and air quality modeling files on a compact disc.

The Amended CECP consists of the installation of six natural-gas-fired combustion GE LMS 100 turbines with approximately 632 MW net output of simple-cycle electric generating capacity. In addition, the project includes the retirement and demolition of the Encina Power Station (EPS). Units 1 through 5 of EPS will be retired and all above-grade elements of the EPS power and support buildings will be demolished.

We have included a check for $$186,613 to cover the initial filing fee for the ATC application package. This application fee was calculated by a SDAPCD permit engineer. Also included is an NRG compliance certification statement.

Please note that we have requested an expedited review of the enclosed ATC application package. If you have any questions regarding this application package, please contact me at (760) 710-2156 (office) or 760-707-6833 (cell).

Sincerely,

George L. Piantka

George L. Piantka, PE
Director, Environmental Services
NRG Energy, West Region

Enclosures (filing fee check, compliance statement, APCD application forms, PTA, CD with modeling files):

cc: Dr. Steven Moore, San Diego APCD
Mike Monasmith, CEC
Tom Andrews, Sierra Research
Robert Mason, CH2M Hill
John McKinsey, Locke Lord
CEC Dockets

NRG Energy Inc.

REFERENCE NUMBER	DATE	VOUCHER	GROSS AMOUNT	DISCOUNT	NET AMOUNT
043014	04/30/2014	1700017893	$186,613.00	0.00	$186,613.00

VCZ081

CHECK NUMBER	DATE	VENDOR NUMBER	VENDOR NAME	TOTAL AMOUNT
1009626	05/02/14	0000238017	COUNTY OF SAN DIEGO	$186,613.00

Refer to above check number and voucher number when inquiring about your payment 0020

nrg

Bank Of New York Mellon
Pittsburgh, PA 15262

60-160
433

Date: 05/02/2014
Check Number: 1009626
Vendor Number: 0000238017

NRG Energy Inc.
211 Carnegie Center,
Princeton, NJ 08540

PAY *One hundred eighty six thousand six hundred thirteen and 00/100 Dollars*

Pay Exactly
***$186,613.00

TO THE ORDER OF

COUNTY OF SAN DIEGO
AIR POLLUTION CONTROL DISTRICT
10124 OLD GROVE ROAD
SAN DIEGO CA 92131

G. Gary Garcia

AUTHORIZED SIGNATURE
VOID WITHOUT SIGNATURE
VOID AFTER NINETY DAYS

⑈1009626⑈ ⑆043301601⑆ 185⑉0728⑈

APCD 116 (Rev. 04/07)

SAN DIEGO AIR POLLUTION CONTROL DISTRICT
10124 OLD GROVE ROAD, SAN DIEGO CA 92131-1649
PHONE (858) 586-2600 • FAX (858) 586-2601

PERMIT / REGISTRATION APPLICATION

SUBMITTAL OF THIS APPLICATION DOES NOT GRANT PERMISSION TO CONSTRUCT OR TO OPERATE EQUIPMENT EXCEPT AS SPECIFIED IN RULE 24(d)

IMPORTANT REMINDERS: Read instructions on the reverse side of this form prior to completing this application. Please ensure that all of the following are included before you submit the application:
☒ Appropriate Permit Fee ☒ Completed Supplemental Form(s) ☒ Signature on Application

REASON FOR SUBMITTAL OF APPLICATION: (check the appropriate item and enter Application (AP) or Permit to Operate (PO) number if required)

1. ☐ New Installation 2. ☐ Existing Unpermitted Equipment or Rule 11 Change 3. ☐ Modification of Existing Permitted Equipment
4. ☐ Amendment to Existing Authority to Construct or AP 5. ☐ Change of Equipment Location 6. ☐ Change of Equipment Ownership
7. ☐ Change of Permit Conditions 8. ☐ Change Permit to Operate Status to Inactive 9. ☐ Banking Emissions
10. ☐ Registration of Portable Equipment 11. ☒ Other (Specify) Modification to an existing stationary source
12. List affected AP/PO#(s): 791 792 793

APPLICANT INFORMATION

13. Name of Business (DBA) Carlsbad Energy Center LLC
14. Nature of Business Electric Power Generation
15. Does this organization own or operate any other APCD permitted equipment at this or any other adjacent locations in San Diego County? ☒Yes ☐No
If yes, list assigned location ID's listed on your PO's 791, 792, 793, 1770, 5238, 1267
16. Type of Ownership ☒ Corporation ☐ Partnership ☐ Individual Owner ☐ Government Agency ☐ Other
17. Name of Legal Owner (if different from DBA)

		A. Equipment Owner	**B. Authority to Construct (if different from A)**
18.	Name	Carlsbad Energy Center LLC	
19.	Mailing Address	5790 Fleet St., Suite 200	
20.	City	Carlsbad	
21.	State	CA Zip 92008	Zip
22.	Phone	(760) 710-2156 FAX (760) 710-2158	( ) FAX ( )
		C. Permit to Operate (if different from A)	**D. Billing Information (if different from A)**
23.	Name		
24.	Mailing Address		
25.	City		
26.	State	Zip	Zip
27.	Phone	( ) FAX ( )	( ) FAX ( )

EQUIPMENT/PROCESS INFORMATION: Type of Equipment: ☒ **Stationary** ☐ **Portable.**
If portable, will operation exceed 12 consecutive months at the same location ☐ **Yes** ☐ **No**

28. Equipment Location Address 4600 Carlsbad Blvd. City Carlsbad Parcel No.
29. State CA Zip 92008 Phone (760) 710-2156 FAX (760) 710-2158
30. Site Contact George L. Piantka, PE Title Director, Env. Business Phone (760) 710-2156
31. General Description of Equipment/Process Replacement of five natural gas fired boilers and one turbine with six new efficient natural gas fired simple cycle turbines.
32. Application Submitted by ☒ Owner ☐ Operator ☐ Contractor ☐ Consultant Affiliation

EXPEDITED APPLICATION PROCESSING: ☒ **I hereby request Expedited Application Processing and understand that:**

33. a) Expedited processing will incur additional fees and permits will not be issued until the additional fees are paid in full (see Rule 40(d)(8)(iv) for details).
b) Expedited processing is contingent on the availability of qualified staff. c) Once engineering review has begun this request cannot be cancelled.
d) Expedited processing does not guarantee action by any specific date nor does it guarantee permit approval.

I hereby certify that all information provided on this application is true and correct.

34. SIGNATURE Jerry Carter Date 5/8/2014
35. Print Name Jerry Carter Title Plant Manager
36. Company Carlsbad Energy Center LLC Phone (760) 268-4011 E-mail Address jerry.carter@nrgenergy.co

APCD USE ONLY

AP # ID # Cust. No. Sector: UTM's X Y SIC
Receipt # Date Amt Rec'd $ Fee Code
Engineering Contact Fee Code AP Fee $ T&M Renewal Fee $
Refund Claim # Date Amt $
Application Generated By NV# NC # Other Date Inspector

SAN DIEGO AIR POLLUTION CONTROL DISTRICT

SUPPLEMENTAL APPLICATION INFORMATION
FEE SCHEDULE 20 D, E, F, G, H

San Diego APCD Use Only
Appl. No.:
ID No.:

GAS TURBINE

COMPANY NAME: Carlsbad Energy Center LLC

ADDRESS: 5790 Fleet St., Suite 200, Carlsbad, CA 92008

A. EQUIPMENT AND PROCESS DESCRIPTION

ENGINE USE: *(Check all that apply.)*

Power Generation: 109 kw Steam Generation: ________ lbs/hr steam

Other (Specify capacity.): ____________________

ENGINE SPECIFICATIONS:

Manufacturer: General Electric Model No.: LMS100 S/N: TBD

HP Rating: ________ Fuel Consumption Rate: 984 MM BTU/HR

1. Type of Liquid Fuel Used*: N/A Fuel Rate(Specify Units): ________

   Maximum %sulfur by wt. in fuel*: ________ %

2. Type of Gaseous Fuel Used*: Natural Gas Fuel Rate: ________ cfh

   Maximum Grains PM/100DSCF @ 12% O_2: 0.2 grains/100dscf

B. EMISSION CONTROL EQUIPMENT *(Check all that apply)*

☐ Low NOx burner ☒ Water injection ☒ SCR w/ Ammonia injection ☐ Anhydrous ☐ Aqeuous

Describe the control equipment to be installed and submit its technical data:

Water injection and SCR

Oxidation Catalyst

C. EMISSION DATA

Provide the manufacturer's specifications and emission factors (lbs/1,000 lbs of fuel) for oxides of nitrogen (NOx), Carbon monoxide (CO), Hydrocarbons (HC), and particulate matter (PM) for the engine at different power settings with corresponding engine exhaust flow rates and temperatures.

25 **D. EXHAUST STACK AND BLDG. DIMENSIONS** *(if air quality modeling is required).*

26 Stack location: Ground __________ (i.e., roof top, wall, ground), direction: ☒ vertical ☐ horizontal

27 Stack dimensions: internal 13.5 ______ft. diameter, or _________ ft. wide x _________ft. long

28 Stack dimensions: external _________ft. diameter, or _________ ft. wide x _________ft. long

(If other shape, then supply sketch of stack cross section)

29 Use an attached page to provide this information for each engine at each power setting.

30 Stack height: Above roof: _________ ft. Above ground level: 90 ________ ft.

31 Site elevation above mean sea level (MSL) 30 _________ ft.

32 Building dimensions: length ________ ft.; width ________ ft.; height _______ ft.

(Supply sketch w/position of exhaust stack)

33 Supply a plot plan showing the test cell/stand location with respect to nearby streets, property lines, and buildings.

34 **E. OTHER EMISSION PRODUCING EQUIPMENT AT THE SITE**

35 APCD permitted ☒ Yes ☐ No

36 Non permitted ☐ Yes ☐ No

37 **F. ADDITIONAL INFORMATION** There will be six identical gas turbines at the site.

38 Unit 6: stack location is 1996935.753021 N, 6229715.609716 E.

39 ______________________________

40 **G. OPERATING SCHEDULE:*** Hours/day: 24 ________ Days/yr: 365 ________

* Emission calculations will be performed using these values and permit conditions may result to comply with applicable rules.

41 **Name of Preparer:** George L. Piantka, PE **Title:** Director, Env. Business

42 **Phone Number:** (760) 710-2156 **Date:** 5/8/2014

NOTE TO APPLICANT:

Before acting on an application for Authority to Construct or Permit to Operate, the District may require further information, plans, or specifications. Forms with insufficient information may be returned to the applicant for completion, which will cause a delay in application processing and may increase processing fees. The applicant should correspond with equipment and material manufacturers to obtain the information requested on this supplemental form.

SAN DIEGO AIR POLLUTION CONTROL DISTRICT

SUPPLEMENTAL APPLICATION INFORMATION
RULE 1200 TOXICS EVALUATION

San Diego APCD Use Only
Appl. No.:
ID No.:

(ALL REQUESTED INFORMATION IS IMPORTANT - PLEASE COMPLETE FULLY)

FACILITY NAME: Carlsbad Energy Center LLC - turbine 6

RELEASE POINT DATA (Examples of commonly encountered release points: the tip of an exhaust stack, a roof vent, an open window, an outdoor area or volume)

How are the emissions from this device released into the outdoor air? Check One

☒ Exhaust Stack or Duct ☐ Unducted Vent ☐ Released Through Windows or Doors

☐ Undirected Emissions (Anything other than the above categories)

If emissions are from a stack or a duct, check off the direction of flow. ☒ Vertical (Up)

☐ Horizontal ☐ Other (**Describe**): ______

If there is an obstruction to vertical flow, is the obstruction a: ☐ Rain Cap

☐ Flapper-Type Valve (Open when there is flow) ☐ Other (**Describe**): ______

Volume Source: If emissions are from a volume source, describe how the emitted gases, vapors, and/or particles get into the air and either the size of the opening (example - 3 ft x 4 ft window) that results in release or the approximate size of the release zone (example - paint spraying, 2' x 2' x 2' bread boxes): ______

______

______

Lateral dimension (ft): ______ Vertical dimension (ft): ______

Please provide the following **STACK** or **RELEASE POINT** information (where applicable):

Parameter	Emission Point #1	Emission Point #2	Emission Point #3
Height of release above ground (ft)	90		
Stack Diameter (ft)	13.5		
Exhaust Gas Temperature* (°F)	781.7		
Exhaust Gas Flow (acfm or fps)	1,022,475		
Distance to Property Line (+/- 10 ft)	295		

* Use "70 °F" or "Ambient" if unknown

FACILITY SITE MAP, PLOT PLAN, and RELEASE POINT INFORMATION

Please provide a copy of a **Thomas Bros. Map** showing the location of your facility.

Please also provide a **facility plot plan** showing the location of emission release point(s) at the facility, property lines, and the location (include approximate distance) and dimensions of buildings (estimated height, width, and length) closer than 100 ft from the release point.

Where is the subject release point located with respect to onsite buildings? Check Any Applicable

☐ On top of a building: Building Height ______ ft Width ______ ft Length ______ ft

☐ On the side of a building: Diameter of Opening ______ ft or Size of Opening ______ ft X ______ ft

☐ Adjacent to a building: Building Height ______ ft Width ______ ft Length ______ ft

SAN DIEGO AIR POLLUTION CONTROL DISTRICT

SUPPLEMENTAL APPLICATION INFORMATION
FEE SCHEDULE 20 D, E, F, G, H

San Diego APCD Use Only
Appl. No.:
ID No.:

GAS TURBINE

COMPANY NAME: Carlsbad Energy Center LLC

ADDRESS: 5790 Fleet St., Suite 200, Carlsbad, CA 92008

A. EQUIPMENT AND PROCESS DESCRIPTION

ENGINE USE: *(Check all that apply.)*

Power Generation: 108.8 kw   Steam Generation: ________ lbs/hr steam

Other (Specify capacity.): ________________

ENGINE SPECIFICATIONS:

Manufacturer: General Electric   Model No.: LMS100   S/N: TBD

HP Rating: ________   Fuel Consumption Rate: 984 MM BTU/HR

1. Type of Liquid Fuel Used*: N/A   Fuel Rate(Specify Units): ________

   Maximum %sulfur by wt. in fuel*: ________ %

2. Type of Gaseous Fuel Used*: Natural Gas   Fuel Rate: ________ cfh

   Maximum Grains PM/100DSCF @ 12% O_2: 0.2 grains/100dscf

B. EMISSION CONTROL EQUIPMENT *(Check all that apply)*

☐ Low NOx burner ☒ Water injection ☒ SCR w/ Ammonia injection ☐ Anhydrous ☐ Aqeuous

Describe the control equipment to be installed and submit its technical data:

Water injection and SCR

Oxidation Catalyst

C. EMISSION DATA

Provide the manufacturer's specifications and emission factors (lbs/1,000 lbs of fuel) for oxides of nitrogen (NOx), Carbon monoxide (CO), Hydrocarbons (HC), and particulate matter (PM) for the engine at different power settings with corresponding engine exhaust flow rates and temperatures.

25 **D. <u>EXHAUST STACK AND BLDG. DIMENSIONS</u>** *(if air quality modeling is required).*

26 Stack location: Ground ___________ (i.e., roof top, wall, ground), direction: ☒ vertical ☐ horizontal

27 Stack dimensions: internal 13.5 ____ ft. diameter, or _________ ft. wide x _________ ft. long

28 Stack dimensions: external _________ ft. diameter, or _________ ft. wide x _________ ft. long

(If other shape, then supply sketch of stack cross section)

29 Use an attached page to provide this information for each engine at each power setting.

30 Stack height: Above roof: _________ ft. Above ground level: 90 ________ ft.

31 Site elevation above mean sea level (MSL) 30 _________ ft.

32 Building dimensions: length ________ ft.; width ________ ft.; height _______ ft.

(Supply sketch w/position of exhaust stack)

33 Supply a plot plan showing the test cell/stand location with respect to nearby streets, property lines, and buildings.

34 **E. <u>OTHER EMISSION PRODUCING EQUIPMENT AT THE SITE</u>**

35 APCD permitted ☒ Yes ☐ No

36 Non permitted ☐ Yes ☐ No

37 **F. <u>ADDITIONAL INFORMATION</u>** There will be six identical gas turbines at the site.

38 Unit 7: stack location is 1996918.892948 N, 6229722.602286 E.

39 ____

40 **G. <u>OPERATING SCHEDULE:</u>*** Hours/day: 24 ________ Days/yr: 365 ________

* Emission calculations will be performed using these values and permit conditions may result to comply with applicable rules.

41 **Name of Preparer:** George L. Piantka, PE **Title:** Director, Env. Business

42 **Phone Number:** (760) 710-2156 **Date:** 5/8/2014

<u>NOTE TO APPLICANT:</u>

Before acting on an application for Authority to Construct or Permit to Operate, the District may require further information, plans, or specifications. Forms with insufficient information may be returned to the applicant for completion, which will cause a delay in application processing and may increase processing fees. The applicant should correspond with equipment and material manufacturers to obtain the information requested on this supplemental form.

SAN DIEGO AIR POLLUTION CONTROL DISTRICT

SUPPLEMENTAL APPLICATION INFORMATION
RULE 1200 TOXICS EVALUATION

San Diego APCD Use Only
Appl. No.:
ID No.:

(ALL REQUESTED INFORMATION IS IMPORTANT - PLEASE COMPLETE FULLY)

FACILITY NAME: Carlsbad Energy Center LLC - turbine 7

RELEASE POINT DATA (Examples of commonly encountered release points: the tip of an exhaust stack, a roof vent, an open window, an outdoor area or volume)

How are the emissions from this device released into the outdoor air? Check One
☒ Exhaust Stack or Duct ☐ Unducted Vent ☐ Released Through Windows or Doors
☐ Undirected Emissions (Anything other than the above categories)

If emissions are from a stack or a duct, check off the direction of flow. ☒ Vertical (Up)
☐ Horizontal ☐ Other (**Describe**): ____

If there is an obstruction to vertical flow, is the obstruction a: ☐ Rain Cap
☐ Flapper-Type Valve (Open when there is flow) ☐ Other (**Describe**): ____

Volume Source: If emissions are from a volume source, describe how the emitted gases, vapors, and/or particles get into the air and either the size of the opening (example - 3 ft x 4 ft window) that results in release or the approximate size of the release zone (example - paint spraying, 2' x 2' x 2' bread boxes): ____

Lateral dimension (ft): ____ Vertical dimension (ft): ____

Please provide the following **STACK** or **RELEASE POINT** information (where applicable):

Parameter	Emission Point #1	Emission Point #2	Emission Point #3
Height of release above ground (ft)	90		
Stack Diameter (ft)	13.5		
Exhaust Gas Temperature* (°F)	781.7		
Exhaust Gas Flow (acfm or fps)	1,022,475		
Distance to Property Line (+/- 10 ft)	299		

* Use "70 °F" or "Ambient" if unknown

FACILITY SITE MAP, PLOT PLAN, and RELEASE POINT INFORMATION

Please provide a copy of a **Thomas Bros. Map** showing the location of your facility.

Please also provide a **facility plot plan** showing the location of emission release point(s) at the facility, property lines, and the location (include approximate distance) and dimensions of buildings (estimated height, width, and length) closer than 100 ft from the release point.

Where is the subject release point located with respect to onsite buildings? Check Any Applicable

☐ On top of a building: Building Height ____ ft Width ____ ft Length ____ ft
☐ On the side of a building: Diameter of Opening ____ ft or Size of Opening ____ ft X ____ ft
☐ Adjacent to a building: Building Height ____ ft Width ____ ft Length ____ ft

SAN DIEGO AIR POLLUTION CONTROL DISTRICT

SUPPLEMENTAL APPLICATION INFORMATION
FEE SCHEDULE 20 D, E, F, G, H

San Diego APCD Use Only
Appl. No.:
ID No.:

GAS TURBINE

COMPANY NAME: Carlsbad Energy Center LLC

ADDRESS: 5790 Fleet St., Suite 200, Carlsbad, CA 92008

A. EQUIPMENT AND PROCESS DESCRIPTION

ENGINE USE: *(Check all that apply.)*

Power Generation: 108.8 kw Steam Generation: __________ lbs/hr steam

Other (Specify capacity.): ____________________

ENGINE SPECIFICATIONS:

Manufacturer: General Electric Model No.: LMS100 S/N: TBD

HP Rating: _________ Fuel Consumption Rate: 984 MM BTU/HR

1. Type of Liquid Fuel Used*: N/A Fuel Rate(Specify Units): ___________

   Maximum %sulfur by wt. in fuel*: ___________ %

2. Type of Gaseous Fuel Used*: Natural Gas Fuel Rate: ___________ cfh

   Maximum Grains PM/100DSCF @ 12% O_2: 0.2 grains/100dscf

B. EMISSION CONTROL EQUIPMENT *(Check all that apply)*

☐ Low NOx burner ☒ Water injection ☒ SCR w/ Ammonia injection ☐ Anhydrous ☐ Aqeuous

Describe the control equipment to be installed and submit its technical data:

Water injection and SCR

Oxidation Catalyst

C. EMISSION DATA

Provide the manufacturer's specifications and emission factors (lbs/1,000 lbs of fuel) for oxides of nitrogen (NOx), Carbon monoxide (CO), Hydrocarbons (HC), and particulate matter (PM) for the engine at different power settings with corresponding engine exhaust flow rates and temperatures.

25 **D.** **EXHAUST STACK AND BLDG. DIMENSIONS** *(if air quality modeling is required).*

26 Stack location: Ground __________ (i.e., roof top, wall, ground), direction: ☒ vertical ☐ horizontal

27 Stack dimensions: internal 13.5 ____ft. diameter, or _________ ft. wide x _________ft. long

28 Stack dimensions: external _________ft. diameter, or _________ ft. wide x _________ft. long

(If other shape, then supply sketch of stack cross section)

29 Use an attached page to provide this information for each engine at each power setting.

30 Stack height: Above roof: _________ ft. Above ground level: 90________ ft.

31 Site elevation above mean sea level (MSL) 30_________ ft.

32 Building dimensions: length ________ ft.; width ________ ft.; height _______ ft.

(Supply sketch w/position of exhaust stack)

33 Supply a plot plan showing the test cell/stand location with respect to nearby streets, property lines, and buildings.

34 **E.** **OTHER EMISSION PRODUCING EQUIPMENT AT THE SITE**

35 APCD permitted ☒ Yes ☐ No

36 Non permitted ☐ Yes ☐ No

37 **F.** **ADDITIONAL INFORMATION** There will be six identical gas turbines at the site.

38 Unit 8: stack location is 1996566.756396 N, 6229868.647913 E.

39 ____

40 **G.** **OPERATING SCHEDULE:*** Hours/day: 24________ Days/yr: 365________

* Emission calculations will be performed using these values and permit conditions may result to comply with applicable rules.

41 **Name of Preparer:** George L. Piantka, PE **Title:** Director, Env. Business

42 **Phone Number:** (760) 710-2156 **Date:** 5/8/2014

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SAN DIEGO AIR POLLUTION CONTROL DISTRICT

SUPPLEMENTAL APPLICATION INFORMATION	San Diego APCD Use Only
RULE 1200 TOXICS EVALUATION	Appl. No.: ID No.:

(ALL REQUESTED INFORMATION IS IMPORTANT - PLEASE COMPLETE FULLY)

FACILITY NAME: Carlsbad Energy Center LLC - turbine 8

RELEASE POINT DATA (Examples of commonly encountered release points: the tip of an exhaust stack, a roof vent, an open window, an outdoor area or volume)

How are the emissions from this device released into the outdoor air? Check One
☒ Exhaust Stack or Duct ☐ Unducted Vent ☐ Released Through Windows or Doors
☐ Undirected Emissions (Anything other than the above categories)

If emissions are from a stack or a duct, check off the direction of flow. ☒ Vertical (Up)
☐ Horizontal ☐ Other (**Describe**): ____________________

If there is an obstruction to vertical flow, is the obstruction a: ☐ Rain Cap
☐ Flapper-Type Valve (Open when there is flow) ☐ Other (**Describe**): ____________________

Volume Source: If emissions are from a volume source, describe how the emitted gases, vapors, and/or particles get into the air and either the size of the opening (example - 3 ft x 4 ft window) that results in release or the approximate size of the release zone (example - paint spraying, 2' x 2' x 2' bread boxes): ____________________

____

____

Lateral dimension (ft): ____________ Vertical dimension (ft): ____________

Please provide the following **STACK** or **RELEASE POINT** information (where applicable):

Parameter	Emission Point #1	Emission Point #2	Emission Point #3
Height of release above ground (ft)	90		
Stack Diameter (ft)	13.5		
Exhaust Gas Temperature* (°F)	781.7		
Exhaust Gas Flow (acfm or fps)	1,022,475		
Distance to Property Line (+/- 10 ft)	295		

* Use "70 °F" or "Ambient" if unknown

FACILITY SITE MAP, PLOT PLAN, and RELEASE POINT INFORMATION

Please provide a copy of a **Thomas Bros. Map** showing the location of your facility.

Please also provide a **facility plot plan** showing the location of emission release point(s) at the facility, property lines, and the location (include approximate distance) and dimensions of buildings (estimated height, width, and length) closer than 100 ft from the release point.

Where is the subject release point located with respect to onsite buildings? Check Any Applicable

☐ On top of a building: Building Height ____________ ft Width ____________ ft Length ____________ ft

☐ On the side of a building: Diameter of Opening ____________ ft or Size of Opening ____________ ft X ____________ ft

☐ Adjacent to a building: Building Height ____________ ft Width ____________ ft Length ____________ ft

SAN DIEGO AIR POLLUTION CONTROL DISTRICT

SUPPLEMENTAL APPLICATION INFORMATION	San Diego APCD Use Only
FEE SCHEDULE 20 D, E, F, G, H	Appl. No.:
	ID No.:

GAS TURBINE

COMPANY NAME: Carlsbad Energy Center LLC

ADDRESS: 5790 Fleet St., Suite 200, Carlsbad, CA 92008

A. EQUIPMENT AND PROCESS DESCRIPTION

ENGINE USE: *(Check all that apply.)*

Power Generation: 108.8 kw Steam Generation: ________ lbs/hr steam

Other (Specify capacity.): ________

ENGINE SPECIFICATIONS:

Manufacturer: General Electric Model No.: LMS100 S/N: TBD

HP Rating: ________ Fuel Consumption Rate: 984 MM BTU/HR

1. Type of Liquid Fuel Used*: N/A Fuel Rate(Specify Units): ________

   Maximum %sulfur by wt. in fuel*: ________ %

2. Type of Gaseous Fuel Used*: Natural Gas Fuel Rate: ________ cfh

   Maximum Grains PM/100DSCF @ 12% O_2: 0.2 grains/100dscf

B. EMISSION CONTROL EQUIPMENT *(Check all that apply)*

☐ Low NOx burner ☒ Water injection ☒ SCR w/ Ammonia injection ☐ Anhydrous ☐ Aqeuous

Describe the control equipment to be installed and submit its technical data:

Water injection and SCR

Oxidation Catalyst

C. EMISSION DATA

Provide the manufacturer's specifications and emission factors (lbs/1,000 lbs of fuel) for oxides of nitrogen (NOx), Carbon monoxide (CO), Hydrocarbons (HC), and particulate matter (PM) for the engine at different power settings with corresponding engine exhaust flow rates and temperatures.

25 **D. EXHAUST STACK AND BLDG. DIMENSIONS** *(if air quality modeling is required).*

26 Stack location: Ground __________ (i.e., roof top, wall, ground), direction: ☒ vertical ☐ horizontal

27 Stack dimensions: internal 13.5 _____ft. diameter, or _________ ft. wide x _________ft. long

28 Stack dimensions: external _________ft. diameter, or _________ ft. wide x _________ft. long

(If other shape, then supply sketch of stack cross section)

29 Use an attached page to provide this information for each engine at each power setting.

30 Stack height: Above roof: _________ ft. Above ground level: 90 ________ ft.

31 Site elevation above mean sea level (MSL) 30 _________ ft.

32 Building dimensions: length ________ ft.; width ________ ft.; height _______ ft.

(Supply sketch w/position of exhaust stack)

33 Supply a plot plan showing the test cell/stand location with respect to nearby streets, property lines, and buildings.

34 **E. OTHER EMISSION PRODUCING EQUIPMENT AT THE SITE**

35 APCD permitted ☒ Yes ☐ No

36 Non permitted ☐ Yes ☐ No

37 **F. ADDITIONAL INFORMATION** There will be six identical gas turbines at the site.

38 Unit 9: stack location is 1996549.896324 N, 6229875.640483 E.

39 ____

40 **G. OPERATING SCHEDULE:*** Hours/day: 24 ________ Days/yr: 365 ________

* Emission calculations will be performed using these values and permit conditions may result to comply with applicable rules.

41 **Name of Preparer:** George L. Piantka, PE **Title:** Director, Env. Business

42 **Phone Number:** (760) 710-2156 **Date:** 5/8/2014

NOTE TO APPLICANT:

Before acting on an application for Authority to Construct or Permit to Operate, the District may require further information, plans, or specifications. Forms with insufficient information may be returned to the applicant for completion, which will cause a delay in application processing and may increase processing fees. The applicant should correspond with equipment and material manufacturers to obtain the information requested on this supplemental form.

SAN DIEGO AIR POLLUTION CONTROL DISTRICT

SUPPLEMENTAL APPLICATION INFORMATION	San Diego APCD Use Only
RULE 1200 TOXICS EVALUATION	Appl. No.: ID No.:

(ALL REQUESTED INFORMATION IS IMPORTANT - PLEASE COMPLETE FULLY)

FACILITY NAME: Carlsbad Energy Center LLC - turbine 9

RELEASE POINT DATA (Examples of commonly encountered release points: the tip of an exhaust stack, a roof vent, an open window, an outdoor area or volume)

How are the emissions from this device released into the outdoor air? Check One

☒ Exhaust Stack or Duct ☐ Unducted Vent ☐ Released Through Windows or Doors
☐ Undirected Emissions (Anything other than the above categories)

If emissions are from a stack or a duct, check off the direction of flow. ☒ Vertical (Up)
☐ Horizontal ☐ Other (**Describe**): ____________________

If there is an obstruction to vertical flow, is the obstruction a: ☐ Rain Cap
☐ Flapper-Type Valve (Open when there is flow) ☐ Other (**Describe**): ____________________

Volume Source: If emissions are from a volume source, describe how the emitted gases, vapors, and/or particles get into the air and either the size of the opening (example - 3 ft x 4 ft window) that results in release or the approximate size of the release zone (example - paint spraying, 2' x 2' x 2' bread boxes): ____________________

____

____

Lateral dimension (ft): ____________ Vertical dimension (ft):____________

Please provide the following **STACK** or **RELEASE POINT** information (where applicable):

Parameter	Emission Point #1	Emission Point #2	Emission Point #3
Height of release above ground (ft)	90		
Stack Diameter (ft)	13.5		
Exhaust Gas Temperature* (°F)	781.7		
Exhaust Gas Flow (acfm or fps)	1,022,475		
Distance to Property Line (+/- 10 ft)	295		

* Use "70 °F" or "Ambient" if unknown

FACILITY SITE MAP, PLOT PLAN, and RELEASE POINT INFORMATION

Please provide a copy of a **Thomas Bros. Map** showing the location of your facility.

Please also provide a **facility plot plan** showing the location of emission release point(s) at the facility, property lines, and the location (include approximate distance) and dimensions of buildings (estimated height, width, and length) closer than 100 ft from the release point.

Where is the subject release point located with respect to onsite buildings? Check Any Applicable

☐ On top of a building: Building Height ____________ ft Width ____________ft Length ____________ft

☐ On the side of a building: Diameter of Opening ____________ft or Size of Opening ____________ft X ____________ft

☐ Adjacent to a building: Building Height ____________ft Width ____________ft Length ____________ft

SAN DIEGO AIR POLLUTION CONTROL DISTRICT

SUPPLEMENTAL APPLICATION INFORMATION
FEE SCHEDULE 20 D, E, F, G, H

San Diego APCD Use Only
Appl. No.:
ID No.:

GAS TURBINE

COMPANY NAME: Carlsbad Energy Center LLC

ADDRESS: 5790 Fleet St., Suite 200, Carlsbad, CA 92008

A. EQUIPMENT AND PROCESS DESCRIPTION

ENGINE USE: *(Check all that apply.)*

Power Generation: 108.8 kw   Steam Generation: ______ lbs/hr steam

Other (Specify capacity.): ______

ENGINE SPECIFICATIONS:

Manufacturer: General Electric   Model No.: LMS100   S/N: TBD

HP Rating: ______   Fuel Consumption Rate: 984 MM BTU/HR

1. Type of Liquid Fuel Used*: N/A   Fuel Rate(Specify Units): ______

   Maximum %sulfur by wt. in fuel*: ______ %

2. Type of Gaseous Fuel Used*: Natural Gas   Fuel Rate: ______ cfh

   Maximum Grains PM/100DSCF @ 12% O_2: 0.2 grains/100dscf

B. EMISSION CONTROL EQUIPMENT *(Check all that apply)*

☐ Low NOx burner   ☒ Water injection   ☒ SCR w/ Ammonia injection   ☐ Anhydrous   ☐ Aqeuous

Describe the control equipment to be installed and submit its technical data:

Water injection and SCR

Oxidation Catalyst

C. EMISSION DATA

Provide the manufacturer's specifications and emission factors (lbs/1,000 lbs of fuel) for oxides of nitrogen (NOx), Carbon monoxide (CO), Hydrocarbons (HC), and particulate matter (PM) for the engine at different power settings with corresponding engine exhaust flow rates and temperatures.

25 **D. EXHAUST STACK AND BLDG. DIMENSIONS** *(if air quality modeling is required).*

26 Stack location: Ground __________ (i.e., roof top, wall, ground), direction: ☒ vertical ☐ horizontal

27 Stack dimensions: internal 13.5 ______ft. diameter, or _________ ft. wide x _________ft. long

28 Stack dimensions: external _________ft. diameter, or _________ ft. wide x _________ft. long

(If other shape, then supply sketch of stack cross section)

29 Use an attached page to provide this information for each engine at each power setting.

30 Stack height: Above roof: _________ ft. Above ground level: 90 _________ ft.

31 Site elevation above mean sea level (MSL) 30 _________ ft.

32 Building dimensions: length _________ ft.; width ________ ft.; height ________ ft.

(Supply sketch w/position of exhaust stack)

33 Supply a plot plan showing the test cell/stand location with respect to nearby streets, property lines, and buildings.

34 **E. OTHER EMISSION PRODUCING EQUIPMENT AT THE SITE**

35 APCD permitted ☒ Yes ☐ No

36 Non permitted ☐ Yes ☐ No

37 **F. ADDITIONAL INFORMATION** There will be six identical gas turbines at the site.

38 Unit 10: stack location is 1995942.302237 N, 6230134.130458 E.

39 ______________________________

40 **G. OPERATING SCHEDULE:*** Hours/day: 24 ________ Days/yr: 365 ________

* Emission calculations will be performed using these values and permit conditions may result to comply with applicable rules.

41 **Name of Preparer:** George L. Piantka, PE **Title:** Director, Env. Business

42 **Phone Number:** (760) 710-2156 **Date:** 5/8/2014

NOTE TO APPLICANT:

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SAN DIEGO AIR POLLUTION CONTROL DISTRICT

SUPPLEMENTAL APPLICATION INFORMATION
RULE 1200 TOXICS EVALUATION

San Diego APCD Use Only
Appl. No.:
ID No.:

(ALL REQUESTED INFORMATION IS IMPORTANT - PLEASE COMPLETE FULLY)

1 **FACILITY NAME:** Carlsbad Energy Center LLC - turbine 10

2 **RELEASE POINT DATA** (Examples of commonly encountered release points: the tip of an exhaust stack, a
3 roof vent, an open window, an outdoor area or volume)

4 How are the emissions from this device released into the outdoor air? Check One
5 ☒ Exhaust Stack or Duct ☐ Unducted Vent ☐ Released Through Windows or Doors
6 ☐ Undirected Emissions (Anything other than the above categories)

7 If emissions are from a stack or a duct, check off the direction of flow. ☒ Vertical (Up)
8 ☐ Horizontal ☐ Other (**Describe**): ____________

9 If there is an obstruction to vertical flow, is the obstruction a: ☐ Rain Cap
10 ☐ Flapper-Type Valve (Open when there is flow) ☐ Other (**Describe**): ____________

11 **Volume Source:** If emissions are from a volume source, describe how the emitted gases, vapors, and/or
12 particles get into the air and either the size of the opening (example - 3 ft x 4 ft window) that results in release or
13 the approximate size of the release zone (example - paint spraying, 2' x 2' x 2' bread boxes): ____________
14 ____________
15 ____________

16 Lateral dimension (ft): ____________ Vertical dimension (ft):____________

17 Please provide the following **STACK** or **RELEASE POINT** information (where applicable):

Parameter	Emission Point #1	Emission Point #2	Emission Point #3
Height of release above ground (ft)	90		
Stack Diameter (ft)	13.5		
Exhaust Gas Temperature* (°F)	781.7		
Exhaust Gas Flow (acfm or fps)	1,022,475		
Distance to Property Line (+/- 10 ft)	288		

* Use "70 °F" or "Ambient" if unknown

18 **FACILITY SITE MAP, PLOT PLAN, and RELEASE POINT INFORMATION**

19 Please provide a copy of a **Thomas Bros. Map** showing the location of your facility.

20 Please also provide a **facility plot plan** showing the location of emission release point(s) at the facility, property
21 lines, and the location (include approximate distance) and dimensions of buildings (estimated height, width, and
22 length) closer than 100 ft from the release point.

23 Where is the subject release point located with respect to onsite buildings? Check Any Applicable
24 ☐ On top of a building: Building Height ________ ft Width________ft Length ________ft
25 ☐ On the side of a building: Diameter of Opening ________ft or Size of Opening ________ft X ________ft
26 ☐ Adjacent to a building: Building Height ________ft Width ________ft Length ________ft

SAN DIEGO AIR POLLUTION CONTROL DISTRICT

SUPPLEMENTAL APPLICATION INFORMATION
FEE SCHEDULE 20 D, E, F, G, H

San Diego APCD Use Only
Appl. No.:
ID No.:

GAS TURBINE

COMPANY NAME: Carlsbad Energy Center LLC

ADDRESS: 5790 Fleet St., Suite 200, Carlsbad, CA 92008

A. EQUIPMENT AND PROCESS DESCRIPTION

ENGINE USE: *(Check all that apply.)*

Power Generation: 108.8 kw Steam Generation: ______lbs/hr steam

Other (Specify capacity.): ______

ENGINE SPECIFICATIONS:

Manufacturer: General Electric Model No.: LMS100 S/N: TBD

HP Rating: ______ Fuel Consumption Rate: 984 MM BTU/HR

1. Type of Liquid Fuel Used*: N/A Fuel Rate(Specify Units): ______

   Maximum %sulfur by wt. in fuel*: ______ %

2. Type of Gaseous Fuel Used*: Natural Gas Fuel Rate: ______ cfh

   Maximum Grains PM/100DSCF @ 12% O_2: 0.2 grains/100dscf

B. EMISSION CONTROL EQUIPMENT *(Check all that apply)*

☐ Low NOx burner ☒ Water injection ☒ SCR w/ Ammonia injection ☐ Anhydrous ☐ Aqeuous

Describe the control equipment to be installed and submit its technical data:

Water injection and SCR

Oxidation Catalyst

C. EMISSION DATA

Provide the manufacturer's specifications and emission factors (lbs/1,000 lbs of fuel) for oxides of nitrogen (NOx), Carbon monoxide (CO), Hydrocarbons (HC), and particulate matter (PM) for the engine at different power settings with corresponding engine exhaust flow rates and temperatures.

25 **D. EXHAUST STACK AND BLDG. DIMENSIONS** *(if air quality modeling is required).*

26 Stack location: Ground (i.e., roof top, wall, ground), direction: ☒ vertical ☐ horizontal

27 Stack dimensions: internal 13.5 ft. diameter, or ______ ft. wide x ______ ft. long

28 Stack dimensions: external ______ ft. diameter, or ______ ft. wide x ______ ft. long

(If other shape, then supply sketch of stack cross section)

29 Use an attached page to provide this information for each engine at each power setting.

30 Stack height: Above roof: ______ ft. Above ground level: 90 ft.

31 Site elevation above mean sea level (MSL) 30 ft.

32 Building dimensions: length ______ ft.; width ______ ft.; height ______ ft.

(Supply sketch w/position of exhaust stack)

33 Supply a plot plan showing the test cell/stand location with respect to nearby streets, property lines, and buildings.

34 **E. OTHER EMISSION PRODUCING EQUIPMENT AT THE SITE**

35 APCD permitted ☒ Yes ☐ No

36 Non permitted ☐ Yes ☐ No

37 **F. ADDITIONAL INFORMATION** There will be six identical gas turbines at the site.

38 Unit 11: stack location is 1995925.442165 N, 6230141.123028 E.

39

40 **G. OPERATING SCHEDULE:*** Hours/day: 24 Days/yr: 365

* Emission calculations will be performed using these values and permit conditions may result to comply with applicable rules.

41 **Name of Preparer:** George L. Piantka, PE **Title:** Director, Env. Business

42 **Phone Number:** (760) 710-2156 **Date:** 5/8/2014

NOTE TO APPLICANT:

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SAN DIEGO AIR POLLUTION CONTROL DISTRICT

SUPPLEMENTAL APPLICATION INFORMATION
RULE 1200 TOXICS EVALUATION

San Diego APCD Use Only
Appl. No.:
ID No.:

(ALL REQUESTED INFORMATION IS IMPORTANT - PLEASE COMPLETE FULLY)

FACILITY NAME: Carlsbad Energy Center LLC - turbine 11

RELEASE POINT DATA (Examples of commonly encountered release points: the tip of an exhaust stack, a roof vent, an open window, an outdoor area or volume)

How are the emissions from this device released into the outdoor air? Check One

☒ Exhaust Stack or Duct ☐ Unducted Vent ☐ Released Through Windows or Doors

☐ Undirected Emissions (Anything other than the above categories)

If emissions are from a stack or a duct, check off the direction of flow. ☒ Vertical (Up)

☐ Horizontal ☐ Other (**Describe**): ____________

If there is an obstruction to vertical flow, is the obstruction a: ☐ Rain Cap

☐ Flapper-Type Valve (Open when there is flow) ☐ Other (**Describe**): ____________

Volume Source: If emissions are from a volume source, describe how the emitted gases, vapors, and/or particles get into the air and either the size of the opening (example - 3 ft x 4 ft window) that results in release or the approximate size of the release zone (example - paint spraying, 2' x 2' x 2' bread boxes): ____________

Lateral dimension (ft): ____________ Vertical dimension (ft): ____________

Please provide the following **STACK** or **RELEASE POINT** information (where applicable):

Parameter	Emission Point #1	Emission Point #2	Emission Point #3
Height of release above ground (ft)	90		
Stack Diameter (ft)	13.5		
Exhaust Gas Temperature* (°F)	781.7		
Exhaust Gas Flow (acfm or fps)	1,022,475		
Distance to Property Line (+/- 10 ft)	288		

* Use "70 °F" or "Ambient" if unknown

FACILITY SITE MAP, PLOT PLAN, and RELEASE POINT INFORMATION

Please provide a copy of a **Thomas Bros. Map** showing the location of your facility.

Please also provide a **facility plot plan** showing the location of emission release point(s) at the facility, property lines, and the location (include approximate distance) and dimensions of buildings (estimated height, width, and length) closer than 100 ft from the release point.

Where is the subject release point located with respect to onsite buildings? Check Any Applicable

☐ On top of a building: Building Height ________ ft Width ________ ft Length ________ ft

☐ On the side of a building: Diameter of Opening ________ ft or Size of Opening ________ ft X ________ ft

☐ Adjacent to a building: Building Height ________ ft Width ________ ft Length ________ ft

APCD 116 (Rev. 04/07)

SAN DIEGO AIR POLLUTION CONTROL DISTRICT
10124 OLD GROVE ROAD, SAN DIEGO CA 92131-1649
PHONE (858) 586-2600 • FAX (858) 586-2601

PERMIT / REGISTRATION APPLICATION

SUBMITTAL OF THIS APPLICATION DOES NOT GRANT PERMISSION TO CONSTRUCT OR TO OPERATE EQUIPMENT EXCEPT AS SPECIFIED IN RULE 24(d)

IMPORTANT REMINDERS: Read instructions on the reverse side of this form prior to completing this application. Please ensure that all of the following are included before you submit the application:
☒ Appropriate Permit Fee ☒ Completed Supplemental Form(s) ☒ Signature on Application

REASON FOR SUBMITTAL OF APPLICATION: (check the appropriate item and enter Application (AP) or Permit to Operate (PO) number if required)

1. ☐ New Installation 2. ☐ Existing Unpermitted Equipment or Rule 11 Change 3. ☐ Modification of Existing Permitted Equipment
4. ☐ Amendment to Existing Authority to Construct or AP 5. ☐ Change of Equipment Location 6. ☐ Change of Equipment Ownership
7. ☐ Change of Permit Conditions 8. ☐ Change Permit to Operate Status to Inactive 9. ☐ Banking Emissions
10. ☐ Registration of Portable Equipment 11. ☒ Other (Specify) Modification to an existing stationary source
12. List affected AP/PO#(s): 791 792 793

APPLICANT INFORMATION

13. Name of Business (DBA) Carlsbad Energy Center LLC
14. Nature of Business Electric Power Generation
15. Does this organization own or operate any other APCD permitted equipment at this or any other adjacent locations in San Diego County? ☒Yes ☐No
If yes, list assigned location ID's listed on your PO's 791, 792, 793, 1770, 5238, 1267
16. Type of Ownership ☒ Corporation ☐ Partnership ☐ Individual Owner ☐ Government Agency ☐ Other
17. Name of Legal Owner (if different from DBA)

		A. Equipment Owner	**B. Authority to Construct (if different from A)**
18.	Name	Carlsbad Energy Center LLC	
19.	Mailing Address	5790 Fleet St., Suite 200	
20.	City	Carlsbad	
21.	State	CA Zip 92008	Zip
22.	Phone	(760) 710-2156 FAX (760) 710-2158	( ) FAX ( )
		C. Permit to Operate (if different from A)	**D. Billing Information (if different from A)**
23.	Name		
24.	Mailing Address		
25.	City		
26.	State	Zip	Zip
27.	Phone	( ) FAX ( )	( ) FAX ( )

EQUIPMENT/PROCESS INFORMATION: Type of Equipment: ☒ Stationary ☐ Portable.
If portable, will operation exceed 12 consecutive months at the same location ☐ Yes ☐ No

28. Equipment Location Address 4600 Carlsbad Blvd. City Carlsbad Parcel No.
29. State CA Zip 92008 Phone (760) 710-2156 FAX (760) 710-2158
30. Site Contact George L. Piantka, PE Title Director, Environmental Busine Phone (760) 710-2156
31. General Description of Equipment/Process Emergency Generator
32. Application Submitted by ☒ Owner ☐ Operator ☐ Contractor ☐ Consultant Affiliation

EXPEDITED APPLICATION PROCESSING: ☒ **I hereby request Expedited Application Processing and understand that:**

33. a) Expedited processing will incur additional fees and permits will not be issued until the additional fees are paid in full (see Rule 40(d)(8)(iv) for details).
b) Expedited processing is contingent on the availability of qualified staff. c) Once engineering review has begun this request cannot be cancelled.
d) Expedited processing does not guarantee action by any specific date nor does it guarantee permit approval.

I hereby certify that all information provided on this application is true and correct.

34. SIGNATURE Jerry Carter Date 5/8/2014
35. Print Name Jerry Carter Title Plant Manager
36. Company Carlsbad Energy Center LLC Phone (760) 268-4011 E-mail Address jerry.carter@nrgenergy.co

APCD USE ONLY

AP # ID # Cust. No. Sector: UTM's X Y SIC
Receipt # Date Amt Rec'd $ Fee Code
Engineering Contact Fee Code AP Fee $ T&M Renewal Fee $
Refund Claim # Date Amt $
Application Generated By NV# NC # Other Date Inspector

4.07 – TW/flm

SAN DIEGO AIR POLLUTION CONTROL DISTRICT

SUPPLEMENTAL APPLICATION INFORMATION		San Diego APCD Use Only
FEE SCHEDULE 34A-J		Appl. No.:
		ID No.:

INTERNAL COMBUSTION ENGINES

Company Name: Carlsbad Energy Center LLC

Equipment Address: 5790 Fleet St., Suite 200, Carlsbad, CA 92008

Reason for submitting application:

☐ Existing Unit, Date of Installation ________ ☐ Compliance with 2004 Diesel Engine ATCM

☐ Replacement of Existing Unit; ☒ New or Additional Unit

A. EQUIPMENT DESCRIPTION

Engine Mfr.: Caterpillar Model: C15 ATAAC S/N: TBD

Engine hp Rating: 779 Fuel Type: ☒ diesel* ☐ natural gas ☐ gasoline

Combination of fuels (specify) ________

Engine Equipment: ☒ turbocharger ☒ aftercooler ☐ 4-degree retard of fuel injection

☐ exhaust gas recirculation ☐ lean burn

☐ pre-chamber combustion ☐ air/fuel controller

☐ diesel particulate filter (attach manufacturer's specification for efficiency, and/or ARB verification.)

☐ other add-on control technology (attach manufacturer's specification for efficiency, and/or ARB verification.)

(Specify) ________

☐ crankcase (blow-by) emission control equipment

(Specify) ________ Model ________

Describe any in stack emission control and/or monitoring devices. (i.e., catalytic converter)

____

____

* Diesel fuel must be Certified California Diesel (CARB Diesel).

B PROCESS DESCRIPTION

Engine Drives: ☐ compressor ____ cfm ☐ pump ____ gpm

☒ generator 500 kw ☐ other (specify) ________

Equipment is: ☐ portable ☒ stationary ☐ continuous service

☐ peak shaving electrical supply ☐ cogeneration

☒ emergency electrical supply ☐ used at any time

C. OPERATING SCHEDULE (typical)

	Hours/day	Days/week	Weeks/year
Average	1	1	50
Maximum			

Equipped with a non-resettable hour meter? ☒ yes ☐ no

D. FUEL CONSUMPTION AND EMISSIONS (@100% Load)

Liquid Fuel: 35.9 gal/hr ________ gal/wk ________ gal/yr

Gaseous Fuel: ________ gal/hr ________ gal/wk ________ gal/yr

________ ___/hr ________ ___/wk ________ ___/yr

Exhaust Emission*:	LB/HR	g/HP-HR	g/HR	PPM
Carbon Monoxides (CO)		0.39		
Nitrogen Oxides (NOx)		2.7		
Hydrocarbons (HC) (Non CH4)		0.03		
Sulfur Oxides (SOx) @ 12% CO2				15
Particulate Matter (PM)		0.03		

*Please attach manufacturer's specifications or source of exhaust emission data.

Exhaust Temperature 1263 °F

Fuel Supplier: ________________________________

Fuel Sulfur Content: 15ppm % Sulfur (% wt. as S. (Liquid Fuel))

Fuel Sulfur Content: ________ % Sulfur (% vol. as H2S (Gaseous Fuel))

Engine year of manufacture: 2013

CARB Certification No.: N/A

EPA Certification No.: TBD

E. RULE 1200 TOXICS EVALUATION:

FACILITY SITE MAP Please provide a copy of a **Thomas Bros. Map** showing the geographic location of your facility. This helps by making it possible for the District to use a Geographic Information System to identify community residents and workers who may be impacted by emissions from your facility.

PLOT PLAN Please also provide a **facility plot plan or diagram** (need not be to scale as long as distances of key features from reference points are shown) showing the **location of emission point(s)** at the facility, property lines, and the **location** and **dimensions of buildings** (estimated height, width, and length) that are closer than 100 ft. from the emission point. This diagram helps by making it possible for the District to efficiently set-up the inputs for a health risk evaluation. Inaccurate information may adversely affect the outcome of the evaluation.

EMISSION POINT DATA Determine if your emission source(s) are ducted sources or if they are unducted/fugitive sources and provide the necessary data below. (**Examples** of commonly encountered emission points: **Ducted or Stack Emissions** - an exhaust pipe or stack, a roof ventilation duct; **Unducted Emissions** - anything not emitted through a duct, pipe, or stack, for instance, an open window or an outdoor area or volume.)

1. **Ducted or Stack Emissions** (For 1 or more emission points). Estimate values if you are unsure.

Parameter	Point #1	Point #2	Point #3	Point #4	Point #5	Point #6
Height of Exhaust above ground (ft)	70					
Stack Diameter (or length/width) (ft)	0.46					
Exhaust Gas Temperature* (°F)	1263					
Exhaust Gas Flow (actual cfm or fps)	3185					
Is Exhaust Vertical (Yes or No)	yes					
Raincap? (None, Flapper Valve, Raincap)	none					
Distance to Property Line (+/- 10 ft)	292					

* Use "70 °F" or "Ambient" if unknown

2. **Unducted Emissions** (For 1 or more emission points). Estimate if you are unsure.

Describe how unducted gases, vapors, and/or particles get into the outside air. Provide a brief description of the process or operation for each unducted emission point. If unducted emissions come out of building openings such as doors or windows, estimate the **size of the opening** (example – 3 ft x 4 ft window).

If unducted emissions originate outside your buildings, estimate the **size of the emission zone** (example - paint spraying 2' x 2' x 2' bread boxes).

RECEPTOR DATA A receptor is a residence or business whose occupants could be exposed to toxic emissions from your facility. In order to estimate the risk to nearby receptors, please provide the distance from the emission point to the nearest residence and to the nearest business.

Distance to nearest residence 2,260 ft

Distance to nearest business 2,201 ft

Distance to nearest school 5,420 ft

Name of Preparer: George L. Piantka, PE **Title:** Director, Env. Business

Phone No.: (760) 710-2156 E-mail: george.Piantka@nrgenergy. **Date:** 5/8/2014

NOTE TO APPLICANT:

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SAN DIEGO AIR POLLUTION CONTROL DISTRICT

SUPPLEMENTAL APPLICATION INFORMATION
RULE 1200 TOXICS EVALUATION

San Diego APCD Use Only
Appl. No.:
ID No.:

(ALL REQUESTED INFORMATION IS IMPORTANT - PLEASE COMPLETE FULLY)

FACILITY NAME: Carlsbad Energy Center LLC - emergency generator

RELEASE POINT DATA (Examples of commonly encountered release points: the tip of an exhaust stack, a roof vent, an open window, an outdoor area or volume)

How are the emissions from this device released into the outdoor air? Check One

☒ Exhaust Stack or Duct ☐ Unducted Vent ☐ Released Through Windows or Doors

☐ Undirected Emissions (Anything other than the above categories)

If emissions are from a stack or a duct, check off the direction of flow. ☒ Vertical (Up)

☐ Horizontal ☐ Other (**Describe**): ____________

If there is an obstruction to vertical flow, is the obstruction a: ☐ Rain Cap

☐ Flapper-Type Valve (Open when there is flow) ☐ Other (**Describe**): ____________

Volume Source: If emissions are from a volume source, describe how the emitted gases, vapors, and/or particles get into the air and either the size of the opening (example - 3 ft x 4 ft window) that results in release or the approximate size of the release zone (example - paint spraying, 2' x 2' x 2' bread boxes): ____________

____

____

Lateral dimension (ft): ____________ Vertical dimension (ft):____________

Please provide the following **STACK** or **RELEASE POINT** information (where applicable):

Parameter	Emission Point #1	Emission Point #2	Emission Point #3
Height of release above ground (ft)	70		
Stack Diameter (ft)	0.46		
Exhaust Gas Temperature* (°F)	1,263		
Exhaust Gas Flow (acfm or fps)	3,185		
Distance to Property Line (+/- 10 ft)	292		

* Use "70 °F" or "Ambient" if unknown

FACILITY SITE MAP, PLOT PLAN, and RELEASE POINT INFORMATION

Please provide a copy of a **Thomas Bros. Map** showing the location of your facility.

Please also provide a **facility plot plan** showing the location of emission release point(s) at the facility, property lines, and the location (include approximate distance) and dimensions of buildings (estimated height, width, and length) closer than 100 ft from the release point.

Where is the subject release point located with respect to onsite buildings? Check Any Applicable

☐ On top of a building: Building Height ____________ ft Width____________ft Length ____________ft

☐ On the side of a building: Diameter of Opening ____________ft or Size of Opening ____________ft X ____________ft

☐ Adjacent to a building: Building Height ____________ft Width ____________ft Length ____________ft

APCD 116 (Rev. 04/07)

SAN DIEGO AIR POLLUTION CONTROL DISTRICT
10124 OLD GROVE ROAD, SAN DIEGO CA 92131-1649
PHONE (858) 586-2600 • FAX (858) 586-2601

PERMIT / REGISTRATION APPLICATION

SUBMITTAL OF THIS APPLICATION DOES NOT GRANT PERMISSION TO CONSTRUCT OR TO OPERATE EQUIPMENT EXCEPT AS SPECIFIED IN RULE 24(d)

IMPORTANT REMINDERS: Read instructions on the reverse side of this form prior to completing this application. Please ensure that all of the following are included before you submit the application:
☒ Appropriate Permit Fee ☒ Completed Supplemental Form(s) ☒ Signature on Application

REASON FOR SUBMITTAL OF APPLICATION: (check the appropriate item and enter Application (AP) or Permit to Operate (PO) number if required)

1. ☐ New Installation 2. ☐ Existing Unpermitted Equipment or Rule 11 Change 3. ☐ Modification of Existing Permitted Equipment
4. ☐ Amendment to Existing Authority to Construct or AP 5. ☐ Change of Equipment Location 6. ☐ Change of Equipment Ownership
7. ☐ Change of Permit Conditions 8. ☐ Change Permit to Operate Status to Inactive 9. ☐ Banking Emissions
10. ☐ Registration of Portable Equipment 11. ☒ Other (Specify) Modification to an existing stationary source
12. List affected AP/PO#(s): 791 792 793

APPLICANT INFORMATION

13. Name of Business (DBA) Carlsbad Energy Center LLC
14. Nature of Business Electric Power Generation
15. Does this organization own or operate any other APCD permitted equipment at this or any other adjacent locations in San Diego County? ☒Yes ☐No
If yes, list assigned location ID's listed on your PO's 791, 792, 793, 1770, 5238, 1267
16. Type of Ownership ☒ Corporation ☐ Partnership ☐ Individual Owner ☐ Government Agency ☐ Other
17. Name of Legal Owner (if different from DBA)

	A. Equipment Owner	**B. Authority to Construct (if different from A)**
18. Name	Carlsbad Energy Center LLC	
19. Mailing Address	5790 Fleet St., Suite 200	
20. City	Carlsbad	
21. State	CA Zip 92008	Zip
22. Phone	(760) 710-2156 FAX (760) 710-2158	( ) FAX ( )
	C. Permit to Operate (if different from A)	**D. Billing Information (if different from A)**
23. Name		
24. Mailing Address		
25. City		
26. State	Zip	Zip
27. Phone	( ) FAX ( )	( ) FAX ( )

EQUIPMENT/PROCESS INFORMATION: Type of Equipment: ☒ Stationary ☐ Portable.
If portable, will operation exceed 12 consecutive months at the same location ☐ Yes ☐ No

28. Equipment Location Address 4600 Carlsbad Blvd. City Carlsbad Parcel No.
29. State CA Zip 92008 Phone (760) 710-2156 FAX (760) 710-2158
30. Site Contact George L. Piantka, PE Title Director, Environmental Busine Phone (760) 710-2156
31. General Description of Equipment/Process Emergency Firepump

32. Application Submitted by ☒ Owner ☐ Operator ☐ Contractor ☐ Consultant Affiliation

EXPEDITED APPLICATION PROCESSING: ☒ **I hereby request Expedited Application Processing and understand that:**

33. a) Expedited processing will incur additional fees and permits will not be issued until the additional fees are paid in full (see Rule 40(d)(8)(iv) for details).
b) Expedited processing is contingent on the availability of qualified staff. c) Once engineering review has begun this request cannot be cancelled.
d) Expedited processing does not guarantee action by any specific date nor does it guarantee permit approval.

I hereby certify that all information provided on this application is true and correct.

34. SIGNATURE Jerry Carter Date 5/8/2014
35. Print Name Jerry Carter Title Plant Manager
36. Company Carlsbad Energy Center LLC Phone (760) 268-4011 E-mail Address jerry.carter@nrgenergy.co

APCD USE ONLY

AP # ID # Cust. No. Sector: UTM's X Y SIC
Receipt # Date Amt Rec'd $ Fee Code
Engineering Contact Fee Code AP Fee $ T&M Renewal Fee $
Refund Claim # Date Amt $
Application Generated By NV# NC # Other Date Inspector

4.07 – TW/flm

SAN DIEGO AIR POLLUTION CONTROL DISTRICT

SUPPLEMENTAL APPLICATION INFORMATION	San Diego APCD Use Only
FEE SCHEDULE 34A-J	Appl. No.:
	ID No.:

INTERNAL COMBUSTION ENGINES

Company Name: Carlsbad Energy Center LLC

Equipment Address: 5790 Fleet St., Suite 200, Carlsbad, CA 92008

Reason for submitting application:

☐ Existing Unit, Date of Installation ________ ☐ Compliance with 2004 Diesel Engine ATCM

☐ Replacement of Existing Unit; ☒ New or Additional Unit

A. EQUIPMENT DESCRIPTION

Engine Mfr.: Clarke Model: JW6H-UFADF0 S/N: TBD

Engine hp Rating: 327 Fuel Type: ☒ diesel* ☐ natural gas ☐ gasoline

Combination of fuels (specify) ________

Engine Equipment: ☒ turbocharger ☒ aftercooler ☐ 4-degree retard of fuel injection

☐ exhaust gas recirculation ☐ lean burn

☐ pre-chamber combustion ☐ air/fuel controller

☐ diesel particulate filter (attach manufacturer's specification for efficiency, and/or ARB verification.)

☐ other add-on control technology (attach manufacturer's specification for efficiency, and/or ARB verification.)

(Specify) ________

☐ crankcase (blow-by) emission control equipment

(Specify) ________ Model ________

Describe any in stack emission control and/or monitoring devices. (i.e., catalytic converter)

____

____

* Diesel fuel must be Certified California Diesel (CARB Diesel).

B PROCESS DESCRIPTION

Engine Drives: ☐ compressor ____ cfm ☒ pump ____ gpm

☐ generator ____ kw ☐ other (specify) ________

Equipment is: ☐ portable ☒ stationary ☐ continuous service

☐ peak shaving electrical supply ☐ cogeneration

☒ emergency electrical supply ☐ used at any time

C. OPERATING SCHEDULE (typical)

	Hours/day	Days/week	Weeks/year
Average	1	1	50
Maximum			

Equipped with a non-resettable hour meter? ☒ yes ☐ no

D. FUEL CONSUMPTION AND EMISSIONS (@100% Load)

Liquid Fuel: 14.8 gal/hr ________ gal/wk ________ gal/yr

Gaseous Fuel: ________ gal/hr ________ gal/wk ________ gal/yr

________ ___/hr ________ ___/wk ________ ___/yr

Exhaust Emission*:	LB/HR	g/HP-HR	g/HR	PPM
Carbon Monoxides (CO)		0.70		
Nitrogen Oxides (NOx)		2.60		
Hydrocarbons (HC) (Non CH4)		0.10		
Sulfur Oxides (SOx) @ 12% CO2				15
Particulate Matter (PM)		0.11		

*Please attach manufacturer's specifications or source of exhaust emission data.

Exhaust Temperature 842 ^{o}F

Fuel Supplier: ____________________

Fuel Sulfur Content: 15ppm % Sulfur (% wt. as S. (Liquid Fuel))

Fuel Sulfur Content: ________ % Sulfur (% vol. as H2S (Gaseous Fuel))

Engine year of manufacture: 2013

CARB Certification No.: N/A

EPA Certification No.: DJDXL09.0114-005

E. RULE 1200 TOXICS EVALUATION:

FACILITY SITE MAP Please provide a copy of a **Thomas Bros. Map** showing the geographic location of your facility. This helps by making it possible for the District to use a Geographic Information System to identify community residents and workers who may be impacted by emissions from your facility.

PLOT PLAN Please also provide a **facility plot plan or diagram** (need not be to scale as long as distances of key features from reference points are shown) showing the **location of emission point(s)** at the facility, property lines, and the **location** and **dimensions of buildings** (estimated height, width, and length) that are closer than 100 ft. from the emission point. This diagram helps by making it possible for the District to efficiently set-up the inputs for a health risk evaluation. Inaccurate information may adversely affect the outcome of the evaluation.

EMISSION POINT DATA Determine if your emission source(s) are ducted sources or if they are unducted/fugitive sources and provide the necessary data below. (**Examples** of commonly encountered emission points: **Ducted or Stack Emissions** - an exhaust pipe or stack, a roof ventilation duct; **Unducted Emissions** - anything not emitted through a duct, pipe, or stack, for instance, an open window or an outdoor area or volume.)

58 1. **Ducted or Stack Emissions** (For 1 or more emission points). Estimate values if you are unsure.

Parameter	Point #1	Point #2	Point #3	Point #4	Point #5	Point #6
Height of Exhaust above ground (ft)	20					
Stack Diameter (or length/width) (ft)	0.5					
Exhaust Gas Temperature* (°F)	842					
Exhaust Gas Flow (actual cfm or fps)	1,867					
Is Exhaust Vertical (Yes or No)	yes					
Raincap? (None, Flapper Valve, Raincap)	none					
Distance to Property Line (+/- 10 ft)	299					

* Use "70 °F" or "Ambient" if unknown

59 2. **Unducted Emissions** (For 1 or more emission points). Estimate if you are unsure.

60 **Describe how unducted gases, vapors, and/or particles get into the outside air.** Provide a brief description of the
61 process or operation for each unducted emission point. If unducted emissions come out of building openings such as
62 doors or windows, estimate the **size of the opening** (example – 3 ft x 4 ft window).

63 If unducted emissions originate outside your buildings, estimate the **size of the emission zone** (example - paint spraying
64 2' x 2' x 2' bread boxes).

65 ______

66 ______

67 ______

68 ______

69 ______

70 ______

71 ______

72 ______

73 **RECEPTOR DATA** A receptor is a residence or business whose occupants could be exposed to toxic emissions from
74 your facility. In order to estimate the risk to nearby receptors, please provide the distance from the emission point to the
75 nearest residence and to the nearest business.

76 Distance to nearest residence 2,595 ft

77 Distance to nearest business 2,402 ft

78 Distance to nearest school 5,075 ft

79 **Name of Preparer:** George L. Piantka, PE **Title:** Director, Env. Business

80 **Phone No.:** (760) 710-2156 E-mail: george.piantka@nrgenergy. **Date:** 5/8/2014

NOTE TO APPLICANT:

Before acting on an application for Authority to Construct or Permit to Operate, the District may require further information, plans, or specifications. Forms with insufficient information may be returned to the applicant for completion, which will cause a delay in application processing and may increase processing fees. The applicant should correspond with equipment and material manufacturers to obtain the information requested on this supplemental form.

SAN DIEGO AIR POLLUTION CONTROL DISTRICT

SUPPLEMENTAL APPLICATION INFORMATION
RULE 1200 TOXICS EVALUATION

San Diego APCD Use Only
Appl. No.:
ID No.:

(ALL REQUESTED INFORMATION IS IMPORTANT - PLEASE COMPLETE FULLY)

FACILITY NAME: Carlsbad Energy Center LLC - diesel firepump

RELEASE POINT DATA (Examples of commonly encountered release points: the tip of an exhaust stack, a roof vent, an open window, an outdoor area or volume)

How are the emissions from this device released into the outdoor air? Check One

☒ Exhaust Stack or Duct ☐ Unducted Vent ☐ Released Through Windows or Doors

☐ Undirected Emissions (Anything other than the above categories)

If emissions are from a stack or a duct, check off the direction of flow. ☒ Vertical (Up)

☐ Horizontal ☐ Other (**Describe**): ____________________

If there is an obstruction to vertical flow, is the obstruction a: ☐ Rain Cap

☐ Flapper-Type Valve (Open when there is flow) ☐ Other (**Describe**): ____________________

Volume Source: If emissions are from a volume source, describe how the emitted gases, vapors, and/or particles get into the air and either the size of the opening (example - 3 ft x 4 ft window) that results in release or the approximate size of the release zone (example - paint spraying, 2' x 2' x 2' bread boxes): ____________________

____

____

Lateral dimension (ft): ____________ Vertical dimension (ft):____________

Please provide the following **STACK** or **RELEASE POINT** information (where applicable):

Parameter	Emission Point #1	Emission Point #2	Emission Point #3
Height of release above ground (ft)	20		
Stack Diameter (ft)	0.5		
Exhaust Gas Temperature* (°F)	842		
Exhaust Gas Flow (acfm or fps)	1,867		
Distance to Property Line (+/- 10 ft)	299		

* Use "70 °F" or "Ambient" if unknown

FACILITY SITE MAP, PLOT PLAN, and RELEASE POINT INFORMATION

Please provide a copy of a **Thomas Bros. Map** showing the location of your facility.

Please also provide a **facility plot plan** showing the location of emission release point(s) at the facility, property lines, and the location (include approximate distance) and dimensions of buildings (estimated height, width, and length) closer than 100 ft from the release point.

Where is the subject release point located with respect to onsite buildings? Check Any Applicable

☐ On top of a building: Building Height ____________ ft Width____________ft Length ____________ft

☐ On the side of a building: Diameter of Opening ____________ft or Size of Opening ____________ft X ____________ft

☐ Adjacent to a building: Building Height ____________ft Width ____________ft Length ____________ft

SECTION 2.0

Project Description

The California Energy Commission (CEC), in its Final Decision dated June 2012,[1] approved the Carlsbad Energy Center Project (07-AFC-06C; CECP) in the city of Carlsbad, San Diego County. The project owner, Carlsbad Energy Center LLC, an indirect, wholly owned subsidiary of NRG Energy, Inc. (Project Owner), proposes to modify the project as licensed by the CEC (the "Licensed CECP") to improve the project's ability to meet regional electrical resource needs, as determined by San Diego Gas and Electric Company (SDG&E). These improvements include contributing to electricity reserves that generally will ensure a reliable energy supply, and providing local and electrical transmission grid support in San Diego County and the southern California region. The proposed changes also address and mitigate many of the expressed reasons for community opposition to the project voiced when the project was licensed. Consequently, the City of Carlsbad supports the amended project, as indicated in its letter of support dated April 23, 2014, which is attached as Appendix 2B (the "City Letter").

This section describes the design, construction, and operation of the proposed amended CECP (the "Amended CECP"), including associated linear features and facilities, and provides a discussion of the proposed demolition of the Cabrillo Power I LLC[2] Encina Power Station (EPS) facilities after the Amended CECP construction is complete.

This Petition to Amend (PTA) includes the above-grade decommissioning and removal of EPS Units 1 through 5 and other existing buildings and support facilities at EPS, after the Amended CECP is online. The shutdown of existing EPS Units 1 through 5 will provide emission offsets and will comply with the State of California's Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling (Once-Through Cooling Policy). The PTA also proposes the above-grade demolition of the existing EPS buildings and related equipment west of the railroad tracks that divide the Amended CECP site from the EPS generation facilities and switchyard. The parcel of land on which the EPS is situated and the CECP will be situated is referred to herein as the "Cabrillo Parcel." The Amended CECP is proposed to come online by fourth quarter 2017, and demolition of the above-grade EPS generating units, buildings, and related equipment would commence as soon as practicable after the Amended CECP is online.

This PTA evolved from an agreement entered into by the project owner, the City of Carlsbad, and SDG&E in January 2014 that resolves many of the points of community opposition with the Licensed CECP and addresses the type of generation that is better suited to meet SDG&E's generation needs in northern San Diego County (see the City Agreement in Appendix 2A). The Licensed CECP consisted of two 1-on-1 combined-cycle units, while the Amended CECP will consist of six simple-cycle combustion turbine units. By using six smaller, fast-start, peaking units instead of two larger combined-cycle trains, the Amended CECP will have greater operational flexibility, whereby any combination of the six units could be used to generate electricity as needed to supply grid demand. The six smaller peaking units will also be much better suited to allow the continued integration of cyclical and intermittent renewable generation, as all of the net output from the Amended CECP will be fast start and readily dispatchable. Additionally, the Amended CECP will retire the older EPS generating system and will eliminate the use of once-through sea water cooling. For the Amended CECP's raw water needs, the project will preferentially use California Code of Regulations (CCR) Title 22 reclaimed water, thereby minimizing the use of potable water onsite. Additionally, following demolition of the aboveground EPS structures, the western portions of the Cabrillo Parcel would be available for non-power-production redevelopment, an important issue for the neighboring community.

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[1] California Energy Commission. 2012. *Carlsbad Energy Center Project Commission Decision.* June. Available online at: http://www.energy.ca.gov/2011publications/CEC-800-2011-004/CEC-800-2011-004-CMF.pdf

[2] Cabrillo Power I LLC is also an indirect, wholly owned subsidiary of NRG Energy, Inc.

The Amended CECP will be a simple-cycle generating facility configured using six, nominally 100-megawatt (MW), natural-gas-fired combustion turbines with a capacity of 632 MW net output.[3] Similar to the Licensed CECP, the Amended CECP's units will interconnect to the electrical transmission system via 138-kilovolt (kV) and 230-kV lines that connect to the respective, neighboring SDG&E switchyards.

In conjunction with the demolition of EPS, the power plant operation and maintenance will be relocated on the east side of the railroad tracks with a new administrative and control room building and a smaller warehouse.

Natural gas will be delivered to the Amended CECP from the existing SDG&E transmission pipeline (Line TL 2009, "Rainbow line") via an approximate 1,100-foot-long interconnection pipeline west of the Amended CECP site that runs parallel to the existing railroad tracks. At the facility, the natural gas will flow through a flow-metering station, gas scrubber/filtering equipment, a gas pressure control station, and a fuel gas compressor station prior to injection into the combustion turbines. Similar to the Licensed CECP, with the exception of short, onsite interconnections, no offsite gas supply lines are required for the Amended CECP.

A new 138-kV transmission line and a new 230-kV transmission line have been developed for this project and are identified in Figure 2.0-1. The 2,200-foot-long, 138-kV transmission line and 4,000-foot-long, 230-kV transmission line will be located along the eastern and southern boundary of the CECP site before crossing the railroad tracks and tying into the SDG&E Encina switchyard. Additional details regarding this transmission line are provided in Section 3.0, Transmission Systems Engineering.

To support the evaporative air-cooling system make-up and other industrial uses, the Amended CECP will use no more than 336 acre-feet per year (afy) of CCR Title 22 reclaimed water provided by the City of Carlsbad (City). This is a decrease in reclaimed water use from the Licensed CECP. The evaporative cooling blow-downs will be recycled to the onsite raw water storage tank for reuse. Reverse osmosis reject stream and other plant wastewater will be discharged to the City of Carlsbad (Encina Wastewater Authority) system via an existing sanitary/industrial sewer line that traverses the Amended CECP site. Reclaimed water will be provisioned to the Amended CECP through a reclaimed water pipeline of the same size, location, and configuration as that proposed for the Licensed CECP. The reclaimed water pipeline will be constructed within City easements on the Amended CECP site, and only approximately 1,000 feet of the line will occupy publicly dedicated streets or property.

The purified ocean water system, authorized in the Licensed CECP, will remain as an option should reclaimed water not be available to support the Amended CECP operations.

Potable water for drinking, eye protection, safety showers, restrooms, and emergency fire protection will be served from the City's existing potable water system, as planned for the Licensed CECP. Also as planned for the Licensed CECP, potable water will remain available as a back-up water source in the event neither purified ocean water nor reclaimed water is available.

Sanitary and industrial wastewater disposal will be discharged to an existing 42-inch City of Carlsbad (Encina Wastewater Authority) sanitary sewer system that runs along the western edge of the Amended CECP site. Connection to the City's existing sewer line will require approximately 1,100 feet of new, onsite piping for points of connection from the proposed six peaking units, administration/control building, and operations/maintenance building.

The Amended CECP's six generating units (designated Units 6, 7, 8, 9, 10 and 11) will be located on a portion of the Licensed CECP site, east of the railroad tracks and west of Interstate 5 (I-5), and in the footprints of four existing fuel oil storage tanks, which will be demolished prior to commencement of construction of the Amended CECP (see Figure 2.0-1). The demolition of the fuel oil storage tanks 5, 6 and 7 are included in the

[3] Rated at average annual ambient condition of 60.3°F with evaporative cooling and 79 percent relative humidity

existing CEC 2012 Final Decision for CECP. The demolition of fuel oil storage tanks 1 and 2 (west of the railroad tracks) and fuel oil storage tank 4 east of the railroad tracks is addressed in a separate PTA.

The Amended CECP will be sited within a recessed location along the eastern boundary of the EPS site. This location significantly reduces or eliminates many issues commonly associated with large power plants, some of which posed challenges for the Licensed CECP. For instance, by being constructed at a lower elevation than the existing topography, the generating units will be minimally visible from many offsite locations and the site's bowl-shaped topography will provide sound energy attenuation. Additionally, the Amended CECP will be located east of the railroad tracks that bisect the EPS site and will be farther from the beach than the existing EPS facilities, ensuring the Amended CECP's consistency with the City of Carlsbad's land use goal of enabling future non-power-production redevelopment of portions of the former EPS footprint.

Once site preparation is complete, construction, commissioning, and operation of the six proposed simple-cycle units will proceed. Once the Amended CECP units are online, EPS Units 1 through 5 and the "black start" generator of EPS will be decommissioned and the above-grade portions of the EPS generating units, buildings and related facilities will be demolished.

To support construction, approximately 19.3 acres of the EPS site situated to the west of the railroad tracks will be used for a combination of equipment laydown and construction worker parking (Figure 2.0-2). Some preparation will be required to ensure the areas are usable for the purpose intended, including site grading and removal of existing, abandoned fuel oil piping that parallels the eastern fence of the SDG&E Encina switchyard to allow construction of a section of the underground portion of the 230-kV transmission line to support the Amended CECP. Similar to the Licensed CECP, no offsite construction worker parking or construction equipment or material laydown areas are anticipated to be necessary for the construction of the Amended CECP.

The approximately 30-acre Amended CECP site is located in the city of Carlsbad, in San Diego County, in an area zoned Public Utility, which specifically allows electrical generation and transmission facilities. Figure 2.0-1 shows the location of the Amended CECP generating facility, its electric transmission lines, natural gas supply pipeline, reclaimed water supply pipeline, and potable water supply line. The total land acreage of the existing EPS is approximately 95 acres, not including the Agua Hedionda Lagoon acreage also owned by Cabrillo Power I LLC. The EPS consists of two parcels: (1) approximately 65-acres containing the existing EPS generating equipment (Assessor Parcel Number [APN] 210-01-43), and (2) an approximately 30-acre plot east of the railroad tracks that currently contains the fuel oil storage tanks that are being removed, where the CEC approved the construction of the Licensed CECP, and upon which the Amended CECP is also proposed to be constructed (APN 210-01-41).

As part of the Amended CECP, existing EPS Units 1 through 5 will be decommissioned and demolished. The removal of the EPS units will create substantial environmental benefits, including permanent air emission reductions from the boiler units; elimination of the 857 million gallons per day of cooling water (seawater) intake capacity of the existing units, and the resulting decrease in impingement and entrainment of marine organisms attributed to those units' cooling water flow in compliance with EPA 316 (B) regulations; cessation of discharge of wastewaters to the Pacific Ocean from Units 1 through 5; and the opportunity to redevelop the portion of the parcel west of the railroad tracks for non-power-production uses.

2.1 Generating Facility Description, Design, and Operation

This section describes the Amended CECP's facility design and operation.

2.1.1 Site Arrangement and Layout

The Amended CECP site plan is shown in Figure 2.1-1. These figures illustrate the location and size of the Amended CECP.

The Amended CECP site is north of the intersection of Avenida Encinas and Cannon Road. The main operations site access and railroad access will also remain unchanged from the Licensed CECP. The primary operations access will be from Carlsbad Boulevard, through the existing EPS site and the Poseidon Desalination Plant, and will use the existing railroad crossing between APN 210-01-43 and APN 210-01-41. The main operations access will also serve as a secondary construction access point. The primary construction access will be from the Cannon Road Service Center gate, west of the railroad tracks. Additional construction access will be from Carlsbad Boulevard, at an entrance just south of the EPS. Heavy haul truck access will be from Cannon Road through the Avenida Encinas entrance to the SDG&E switchyard property, east of the railroad tracks. An existing North County Transit District railroad spur that terminates on APN 210-01-43 will be used for select heavy and oversize equipment deliveries during construction.

Portions of the Amended CECP site will be paved to provide internal access to project facilities and site buildings. The area surrounding equipment, where not paved, will have gravel surfacing. Similar to the Licensed CECP, the 138-kV and 230-kV high-voltage transmission lines will run from the Amended CECP power block area to the existing SDG&E 138-kV and 230-kV switchyards on the EPS property. The onsite route for the high-voltage lines is shown in Figures 2.0-1 and 2.1-1. The single-line representation of the interconnection scheme is depicted in Figure 2.1-2. Based on the previously approved large generator interconnection agreements (LGIA), SDG&E will expand the existing Encina switchyard to accommodate the new interconnection from the Amended CECP power block. Additional detail is provided in Section 3.0, Transmission System Engineering. Interconnection system impact re-studies for the 138-kV and 230-kV systems will be submitted to the California Independent System Operator (CAISO) for review. These system impact re-studies are expected to demonstrate that no offsite transmission upgrades are required for the Amended CECP.

2.1.2 Process Description

The Amended CECP will consist of six independent combustion turbine generators (CTG) designed for demineralized water injection to reduce nitrogen oxide production; an air-cooled fin-fan cooler; a shell and tube heat exchanger for cooling of system cooling water as well as the intercooler between the low-pressure and high-pressure compressor stages; and associated support equipment providing 632 MW net output. The combustion turbines will be GE LMS100 units, which boast the highest simple-cycle thermal efficiency, in excess of 44 percent, of any comparable technology. The CTGs will be supported by common, balance of plant (BOP) equipment including a bulk water storage and treatment plant, fuel gas compressor enclosure, compressed air system, fire protection enclosure, and an aqueous ammonia storage area.

Each GE LMS100 turbine is capable of reaching 100 percent load in 10 minutes or less with ramp rates up to 50 MW per minute, providing rapid response to changes in grid demand.

Associated equipment for the Amended CECP will include emission control systems necessary to meet the proposed local, state, and federal emission limits.

2.1.3 Generating Facility Cycle

Within each CTG, combustion air will flow through the inlet air filter, through the evaporative cooler and associated air inlet ductwork, be compressed in the gas turbine compressor section, and then flow to the CTG combustor. The LMS100 design incorporates an intercooler between the low pressure compressor and high pressure compressor, which assists in providing high thermal efficiency. Natural gas fuel will be injected into the compressed air in the combustor and ignited. The hot combustion gases will expand through the power turbine section of the CTG, causing the shaft to rotate and drive the electric generator and CTG compressor.

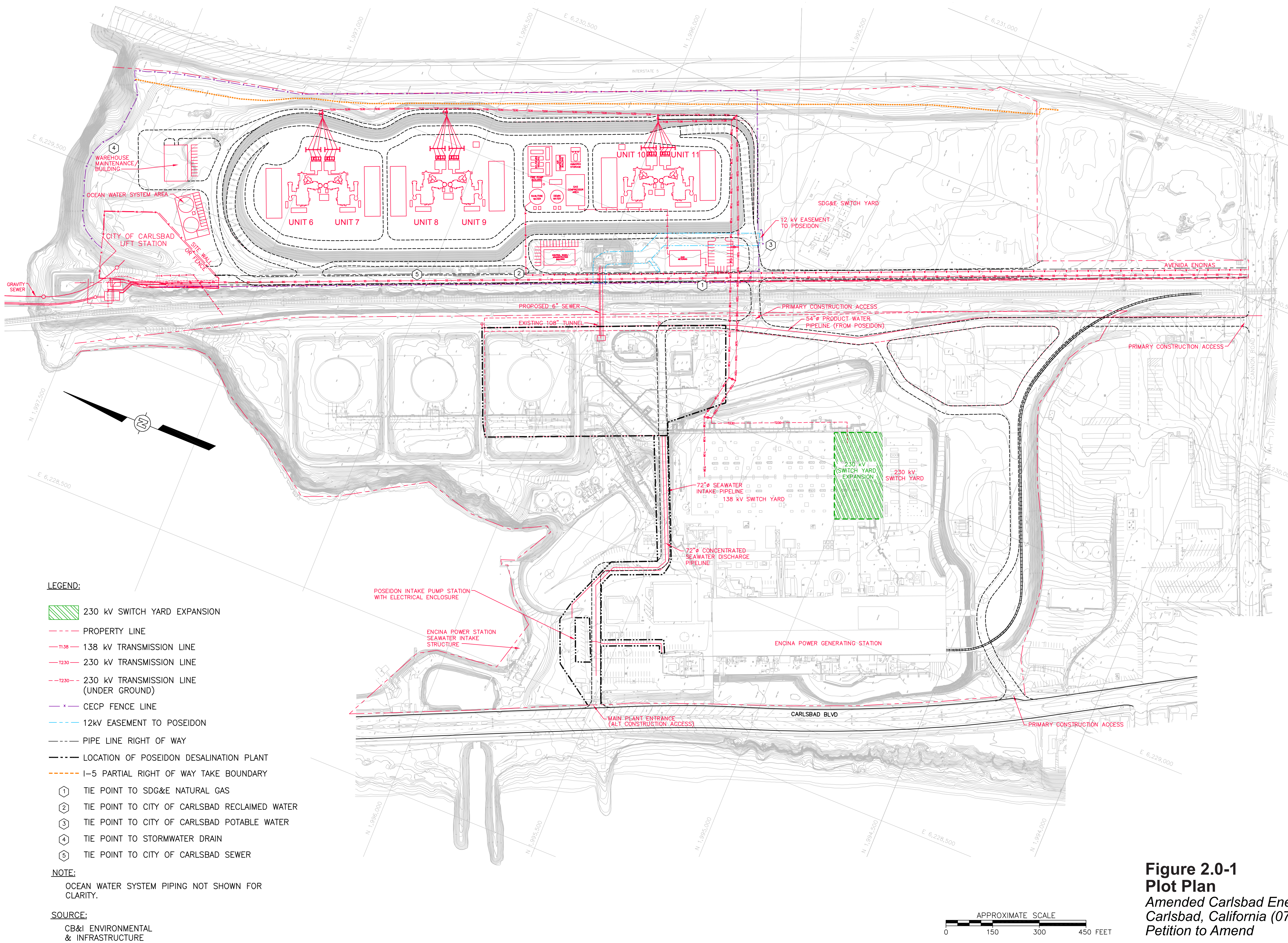


Figure 2.0-1
Plot Plan
Amended Carlsbad Energy Center Project
Carlsbad, California (07-AFC-06C)
Petition to Amend

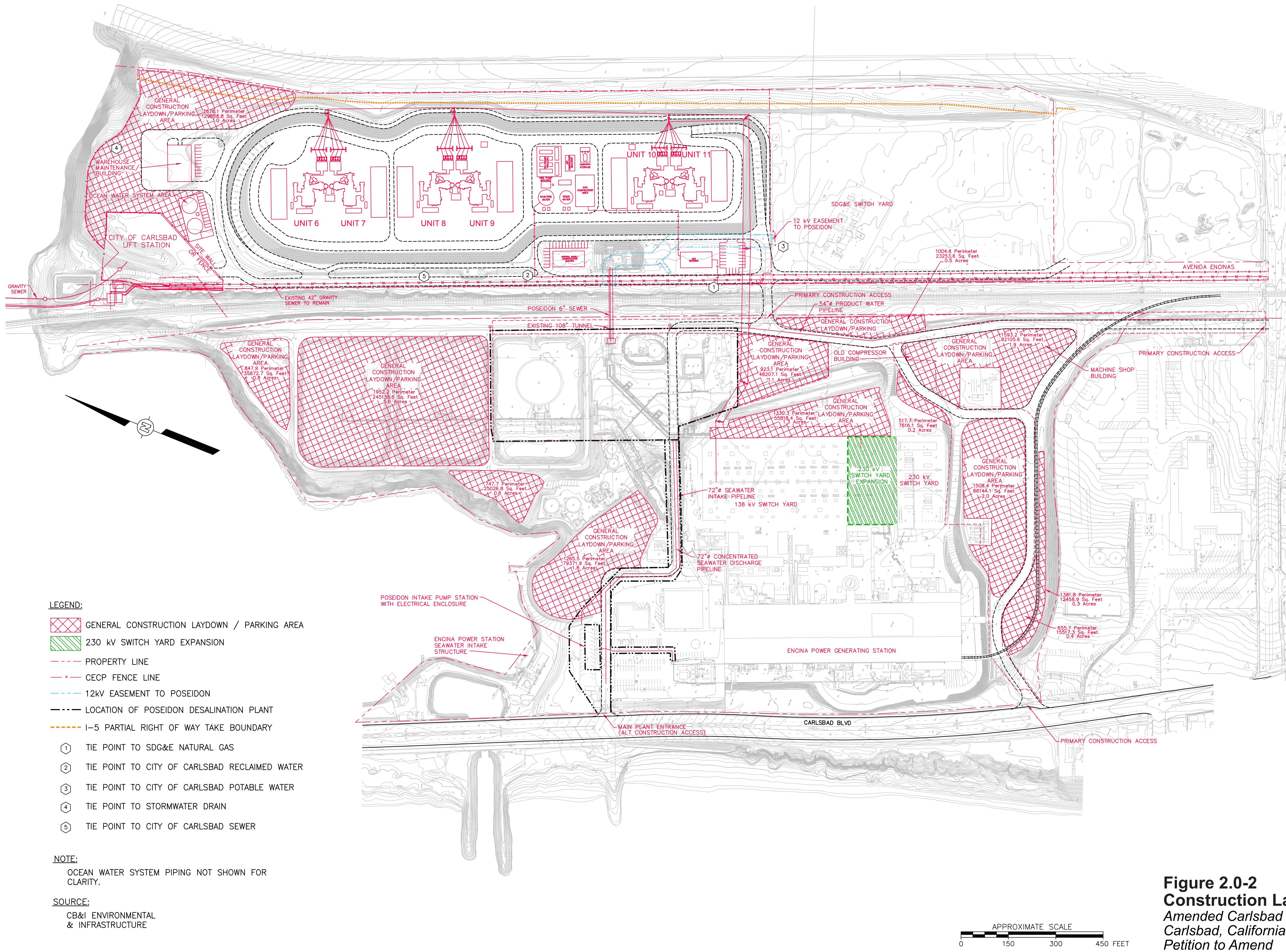
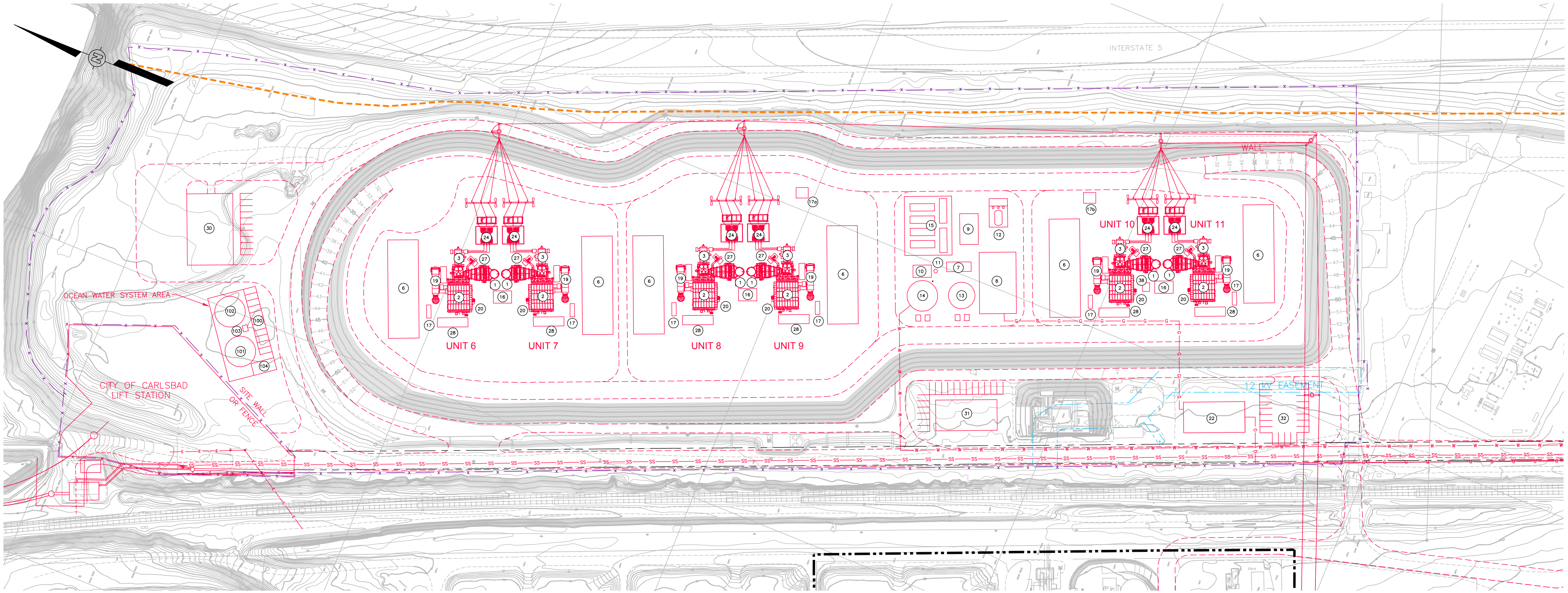


Figure 2.0-2
Construction Laydown and Parking
Amended Carlsbad Energy Center Project
Carlsbad, California (07-AFC-06C)
Petition to Amend

CH2MHILL



LEGEND:

- LOCATION OF POSEIDON DESAL PLANT
- PIPE LINE RIGHT OF WAY
- I–5 PARTIAL RIGHT OF WAY TAKE BOUNDARY
- G — GAS LINE (APPROVED ROUTING PER PEAR)
- W — RECLAIMED WATER LINE (APPROVED ROUTING PER AFC)
- SS — SANITARY SEWER LINE
- x — FENCE LINE / PROJECT BOUNDARY
- 12kV EASEMENT TO POSEIDON

EQUIPMENT LIST

1	EXHAUST STACK
2	COMBUSTION TURBINE ENCLOSURE
3	GENERATOR ENCLOSURE
6	FIN FAN COOLERS
7	BOP PDC
8	GAS COMPRESSOR BUILDING
9	AIR COMPRESSOR BUILDING
10	FIRE PUMP BUILDING
11	DIESEL STORAGE TANK (IF NEEDED)
12	AMMONIA STORAGE AREA
13	DEMINERALIZED WATER TANK
14	RAW/FIRE WATER TANK
15	WATER TREATMENT TRAILERS
16	CEMS ENCLOSURE
17	UNIT AUXILIARY TRANSFORMER
18	AMMONIA PREP SKID
19	SHELL AND TUBE HEAT EXCHANGER
20	AUXILIARY SKID
22	GAS METERING
24	GSU TRANSFORMER
27	ATTEMPORATION BLOWER SKID
28	CTG AND INTERCOOLER MCC
30	WAREHOUSE AND MAINTENANCE BUILDING
31	CONTROL ROOM AND ADMINISTRATION BUILDING
32	PARKING LOT
38	EMERGENCY DIESEL GENERATOR
100	OCEAN WATER TRAILERS
101	OCEAN WATER STORAGE TANK
102	ULTRA FILTRATION STORAGE TANK (OWS)
103	ULTRA FILTRATION PUMPS
104	SOLIDS UNLOADING SPACE

SOURCE:

CB&I ENVIRONMENTAL & INFRASTRUCTURE

NOTE:

SOME EQUIPMENT NOT SHOWN FOR CLARITY.

APPROXIMATE SCALE

0 80 160 240 FEET

Figure 2.1-1
Site Plan
Amended Carlsbad Energy Center Project
Carlsbad, California (07-AFC-06C)
Petition to Amend

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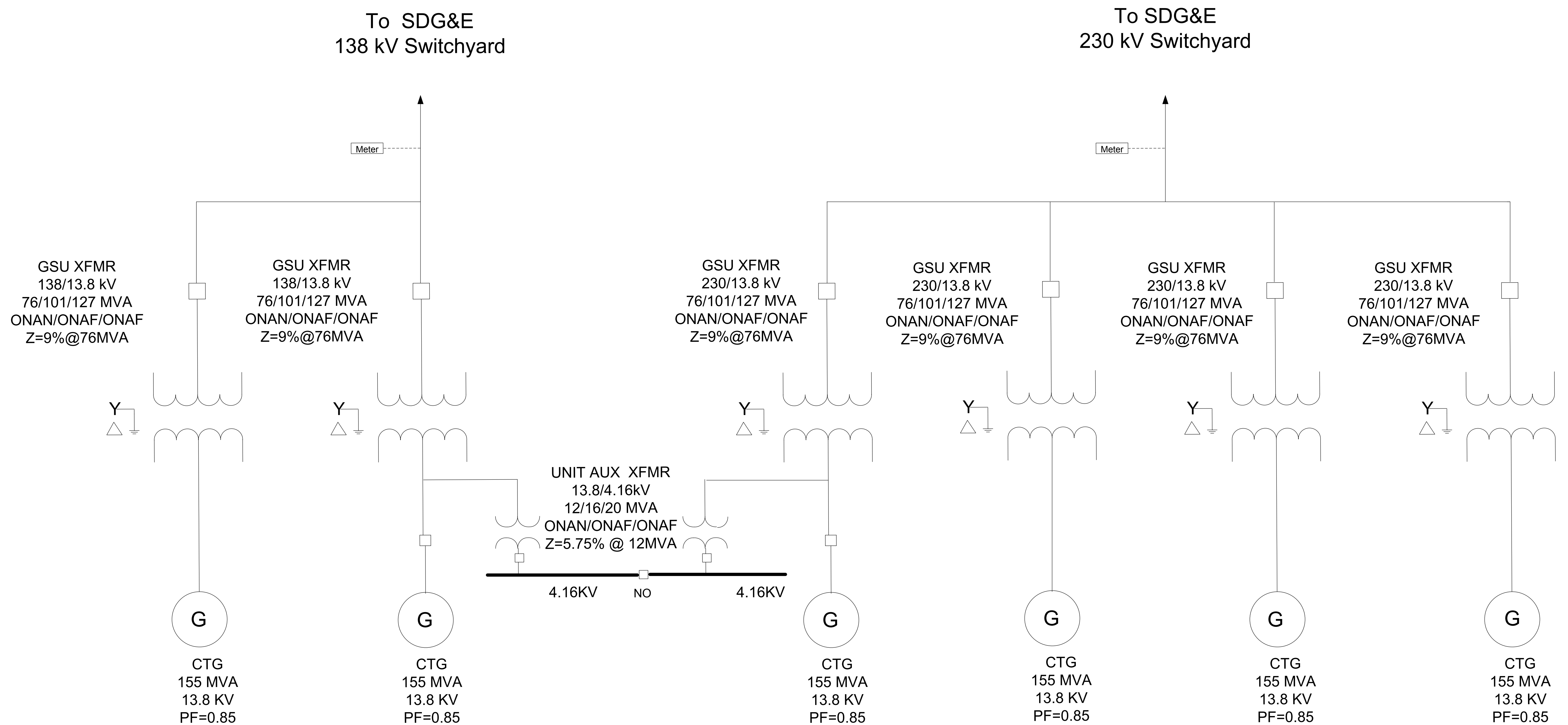


Note:

1. The 138kV transmission line and the 230kV transmission line will each be equipped with a set of metering equipment.
2. Ratings and equipment configuration shown are preliminary and will be finalized during detail design.

Figure 2.1-2
CECP Conceptual One-Line Diagram
Amended Carlsbad Energy Center Project
Carlsbad, California (07-AFC-06C)
Petition to Amend

2.1.4 Combustion Turbine Generators

Electricity would be produced by any one of the proposed six CTGs. In a typical GE LMS100 CTG, thermal energy is produced through the combustion of natural gas, which is converted into mechanical energy required to drive the combustion turbine compressors and electric generators. Each CTG system consists of a stationary combustion turbine generator, supporting systems, and associated auxiliary equipment. The CTGs will be equipped with the following required accessories to provide safe and reliable operation:

- Inlet air filters
- Inlet air evaporative coolers
- Demineralized water injection skid
- Compressor intercooler
- Fin/fan cooler and shell and tube heat exchanger as well as a cooling water circulating pump
- Metal acoustical enclosure
- Redundant lube oil coolers
- Compressor wash system
- Fire detection and protection system

The metal acoustical enclosures will be provided for the CTGs and respective accessory equipment, all of which will be located outdoors.

Each CTG exhaust will be equipped with a carbon monoxide oxidation (CO) catalyst and a selective catalytic reduction (SCR) emission control system that uses 19% aqueous ammonia in the presence of a catalyst to reduce oxides of nitrogen (NO_x) levels in the exhaust gases. Ammonia from the aqueous ammonia storage tank will be vaporized and then injected into the CTG exhaust gas stream via a grid of nozzles located upstream of the catalyst module. The subsequent chemical reaction will reduce NO_x to nitrogen and water. Exhaust from each CTG will be discharged from individual, 90-foot-tall, 14.25-foot-diameter exhaust stacks.

2.1.5 Major Electrical Equipment and Systems

For the Amended CECP, like the Licensed CECP, the bulk of the electric power produced by the facility will be interconnected to the CAISO grid via the existing SDG&E 138-kV and 230-kV switchyards located on the EPS site. A small amount (approximately 20.6 MW) of parasitic electric power will be used to power the Amended CECP's onsite auxiliaries such as pumps, fans and compressors, control systems, and general facility loads including lighting, heating, and air conditioning. Some power will also be converted from alternating current (AC) to direct current (DC), which will be used as backup power for control systems and other critical uses. Transmission and auxiliary uses are discussed in the following subsections.

2.1.5.1 AC Power—Transmission

Power will be generated by the six CTGs at 13.8 kV and then stepped up by independent transformers for each CTG. Two CTGs will have voltage increased to 138 kV, and the remaining four CTGs will be stepped up to 230 kV for high voltage feed to the respective existing SDG&E switchyards. An overall single-line diagram of the amended facility's electrical system is shown in Figure 2.1-2. The CTGs will be connected by iso-phase bus duct to oil-filled step-up transformers that increase the voltage to 138-kV/230-kV respectively, as indicated on the single-line diagram. Surge arresters will be provided at the high-voltage bushings to protect the transformers from surges on the high-voltage systems caused by lightning strikes or other system disturbances. The transformers will be set on concrete foundations within containments designed to contain the transformer oil in the unlikely event of a leak or spill. The high-voltage side of the step-up transformers will be interconnected to the existing switchyards. As previously mentioned, from the existing switchyards, power will be transmitted via 138-kV and 230-kV transmission lines to the CAISO-controlled electric grid.

A more detailed discussion of the transmission system is provided in Section 3.0.

2.1.5.2 AC Power—Distribution to Auxiliaries

Auxiliary power to the combustion turbine power block will be supplied at 4,160 volts AC by a double-ended 4,160-volt switchgear lineup. Two oil-filled, 13.8-to-4.16-kV unit auxiliary stepdown transformers will supply power to the switchgear. The high-voltage side (13.8 kV) of the unit auxiliary transformers will be connected to the outputs of two CTGs, one associated with the 138-kV transmission line and one associated with the 230 kV transmission line. This connection will allow the switchgear to be powered from any of the six generators or by back-feeding power from the existing switchyards through either of the unit auxiliary transformers. Low-voltage side (13.8 kV) generator circuit breakers will be provided for the CTGs. These circuit breakers are used to isolate and synchronize these two generators, and will be located between the generators and the connections to the transformers. The remaining four CTGs will be synchronized via a high-voltage circuit breaker located on the high-voltage side of the step-up transformers. The 4,160-volt switchgear lineup supplies power to the various 4,160-volt motors, to the combustion turbine starting system, and to the load center transformers (used for 4,160- to 480-volt reductions and for 480-volt power distribution). The 4,160-volt switchgear will use vacuum interrupter circuit breakers to isolate the main incoming feeds and respective power distribution.

The load center transformers will be oil-filled with each supplying 480-volt, 3-phase power to the double-ended load centers.

The load centers will provide power through feeder breakers to the various 480-volt motor control centers (MCC). The MCCs will distribute power to ancillary equipment including 480-volt motors, 480-volt power distribution panels, and lower-voltage lighting and distribution panel transformers. Power for the AC power supply (120-volt/208-volt) system will be provided by the 480-volt MCCs and 480-volt power panels. 480-120/208-volt dry-type transformers will provide transformation of 480-volt power to 120/208-volt power.

2.1.5.3 125-Volt DC Power Supply System

The Amended CECP will deploy one common 125-volt DC power supply system consisting of one 100-percent-capacity battery bank, two 100-percent-capacity static battery chargers, a switchboard, and two or more distribution panels that will be supplied for BOP equipment. Each CTG will be provided with its own dedicated battery systems and charger.

Under normal operating conditions, the battery chargers will supply DC power to the DC loads. The battery chargers receive 480-volt, three-phase AC power from the AC power supply (480-volt) system and continuously charge the battery banks while simultaneously supplying power to the DC loads.

Under abnormal or emergency conditions, should the power from the AC power supply (480-volt) system be disrupted, the batteries will supply DC power to the DC system loads. Similar to the Licensed CECP, the batteries for the system at the Amended CECP will be sized to provide up to 3 hours of continuous supply to the site vital DC loads. Recharging of discharged batteries occurs upon restoration of 480-volt power from the AC power supply (480-volt) system. The battery re-charge rate is dependent on the characteristics of the battery, battery charger, and the connected DC load during charging. The anticipated maximum recharge time will be 12 hours.

The 125-volt DC system will also be used to provide control power to the 138 kV/230 kV generator breakers, 4,160-volt switchgear, 480-volt load centers, critical control circuits, and emergency DC motors.

2.1.5.4 Uninterruptible Power Supply System

The combustion turbines will also have an essential service 120-volt AC, single-phase, 60-hertz (Hz) uninterruptible power supply (UPS) to supply AC power to critical equipment loads as well as provide power for unit protection and safety systems that require uninterruptible AC power.

A UPS inverter will supply 120-volt, AC single-phase power to the UPS panel distribution boards that supply critical AC loads. The UPS inverter will be fed from the station 125-volt DC power supply system. Each UPS system will consist of one full-capacity inverter, a static transfer switch, a manual bypass switch, an alternate source transformer, and two or more panel boards.

The normal source of power to the system will be from the 125-volt DC power supply system through the inverter to the panel board. A solid-state static transfer switch will continuously monitor both the inverter output and the alternate AC source. The transfer switch will automatically transfer essential AC loads without interruption from the inverter output to the alternate source upon loss of the inverter output.

A manual bypass switch will also be included to enable isolation of the inverter for testing and maintenance without interruption to the essential service AC loads.

The distributed control system (DCS) operator stations will be supplied from the UPS. Additionally, the continuous emission monitoring (CEM) equipment, DCS controllers, and input/output (I/O) modules will be fed from either the UPS system or from 125-volt DC power directly.

2.1.6 Fuel System

The proposed CTGs are designed to burn natural gas only. The natural gas requirement during full load operation at extreme high ambient temperature of 96.0°F is approximately 798.6 million British thermal units per hour (MMBtu/hr).[4] The maximum natural gas requirement, expected during low ambient temperature operation conditions, is approximately 865.6 MMBtu/hr (LHV basis).

Similar to the Licensed CECP, natural gas will be delivered to the Amended CECP via a 20-inch-diameter pipeline from an existing SDG&E high-pressure, natural gas pipeline located within an existing right-of-way on the EPS site. This pipeline will extend to the facility from the existing SDG&E natural gas pipeline (Line TL 2009, "Rainbow line") located adjacent to the Amended CECP site, on the west side of and parallel to the railroad tracks on the EPS site. At the Amended CECP site, the natural gas will flow through a flow-metering station, gas scrubber/filtering equipment, a gas pressure control station, and gas compressors prior to entering the combustion turbines.

Historical data indicate that the pressure on the SDG&E Line TL 2009 generally is approximately 250 pounds per square inch gauge (psig) minimum. Three 50-percent-capacity electric-driven fuel gas compressors will be provided to boost the pressure to the 850 psig required by the combustion turbines. The gas compressors will be located in an enclosure in the BOP area of the Amended CECP.

Additional detailed information on the natural gas supply and plant usage at the Amended CECP is provided in Section 4.0.

2.1.7 Water Supply and Use

The Application for Certification (AFC), Section 3.0, for the Licensed CECP[5] identified the primary project water supply as City of Carlsbad CCR Title 22 reclaimed water supplied to the site from the utility easement on the east side of the railroad tracks, as shown in Figure 2.0-1. The Project Enhancement and Refinement (PEAR), Section 2.3.2,[6] added an alternative to the City of Carlsbad reclaimed water source. This alternative is an ocean water source to be withdrawn via the Agua Hedionda Lagoon and the existing EPS once-through cooling water discharge channel. This alternate design requires an added water pre-treatment system to remove filterable solids and to treat the saltwater to a level that can be accepted by the reverse osmosis and

[4] Lower heat value [LHV] basis, for each CTG unit

[5] Carlsbad Energy Center LLC. 2007. *Carlsbad Energy Center Project Application for Certification.* November. Available online at: http://www.energy.ca.gov/sitingcases/carlsbad/documents/applicant/afc/

[6] CH2M HILL and Shaw, Stone & Webster. 2008. *Carlsbad Energy Center Project (07-AFC-6) Project Enhancement and Refinement Document. Submitted by Carlsbad Energy Center LLC.* July. Available online at: http://www.energy.ca.gov/sitingcases/carlsbad/documents/applicant/2008-08-27_PROJECT_ENHANCEMENT_AND_REFINEMENT.PDF

polishing water treatment system. To accommodate the necessary equipment, the water treatment system will be located on the north rim of the Amended CECP power block area, as shown in Figure 2.1-1.

The Amended CECP will preferentially use Title 22 reclaimed water as the primary water source, provided it is available. The ocean water alternative approved in the Licensed CECP will be implemented as a backup water supply in the event reclaimed water is unavailable. Figures 2.1-3a and 2.1-3b show daily average consumption with six CTGs operating at up to a 31 percent capacity factor with CTG evaporative cooling, for reclaimed water and ocean water, respectively. While high-purity demineralized water will no longer be required for the steam cycle, it will be required for emission control via direct injection into the combustion turbines and turbine wash water.

The Amended CECP fire protection system will be modified from the Licensed CECP to have a common but larger raw water tank for fire protection and process use, as well as expanded fire loops for the expanded Amended CECP site. Both the power block area and rim area hydrants will be charged by this source, eliminating the tie to the existing EPS. Potable water from the existing City of Carlsbad supply will be used for the new administration/control building, warehouse, and emergency eyewash and safety showers, and will also serve as an emergency connection for the fire water tank should reclaimed or ocean water become interrupted.

Up to approximately 30 gallons per minute (gpm) of reclaimed water will be used to irrigate site landscaping, which is included in the water balance diagrams.

A more detailed description of the water supply system, treatment, and permits is provided in Section 5.11, Soil and Water Resources.

2.1.7.1 Primary Source—Reclaimed Water

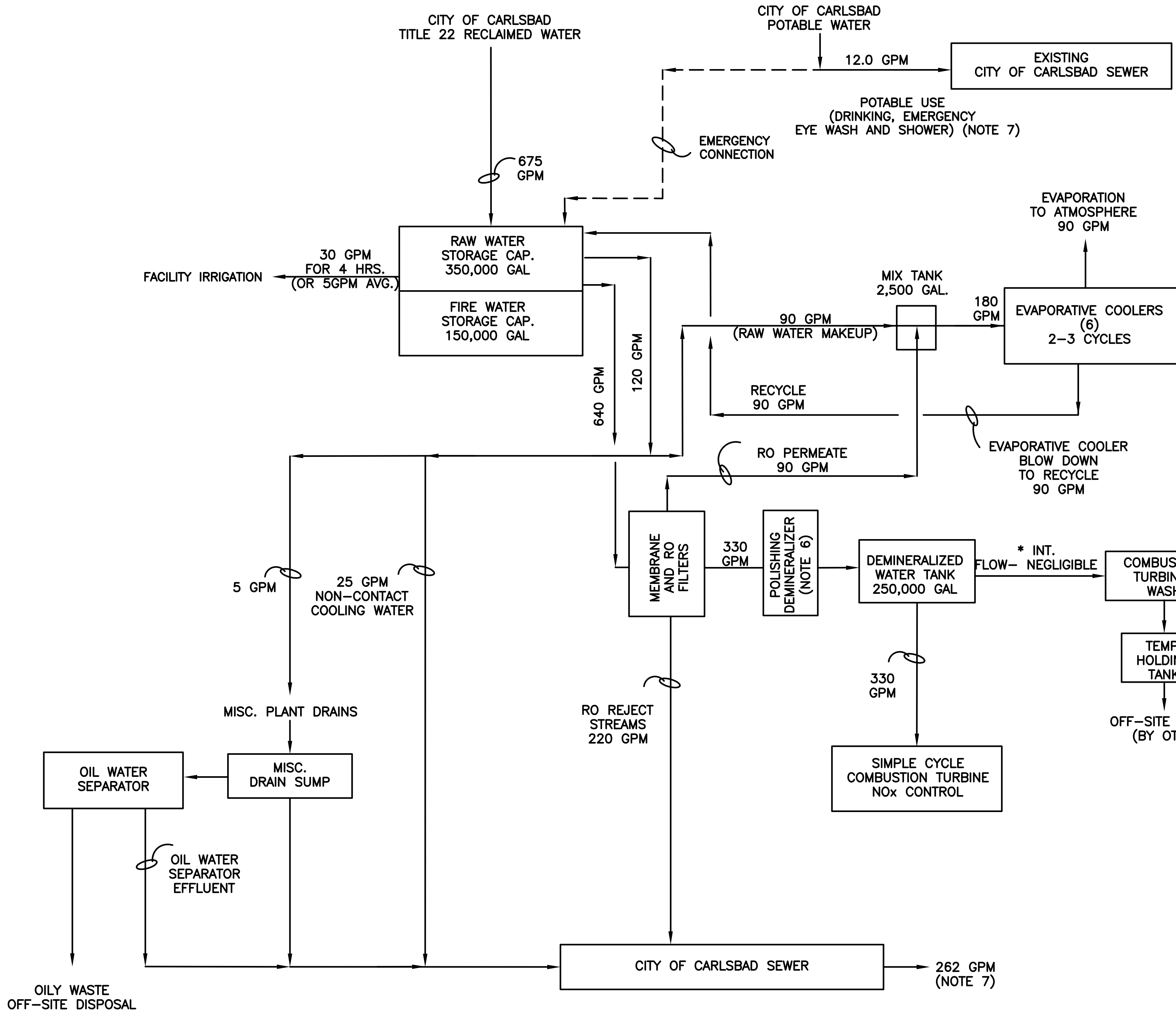
Reclaimed water will be obtained via a new reclaimed water line that will tie into the new 500,000-gallon aboveground raw water tank. This tank will have a dedicated capacity of 150,000 gallons for the fire water and 350,000 gallons for process water. The process water will be pretreated with a combination of cartridge and membrane filters and subsequent reverse osmosis and a final demineralization process. The demineralized water will be stored in a dedicated 250,000-gallon demineralized water storage tank and used for NOx emission control of the combustion turbines. A portion of the reverse osmosis permeate will be mixed with untreated process water in a 2,500-gallon mix tank and used for evaporative cooling of the inlet air for the combustion turbines, as needed. The demineralized water, mixed with minimal, non-toxic cleaning chemicals, will also be used for infrequent cleaning of the internal components of the combustion turbines during scheduled outages.

The reclaimed water balance diagram (Figure 2.1-3a) shows the equipment required as well as water uses and waste streams for both a daily maximum and yearly average use.

2.1.7.2 Alternate Source—Ocean Water

In the unlikely event that reclaimed water is unavailable, an ocean water system will be implemented. To obtain ocean water, the existing EPS intake and discharge structure will be used, as well as piping from the withdraw point on the discharge side of the structure – the current ocean water withdrawal point for the Poseidon Desalination Plant and terminating at the Amended CECP site. The current intake structure for the cooling water system removes water from the Agua Hedionda Lagoon, which was designed for 857 million gallons per day (mgd) of cooling water. The Poseidon Desalination Plant will withdraw approximately 100 mgd of the Encina discharge water prior to re-admittance to the ocean discharge system.

Processed ocean water will be stored in the 500,000-gallon raw water tank to be located near the processing trailers on the north end of the rim of the power block. An approximately 40,000-gallon service water tank will be required to store the processed water to be used for evaporative coolers and as the source for the second stage reverse osmosis equipment.



NOTES:

1. DESIGN BASIS:
   a) NOx USE – 55 GPM PER TURBINE
   b) EVAP COOLING USE – 15 GPM PER TURBINE
2. * INT. = INTERMITTENT FLOWS
3. MAXIMUM DAILY CONSUMPTION
   a) TITLE 22 RECLAIMED WATER 729,000 GALS./DAY
   b) POTABLE WATER – 17,200 GALS./DAY (NON-FIRE USE)
   c) POTABLE WATER – EMERGENCY ONLY (FIRE USE)
   d) FIRE WATER STORAGE REFILL – 500GPM MINIMUM (150,000 GALS./FILL)
4. FLOW RATE (GPM) IS DAILY AVERAGE, BASED ON 18 HR. OPERATION PER DAY. EVAP COOLER ON 18-HRS/DAY.
5. MAXIMUM ANNUAL CONSUMPTION:
   a) TITLE 22 RECLAIMED WATER – 109,350,000 GALS.
   b) POTABLE WATER – 2,592,000 GALS.
6. DEMINERALIZER SYSTEM TO CONSIST OF A COMBINATION OF MEMBRANE FILTRATION (MF), REVERSE OSMOSIS (RO) AND A POLISHING DEMINERALIZER.
7. FLOWS INCLUDED IN TOTAL PLANT DISCHARGE TO CITY OF CARLSBAD SEWER

SOURCE: CB&I ENVIRONMENTAL & INFRASTRUCTURE, INC

Figure 2.1-3a
Reclaimed Water Balance
Amended Carlsbad Energy Center Project
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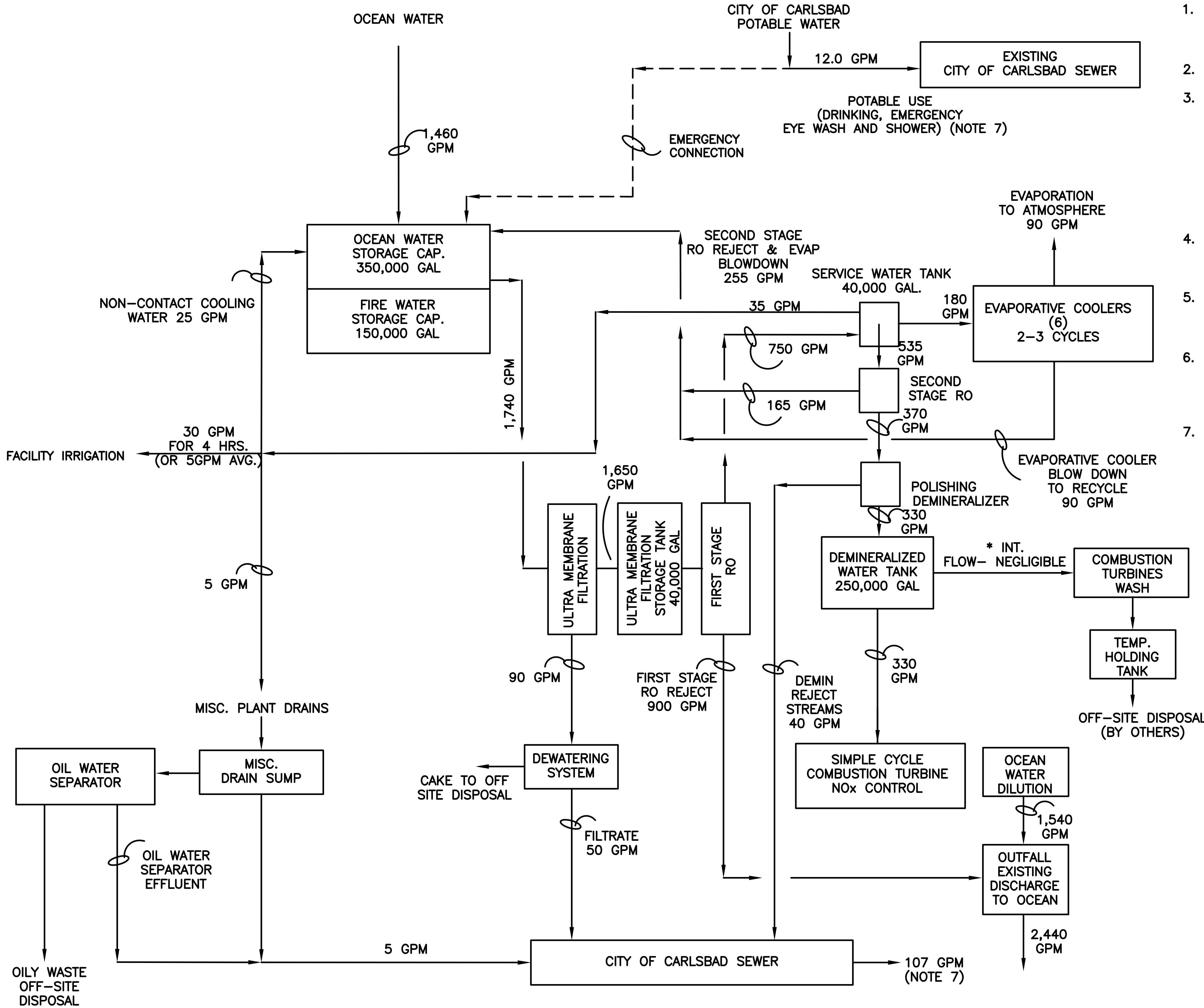

NOTES:

1. DESIGN BASIS:
   a) NOx USE – 55 GPM PER TURBINE
   b) EVAP COOLING USE – 15 GPM PER TURBINE
2. * INT. = INTERMITTENT FLOWS
3. MAXIMUM DAILY CONSUMPTION
   a) OCEAN WATER – 1,576,800 GALS./DAY
   b) POTABLE WATER – 17,200 GALS./DAY (NON-FIRE USE)
   c) POTABLE WATER – EMERGENCY ONLY (FIRE USE)
   d) FIRE WATER STORAGE REFILL – 500GPM MINIMUM (150,000 GALS./FILL)
4. FLOW RATE (GPM) IS DAILY AVERAGE, BASED ON 18 HR. OPERATION PER DAY. EVAP COOLER ON 18-HRS/DAY.
5. MAXIMUM ANNUAL CONSUMPTION:
   a) OCEAN WATER – 236,520,000 GALS.
   b) POTABLE WATER – 2,592,000 GALS.
6. DEMINERALIZER SYSTEM TO CONSIST OF A COMBINATION OF MEMBRANE FILTRATION (MF), 2-STAGE REVERSE OSMOSIS (RO) AND A POLISHING DEMINERALIZER.
7. POTABLE WATER FLOWS INCLUDED IN TOTAL DISCHARGE TO CITY OF CARLSBAD SEWER

SOURCE: CB&I ENVIRONMENTAL & INFRASTRUCTURE, INC

Figure 2.1-3b
Ocean Water Balance
Amended Carlsbad Energy Center Project
Carlsbad, California (07-AFC-06C)
Petition to Amend

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The first stage reverse osmosis reject will be diluted and returned to the intake structure by the ocean-water-system return line, and the second stage reverse osmosis reject will be recycled into the bulk ocean water/fire water storage tank for re-use.

Because of the much higher salinity of the ocean water relative to the reclaimed water, a two-stage reverse osmosis system will be used for demineralizing the ocean water, followed by polishing. Seawater reverse osmosis systems operate at elevated pressures (800 to 1,000 psi), use a higher amount of ocean water, and produce more reject streams for the same amount of treated water produced. The ocean water entering the reverse osmosis stages will be pre-treated with cartridge and membrane filters, which will remove filterable solids. A solids dewatering system will be provided to remove any moisture from the filter cake, which will be disposed of offsite. The demineralization process will also require additional treatment such as chlorination, dechlorination, and degasification processes prior to and after the reverse osmosis stages.

The ocean water balance diagram (Figure 2.1-3b) shows the equipment required as well as daily average water use.

2.1.7.3 Fire Water

Raw water will be allocated for firefighting and will be stored in an approximately 500,000-gallon aboveground storage tank. This tank will hold a minimum of 150,000 gallons for dedicated fire protection. The remaining 350,000-gallon capacity will be allocated for storing process water.

2.1.7.4 Potable Water

The Amended CECP will require potable water for the administration/control building and the warehouse buildings, as well as for emergency eye wash stations and showers in the power block area. Similar to the Licensed CECP, the Amended CECP will use potable water as the backup water source for all CECP needs should the reclaimed water or ocean water systems become unavailable or interrupted. Potable water will be supplied from the City system and will be protected against cross-contamination with the use of a reduced-pressure backflow prevention device or air gap.

2.1.7.5 Sanitary Sewers

Sanitary and industrial wastewater disposal will be served by the City of Carlsbad (Encina Wastewater Authority) sewer system.

A more detailed description of the water supply system, treatment, and permits is provided in Section 5.11, Soil and Water Resources.

2.1.7.6 Construction Practices

The Amended CECP's connection to the existing potable water line and connection to the existing City of Carlsbad sewer line will be constructed from the tie points shown in Figure 2.1-1. The construction will be open trench work with approximately 36 inches of ground cover for the installed pipes. During non-work hours, trench plates will cover exposed trench excavations.

The new reclaimed water line is more extensive in scope, extending approximately 3,700 feet to the Amended CECP site from the south at Cannon Road/Avenida Encinas. The reclaimed water line will be installed under Cannon Road using partial traffic lane closures to accommodate open trench construction. The installation crossing of Cannon Road is expected to occur over a period of approximately 3 weeks.

The alternate ocean water source will require installation of a new pipeline from the existing EPS discharge channel crossing east through the Poseidon Desalination Plant and entering the Amended CECP site boundary, where the pipeline will turn north toward the ocean water treatment system facilities.

All trenches will be backfilled using excavated soil and compacted for pipe stability and minimum subsequent subsidence. Backfill will be to original grade or level. The Cannon Road crossing for the reclaimed water line will be repaved to achieve original traffic surface conditions.

2.1.7.7 Water Requirements

The estimated average daily, maximum daily, and maximum annual quantity of reclaimed water required for operation of the Amended CECP is presented in Table 2.1-1. The alternate source ocean water requirements are presented in Table 2.1-2. The daily water requirements shown are estimated quantities based on the simple-cycle plant operating at a 31 percent capacity factor, with evaporative cooling.[7]

TABLE 2.1-1
Daily and Annual Water Use for Amended CECP Operations—Reclaimed Water Supply

Water Use	Average Daily Use (gpm)	Maximum Daily Use (gpd)	Maximum Annual Use (afy)
Reclaimed Water	210*	675	336*
Potable Water	12	12	19

*Based on an annual operation of 2,700 hours/year at full plant output

TABLE 2.1-2
Daily and Annual Water Use for Amended CECP Operations—Ocean Water Supply

Water Use	Average Daily Use (gpm)	Maximum Daily Use (gpd)	Maximum Annual Use (afy)
Ocean Water	450*	1,460	726*
Potable Water	12	12	19

*Based on an annual operation of 2,700 hours/year at full plant output

2.1.8 Plant Cooling Systems

The Amended CECP's cycle heat rejection system will consist of air-cooled fin-fan coolers, shell and tube heat exchangers with closed loop circulating water pumps, and evaporative coolers. The heat rejection system will cool the CTG lube oil to within limits specified by the CTG manufacturer as well as reject the heat created by the high-temperature inter-cooler.

Mixed reclaimed and reverse osmosis permeate will be used for evaporative cooling. Mixing of reclaimed and reverse osmosis permeate will be necessary to avoid formation of scales on the evaporative cooler media.

It is estimated that 50 percent of the evaporative cooling water will be lost to atmosphere via CTG exhaust and the remaining 50 percent will be recycled to the raw water storage tank. The evaporative cooling water will not be treated with any chemicals.

2.1.9 Waste Management

Similar to the Licensed CECP, all wastes produced at the Amended CECP will be properly collected, treated if necessary, and properly disposed of. Wastes will include process and sanitary wastewater, and nonhazardous waste and hazardous waste, both liquid and solid. Waste management is discussed in more detail in Section 5.14.

[7] Peak water requirements shown in Tables 2.1-1 and 2.1-2 are based on the plant operating at full load, with evaporative cooling, and an ambient temperature of 96.0°F and 36.0 percent relative humidity.

2.1.9.1 Wastewater Collection, Treatment, and Disposal

The reject stream from the reverse osmosis units will be sent to the City of Carlsbad sewer system. Evaporative cooler blowdown will be internally recycled for reuse. Miscellaneous plant drains (sample cooling, pump leaks, equipment washwater) will be collected, oil and suspended solids contamination will be removed by an oil/water separator, and the balance will be discharged to the City of Carlsbad sewer system (also referred to as the Encina Wastewater Authority's sanitary sewer system).The water balance diagrams, Figures 2.1-3a and 2.1-3b, show the anticipated wastewater streams and flow rates for the Amended CECP. A second wastewater collection system will collect sanitary wastewater from sinks, toilets, showers, eye wash stations, and other sanitary facilities, and subsequently discharge to Encina Wastewater Authority's sanitary sewer system.

Accidental leaks and discharges inside the power generating areas will be contained and disposed offsite, in accordance with approved spill prevention, control and countermeasures plans.

2.1.9.1.1 Reverse Osmosis Reject / Demineralizer Disposal

Processing of the City reclaimed water through the reverse osmosis system will produce a reject stream that will contain higher concentrations of reclaimed water constituents and traces of water-treatment chemicals added to the reclaimed water to prevent bio-fouling and scaling of reverse osmosis membranes. The concentrations of water constituents in the reject stream will be below the maximum permissible discharge limits before they enter the City of Carlsbad (Encina Wastewater Authority) sewer system.

The characteristics of the Amended CECP's combined discharge to the sewer system are provided in Table 2.1-3. Average discharge will be 81 gpm; peak flow to the sewer will be approximately 262 gpm.

The mixed bed polishing units will be regenerated offsite and will produce no liquid or solid wastes inside the Amended CECP boundary.

TABLE 2.1-3
Summary of Average Water Quality Characteristics for Amended CECP Wastewater Compared to Encina Wastewater Authority Discharge Limits

Constituent	Unit	Wastewater (reverse osmosis reject water)	Allowable Discharge Limits
Cadmium	ppm	0.02	0.43
Chromium (T)	ppm	0.02	3.50
Copper	ppm	0.03	4.40
Lead	ppm	0.02	1.8
Nickel	ppm	0.03	1.8
Silver	ppm	0.03	4.2
Zinc	ppm	0.07	6.2
pH	Units	6 to 9	5.5-11

2.1.9.1.2 Plant Drains and Oil/Water Separator

Blowdown from the inlet air evaporative cooling system will be recycled to the raw water tank for re-use. Normal plant drains will collect any containment area washdown, sample drains, and drainage from facility equipment drains. Water from these areas will be collected in a system of floor drains, hub drains, and sumps. Oil and grease and suspended solids will be filtered from the water and the balance discharged to the sewer system. Drains that can potentially contain accidental spills of oil or grease will be routed through an oil/water separator first. Plant wastewater that might carry high amounts of oil and grease or chemicals will be collected and removed for offsite disposal. Wastewater from combustion turbine water washes will be collected in sumps and will be trucked offsite for disposal at an approved wastewater disposal facility.

2.1.9.1.3 Storm Drains

The storm drain system will be installed to manage stormwater collection around each power block and the BOP area, and gravity drains to an oil/water separator. A secondary containment system will provide additional verification that no hydrocarbons are present prior to pumping the water to a bio-swale on the north side of the Amended CECP site. From the swale, the remaining water that has not evaporated or absorbed will be drained through the existing permitted discharge into the lagoon. An emergency generator will supply backup power for the storm drain system. The existing National Pollutant Discharge Elimination System (NPDES) permit for the EPS will be modified to support the Amended CECP (see Section 5.11, Soil and Water Resources).

2.1.9.1.4 Solid Wastes

The Amended CECP will produce wastes typical of power generation operations and routine maintenance. Generation plant wastes include oily rags, broken and rusted metal and machine parts, defective or broken electrical materials, empty containers, and other solid wastes, including the typical refuse generated by workers. Solid wastes will be trucked offsite for recycling and/or disposal (see Section 5.14).

2.1.9.1.5 Hazardous Wastes

Several methods will be used to properly manage and dispose of hazardous wastes generated by the Amended CECP. Waste lubricating oil will be recovered and recycled by a waste oil recycling contractor. Spent lubrication oil filters will be disposed of in a Class I landfill. Spent SCR and oxidation catalysts will be recycled by the supplier or disposed of in accordance with regulatory requirements. Workers will be trained to handle hazardous wastes generated at the site.

2.1.10 Management of Hazardous Materials

The Amended CECP will make us of the same hazardous material management detailed in the Licensed CECP.

A list of the chemicals anticipated to be used at the Amended CECP and their storage locations is provided in Section 5.5, Hazardous Materials Handling. This list identifies each chemical by type, intended use, and estimated quantity to be stored onsite. Section 5.5 includes additional information on hazardous materials handling.

2.1.11 Emission Control and Monitoring

Air emissions from the combustion of natural gas in the CTGs will be controlled using state of-the-art systems pursuant to federal, state, and local regulations. To ensure that the systems perform correctly, continuous emissions monitoring for NO_x and CO will be performed. Section 5.1, Air Quality, includes additional information on emission control and monitoring.

2.1.11.1 NO_x Emission Control

The CTGs selected for the Amended CECP require high-purity demineralized water for injection into the combustors to control emissions of NO_X. In addition, the exhaust duct work incorporates SCR systems to further control NO_x concentrations in the exhaust stacks to no more than 2.5 ppmvd, corrected to 15% oxygen (O_2). The SCR process will use 19% aqueous ammonia. Ammonia slip, or the concentration of unreacted ammonia in the stack exhaust, will be limited to 5.0 ppmvd, corrected to 15% O_2. The SCR equipment will include a reactor chamber, catalyst modules, ammonia storage system, ammonia vaporization and injection system, and monitoring equipment and sensors.

2.1.11.2 Carbon Monoxide and Volatile Organic Compound Emission Control

The combustion turbine combustors incorporate staged combustion of a pre-mixed fuel/air charge, resulting in high thermal efficiencies with reduced CO and volatile organic compounds (VOC) emissions. CO and VOC emissions will be further controlled by means of a CO oxidation catalyst. CO emission rate in stack exhaust will be limited to 4.0 ppmvd, corrected to 15% O_2. VOC emission rate will be limited to 2.0 ppmvd, corrected to 15% O_2.

2.1.11.3 Particulate Emission Control

Emissions will be controlled by the use of best combustion practices, high-efficiency air inlet filtration, and the use of natural gas. Similar to the Licensed CECP, natural gas will be the only fuel used, which, relative to other burnable materials, is low in sulfur and is very low in particulate emissions.

2.1.11.4 Continuous Emission Monitoring

Similar to the Licensed CECP, each CTG will have a continuous emission monitoring system (CEMS) that will sample, analyze, and record fuel gas flow rate, NO_x and CO concentration levels, and percentage of O_2 in the exhaust gas from the CTG exhaust stacks. The CEMS system will transmit data to a data acquisition system (DAS) that will store the data and generate emission reports in accordance with federal, state, and regional permit requirements. The DAS will also include alarm features that will propagate alarm signals to the plant DCS when the emissions approach or exceed pre-selected limits.

2.1.12 Fire Protection

The fire protection system design detailed in the Licensed CECP has been modified to reflect the Amended CECP site layout. The existing potable water fire suppression system will be removed and replaced by a deluge system by interconnection to the City of Carlsbad reclaimed water supply. This system will have onsite storage in a dual-purpose, combination raw water/fire water storage tank. City of Carlsbad potable water will be the emergency backup water source should there be an unlikely interruption in the reclaimed water supply. Two separate distribution loops will be installed at the Amended CECP site: one located around the perimeter of the reconfigured power block in the recessed area, and a secondary loop surrounding the perimeter of the area above the recessed power block. Access roads on the site will be expanded to a width of 28 feet to ensure adequate space for firefighting trucks to access the site, as shown in Figure 2.1-4.

Additionally, GE will provide self-contained systems to provide independent protection of the individual CTGs. The new deluge system layout is shown in Figure 2.1-5. The GE system will deploy National Fire Protection Association (NFPA) required protection for the new equipment.

The GE Fire and Explosion Protection System includes the following fire protection measures:

- Mitigates fires from starting, through fire prevention,
- Detects fires in early stages with fire detection systems,
- Contains fires using confinement designs, and
- Employs active fire suppression systems.

The Amended CECP’s additional fire protection measures will include:

- Establishing fire zones with physical separation between buildings,
- Separating buildings and structures for mitigating smoke spread,
- Constructing containment walls where oil is used,
- Minimizing the use of combustible materials,
- Providing sloped surfaces for draining combustible material to containment sumps,
- Adding separate escape routes in enclosures to the outside, and
- Implementing egress escape plans for large structures.

The Amended CECP fire protection system consists of wet pipe sprinkler systems and carbon dioxide (CO_2) systems. Fire detection devices or methods for detection include fuel gas, thermal rate compensated, and smoke- or manual-activated sensing. Potential hazards being monitored include ammonia, natural gas, lubricating oil, hydraulic oil, insulating oil, electrical gear, wood, PVC, and other flammable material like the gas turbine inlet filter. System isolation and area classifications will be in accordance with NFPA recommendations.

The primary source of the fire protection systems is the raw water storage tank supplied with reclaimed water, with backup sources from the City potable water system. Tank sizing is governed by NFPA 850A: a 100-percent-capacity electric and a 100-percent-capacity diesel-driven fire pump will maintain system pressure during filling and fire events. A low-capacity jockey fire pump will maintain system pressure during non-fire suppression system activity.

A fire water loop will surround the power block with hydrants installed per criteria specified in NFPA codes and standards. This loop will also supply the deluge system in the air compressor enclosure, gas compressor enclosure, and the fire pump enclosure in the BOP area, as well as provide fire suppression for the warehouse/maintenance and administration/control buildings. Electrically sensitive areas in the administration/control building will be protected by automated dry agent fire protection suitable for occupied spaces. Each CTG will be equipped with a CO_2 fire-suppression system that is integrated into the turbine control system. The automatically actuated CO_2 system provides fire suppression in the turbine compartments.

Power distribution centers and auxiliary enclosures in the power block will also be equipped with fire extinguishers per NFPA guidelines.

The main transformers will be designed in accordance with NFPA 78 and will not be provided with specific fire suppression systems.

Local fire protection and suppression panels will be provided for each area being protected with automated functions and alarming. Local alarm annunciation will also be replicated to the main control system.

Section 5.5, Hazardous Materials Handling, includes additional information for fire and explosion risk, and Section 5.10, Socioeconomics, provides information on local fire protection capability.

2.1.13 Plant Auxiliaries

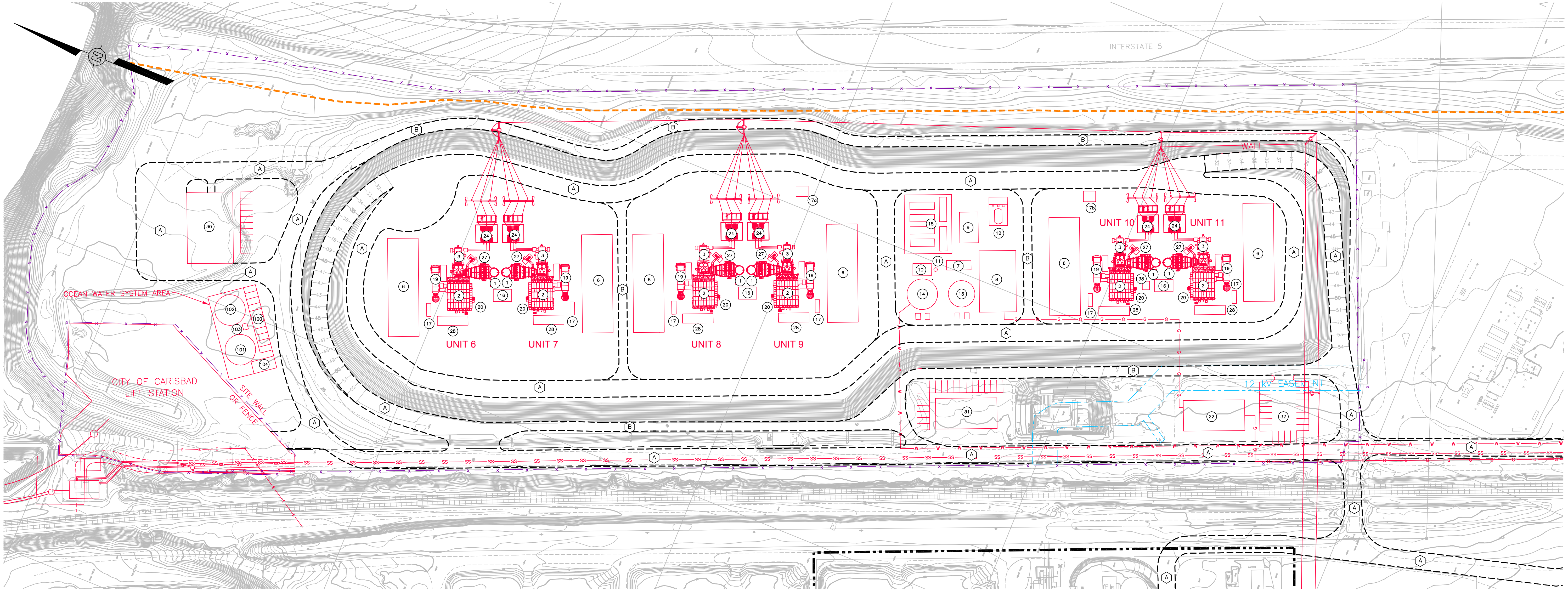
The following systems will support, protect, and control the generating facility.

2.1.13.1 Lighting

The Amended CECP will employ the same standards and design intent of the lighting system as the Licensed CECP.

2.1.13.2 Grounding

The same engineering standards will be incorporated into the grounding system of the Amended CECP as with the Licensed CECP.



LEGEND:

- LOCATION OF POSEIDON DESAL PLANT
- PIPE LINE RIGHT OF WAY
- I-5 PARTIAL RIGHT OF WAY TAKE BOUNDARY
- G — GAS LINE (APPROVED ROUTING PER PEAR)
- W — RECLAIMED WATER LINE (APPROVED ROUTING PER AFC)
- SS — SANITARY SEWER LINE
- x — FENCE LINE / PROJECT BOUNDARY
- 12kV EASEMENT TO POSEIDON
- (A) FIRE & HEAVY HAUL ROAD
- (B) SERVICE & MAINTENANCE ROAD

EQUIPMENT LIST

1	EXHAUST STACK
2	COMBUSTION TURBINE ENCLOSURE
3	GENERATOR ENCLOSURE
6	FIN FAN COOLERS
7	BOP PDC
8	GAS COMPRESSOR BUILDING
9	AIR COMPRESSOR BUILDING
10	FIRE PUMP BUILDING
11	DIESEL STORAGE TANK (IF NEEDED)
12	AMMONIA STORAGE AREA
13	DEMINERALIZED WATER TANK
14	RAW/FIRE WATER TANK
15	WATER TREATMENT TRAILERS
16	CEMS ENCLOSURE
17	UNIT AUXILIARY TRANSFORMER
18	AMMONIA PREP SKID
19	SHELL AND TUBE HEAT EXCHANGER
20	AUXILIARY SKID
22	GAS METERING
24	GSU TRANSFORMER
27	ATTEMPORATION BLOWER SKID
28	CTG AND INTERCOOLER MCC
30	WAREHOUSE AND MAINTENANCE BUILDING
31	CONTROL ROOM AND ADMINISTRATION BUILDING
32	PARKING LOT
38	EMERGENCY DIESEL GENERATOR
100	OCEAN WATER TRAILERS
101	OCEAN WATER STORAGE TANK
102	ULTRA FILTRATION STORAGE TANK (OWS)
103	ULTRA FILTRATION PUMPS
104	SOLIDS UNLOADING SPACE

SOURCE:

CB&I ENVIRONMENTAL & INFRASTRUCTURE

APPROXIMATE SCALE

0 80 160 240 FEET

Figure 2.1-4
Site Road Plan
Amended Carlsbad Energy Center Project
Carlsbad, California (07-AFC-06C)
Petition to Amend

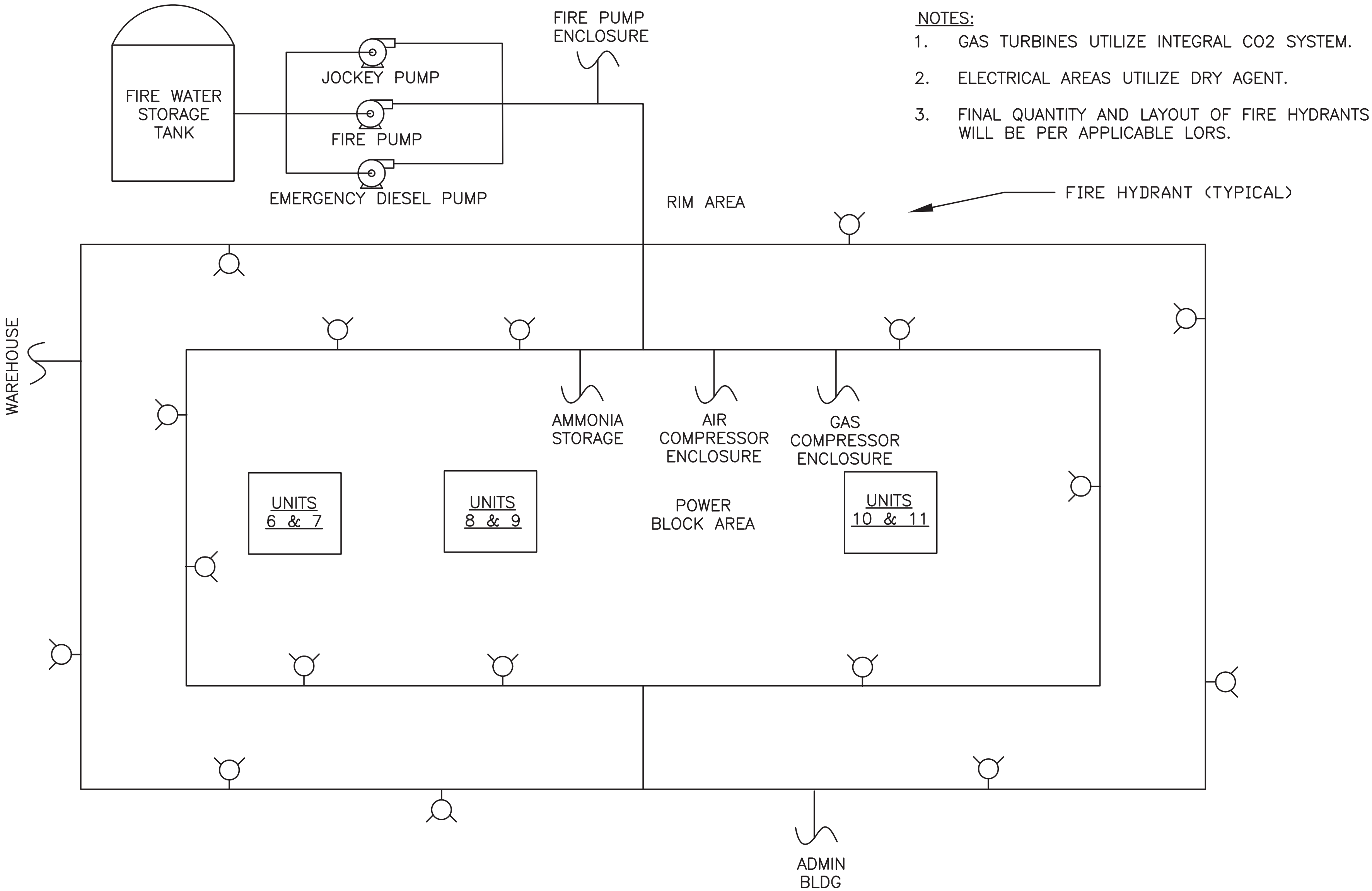


Figure 2.1-5
CECP Fire Protection
Amended Carlsbad Energy Center Project
Carlsbad, California (07-AFC-06C)
Petition to Amend

SOURCE: CB&I ENVIRONMENTAL & INFRASTRUCTURE, INC

2.1.13.3 Distributed Control System

The DCS provides modulating control, digital control, monitoring, and indicating functions for the plant power block systems. The following functions will be provided:

- Controlling the CTGs and other generation systems in a safe, coordinated manner;
- Controlling of BOP systems in response to plant demands;
- Monitoring controlled plant equipment and process parameters and delivery of this information to plant operators;
- Providing graphical user interface control displays (printed logs, video monitors) for signals generated within the system or received from input / output (I/O);
- Providing consolidated plant process status information through displays presented in a timely and meaningful manner;
- Providing alarms of out-of-limit parameters or parameter trends, displaying on alarm video monitors(s), and recording on an alarm historian; and
- Providing means for data storage and historical data retrieval.

The DCS will be a redundant microprocessor-based system and will consist of the following major components:

- PC-based operator console(s) with video monitors
- Engineer work station(s)
- Distributed processing units
- I/O cabinets
- Historian system
- Printer(s)
- Data telemetry to the combustion turbine control systems

The DCS will have a functionally distributed architecture comprising a group of similar redundant processing units linked to a group of operator consoles and the engineer workstation(s) by virtue of redundant data highways. Each processor will be programmed to perform specific dedicated tasks for control information, data acquisition, annunciation, and retain historical information. Redundancy offers a fail-safe mode of operation wherein no single processor failure can cause or prevent a unit trip.

The DCS will interface with the control systems furnished by the CTG supplier to provide remote control capabilities, as well as data acquisition, annunciation, and historical storage of turbine and generator operating information.

The system will be designed with sufficient redundancy to preclude a single device failure from significantly affecting overall plant control and operation. This also will allow critical control and safety systems to have redundancy of controls, as well as an uninterruptible power source.

As part of the quality control program, daily operator logs will be available for review to determine the status of the operating equipment.

2.1.13.4 Cathodic Protection

The cathodic protection system will be designed to control the electrochemical corrosion of designated metal piping buried in the soil. Depending on the corrosion potential and the site soils, either passive or impressed current cathodic protection will be provided.

2.1.13.5 Service Air

The service air system will supply compressed air to hose connections for general plant use. Service air headers will be routed to hose connections located at various points throughout the facility.

2.1.13.6 Instrument Air

The instrument air system will provide dry air to pneumatic operators and devices. An instrument air header will be routed to locations within the facility equipment areas and within the water treatment facility where pneumatic operators and devices will be located.

2.1.14 Administrative Building and Warehouse

2.1.14.1 Administrative Building

The Administrative Building will replace the functionality of the existing Encina plant operations by creating a workspace for site administration and control room operation. In addition to the required parking areas, an additional parking area will be provided for visitors or meeting attendees. Utilities for this building will also be provided.

The workspace will provide a control room, DCS room including uninterruptable power supply equipment, electrical room, plant and maintenance operations supervision offices, mail room, reception entry, general service offices, and conference rooms along with associated restroom and locker facilities.

2.1.14.2 Warehouse

The warehouse will replace the functionality of the existing Encina facility by creating an enclosed Maintenance workspace. Utilities will also be provided to this structure.

The workspace will support maintenance activities including warehousing spare parts, service air compressors, welding area, maintenance shop area, electrical/instrument and control shop area, tool cribs, offices, high-value storage area along with the associated restrooms, and changing areas. A loading dock area will be included for deliveries.

2.1.15 Interconnect to Electrical Grid

The six CTGs will be interconnected to the regional electrical grid through new 138-kV/230-kV transmission connection lines that will exit the Amended CECP power block site to the southwest and be routed to the respective existing SDG&E switchyards (see Section 3.0, Transmission System Engineering). Similar to the Licensed CECP, no offsite additional electrical transmission lines are required.

2.1.16 Project Construction

The construction schedule addressed in the AFC has changed to accommodate the modifications proposed in the PTA, and the following construction workforce tables have changed accordingly. The construction and Commercial Operating Date schedule selected for the amended project will be based on the terms of a negotiated Power Purchase Agreement.

Table 2.1-4 provides the Amended CECP construction workforce by labor craft by month during the 24-month construction schedule. See Section 5.10, Socioeconomics, for the average and peak construction workforce for the Amended CECP.

The hours at which construction takes place for the Amended CECP are not changed from the Licensed CECP. Table 2.1-5A provides the anticipated construction deliveries by truck, and Table 2.1-5b shows the anticipated truck and rail deliveries for heavy or oversize deliveries. See Section 5.12, Traffic and Transportation, for average and peak construction traffic (construction workers and deliveries) for both of the Amended CECP construction schedule options.

TABLE 2.1-4
Amended CECP Construction Workforce by Labor Craft by Month

	Months After Notice to Proceed																								
				Construction Phase																		Commissioning Phase			
Craft	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**Total**
Plant																									
Insulation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7	9	11	11	11	18	14	0	0	0	81
Boiler Makers	0	0	3	3	5	10	12	12	19	19	17	19	19	22	19	14	6	6	6	6	6	11	0	0	234
Masons	0	0	0	2	4	4	4	4	3	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	32
Carpenters	3	3	15	25	18	26	26	26	26	26	26	15	15	21	20	11	10	9	7	5	5	2	1	0	341
Electricians	3	3	5	7	8	10	14	20	24	24	24	25	25	35	35	35	18	15	11	7	7	5	5	5	370
Ironworkers	0	0	4	9	6	7	13	16	16	22	20	20	20	27	29	31	14	11	10	9	9	3	0	0	296
Laborers	22	34	34	38	38	38	38	38	38	38	36	28	25	34	25	25	14	13	13	15	15	3	2	2	606
Millwrights	0	0	0	0	0	0	6	6	7	7	7	11	11	14	13	10	9	8	8	8	8	1	1	1	136
Operating Engineers	24	30	0	3	6	9	7	9	10	10	12	12	12	13	15	16	9	8	7	7	7	1	1	0	228
Plasterers	0	0	0	0	0	0	0	0	1	2	2	2	3	4	4	2	2	1	0	0	0	0	0	0	23
Painters	0	0	0	0	0	0	0	1	1	2	2	4	3	4	4	4	4	4	3	3	2	2	0	0	43
Pipefitters	3	5	10	10	12	20	30	30	34	34	34	32	34	36	36	36	25	20	20	16	14	4	4	4	503
Sheetmetal Workers	0	0	0	0	0	2	4	7	7	8	8	9	10	11	11	8	6	5	3	3	3	1	0	0	106
Sprinkler Fitters	0	0	0	0	0	0	1	1	1	1	3	4	7	7	7	5	5	4	4	3	3	0	0	0	56
Teamsters	24	27	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1	1	1	0	85
Surveyors	3	5	5	5	4	5	4	4	3	3	3	3	3	3	3	2	2	2	2	1	1	2	0	0	68
Manual Staff Subtotal	**82**	**107**	**78**	**104**	**103**	**133**	**161**	**176**	**192**	**199**	**197**	**187**	**190**	**234**	**231**	**210**	**137**	**119**	**107**	**103**	**95**	**36**	**15**	**12**	**3208**
Other Plant Staff	14	20	34	46	46	46	34	34	38	38	45	44	46	40	38	34	30	21	21	21	21	18	17	17	763
Plant Total	**96**	**127**	**112**	**150**	**149**	**179**	**195**	**210**	**230**	**237**	**242**	**231**	**236**	**274**	**269**	**244**	**167**	**140**	**128**	**124**	**116**	**54**	**32**	**29**	**3971**
Linear Construction																									**0**
Laborers												18	21												39
Operating Engineers												9	7												16
Pipefitters												7	7												14
Teamsters												5	4												9
Manual Staff Subtotal												**39**	**39**												**78**
Linear Construction Staff												4	4												8
Linear Construction Total												**43**	**43**												**86**
Total Construction Staff	**96**	**127**	**112**	**150**	**149**	**179**	**195**	**210**	**230**	**237**	**242**	**274**	**279**	**274**	**269**	**244**	**167**	**140**	**128**	**124**	**116**	**54**	**32**	**29**	**4057**

TABLE 2.1-5A

Anticipated Construction Schedule for Truck Deliveries of Equipment (Excluding Heavy Equipment Deliveries and Demolition)

Month After Construction Mobilization	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Equipment and Materials																								
Generating Facility																								
Combustion Turbine/Generator							5	13	25	32	34	29	19	10	10									
Mechanical Equipment			5	5	16	16	32	32	54	54	53	53	32	26	13	5	3							
Electrical Equipment and Materials		3	3	8	8	11	16	16	32	32	32	43	37	27	16	16	5	5						
Piping, Supports & Valves		3	4	8	14	27	43	43	53	54	64	53	32	26	16	5	5							
Concrete and Rebar		50	197	245	484	484	105	87	43	17	9													
Miscellaneous Steel/Architectural				5	5	16	27	32	32	26	10	5												
Consumables/Supplies	14	16	35	38	43	43	43	43	43	46	46	46	46	37	37	27	27	10	10	3				
Contractor Mobilization & Demobilization	11	11	16	10	5										3	10	16	10	10	3				
Construction Equipment	5	5	11	8	8	5	5	5	4	4	2	2	1	1	3	3	5	3	3					
Miscellaneous																					3	3	3	3
Subtotal	**30**	**88**	**271**	**327**	**583**	**602**	**276**	**271**	**286**	**265**	**250**	**231**	**167**	**127**	**98**	**66**	**61**	**28**	**23**	**6**	**3**	**3**	**3**	**3**
Average Daily	**1.4**	**4.2**	**12.9**	**15.6**	**27.8**	**28.7**	**13.1**	**12.9**	**13.6**	**12.6**	**11.9**	**11.0**	**8.0**	**6.0**	**4.7**	**3.1**	**2.9**	**1.3**	**1.1**	**0.3**	**0.1**	**0.1**	**0.1**	**0.1**
Project Linears																								
Electrical Equipment and Materials												6	6											
Piping, Supports & Valves												18	18											
Concrete and Rebar												20	23											
Miscellaneous Steel/Architectural												2	4											
Consumables/Supplies												18	18											
Construction Equipment												13	13											
Subtotal												**77**	**82**											
Average Daily												**3.5**	**3.9**											
Total	**30**	**88**	**271**	**327**	**583**	**602**	**276**	**271**	**286**	**265**	**250**	**308**	**249**	**127**	**98**	**66**	**61**	**28**	**23**	**6**	**3**	**3**	**3**	**3**
Total Average Daily	**1.4**	**4.2**	**12.9**	**15.6**	**27.8**	**28.7**	**13.1**	**12.9**	**13.6**	**12.6**	**11.9**	**14.0**	**11.9**	**5.8**	**4.5**	**3.0**	**3.0**	**1.3**	**1.1**	**0.3**	**0.1**	**0.1**	**0.1**	**0.1**

TABLE 2.1-5B

Anticipated Construction Deliveries, Both Truck Deliveries and Rail Deliveries (Heavy and Oversize Loads)

Months	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total
Rail Delivery w/ Heavy Haul[a]													2	2	2	2	2	2		8	6				28
Rail Delivery[b]													1	2	2	2	2	1		8					16
Total Rail Deliveries	0	0	0	0	0	0	0	0	0	0	0	0	3	4	4	4	4	3	0	16	6	0	0	0	44
Truck Deliveries[c]																									
GE Power Plant					154	202	222	326	369	349	316	286	307	264	239	205	194	186	192	120	64	30	19	11	4,055
Site Prep / Access Roads	180	270	100																						550
Berms - Gunite & Wire Mesh			8	2																					10
Project Linears												10	8	2											20
Transmission													9	16	6	2			2						35
Total Truck Deliveries	180	280	116	4	154	202	222	326	369	349	316	286	324	282	245	207	194	186	194	120	64	30	19	11	4,670

[a]All rail deliveries relate to GE power plant activities. Heavy haul transporter to move equipment from rail spur to construction location at power block (assume 500 hp range) (distance: approx. 4,300 ft.)

[b]Typical flatbed train car is 27 tons unloaded, 110 tons fully loaded

[c]Assume semi tractor/trailer or dump truck approx. 450 to 470 hp range

Construction laydown and construction worker parking areas for the Amended CECP will occupy about 19.3 acres at selected locations within the existing EPS site (see Figure 2.0-2). Construction truck delivery access will be from Cannon Road and Carlsbad Boulevard, as shown in Figure 2.0-2. Materials and equipment will be delivered by truck and rail. An existing railroad track is located immediately on the west side of the Amended CECP site and will be available for delivery of large or heavy equipment (see Figure 2.0-2, Construction Laydown and Parking).

2.1.17 Generating Facility Operation

Operations at the Amended CECP will be staffed with an estimated 18-person workforce including operators on rotating shifts and maintenance technicians during the standard 8-hour work day. This estimated 18-person workforce will be sourced from the existing 50-person workforce that presently operates the existing EPS. The facility will be staffed 7 days a week, 24 hours per day, but will have a limit of 2,700 operating hours per CTG annually.

It is expected that the Amended CECP will be operated primarily as a peaking facility on daily cycles, especially during summer months. The exact operational profile of the Amended CECP, however, cannot be defined in detail because operation of the facility depends on the variable demand in the service area and various grid conditions.

The Amended CECP may be operated in one or all of the following conditions:

- **Load Following**. During non-peak seasons (primarily spring and fall), the facility will most likely be operated at loads that may vary between maximum continuous output (all six units operating at base load) and minimum load (one CTG operating as low as 25 percent load) to meet electrical demand at all times between 0600 and 2400 hours.[8] In this mode, the plant is dispatched in real-time fashion.
- **Daily Cycling**. The facility will most likely be operated in daily cycling condition, wherein the plant is operated at pre-determined fixed load points during the day and totally shut down at night or on weekends. This condition may occur either with daily nighttime shutdowns or with weekend shutdowns depending on electrical demand, and other issues.
- **Full Shutdown**. This would occur if forced by lack of load demand/dispatch, equipment malfunction, fuel supply interruption, transmission line disconnect, or scheduled maintenance.

In the unlikely event of a situation that causes a longer-term cessation of normal operations, security of the facilities will continue to be maintained on a 24-hour basis, and the CEC will be notified. Depending on the length of shutdown, a contingency plan for the temporary cessation of operations may be implemented. Such contingency plan will be in conformance with all applicable laws, ordinances, regulations, and standards (LORS) and protection of public health, safety, and the environment. The plan, depending on the expected duration of the shutdown, could include the draining of all chemicals from storage tanks and other equipment and the safe shutdown of all equipment. All wastes will be disposed of according to applicable LORS. (See Section 2.4, Facility Closure, for a full discussion of temporary cessation of operations and full closure of the Amended CECP.)

2.2 Encina Power Station Demolition

This PTA incorporates the shutdown and demolition of the EPS as part of the Amended CECP. Following shutdown of EPS Units 1 through 5, the project owner will demolish the EPS aboveground structures west of the railroad tracks. This will include the removal of the emergency/black start combustion turbine generator. This change will also allow and facilitate future redevelopment of western portions of the EPS

[8] Between mutual agreement with City of Carlsbad, the CECP will normally operate between 0600 and 2400 hours. Only in emergency situations will the plant operate between 2400 and 0600 hours.

site for non-power-production uses. Though not part of the Amended CECP, the project owner entered into an agreement with the City of Carlsbad and SDG&E that may move the current SDG&E Cannon Street maintenance yard to a new, inland location. The demolition of EPS is another step toward facilitating a remodeled coastal area and reflects a significant and important community development flowing from the Amended CECP.

2.2.1 EPS Background

The EPS Units 1, 2 and 3 were constructed in the 1950s, and feature 100-, 104- and 110-MW GE steam turbines and generators, respectively. Units 4 and 5 were built in the 1970s, and utilize approximately 300-MW and 330-MW Westinghouse steam turbines and generators, respectively. Additionally, a 17-MW GE Frame 5 simple-cycle gas turbine and generator is used for black-start back feed capability. All five units contain steam boilers, and all units are connected to the ocean water intake and discharge systems. The 400-foot-tall exhaust stack is shared by the five units. Other miscellaneous equipment and structures west of the railroad tracks include administrative, operations, and maintenance buildings and wastewater storage tanks and associated pumps that manage EPS's wastewater.

The Amended CECP will replace this aging infrastructure with more efficient, effective generating units, located inland, east of the railroad tracks. This replacement will then allow demolition of the EPS and redevelopment of the western portions of the EPS property, subject to necessary easements to support the operation and security of the Amended CECP. The demolition must also accommodate the infrastructure required to maintain the Poseidon Desalination Plant (Poseidon) operations and the continued function of the SDG&E switchyard. Access roadwork, utility connections, and security for the Amended CECP operations will be retained or modified in the western portion of the site.

2.2.2 Demolition Phase

The EPS demolition phase is anticipated to take 22 months and will begin after shutdown of EPS Units 1 through 5. Demolition mobilization will occur after achieving commercial operation of the Amended CECP and retirement of the EPS generating units. The subject demolition areas are shown in Figure 2.2-1, Encina Power Station Demolition, and Figure 2.2-2 depicts the site after EPS demolition is complete. The EPS demolition will generally occur within an area bounded by the property fence line west of the railroad tracks, south of the lagoon, east of Carlsbad Boulevard or the Pacific Coast Highway, and north of the SDG&E maintenance property. Two EPS water storage tanks located on the SDG&E maintenance property will be included in the demolition. No activity is planned west of Carlsbad Boulevard. The SDG&E Encina switchyards and supporting control house are excluded from demolition. Additionally, areas of the EPS property in the previously described boundary will remain, such as the leased areas required by the Poseidon Desalination Plant. There are no plans to use areas of the property east of the railroad tracks for demolition activities, but site access could occur through the southwest corner of the Amended CECP site.

Generally, demolition will proceed as a set of segmented tasks associated with each of the following major components or component areas on site:

- Power plant building and contents
- Combustion turbine and structures, east power plant building
- Ocean water intake/discharge piping, structures and equipment
- Northwest structures, tanks, and piping
- Fuel oil piping and supports
- Southeast corner structures
- Two domestic water tanks on SDG&E property

The actual sequencing of the overall EPS demolition will be such that it provides a programmatic approach to removal of the power plant while supporting continued operation and maintenance activities of the property co-inhabitants, Poseidon and SDG&E, and also provides support of the Amended CECP. Sequencing is described further below. The following is a more complete description of the seven primary demolition targets:

Power plant building and contents: The main powerhouse structures and systems will be demolished to an "at grade" condition. This includes the transformers up to an interface with the SDG&E switchyard. Crushed concrete will be used to fill basements and other subgrade infrastructure that represent a safety risk by not being filled.

Combustion turbine and structures, east power plant building: Removal of the emergency/black-start gas turbine generator to include ISO phase bus and dedicated water storage tank, and structures that will no longer be necessary for SDG&E switchyard operations and maintenance.

Ocean water intake/discharge piping, structures, and equipment: The ocean water intake system will be isolated from the lagoon. Poseidon will continue to intake ocean water for the Carlsbad Desalination Project from the current EPS discharge tunnel, as permitted. The intake will have stop logs installed to allow a concrete plug to be poured to isolate the intake piping from the lagoon, and the circulating water piping at the inlet and exit of each condenser will be cut and a welded cap installed. Aboveground piping, valves, screens, filters, and other structures will be demolished and removed. The intake canals and underground circulating piping will be isolated and remain intact. Crushed concrete and other onsite fill will be used to restore subgrade areas to grade where they represent a safety risk by not being filled. Detailed plans for the isolation of the intake structure and discharge piping that Poseidon will continue to use will be documented in an EPS Demolition Plan that will be submitted to the CEC Compliance Project Manager for review and approval.

Northwest structures, tanks and piping: The industrial wastewater facility north of the switchyard will be demolished. Some of the tanks and equipment that will be removed are Low Volume Waste Tanks #1 and #2 (that discharge via the NPDES permit), Extended Waste Tanks #3 and #4 and Treated Water Tanks #5 and #6 (that discharge to Encina Water Authority), as well as supporting pumps, filters, piping, instrumentation and controls. The tanks, piping, valves, pumps, and other structures will be demolished and removed and crushed concrete and other onsite fill will be used to fill subgrade areas that represent a safety risk by not being filled.

Fuel oil piping and supports: Any final above-grade fuel oil piping and supports not previously removed as part of the Amended CECP development and/or during construction of the Poseidon facility will be removed.

Southeast corner structures: The machine shop and compressor building, each on either side of the existing fuel gas regulating station, will be demolished to grade.

Two domestic water tanks on SDG&E property: Two welded steel tanks, located on the SDG&E maintenance yard to the south of EPS, serve as storage for the EPS fire water system. The aboveground tanks and associated piping, pumps, and structures will be demolished to grade.

2.2.3 Demolition Sequencing and Process

Demolition of EPS, and of each of the above seven components and component areas, will follow a general systematic approach that allows for cleanup and removal of hazardous building materials, recycling of valuable materials, physical demolition and removal of equipment and structures, and final site grading and clean up. Conventional demolition with continual separation of salvageable materials will be the most cost-effective method of disposal. The project is expected to follow the typical sequence, however, some tasks may be completed in parallel and may be subject to change based on permit requirements including work plan development, approval of designated disposal/recycling targets, hazardous building materials (HBM) abatement plans, permitting, grading, site-specific health and safety plan, etc.

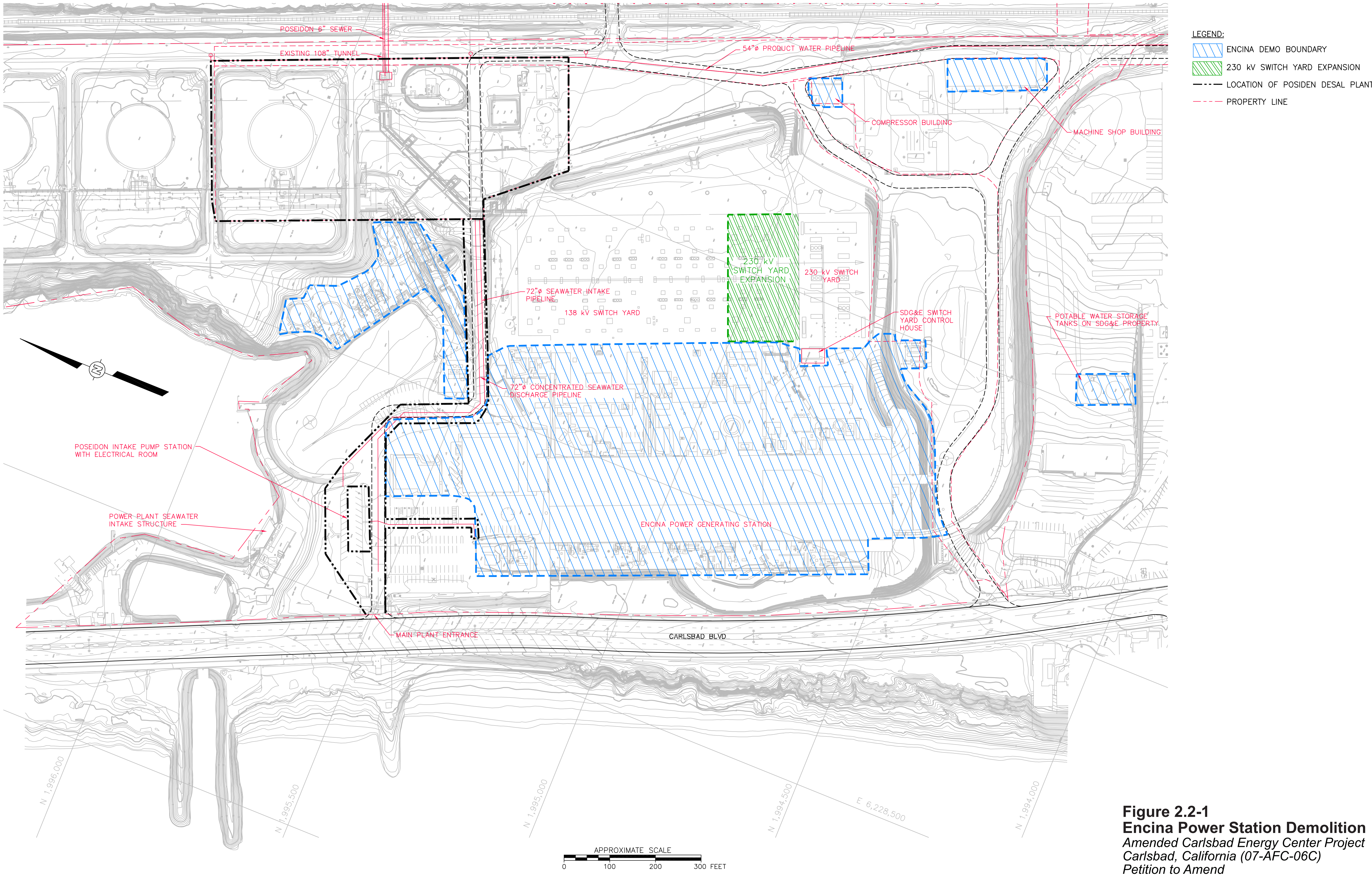


Figure 2.2-1
Encina Power Station Demolition
Amended Carlsbad Energy Center Project
Carlsbad, California (07-AFC-06C)
Petition to Amend

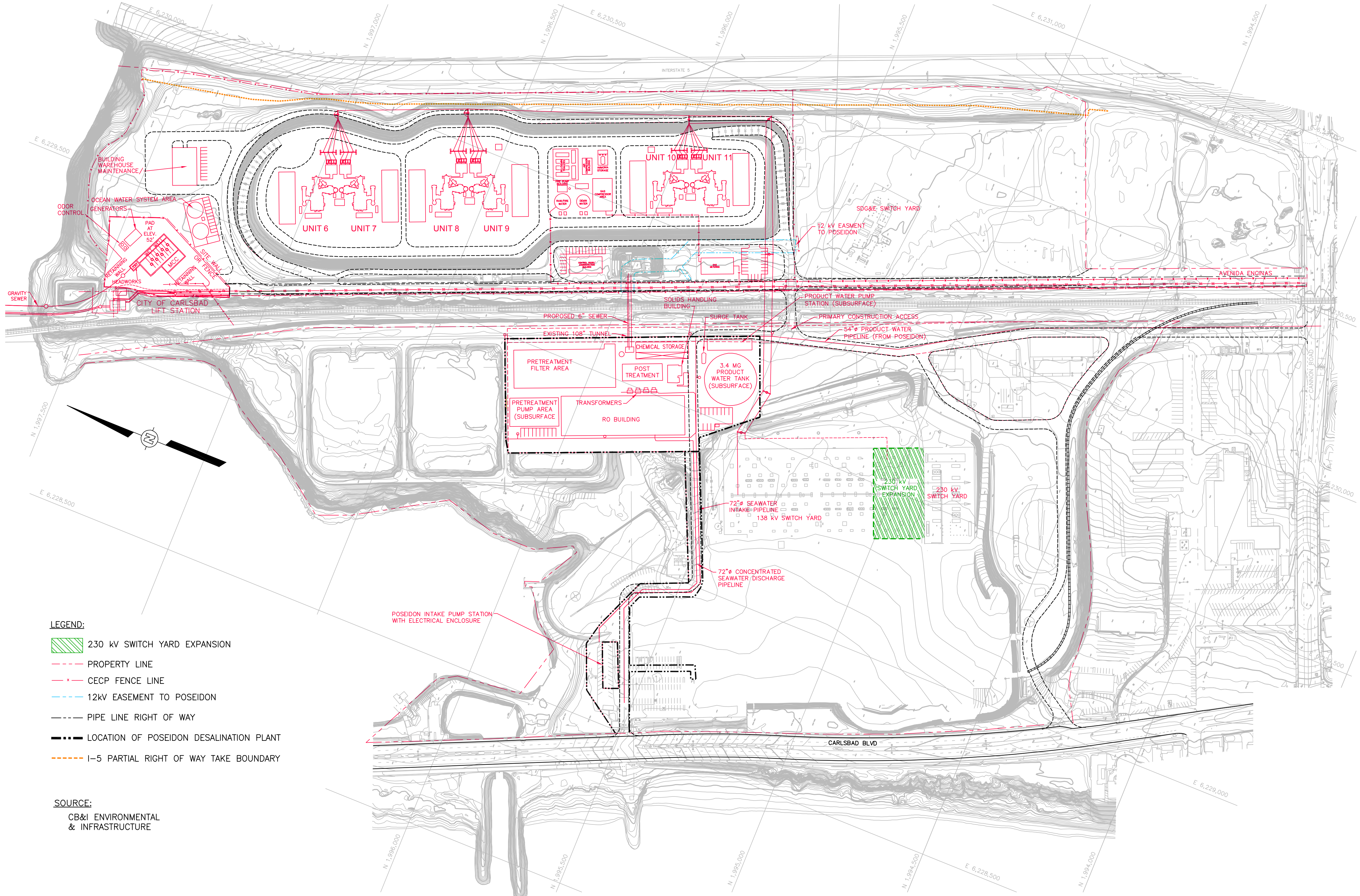


Figure 2.2-2
Depiction of Site after EPS Demolition
Amended Carlsbad Energy Center Project
Carlsbad, California (07-AFC-06C)
Petition to Amend

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Generally, the demolition process will proceed as follows:

- **Planning and assessment:** Surveys and evaluations will be conducted to identify and assess the presence of HBMs as well as recyclable metals, materials, and equipment. Generally this phase will proceed as follows:
  - Develop the implementation plans for the identification, testing, agency permitting, removal, monitoring, and disposal of any hazardous building materials prior to the demolition of the structures.
  - Determine the final configuration and construction requirements for isolating the ocean water intake and discharge in a manner that supports final plans for Poseidon's use of ocean water and also supports any final plans to use ocean water to produce purified ocean water for plant makeup purposes.
  - Develop demolition plans.
  - Contract for services related to the plans.

  At the completion of this phase, the demolition of EPS will be ready to commence. The exact timing of the initiation of demolition will be driven by actual dates that Units 1 through 5 are shut down and released from service, the Amended CECP is commercially operating, and the Amended CECP construction contractor has demobilized to the extent such demobilization is needed to allow demolition of EPS.
- **Demolition mobilization**: Any permits required beyond the CEC license will be drawn. To the maximum extent possible, existing construction infrastructure for CECP will remain onsite and be used to support demolition of EPS.
- **Preliminary HBM abatement and material recycling:** Any preliminary recycling activities will commence as will any HBM abatement identified in plans as being completed prior to major structure or demolition activities.
- **Demolition of selected structures to facilitate construction, demolition, and laydown:** Some structures and equipment will be removed first to provide working areas for remaining demolition equipment and activities. This will be primarily in the area east and north of the main power building. It is also expected that other areas of the property west of the railroad tracks will be identified as temporary storage areas for scrap, recycle, and/or offsite disposal to various end users and staging.
- **Seal intake structure:** Remove HBMs and materials not pertinent to onsite storage and scrap value materials from the structure and sequentially demolish and fill the structure or associated void to the extent required for safety and environmental best management practices.
- **Outlying structures and piping systems:** Removing HBMs and materials not pertinent to onsite storage and scrap value materials from the structures and sequentially demolish and remove the structures.
- **Main power building:** Remediate all HBMs and materials not pertinent to onsite storage and scrap value materials from the structure and sequentially deconstruct the structure.
- **Stack removal:** The stack is the largest visual structure. The concrete in the stack will be used to begin a material spoils system for filling below-grade spaces, and the steel liner will be demolished and prepared for recycling.
- **Remaining systems and structures required during demolition:** This includes but is not limited to lighting, fire protection, electrical relays for switchyard interconnections, repurposed administration and maintenance facilities, or other systems identified during the engineering phase as necessary to support demolition.

- **Demobilize demolition**: Remove trailers, equipment, and any remaining materials left over from demolition.
- **Final "as left" acceptance:** Gain CEC approval that EPS demolition is completed and the western portion is available for redevelopment under other jurisdictional bodies.

2.2.4 Safety and Hazardous Materials Removal

Key health and safety aspects such as physical hazards, asbestos, lead, and other HBMs require careful management during demolition to minimize risks to site workers and the public while complying with LORS. HBMs, including asbestos, mercury, and lead-based paints have been identified by a limited survey performed in 2006 by Shaw Environmental & Infrastructure, Inc., and additional identification will be required at the outset and throughout the demolition process. Asbestos is one of the most prevalent HBMs present in EPS structures. Asbestos removal will be monitored to ensure no asbestos is released into ambient air. See the Hazardous Materials, the Waste Management, and the Worker Safety sections of this PTA for a complete explanation of how these hazards and risks will be managed.

2.2.5 Demolition Practices

For each element of the demolition, activity includes:

- Mobilize and set up demolition support needs, like power.
- Make site and structures safe and secure for worker access and demolition.
- Implement erosion control plan.
- Confirm energy sources, utilities, and pipelines, etc.
- Develop and implement utility capping plan and lockout/tagout (LOTO) plan, as required.
- Remove universal wastes.
- Remove asbestos and lead or other HBMs.
- Identify equipment and scrap recovery.
- Remove structure through mechanical means.
- Segregate process steel and masonry/concrete from other streams.
- Backfill subsurface with appropriate fill to final grade and restore surface cover per plan.
- Demobilize all demolition equipment.

Table 2.2-1 provides quantity estimates for major equipment required, Table 2.2-2 provides quantity estimates for craft and support staff, and Table 2.2-3 provides an estimate for truck deliveries to the site to support the EPS demolition.

2.2.6 Remediation

Subsurface remediation of the EPS site is not included as part of the demolition activities to occur under this amendment, but may be conducted at a later date for future redevelopment of the site. During demolition, if obvious areas of contamination are found (stained soil or soil with a strong odor), samples will be taken to determine the type and potential extent of contamination. If these samples exceed county or state standards, they will be cleaned to industrial clean up levels in coordination with the appropriate agencies.

TABLE 2.2-1
Major Equipment Quantities for EPS Demolition

Months	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	Totals
Crawler Excavator w/Breaker						2	3	3	4								2						14
Crawler Excavator w/Grapple or Bucket	1	1	1	1	1	1	2	2	2	1	1	1	1	3	3	3	3						31
Crawler Excavator w/Shear						1	2	2	2	1	1	1	1	3	3	3	3						23
Crawler Excavator w/Pulverizer								2	2														4
Skid Steer Loader	2	2	6	8	8	10	10	10	12	6	6	6	6	6	6	6	6			2	2	2	122
Track Loader	1	1	1	1	1	1	1	1	2	1	1	1	1	1	1	1	1	2	2	1	1	1	25
Rubber Tire Loader											1	1	1	1	1	1	1	1	1				10
Water Truck	1	1	1	1	1	2	2	3	3	2	2	2	2							1	1	1	26
Hydro-Crane			1	1			2	2	1	1	1	1	2										12
Portable Crusher										1	1	1	1	1	1	1	1	1	1				10
Ten Wheeler with Dump Bins				2	2	2	2	2	2	2	2	2	2										20
Semi-End Dumps						2	3	4	6	2	2	2	2	8	4	14	14	3	3				79
Tractor/Trailer	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	2	2	2	25

Estimates of work force demographics required for the demolition of EPS are shown in Table 2.2-2.

TABLE 2.2-2
Labor Work Force Demographics for EPS Demolition

Months	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	Totals
Craft																							
Laborers	10	10	45	105	155	165	146	91	72	56	50	28	25	25	15	15	15	12	10	10	10	10	1080
Operating Engineers	2	2	2	2	2	4	8	10	12	4	4	4	2	8	8	8	8	4	2	2	2	2	102
Contractor Staff																							
Construction Manager	3	3	7	13	17	20	20	16	13	10	9	7	6	9	6	6	6	5	0	0	0	0	176
Administrators	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	44
Engineering Supervisor	3	3	1	1	1	1	1	1	1	1	1	1	1	3	1	1	1	1	1	1	1	1	28
Health and Safety Engineer	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	44
Monthly Totals	22	22	59	125	179	194	179	122	102	75	68	44	38	49	34	31	34	26	17	17	17	17	1474

Estimates of truck deliveries required for the demolition of EPS are shown in Table 2.2-3.

TABLE 2.2-3
Truck Deliveries Required for EPS Demolition

Months	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	Totals
Equipment Services	1	1	4	4	4	4	8	8	8	8	8	8	8	8	8	8	8	8	8	1	1	1	139
Oxygen and Propane	1	1	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4				70
Diesel Fuel	4	4	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	2	2	2	218
Drinking Water	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	22
First Aid Supplies	1						1						1						1				4
Small Tools and Supplies	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	2	2	2	82

2.3 Engineering

In accordance with CEC siting regulations, this subsection, together with the engineering appendices and other pertinent sections, including Section 3.0, Transmission System Engineering; Section 4.0, Natural Gas Supply; and Section 5.11, Soil and Water Resources; presents information concerning the design and engineering of the Amended CECP. It describes the design of the facility and discusses the reliability and estimated thermal efficiency of the facility. The LORS applicable to the engineering of the Amended CECP are provided along with a list of agencies that have jurisdiction, the contact persons within those agencies, and a list of the permits that will be required.

The Amended CECP will require the following three major engineering changes from the Licensed CECP:

- Re-design of the power block to simple-cycle configuration, eliminating the steam cycle requirements
- Addition of an administration/control room building and an operations/maintenance warehouse.
- Expanding the decommissioning and demolition to include the existing EPS Units 1 through 5, retaining the functionality to support the existing SDG&E switchyard and existing EPS ocean water intake structure to service the Poseidon desalinization plant.

2.3.1 Facility Design

A detailed description of the Amended CECP is provided in Section 2.1, Generating Facility Description, Design, and Operation. Design for safety is provided in Section 2.3.2, Facility Safety Design.

Geotechnical aspects for the Amended CECP site, based on available information, are discussed in Section 5.4, Geologic Hazards and Resources.

Descriptions of the following design criteria are included in Appendix 2C:

- Civil Engineering Design Criteria
- Structural Engineering Design Criteria
- Mechanical Engineering Design Criteria
- Electrical Engineering Design Criteria
- Control Engineering Design Criteria
- Chemical Engineering Design Criteria
- Geologic and Foundation Design Criteria

Design and engineering information and data for the following systems are provided in the following subsections of this PTA:

- **Power Generation**—See Section 2.1.4, Combustion Turbine Generators; Appendix 2C; and Sections 2.1.5 through 2.1.13, which describe the various plant auxiliaries.
- **Heat Dissipation**—See Section 2.1.8, Plant Cooling Systems; and Appendix 2C.
- **Cooling Water Supply System**—See Section 2.1.7, Water Supply and Use; and Appendix 2C.
- **Air Emission Control System**—See Section 2.1.11, Emission Control and Monitoring, and Section 5.1, Air Quality.
- **Waste Disposal System**—See Section 2.1.9 and Section 5.14, Waste Management.
- **Noise Abatement System**—See Section 5.7, Noise.
- **Switchyards/Transformer Systems**—See Section 2.1.5, Major Electrical Equipment and Systems; Section 2.1.13.2, Grounding; Section 2.1.5.1, AC Power—Transmission; Section 2.1.15, Interconnect to Electrical Grid; Section 3.0, Transmission System Engineering; and Appendix 2C.

2.3.2 Facility Safety Design

The Amended CECP will be designed to maximize safe operation. Potential hazards that could affect the facility include earthquake, flood, and fire. Facility operators will be trained in safe operation, maintenance, and emergency response procedures to minimize the risk of personal injury and damage to the plant.

2.3.2.1 Natural Hazards

The principal natural hazard associated with the Amended CECP site is earthquakes. The site is located in Seismic Risk Zone 4. Structures for the Amended CECP, as for the Licensed CECP, will be designed to meet the seismic requirements of CCR Title 24 and the latest California Building Code (CBC). Section 5.4, Geologic Hazards and Resources includes a review of potential geologic hazards, seismic ground motion, and potential for soil liquefaction due to ground-shaking. Potential seismic hazards will be mitigated by implementing the CBC construction guidelines. Appendix 2C includes the structural seismic design criteria for the buildings and equipment.

Flooding is not a hazard of concern for the Amended CECP. According to the Federal Emergency Management Agency, the site is not within either the 100- or 500-year flood plain. Section 5.11, Soil and Water Resources, includes additional information on the potential for flooding.

2.3.2.2 Emergency Systems and Safety Precautions

This subsection discusses the fire protection systems, emergency medical services, and safety precautions to be used by project personnel. Section 5.10, Socioeconomics, includes additional information on area medical services, and Section 5.15, Worker Health and Safety, includes additional information on safety for workers. Appendix 2C presents the design practices and codes applicable to safety design for the Amended CECP. Compliance with these requirements will minimize impacts of the Amended CECP on public and employee safety.

2.3.2.2.1 Emergency Ingress and Transmission Line Design

The transmission lines will be owned and operated by the CECP. The CECP will have up to date information with respect to the status of the transmission line. In the event that the CECP requests assistance from the Fire Department, the CECP will inform the Fire Department of whether the transmission line is currently energized or de-energized. An existing pole has been relocated to reduce the span of the overhead transmission line across the entrance to the Amended CECP, in accordance with discussions with the Fire Department.

The transmission line will be designed to withstand wind loading based on 85 mph basic wind speed and the seismic acceleration suitable for the location. In addition this transmission line will be equipped with HV circuit breakers on both ends, and redundant current differential protective relays will be installed to protect each transmission line. The redundant current differential protective relays will be purchased from two different manufacturers to eliminate the likelihood of common mode failures.

The current differential protective relays continuously monitor the current in each conductor in the transmission line. It automatically trips (opens) the circuit breakers on both end of the transmission line if the current flowing into one end of the conductor does not equal the current flowing out of the other end of the conductor. This situation could occur if there is a break in the conductor, or there is a line-to-ground fault. The total clearing time, from sensing the fault (or breaking of the conductor) to opening the circuit breakers is less than five cycles, or 0.083 seconds. In addition, the circuit breakers are equipped with other relays to provide short circuit protections.

2.3.2.2.2 Fire Protection Systems

The Amended CECP will rely on both onsite fire protection systems and local public fire protection services.

The fire protection systems are designed to protect personnel and limit property loss and plant downtime from fire or explosion. The Amended CECP will have the following fire protection systems.

CO_2 Protection Systems

These systems protect the combustion turbines and certain accessory equipment compartments from fire. The system will have fire detection sensors in all protected compartments. Actuating one sensor will provide a high-temperature alarm on the combustion turbine control panel. Actuating a second sensor will trip the combustion turbine, turn off ventilation, close ventilation openings, and automatically release the gas and chemical agents. The gas and chemical agents will be discharged at a design concentration adequate to extinguish the fire.

Fire Hydrants/Hose Stations

This system will replace the existing EPS's fixed fire-suppression systems. Water will be supplied from the Amended CECP water treatment system with an emergency fill from the potable water system. Hydrants will be located to support firefighting with the existing Carlsbad Fire Services hose system.

Fire Extinguishers

The plant administrative/control/warehouse/maintenance buildings and other structures will be equipped with fixed fire suppression systems and portable fire extinguishers as prescribed by the local fire department.

Local Fire Protection Services

In the event of a major fire, the plant personnel will be able to call upon Carlsbad Fire Services for assistance. The Hazardous Materials Risk Management Plan (see Section 5.5, Hazardous Materials Handling) for the plant will include all information necessary to allow fire-fighting and other emergency response agencies to plan and implement safe responses to fires, spills, and other emergencies.

Fire Roads

Fire road access to the project boundary and within the project site is shown on the Site Road Plan, Figure 2.1-4.

2.3.2.2.3 Personnel Safety Program

The Amended CECP will operate in compliance with federal and state occupational safety and health program requirements. Compliance with these programs will minimize project effects on employee safety. These programs are described in Section 5.15, Worker Health and Safety.

2.3.3 Facility Reliability

This subsection discusses the Amended CECPs expected availability, equipment redundancy, fuel availability, water availability, and project quality control measures.

2.3.3.1 Facility Availability

Because of regional system electrical needs, it is anticipated that the Amended CECP will normally be called upon to operate at peaking average annual capacity factors. The facility will be designed to operate between 25 and 100 percent load for any one of the six units to support dispatch service in response to customer demands for electricity.

The Amended CECP will be designed for an operating life of a minimum of 30 years. Reliability and availability projections are based on this operating life. Operation and maintenance procedures will be consistent with industry standard practices to maintain the useful life status of plant components.

The percent of time that the Amended CECP is projected to be operated is defined as the "service factor." The service factor considers the amount of time that a unit is operating and generating power, whether at full or partial load. Because the Amended CECP is intended for peaking use, it is difficult to predict the service factor. Each unit of the Amended CECP will be limited to approximately 2,700 operating hours per year.

The six separate CTG power generation units will operate in parallel. Each CTG will provide approximately 17 percent of the total simple-cycle power output.

The combustion turbine subsystems include the combustion turbine, inlet air filtration and evaporative coolers, generator and excitation systems, turbine lube oil system, hydraulic system, and turbine control and instrumentation. The combustion turbine will produce thermal energy through the combustion of natural gas and the conversion of the thermal energy into mechanical energy through rotation of the combustion turbine that drives the compressor and generator. The generator will be an open air-cooled type.

The generator excitation system will be a solid-state static system. Combustion turbine control and instrumentation (interfaced with the DCS) will coordinate the turbine governing system, and the protective system.

The simple-cycle power block is served by the following BOP systems.

2.3.3.1.1 Distributed Control System

The DCS will be a redundant microprocessor-based system that will provide the following functions:

- Control the CTGs and other systems in response to unit load demands (coordinated control)
- Provide control room operator graphical user interface
- Monitor plant equipment and process parameters and provide this information to the plant operators in a meaningful graphical format
- Provide visual and audible alarms for abnormal events based on field signals or software-generated signals from plant systems, processes, or equipment

The DCS will have functionally distributed architecture comprising a group of similar redundant processing units linked to a group of operator consoles and an engineer workstation by redundant data highways. Each processor will be programmed to perform specific dedicated tasks for control information, data acquisition, annunciation, and historical purposes.

Plant operation will be controlled from the operator panel located in the control room. The operator panel will consist of two individual video/keyboard consoles and one engineering workstation. Each video/keyboard console will be an independent electronic package such that failure of a single package does not disable more than one video/keyboard. The engineering workstation will allow the control system operator interface to be monitored and revised by authorized personnel.

2.3.3.1.2 Demineralized Water System

The demineralized water system will consist of four 33-percent capacity demineralizer trains from an onsite water treatment system consisting of reverse osmosis units and mixed ion-exchange beds. The unit(s) will be leased portable/mobile trailer-mounted units. Demineralized water will be stored in a 250,000-gallon demineralized water storage tank. The reverse osmosis reject will be discharged to the City of Carlsbad (Encina Wastewater Authority) sewer system. The mixed beds will be regenerated offsite and will produce no liquid or solid wastes onsite.

2.3.3.1.3 Power Cycle Makeup and Storage

The power cycle makeup and storage subsystem provides demineralized water storage and pumping capabilities to supply high-purity water for injection into the CTGs for NOx control and chemical cleaning operations. Major components of the system are the demineralized water storage tank, providing for more than a 12-hour supply capacity of demineralized water at peak load, and two 100-percent-capacity, horizontal, centrifugal, cycle makeup water pumps.

2.3.3.1.4 Compressed Air

The compressed air system provides instrument air and service air to points of use throughout the facility. The compressed air system will include two 100-percent-capacity motor-driven air compressors, two 100-percent-capacity air dryers with pre-filters and after filters, two air receivers, instrument air header, and service air header. Only instrument air will be dried. A self-contained service air system is planned for the warehouse building.

2.3.3.2 Fuel Availability

Natural gas will be delivered via a new, 1,100-foot-long pipeline that will connect into SDG&E's TL 2009 gas line adjacent to the plant site.

2.3.3.3 Water Availability

The Amended CECP will use no more than 336 afy of CCR Title 22 reclaimed water provided by the City of Carlsbad for evaporative cooling make-up, as feed water to the demineralizers that will provide high-purity water for the CTGs and miscellaneous plant uses. Reclaimed water will also be used to irrigate site landscaping. Potable water will be used as alternate emergency supply to the fire protection system should the availability of reclaimed water be interrupted for more than 10 hours. Water for drinking, eye wash stations, safety showers, and service water will be provided from the City's potable water system.

The availability of water to meet the needs of the Amended CECP is discussed in more detail in Section 5.11, Soil and Water Resources.

2.3.4 Quality Assurance Program

The Quality Assurance Program that will be applied to the Amended CECP is summarized in this subsection. The objective of the Quality Assurance Program is to ensure that all systems and components have the appropriate quality measures applied; whether it is during design, procurement, fabrication, construction, or operation. The goal of the Quality Assurance Program is to achieve the desired levels of safety, reliability, availability, operability, survivability, constructability, and maintainability for the generation of electricity.

The required quality assurance for a system is obtained by applying controls to various activities, according to the activity being performed. For example, the appropriate controls for design work are checking and review, and the appropriate controls for manufacturing and construction are inspection and testing. Appropriate controls will be applied to each of the various activities for the project.

2.3.4.1 Project Stages

For quality assurance planning purposes, the project activities have been divided into the following ten stages that apply to specific periods of time during the amended project:

- **Conceptual Design Criteria.** Activities such as definition of requirements and engineering analyses.
- **Detail Design.** Activities such as the preparation of calculations, drawings, and lists needed to describe, illustrate, or define systems, structures, or components.
- **Procurement Specification Preparation.** Activities necessary to compile and document the contractual, technical and quality provisions for procurement specifications for plant systems, components, or services.
- **Manufacturer's Control and Surveillance.** Activities necessary to ensure that the manufacturers conform to the provisions of the procurement specifications.
- **Manufacturer Data Review.** Activities required to review manufacturers' drawings, data, instructions, procedures, plans, and other documents to ensure coordination of plant systems and components, and conformance to procurement specifications.

- **Receipt Inspection.** Inspection and review of product at the time of delivery to the construction site.
- **Construction/Installation.** Inspection and review of storage, installation, cleaning, and initial testing of systems or components at the facility.
- **System/Component Testing.** Actual operation of generating facility components in a system in a controlled manner to ensure that the performance of systems and components conform to specified requirements.
- **Plant Operation.** As the Amended CECP progresses, the design, procurement, fabrication, erection, and checkout of each generating facility system will progress through the stages defined above.
- **EPS Demolition.** Prior to the commencement of the EPS demolition, an engineering analysis and design will be performed to identify systems to be retained for the SDG&E switchyard and ocean water intake structure functionality for Poseidon.

2.3.4.2 Quality Assurance Records

The quality assurance record practice in the Licensed CECP will be used for the Amended CECP.

A plant operation and maintenance program, typical of a project this size, will be implemented to control operation and maintenance quality. A specific program for the Amended CECP will be defined and implemented during initial plant startup.

2.3.5 Thermal Efficiency

The maximum thermal efficiency that can be expected from a natural-gas-fired simple-cycle plant using GE LMS100 combustion turbine units is approximately 44 percent on a lower heating value basis. Other types of operations, particularly those at less-than-full gas turbine output, will result in lower efficiencies. The basis of the Amended CECP operations will be system dispatch within California's power generation and transmission system. It is expected that the Amended CECP will be primarily operated as a peaking unit, on daily cycles especially during summer months, of higher system demands, with operations limited to approximately 2,700 hours per CTG per year. There will be off-peak periods when the Amended CECP will be shut down for lack of economic dispatch. The number of startup and shutdown cycles is expected to range between zero and 400 per year per CTG.

The GE LMS100 units are capable of ramp rates of 50 MW per minute, and can reach full power in 10 minutes. Plant fuel consumption will depend on the operating profile of the amended power plant. It is estimated that the range of fuel consumed by the Amended CECP will be from a minimum of near zero British thermal units (Btu) per hour to a maximum of approximately 887.2 MMBtu per hour per unit (LHV basis) at full load and average ambient conditions. Using a projected heat rate of 7,953 Btu/kWh; this results in a total yearly consumption of 2.3 Million MMBtu of gas consumption per unit.

2.4 Facility Closure

This section provides the following information regarding the temporary or permanent closure of the Amended CECP:

- A schedule for the development of a preliminary closure plan for the Amended CECP facility when it ceases operations at the end of its useful physical or economic life.
- A discussion of how facility closure will be accomplished in the event of premature or unexpected cessation of operations prior to the end of the facility's useful life.

The project owner will approach a closure of the Amended CECP in the same manner as would have been implemented for the Licensed CECP. Section 2.4.1 discusses temporary facility closure and Sections 2.4.2 and 2.4.3 discuss permanent facility closure.

2.4.1 Unexpected Temporary Cessation of Operations

In the event of a short-term, unexpected temporary cessation of operations that does not involve facility damage, the project owner will maintain the Amended CECP in working condition so that the facility is able to restart operations when the unexpected cessation of operations event is resolved or ceases to restrict operations. If there is a possibility of hazardous substances release, the project owner will notify the CEC's compliance unit and appropriate local agencies in accordance with: (1) the applicable LORS in effect at the time; (2) the procedures set forth in the Amended CECP contingency plan described below; and (3) the CECP's facility Risk Management Plan.

In the event the temporary closure includes damage to the facility, and there is a release or threatened release of hazardous materials into the environment, the procedures set forth in the Amended CECP's Risk Management Plan will be implemented. Although tailored to the Amended CECP, these procedures will be generally identical to those procedures that would be employed for the Licensed CECP.

Depending on the expected duration of the temporary cessation of operations, chemicals may be drained from storage tanks and other equipment and removed from the site. The integrity of the equipment and facilities will be maintained. The project owner will handle and dispose of waste materials (hazardous and nonhazardous) in accordance with the applicable LORS in effect at the time of unexpected temporary cessation of operations. The project owner will maintain facility security procedures during temporary cessation of operations so the Amended CECP is secure from trespass.

Prior to initiation of operations of the Amended CECP, the project owner will prepare an onsite contingency plan and submit this plan to the CEC's compliance unit. The contingency plan will specifically address actions that will be implemented by the project owner during temporary and unplanned or unexpected cessation of operations of the CECP. The plan will ensure that necessary steps to protect public health and safety, and mitigate potential environmental impacts, are taken in a timely manner in accordance with the applicable LORS in effect at the time. The Amended CECP contingency plan will include the same elements as the Licensed CECP's contingency plan.

And as with the plan for the Licensed CECP, the project owner will periodically review the Amended CECP onsite contingency plan and will update the plan as necessary.

2.4.2 Planned Permanent or Premature Cessation of Operations

The anticipated life of the simple-cycle units that will be installed as part of the Amended CECP is a minimum of 30 years. Continued operation of the Amended CECP beyond 30 years is likely to be a viable option, especially with good maintenance practices and selective replacement of various plant equipment and components. Prior to planned permanent or premature cessation of operations of the new units at the Amended CECP, the project owner will prepare a closure plan in the manner and containing the elements described in the AFC for the Licensed CECP. The project owner's approach to permanently closing the Amended CECP will mirror the procedure approved by the CEC for the Licensed CECP, except to the extent any deviations are necessary due to the reconfigured power block for the Amended CECP.

2.4.3 Unexpected Permanent Cessation of Operations

In the event of an unexpected permanent cessation of operations of CECP, the project owner will follow the procedures outlined in the Amended CECP contingency plan to assure that appropriate steps to mitigate public health and safety and environmental concerns are taken in a timely manner. As discussed above, prior to initiation of operations of CECP, the project owner will prepare a contingency plan for the new generating units at the Amended CECP and submit this plan to the CEC's compliance unit. The contingency plan will specifically address actions that will be implemented by the project owner during unexpected permanent cessation of operations of the Amended CECP. The plan will ensure that necessary steps to protect public health and safety, and mitigate potential environmental impacts, are taken in a timely manner in accordance with the applicable LORS in effect at the time. This contingency plan will include the same elements as the contingency plan for the Licensed CECP.

The project owner will periodically review the Amended CECP's onsite contingency plan and will update the plan as necessary.

In the event of an unexpected permanent cessation of operations of the Amended CECP, the project owner will notify the CEC and other responsible agencies. These agencies will be informed of the status of the unexpected permanent closure activities. Concurrently, the project owner will prepare a permanent closure/decommissioning plan which will address the same issues as described above for the planned permanent closure/decommissioning plan. This plan will be developed in coordination with the CEC and other responsible agencies.

2.5 Laws, Ordinances, Regulations, and Standards

2.5.1 General LORS

The following LORS are generally applicable to the project:

- Uniform Fire Code, Article 80
- Occupational Safety and Health Act—29 CFR 1910 and 29 CFR 1926
- Environmental Protection Agency—40 CFR 60, 40 CFR 75, 40 CFR 112, 40 CFR 302, 40 CFR 423, 40 CFR 50, 40 CFR 100, 40 CFR 260, 40 CFR 300, and 40 CFR 400
- California Code of Regulations—Title 8, Sections 450 and 750 and Title 24, 2013, Titles 14, 17, 19, 20, 22, 23, 26, and 27
- California Department of Transportation—Standard Specifications
- California Occupational Safety and Health Administration—Regulations and Standards
- California Business and Professions Code—Sections 6704, 6730, and 6736
- California Vehicle Code—Section 35780
- California Labor Code—Section 6500
- Federal Aviation Agency—Obstruction Marking and Lighting AC No. 70/7460-1H
- City of Carlsbad—Regulations and Ordinances

Codes and standards pertinent to the Amended CECP generating facility are presented in Appendix 2C. The applicable local LORS and local agency contacts involved in administration and enforcement are described below.

2.5.2 Local LORS

The Amended CECP site is located in the city of Carlsbad, in an area zoned for Public Utility use, which allows for the presence of electrical generation and transmission facilities. Therefore, development of a generating facility on the Amended CECP site is a permitted use. The Amended CECP will be subject to all applicable regulations of the City of Carlsbad (see Section 5.6, Land Use).

2.6 Local Agency Contacts

Table 2.6-1 lists local agency contacts.

TABLE 2.6-1
Local Agency Contacts

Agency	Contact	Title	Telephone
City of Carlsbad Fire Services	Gregory Ryan	Deputy Fire Marshall	(760) 602-4663
City of Carlsbad Building Dept.	Mike Peterson	Senior Building Official	(760) 602-2721
City of Carlsbad Planning Dept.	Scott Donell	Senior Planner	(760) 602-4618
City of Carlsbad Engineering Dept.	Not yet assigned		

2.7 Local Permits Required and Permit Schedule

After the receipt of the approval of the amended project design, several permits will be required and will be issued by the CEC Assigned Chief Building Official (CBO). These are summarized in Table 2.7-1.

TABLE 2.7-1
Permits and Agency Contacts

Permit or Approval	Schedule	Agency Contact	Applicability
Approval of Grading Plan; issuance of construction, grading, and building permits	Minimum of 30 days prior to construction	CBO	Site grading, and excavation at site or along linear project features within public right-of-way
Certificate of Occupancy	Completion of construction	CBO	Occupancy of facilities once construction is completed.
RMP	Completion of construction	San Diego County DEHS	Modification of existing RMP (i.e., management of change)

5.1 Air Quality

This section provides the Project Owner's evaluation of how the Amended CECP could impact air quality and how the Amended CECP would comply with laws, ordinances, regulations, and standards (LORS) applicable to air quality. Consistent with this PTA, this section focuses on changes to the impact or compliance of the project as it was previously evaluated and approved in the original Application for Certification (AFC) process. Any proposed changes to Conditions of Certification (COCs) are provided.

This section presents the methodology and results of the air quality analyses performed to assess potential impacts associated with air emissions from construction and operation of the Amended CECP. Potential public health risks posed by emissions of non-criteria pollutants are also addressed in Section 5.9, Public Health.

5.1.1 Amendment Overview

As discussed in detail in Section 2.0, Project Description, the Amended CECP would be different than the project as approved in the Final Decision. For that reason, an evaluation of environmental impacts including the potential for changes or additions to COCs for the project is required. This PTA proposes implementing the following general changes to the Licensed CECP:

- Change in generation equipment and technology from Siemens fast response, combined-cycle to GE LMS 100 simple-cycle turbines to allow better support of renewable energy integration and local and regional demand. The Amended CECP will have six natural-gas-fired combustion GE LMS 100 turbines with approximately 632 MW[1] net output of simple-cycle electrical generating capacity.
- Add retirement and demolition of Encina Power Station (EPS). Units 1 through 5 of EPS will be retired and all above-grade elements of the EPS power and support buildings will be demolished.

As previously discussed in the Project Description, the Amended CECP would continue to occupy a portion of the Cabrillo Parcel, which is located in a City of Carlsbad Public Utility zone (as depicted in Figure 2.0-1). CECP will continue to be situated adjacent to EPS, in the eastern portion of the Cabrillo Parcel, between the existing railroad tracks and I-5, but the Amended CECP will have a larger footprint occupying most of that area. Construction equipment/material laydown and construction worker parking areas for the project will continue to be located immediately north of the CECP facility, as well as in various areas west of the existing railroad tracks. No offsite parking or laydown areas (outside of use of the 95-acre Cabrillo Parcel) are anticipated to be necessary for the construction of the Amended CECP.

The Amended CECP will continue interconnect to the electrical transmission system via 138-kilovolt (kV) and 230-kV lines that connect to the respective San Diego Gas and Electric Company (SDG&E) switchyards situated on and adjacent to the Cabrillo Parcel. Natural gas will be delivered to the Amended CECP from the existing SDG&E transmission pipeline (Line TL 2009, "Rainbow line") via an approximate 1,100-foot-long interconnection pipeline west of the Amended CECP site that runs parallel to the existing railroad tracks. At the facility, the natural gas will flow through a flow-metering station, gas scrubber/filtering equipment, a gas pressure control station and a fuel gas compressor station prior to injection into the combustion turbines. Similar to the Licensed CECP, with the exception of short, onsite interconnections, no offsite gas supply lines are required for the Amended CECP. The Amended CECP will use reclaimed water and/or potable water from the City of Carlsbad, or ocean water, and will connect to an existing City of Carlsbad (Encina Wastewater Authority) sanitary sewer line.

Upon completion of construction of the CECP and achievement of commercial operations, EPS will be retired and the above-grade elements of the main EPS power building and all support buildings will be demolished.

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[1] Rated at an average annual ambient temperature of 60.3 degrees Fahrenheit [°F] 79 percent relative humidity and with inlet air evaporative cooling.

Upon completion of demolition of EPS portions of the western areas of the Cabrillo Parcel will be removed from California Energy Commission (CEC) jurisdiction and made available for redevelopment plans along with any other available adjacent lands. Some portions of the western areas of the Cabrillo Parcel will remain dedicated to CECP, such for transportation access, electrical interconnection, and water or gas supply.

5.1.2 Affected Environment

5.1.2.1 Air Quality Setting

The geography of the project site, elevations of the surrounding landscape, long-term climatic characteristics, and short-term weather variations all have important effects on the resulting ground-level pollutant concentrations that would result from air emissions related to the Amended CECP. The effects of the land and atmospheric variables are discussed separately.

5.1.2.2 Geography and Topography

The CECP will be located at the existing EPS site. The six new units (designated Units 6 through 11) will be located in the northeast area of the existing site, between the existing rail line and I-5, and at the location of previously existing fuel oil tanks.

5.1.2.3 Climate and Meteorology

The climate of San Diego County is subtropical with large-scale wind and temperature regimes controlled by the proximity of the Pacific Ocean and seasonal migration of the Pacific high-pressure system. As a result, summers are relatively cool and winters are warm in comparison to other locations. Temperatures below freezing occur infrequently, as do temperatures over 100°F.

The amount of solar radiation is one factor influencing thermal turbulence; the more thermal turbulence, the more dispersion of pollutants. The project area receives significant sunshine throughout the year, even during winter. Annual average sunshine is the percentage of maximum possible time the sun can shine, and is approximately 68 percent in the San Diego area.

Wind speed and direction are key factors influencing the dispersion and transport of pollutants. Wind flows on an annual basis are predominately westerly. At Camp Pendleton, which is located approximately 10 kilometers (km) north of the Amended CECP site and is the source of the meteorological data used in air dispersion modeling (approved by the San Diego Air Pollution Control District [SDAPCD]), the most frequent wind direction is from the west-northwest during February through October, and from the northeast during November through January. Wind speeds average approximately 7 miles per hour, and the maximum wind speed is approximately 29 miles per hour (National Climatic Data Center, 1993). Appendix 5.1A provides the quarterly and annual wind roses and wind speed frequency tables for the 5 years, 2008 through 2012, used in the air dispersion modeling.

Temperatures in the project area range from an average of 57°F in December and January to 72°F in August, and relative humidity averages 58% during the daytime and 74% during the nighttime. Precipitation in the vicinity of the project site averages approximately 10.6 inches per year, with most of the precipitation occurring during winter (WorldClimate, 2014).

Air quality is determined primarily by the type and amount of pollutants emitted into the atmosphere, the topography of the air basin, and local meteorological conditions. The stable atmospheric conditions and light winds in the project area are conducive for accumulation of pollutants in the air basin.

5.1.2.4 Overview of Air Quality Standards

The U.S. Environmental Protection Agency (EPA) has established national ambient air quality standards (NAAQS) for ozone, nitrogen dioxide (NO_2), carbon monoxide (CO), sulfur dioxide (SO_2), particulate matter with aerodynamic diameter less than or equal to 10 microns (PM_{10}), particulate matter with aerodynamic diameter less than or equal to 2.5 microns ($PM_{2.5}$), and airborne lead. Areas with ambient levels above these standards are designated by EPA as "nonattainment areas" subject to planning and pollution control requirements that are more stringent than standard requirements.

The California Air Resources Board (CARB) has established California ambient air quality standards (CAAQS) for ozone, CO, NO_2, SO_2, sulfates, PM_{10}, $PM_{2.5}$, airborne lead, hydrogen sulfide, and vinyl chloride at levels designed to protect the most sensitive members of the population, particularly children, the elderly, and people who suffer from lung or heart diseases.

Both state and national air quality standards consist of two parts: an allowable concentration of a pollutant, and an averaging time over which the concentration is to be measured. Allowable concentrations are based on the results of studies of the effects of the pollutants on human health, crops and vegetation, and, in some cases, damage to paint and other materials. The averaging times are based on whether the damage caused by the pollutant is more likely to occur during exposures to a high concentration for a short time (one hour, for instance), or to a relatively lower average concentration over a longer period (8 hours, 24 hours, or 1 month). For some pollutants there is more than one air quality standard, reflecting both short-term and long-term effects. Table 5.1-1 presents the NAAQS and CAAQS for selected pollutants. The California standards are generally set at concentrations lower than the federal standards and, in some cases, have shorter averaging periods.

EPA's current NAAQS for ozone went into effect on May 27, 2008. For ozone, the previous 1-hour ozone standard of 0.12 parts per million (ppm) was revoked in 1997 in all areas and the previous federal 8-hour standard of 0.08 ppm was revised to a level of 0.075 ppm.[2] Compliance with this ozone standard is based on the 3-year average of the annual fourth-highest daily maximum 8-hour average concentration measured at each monitor within an area. The NAAQS for particulates were revised in several respects. On December 14, 2012, the national annual $PM_{2.5}$ standard was lowered from 15 micrograms per cubic meter ($\mu g/m^3$) to 12.0 $\mu g/m^3$, based on the three-year average of annual arithmetic means. The existing national 24-hour $PM_{2.5}$ standard was retained at 35 $\mu g/m^3$, based on the 3-year average of the 98th percentile of 24-hour average concentrations at each monitor within an area. The existing 24-hour PM_{10} standard of 150 $\mu g/m^3$ was also retained, and this 24-hour PM_{10} standard is not to be exceeded more than once per year on average over a 3-year period. The national lead standard is 0.15 $\mu g/m^3$ based on a rolling 3-month average.[3] Effective on April 12, 2010, a new 1-hour standard of 0.100 ppm (100 parts per billion [ppb]) for NO_2 was added; this 1-hour NO_2 standard is based on the 3-year average of the 98th percentile of the annual 1-hour daily maximum concentrations.[4] The state has an annual PM_{10} standard of 20 $\mu g/m^3$, and a $PM_{2.5}$ standard of 12 $\mu g/m^3$ on an annual average basis; both standards became effective on July 5, 2003. On April 28, 2005, CARB approved an 8-hour ozone standard of 0.070 ppm; this new standard became effective on May 17, 2006. Finally, on February 22, 2007, CARB approved a 1-hour NO_2 standard of 0.18 ppm; this new standard became effective on March 20, 2008.

[2] 73 FR 16436, Mar 27, 2008

[3] 73 FR 66964, Nov 12, 2008

[4] 75 FR 6474, Feb 9, 2010

TABLE 5.1-1
Ambient Air Quality Standards

Pollutant	Averaging Time	California Standards	National Standards	
		Concentrations	Primary	Secondary
Ozone	1 hour	0.09 ppm	—	Same as Primary Standard
	8 hours	0.070 ppm	0.075 ppm[a]	
Fine Particulate Matter (2.5 Microns)	24 hours	—	35 µg/m^3[c]	Same as Primary Standard
	Annual Arithmetic Mean	12 µg/m^3	12 µg/m^3	15 µg/m^3
Carbon Monoxide	1 hour	20 ppm	35 ppm	—
	8 hours	9.0 ppm	9 ppm	—
Nitrogen Dioxide	1 hour	0.18 ppm	100 ppb (196 µg/m^3)[c]	—
	Annual Arithmetic Mean	0.030 ppm	53 ppb (100 µg/m^3)	Same as Primary Standard
Sulfur Dioxide	1 hour	0.25 ppm (655 µg/m^3)	75 ppb (196 µg/m^3)[d]	—
	3 hours	—	—	0.5 ppm (1300 µg/m^3)
	24 hours	0.04 ppm (105 µg/m^3)	—	—
Lead	30 days Average	1.5 µg/m^3	—	—
	Calendar Quarter	—	1.5 µg/m^3[e]	Same as Primary Standard
	Rolling 3-month Average		0.15 µg/m^3	
Visibility Reducing Particles	8 hours	[f]		
Sulfates	24 hours	25 µg/m^3	No National Standards	
Hydrogen Sulfide	1 hour	0.03 ppm (42 µg/m^3)		
Vinyl Chloride	24 hours	0.01 ppm (26 µg/m^3)		

[a]3-year average of annual fourth-highest daily maximum 8-hour concentration.

[b]EPA revoked the annual PM_{10} NAAQS in 2006

[c]3-year average of 98th percentile

[d]3-year average of 99th percentile of 1-hour daily maximum

[e]NAAQS for lead was revised to a rolling 3-month average. The previous 1978 lead standard (1.5 µg/m^3 as a quarterly average) remains in effect until one year after an area is designated for the 2008 standard, except that in areas designated nonattainment for the 1978 standard, the 1978 standard remains in effect until implementation plans to attain or maintain the 2008 standard are approved.

[f]In sufficient amount to produce an extinction coefficient of 0.23 per kilometer due to particles when the relative humidity is less than 70%.

Source: CARB, 2014a

5.1.2.5 Existing Air Quality

Data from several ambient air monitoring stations were used to characterize air quality for the CECP site. The Camp Pendleton monitoring station is the nearest ambient air quality monitoring station to the project site; it is located approximately 19 km to the northeast. However, because the Camp Pendleton station measures only ambient ozone and NO_2 levels, data collected at the Escondido monitoring station were used for CO, PM_{10}, and $PM_{2.5}$. The Escondido monitoring station is located approximately 24 km east of the project site. For ambient SO_2 levels, the nearest monitoring station is located in San Diego approximately 55 km south of the project site. The nearest sulfate monitor is located in Riverside, Riverside County (approximately 90 km northeast of the project site). Sulfate measurements at most monitoring stations in California were discontinued years ago because sulfur dioxide emissions are low enough to prevent sulfate levels from being anywhere near the CAAQS of 25 µg/m^3 on a 24-hour average basis. All ambient air quality data presented in this section were taken from CARB publications and data sources or EPA air quality data tables.

5.1.2.6 Ozone

Ozone is generated by a complex series of chemical reactions between volatile organic compounds (VOC) and oxides of nitrogen (NOx) in the presence of ultraviolet radiation. Ambient ozone concentrations follow a seasonal pattern: higher in the summertime and lower in the wintertime. At certain times, the general area can provide ideal conditions for the formation of ozone due to the persistent temperature inversions, clear skies, mountain ranges that trap the air mass, and exhaust emissions from millions of vehicles and stationary sources. Based upon ambient air measurements at stations throughout the area, San Diego County is classified as a serious nonattainment area[5,6] for the state ozone standard and a nonattainment area for the 2008 federal 8-hour ozone standard.[7]

Maximum ozone concentrations at the Camp Pendleton station usually are recorded during the spring and fall months. Table 5.1-2 shows the annual maximum hourly ozone levels recorded at this station during the period 2003 - 2012, as well as the number of days during which the state and federal standards were exceeded. The 8-hour ozone NAAQS requires that the 3-year average of the fourth-highest values for individual years be maintained at or below 0.075 ppm. Therefore, the number of days in each year that the maximum 8-hour concentrations were above the standard, as shown in Table 5.1-1, does not equate to the number of violations. Trends of the maximum and the 3-year average of the fourth-highest daily concentrations of 8-hour average ozone readings and exceedances of the federal standard are shown in Figure 5.1-1. There have been no violations of the federal 8-hour ozone standards at this station since 2006. The long-term trends of maximum 1-hour ozone readings and violations of the state and federal standard are shown in Figure 5.1-2 for this monitoring station.

[5] Serious nonattainment is of "mid-range" magnitude in a nonattainment classification system based on the amount by which monitored levels of ozone have exceeded ambient air quality standard during the last 3 years. The classification, in order of increasing magnitude, includes marginal, moderate, serious, severe, and extreme.

[6] State Area Designations were approved by the Executive Officer on December 28, 2012 and became effective on April 1, 2013. An ozone 1-hour area classification map is available online at: http://www.arb.ca.gov/desig/adm/adm.htm

[7] Source: EPA, 2013.

TABLE 5.1-2
Ozone Levels in San Diego County, Camp Pendleton Monitoring Station, 2003–2012 (ppm)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Highest 1-Hour Average	0.099	0.110	0.090	0.086	0.083	0.104	0.090	0.092	0.085	0.092
Highest 8-Hour Average	0.085	0.095	0.075	0.073	0.074	0.077	0.077	0.079	0.071	0.081
Fourth-highest values, 3-year average	0.075	0.077	0.076	0.073	0.070	0.071	0.070	0.068	0.067	0.064
Number of Days Exceeding:										
State Standard (0.090 ppm, 1-hour)	4	4	0	0	0	1	0	0	0	0
State Standard (0.070 ppm, 8-hour)	10	12	2	5	4	3	5	1	2	1
Federal Standard* (0.075 ppm, 8-hour)	5	6	0	0	0	2	1	1	0	1

*To attain this standard, the 3-year average of the fourth-highest maximum 8-hour average ozone concentrations measured at each monitor within an area over each year must not exceed 0.075 ppm. (Effective May 27, 2008).
Note: Highest 1-hour and 8-hour State maximum were reported in this table

Source: CARB, 2014b

FIGURE 5.1-1
Maximum 8-Hour Average Ozone Levels, Camp Pendleton, 2003–2012

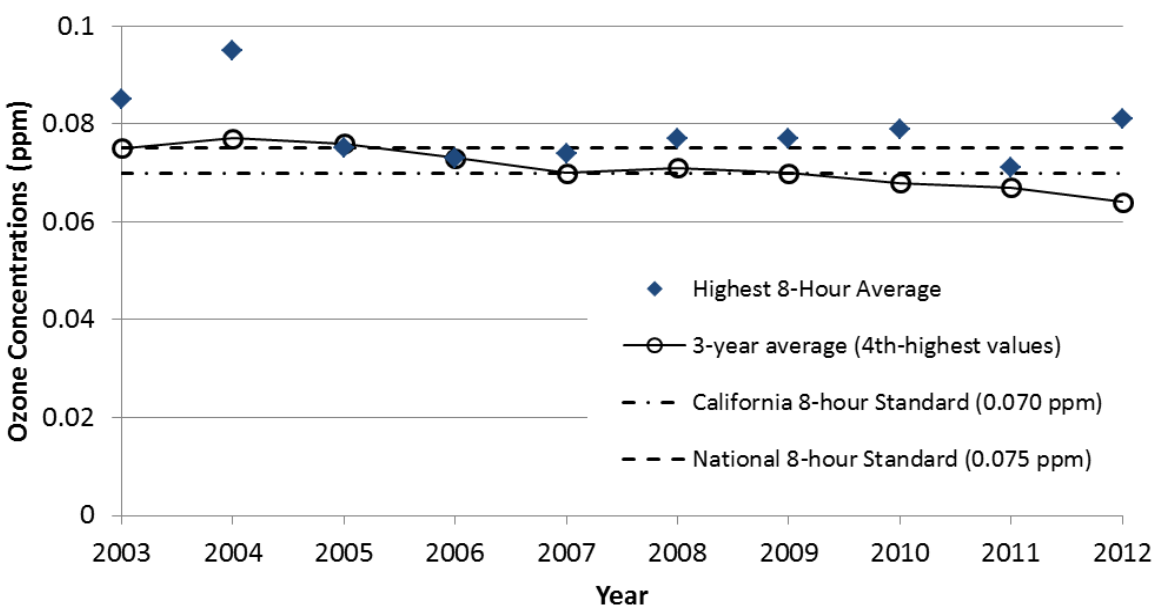
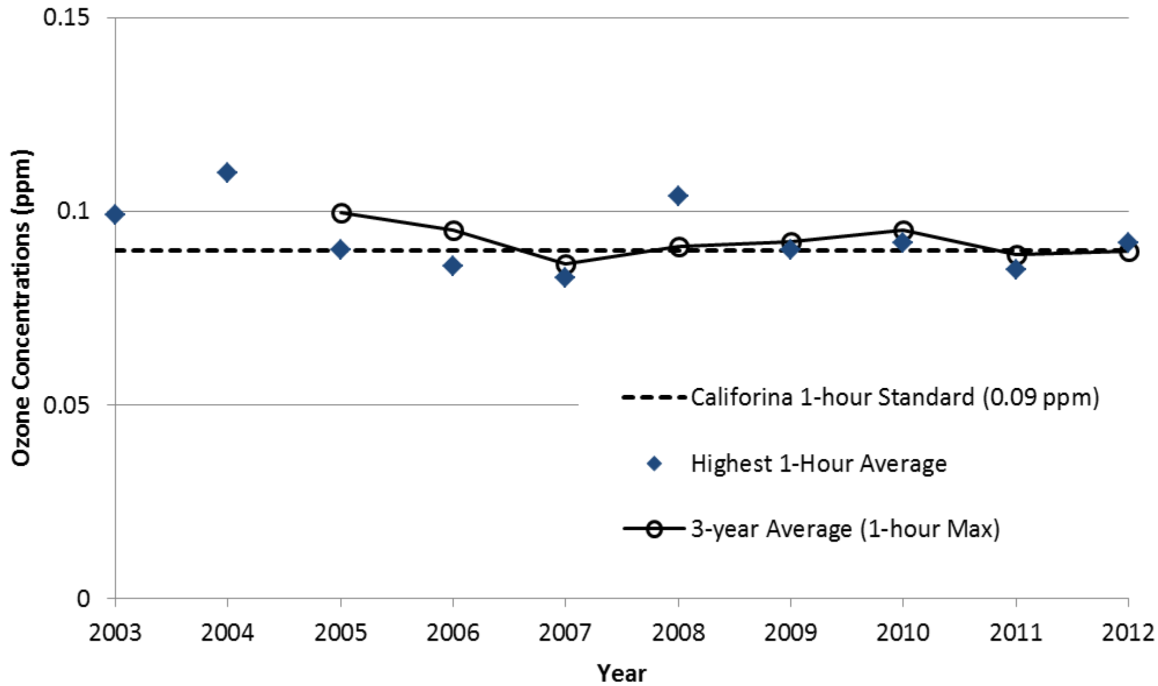


FIGURE 5.1-2
Maximum 1-Hour Average Ozone Levels, Camp Pendleton, 2003–2012



5.1.2.6.1 Nitrogen Dioxide

Atmospheric NO_2 is formed primarily from reactions between nitric oxide (NO) and oxygen or ozone. NO is formed during high-temperature combustion processes, when the nitrogen and oxygen in the combustion air combine. Although NO is less harmful than NO_2, it can be converted to NO_2 in the atmosphere within minutes to hours, depending on the composition and temperature of the atmosphere. For purposes of state and federal air quality planning, San Diego County is in attainment for NO_2.

Table 5.1-3 shows the long-term trend of maximum 1-hour NO_2 levels recorded at the Camp Pendleton monitoring station during the period from 2003 to 2012, as well as the annual average level for each of those years. During the period from 2003 to 2012, there were no violations of the CAAQS 1-hour standard (0.18 ppm) at the monitoring station. The highest 1-hour concentration recorded at the Camp Pendleton monitoring station during the years 2003 to 2012 was 0.099 ppm in 2004. A new federal 1-hour NO_2 standard of 0.100 ppm became effective on April 12, 2010. To attain this standard, the 3-year average of the 98th percentile of the daily maximum 1-hour average at each monitor must not exceed 0.100 ppm. Table 5.1-3 also shows that there were no violations of the annual NAAQS (0.053 ppm) or annual CAAQS (0.030 ppm) at the Camp Pendleton station during this period. Figure 5.1-3 shows the historical trend of maximum 1-hour NO_2 levels at this monitoring station. Annual average concentrations and trends are shown in Figure 5.1-4.

TABLE 5.1-3
Nitrogen Dioxide Levels in San Diego County, Camp Pendleton Monitoring Station, 2003–2012 (ppm)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Highest 1-Hour Average	0.095	0.099	0.077	0.081	0.068	0.089	0.068	0.081	0.066	0.061
98th Percentile, 1-Hour, 3-year average	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.056	0.051	0.048
Annual Average	0.012	0.012	0.012	0.011	0.011	0.010	[a]	0.009	[a]	0.008
Number of Days Exceeding:										
State Standard (0.180 ppm, 1-hour)	0	0	0	0	0	0	0	0	0	0
Federal Standard[b] (0.100 ppm, 1 hour)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0	0	0

[a]There were insufficient data available to determine the value.

[b]The new federal 1-hour average NO_2 standard of 0.100 ppm was announced by EPA on February 9, 2010, and became effective April 12, 2010. To attain this standard, the 3-year average of the 98th percentile of the daily maximum 1-hour average values at each monitor must not exceed 100 ppb.

Source: CARB, 2014b

FIGURE 5.1-3
Maximum 1-Hour Average Nitrogen Dioxide Levels, Camp Pendleton, 2003–2012

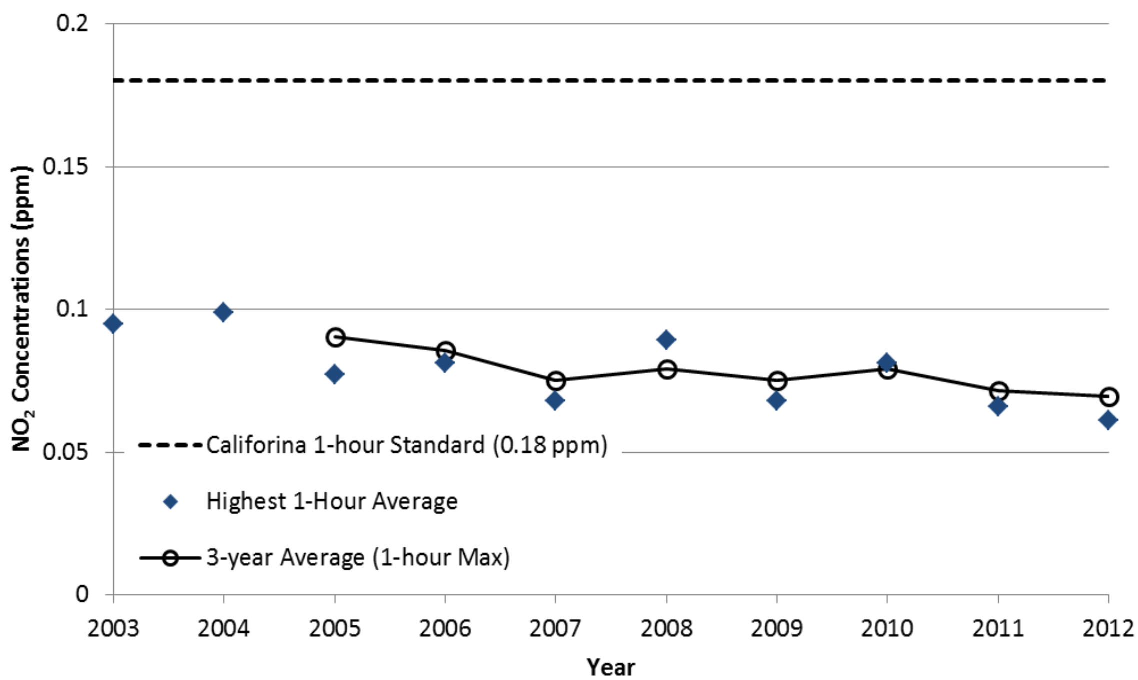
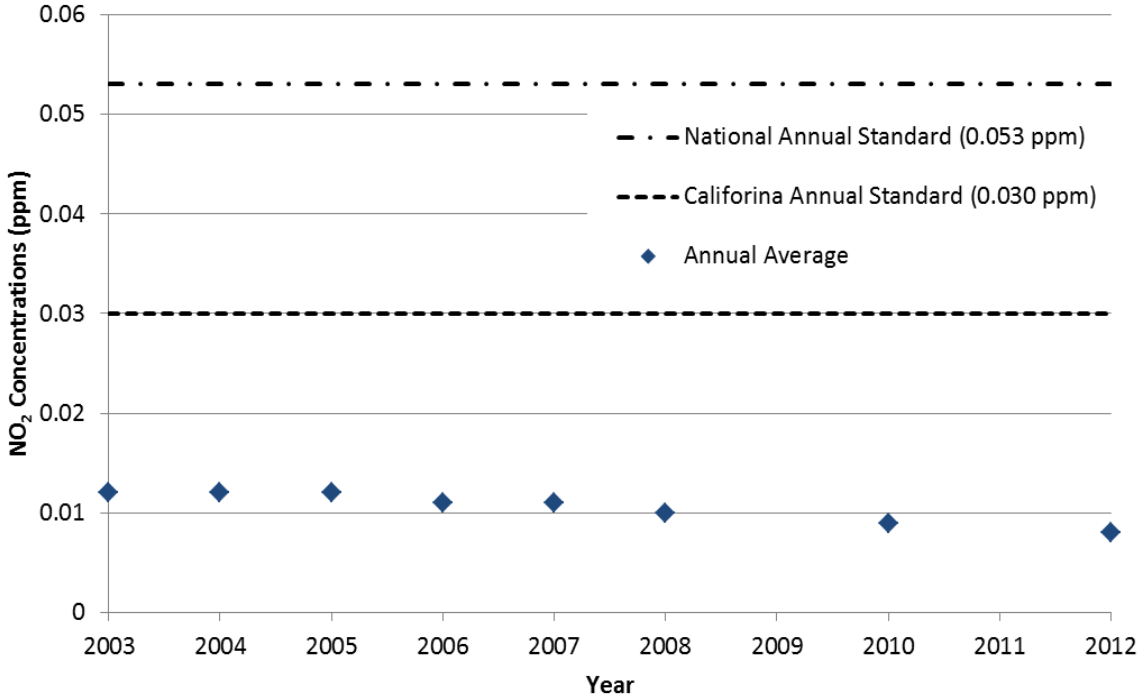


FIGURE 5.1-4
Annual Average Nitrogen Dioxide Levels, Camp Pendleton, 2003–2012



5.1.2.6.2 Carbon Monoxide

CO is a product of inefficient combustion, principally from automobiles and other mobile sources of pollution. In many areas of California, CO emissions from wood-burning stoves and fireplaces can also be measurable contributors to ambient CO levels. Industrial sources typically contribute less than 10% of ambient CO levels. Peak CO levels usually occur during winter due to a combination of higher emission rates and calm weather conditions with strong, ground-based inversions. San Diego County is classified as an attainment area for CO with respect to both state and national standards.

Table 5.1-4 shows the NAAQS and CAAQS for CO, and the maximum 1-hour and 8-hour average levels recorded at the Escondido monitoring station during the period 2003 to 2012. As indicated by this table, the maximum measured 1-hour average CO levels comply with the NAAQS and CAAQS (35.0 ppm and 20.0 ppm, respectively) and the maximum 8-hour values comply with the NAAQS and CAAQS of 9.0 ppm. The highest individual 1-hour and 8-hour CO concentrations at this station during the period from 2003 to 2012 were 10.64 ppm and 12.7 ppm, respectively, both recorded in 2003.

Trends of maximum 1-hour and 8-hour average CO concentrations are shown in Figure 5.1-5 and Figure 5.1-6, which show that, with the exception of 2003, maximum ambient CO levels monitored at the Escondido station have been well below the state standards for the last 10 years.

TABLE 5.1-4
Carbon Monoxide Levels in San Diego County, Escondido Monitoring Station, 2003 – 2012 (ppm)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Highest 1-hour average	12.7	6.3	5.9	5.7	5.2	5.6	4.4	3.9	3.5	4.4
Highest 8-hour average	10.64	3.81	3.10	3.61	3.19	2.81	3.54	2.46	2.30	3.70
Number of days exceeding:										
State Standard (20.0 ppm, 1-hr)	0	0	0	0	0	0	0	0	0	0
State Standard (9.0 ppm, 8-hr)	1	0	0	0	0	0	0	0	0	0
Federal Standard (9.0 ppm, 8-hr)	1	0	0	0	0	0	0	0	0	0

Source: CARB, 2014b and EPA, 2014.

FIGURE 5.1-5
Maximum 1-Hour Average Carbon Monoxide Levels, Escondido, 2003–2012

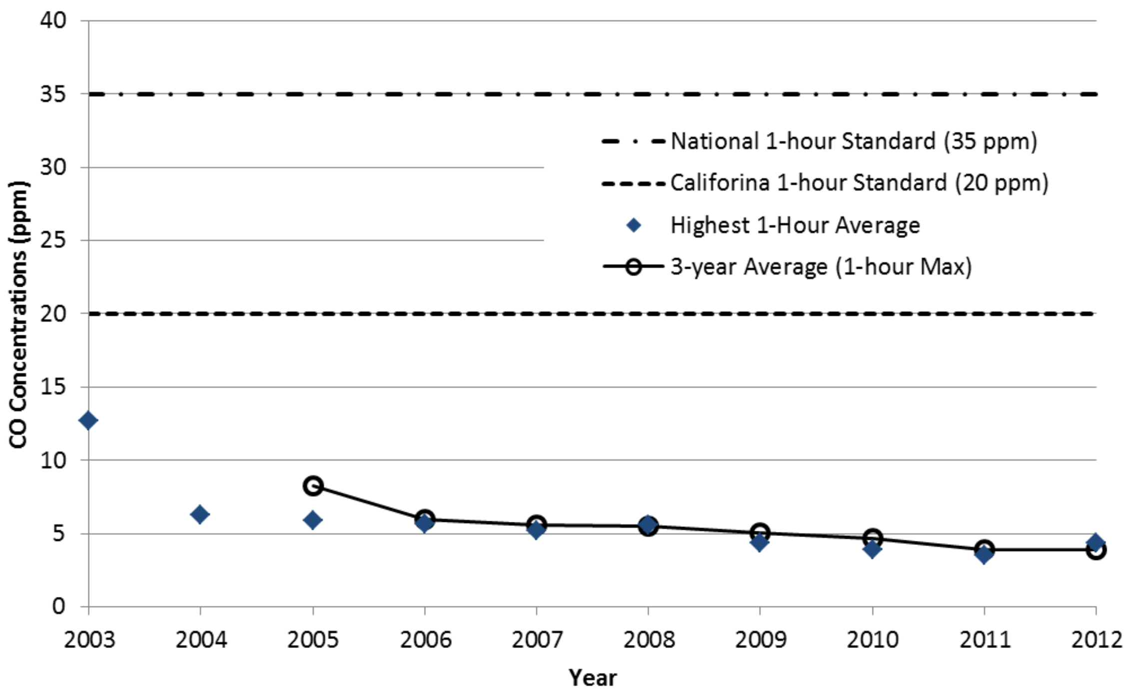
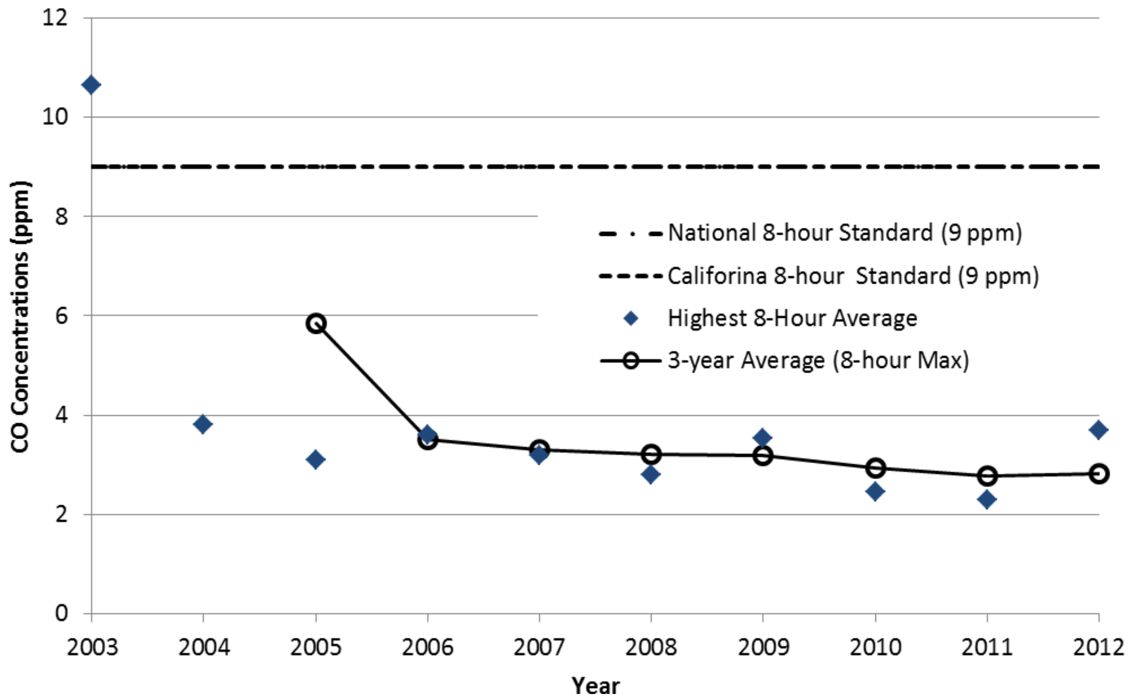


FIGURE 5.1-6
Maximum 8-Hour Average Carbon Monoxide Levels, Escondido, 2003–2012



5.1.2.6.3 Sulfur Dioxide

SO_2 is produced when any sulfur-containing fuel is burned. It is also emitted by chemical plants that treat, or refine, sulfur or sulfur-containing chemicals. Natural gas contains nearly negligible sulfur, whereas fuel oils may contain much larger amounts. Peak, but low, concentrations of SO_2 occur at different times of the year in different parts of California, depending on local fuel characteristics, weather, and topography. San Diego County is considered to be in attainment for SO_2 for purposes of state and federal air quality planning.

Table 5.1-5 shows the available data on maximum 1-hour, 24-hour, and annual average SO_2 levels recorded at the San Diego monitoring stations during the period from 2003 to 2012. As indicated by this table, the maximum measured 1-hour average SO_2 levels comply with the new NAAQS (75 ppb) and CAAQS (0.25 ppm), and the maximum 24-hour values comply with the NAAQS and CAAQS of 0.14 ppm and 0.04 ppm, respectively. The table also demonstrates compliance with the annual SO_2 NAAQS of 0.03 ppm. Figure 5.1-7 shows that for the past years the maximum 24-hour SO_2 levels typically have been well below the state standard.

TABLE 5.1-5
Sulfur Dioxide Levels in San Diego County, San Diego Monitoring Station, 2003–2012 (ppm)

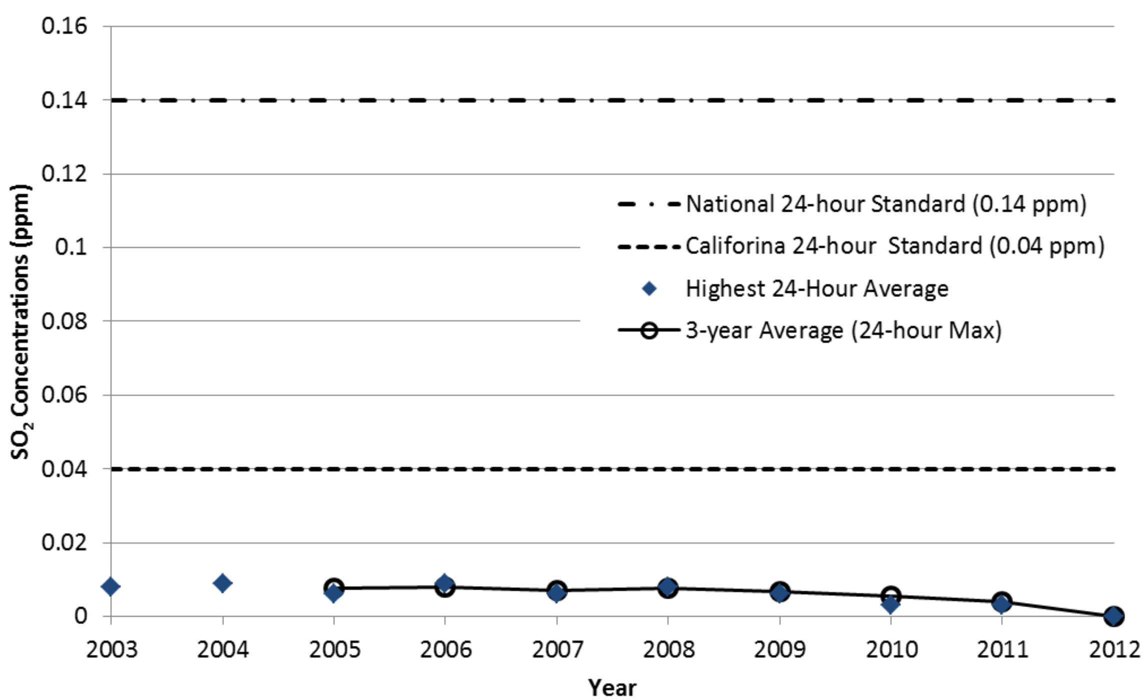
	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Highest 1-Hour Average	0.036	0.042	0.036	0.034	0.018	0.037	0.021	0.008	0.013	[a]
Highest 24-Hour Average	0.008	0.009	0.006	0.009	0.006	0.008	0.006	0.003	0.003	[a]
99th percentile 1-Hour, 3-year average	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.014	0.010	[a]
Annual Average	0.005	0.004	0.003	0.004	0.002	0.003	0.001	0.000	[a]	[a]
Number of days exceeding:										
State Standard (0.25 ppm, 1-hr)	0	0	0	0	0	0	0	0	0	0
Federal Standard[b] (0.075 ppm, 1-hr)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0	0	0
State Standard (0.040 ppm, 24-hr)	0	0	0	0	0	0	0	0	0	0
Federal Standard (0.140 ppm, 24-hr)	0	0	0	0	0	0	0	0	0	0

[a]There were insufficient data available to determine the value.

[b]Final rule signed June 22, 2010, effective August 23, 2010. To attain this standard, the 3-year average of the 99th percentile of the daily maximum 1-hour average at each monitor within an area must not exceed 75 ppb.

Source: CARB, 2014b and EPA, 2014

FIGURE 5.1-7
Maximum 24-Hour Average Sulfur Dioxide Levels, San Diego, 2003–2012



5.1.2.6.4 Respirable Particulate Matter (PM_{10})

Particulates in the air are caused by a combination of wind-blown fugitive dust; particles emitted from combustion sources and manufacturing processes; sea salts; and organic, sulfate, and nitrate aerosols formed in the air from emitted hydrocarbons, sulfur oxides, and nitrogen oxides, respectively. In 1984, CARB adopted standards for PM_{10} and phased out the total suspended particulate (TSP) standards that had been in effect previously. PM_{10} standards were substituted for TSP standards because PM_{10} corresponds to the size range of particulates that can be inhaled into the lungs (respired), and therefore is a better measure to use in assessing potential health effects. In 1987, EPA also replaced national TSP standards with PM_{10} standards. San Diego County is unclassified for the federal PM_{10} standard and is a nonattainment area for the state standard.

Table 5.1-6 shows the federal and state air quality standards for PM_{10}, maximum levels recorded at the Escondido monitoring station during 2003 to 2012, and arithmetic annual averages for the same period. At the Escondido station, the maximum 24-hour PM_{10} levels exceed the CAAQS state standard of 50 µg/m^3 a number of times per year up to 2009. The maximum daily concentration recorded during the analysis period was 179 µg/m^3 (both state and federal samplers) in 2003. The maximum annual arithmetic mean concentration recorded was 32.7 µg/m^3, also in 2003, which is above the state standard of 20 µg/m^3. The federal annual PM_{10} standard was revoked by the EPA in 2006.

TABLE 5.1-6
PM_{10} Levels in San Diego County, Escondido Monitoring Station, 2003–2012 (µg/m^3)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Highest 24-Hour Average (Federal testing samplers)	179	57	42	51	68	82	73	42	40	33
Highest 24-Hour Average (State testing samplers)	179	58	42	52	68	84	74	43	40	33
Annual Arithmetic Mean	32.7	27.3	23.9	24.2	26.8	*	24.6	21.0	18.8	18.1
Number of Days Exceeding:										
State Standard (50 µg/m^3, 24-hour)	31	6	0	6	12	*	6	0	0	0
Federal Standard (150 µg/m^3, 24-hour)	3	0	0	0	0	0	0	0	0	0

*There were insufficient (or no) data available to determine the value.

Source: CARB, 2014b

The trend of maximum 24-hour average PM_{10} levels is plotted in Figure 5.1-8. The trend of maximum annual average PM_{10} readings and the California standard is shown in Figure 5.1-9. Annual average PM_{10} concentrations are above the state standard of 20 µg/m^3.

FIGURE 5.1-8
Maximum 24-Hour Average PM_{10} Levels, Escondido, 2003–2012

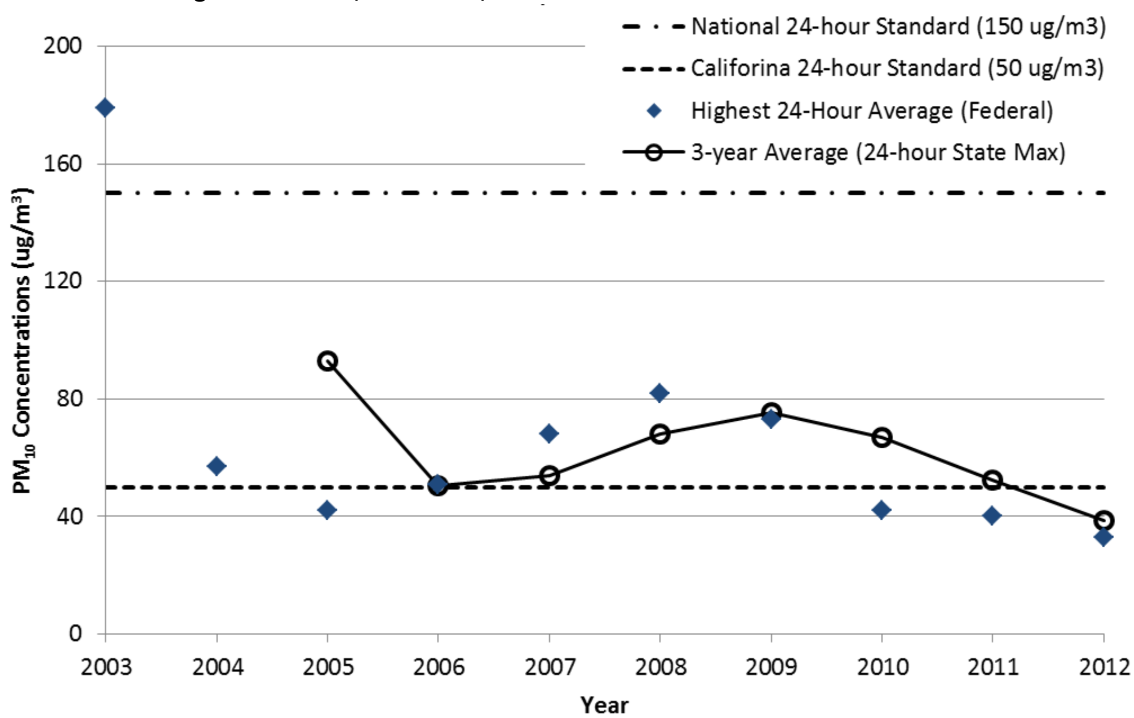
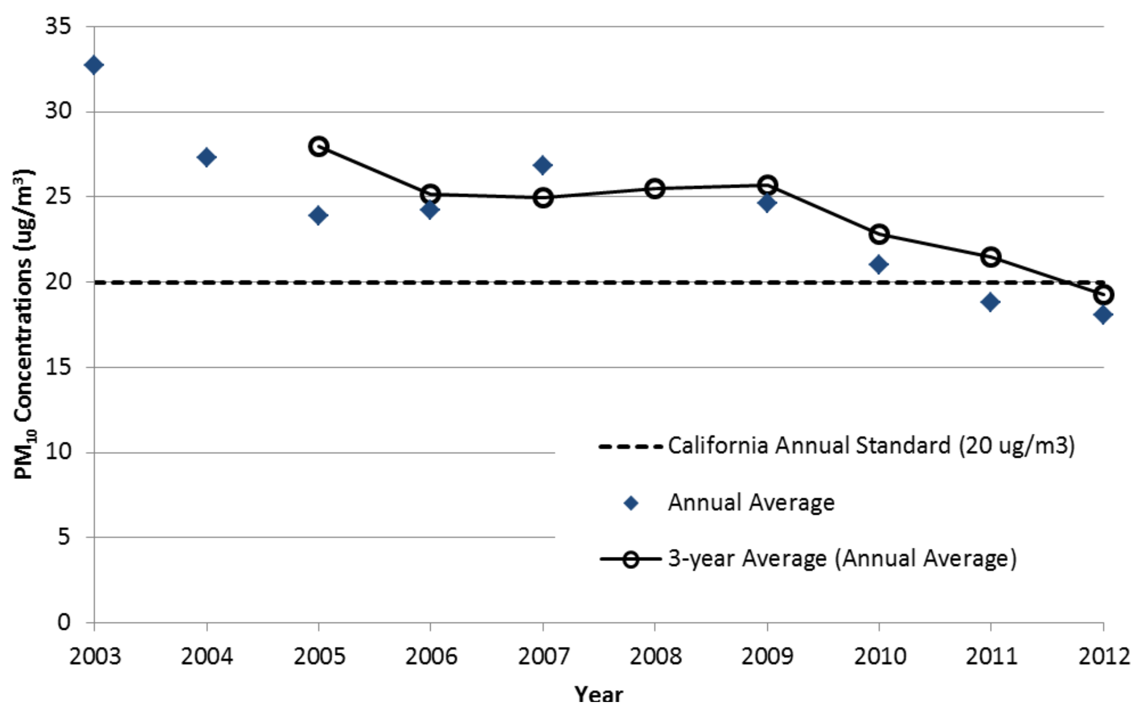


FIGURE 5.1-9
Annual Average PM_{10} Levels, Escondido, 2003–2012



5.1.2.6.5 Fine Particulate Matter ($PM_{2.5}$)

As discussed previously, the national annual $PM_{2.5}$ standard was lowered from 15 µg/m^3 to 12.0 µg/m^3 on December 14, 2012, based on the 3-year average of annual arithmetic means. The existing national 24-hour $PM_{2.5}$ standard was retained at 35 µg/m^3, based on the 3-year average of the 98th percentile of 24-hour average concentrations. $PM_{2.5}$ data have been collected at the Escondido monitoring station since 1999, and are presented below.

Table 5.1-7 shows the state and federal air quality standards for $PM_{2.5}$, maximum levels recorded at the Escondido monitoring station 2003-2012, and 3-year averages for the same period. During the past 10 years, the 24-hour average concentrations have not exceeded the federal standard of 35 µg/m^3 established in December 2006. During the past 5 years, annual average $PM_{2.5}$ levels have generally been above the federal and state standard of 12.0 µg/m^3. San Diego County is considered a nonattainment area for the state $PM_{2.5}$ standard, but is unclassified for the federal standard.

The trends of 24-hour and annual average $PM_{2.5}$ levels are plotted in Figure 5.1-10 and Figure 5.1-11, respectively.

TABLE 5.1-7
$PM_{2.5}$ Levels in San Diego County, Escondido Monitoring Station, 2003–2012 (µg/m^3)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Highest 24-Hour Average (Federal)[b]	69.2	67.3	43.1	40.6	126.2	44.0	64.9	48.4	69.8	70.7
Number of Days Exceeding:										
Federal Standard (35 µg/m^3, 24-hour)	3	9	[a]	1	11	[a]	2	2	3	1
98th Percentile 24-hour	33.9	37.4	[a]	28.3	37.7	[a]	25.2	26.6	27.4	21.4
98th Percentile 24-hour, 3 year average	38	37	[a]	[a]	[a]	[a]	[a]	[a]	26	25
Annual Arithmetic Mean	14.2	14.1	[a]	11.5	13.3	12.4	13.5	12.7	13.2	10.8

[a]There were insufficient data available to determine the value.

[b]EPA lowered the 24-hour standard to 35 µg/m3 on December 17, 2006. Compliance with this standard is based on the 3-year average of the 98th percentile daily concentrations.

Source: CARB, 2014b and EPA, 2014

FIGURE 5.1-10
Maximum 24-Hour Average $PM_{2.5}$ Levels, Escondido, 2003–2012

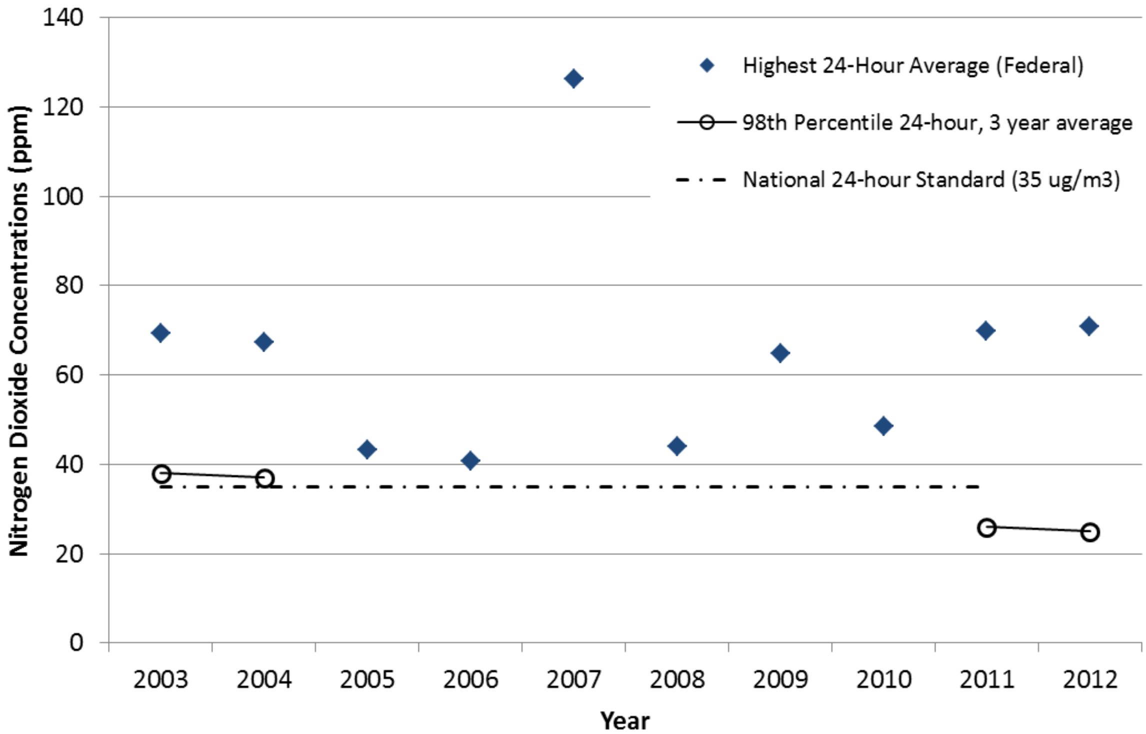
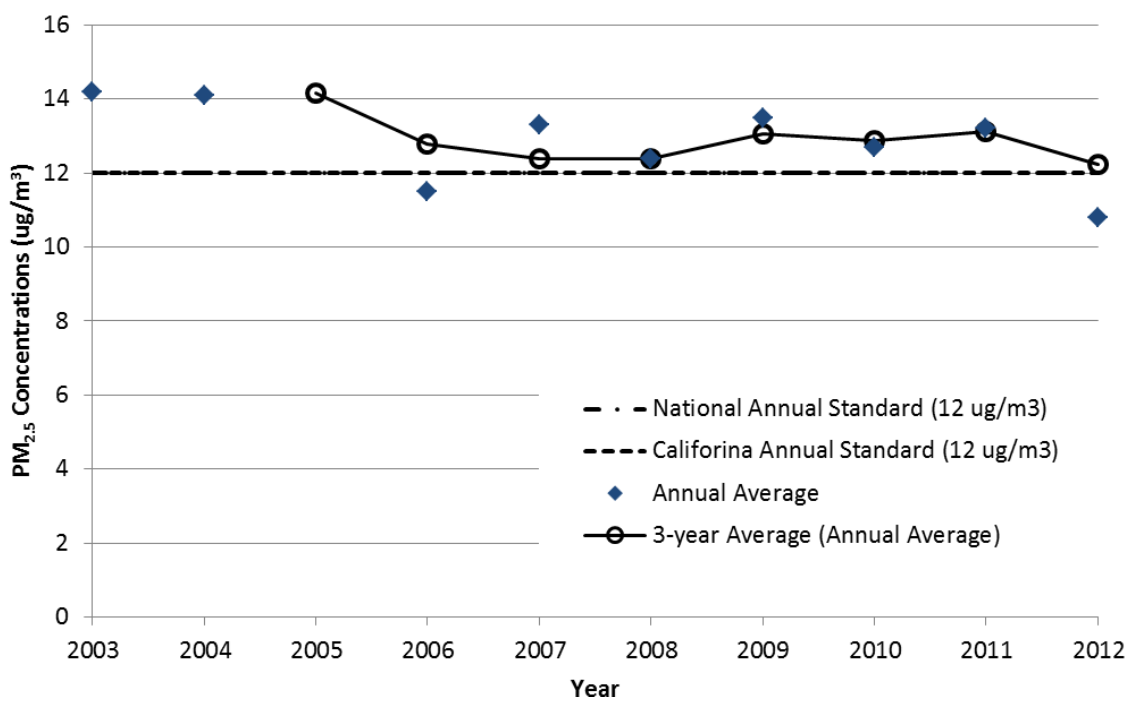


FIGURE 5.1-11
Annual Average $PM_{2.5}$ Levels, Escondido, 2003–2012



5.1.2.6.6 Airborne Lead

The majority of lead in the air results from the combustion of fuels that contain lead. Forty years ago, motor gasoline contained relatively large amounts of lead compounds used as octane-rating improvers, and ambient lead levels were relatively high. Beginning with the 1975 model year, new automobiles began to be equipped with exhaust catalysts, which were poisoned by the exhaust products of leaded gasoline. Thus, unleaded gasoline became the required fuel for an increasing fraction of new vehicles, and the phase-out of leaded gasoline began. As a result, ambient lead levels decreased dramatically. San Diego County has been in attainment of state and federal airborne lead levels for air quality planning purposes for a number of years.

On October 15, 2008, EPA revised the federal ambient air quality standard for lead, lowering it from 1.5 $\mu g/m^3$ to 0.15 $\mu g/m^3$ for both the primary and the secondary standard. EPA subsequently published the final rule in the Federal Register on November 12, 2008. This is the first time that the federal lead standard has been revised since it was first issued in 1978. In addition to revising the level of the standard, EPA changed the averaging time from a quarterly average to a rolling 3-month average. The level of the standard is “not to be exceeded” and is evaluated over a 3-year period. Many of stations stopped monitoring lead concentrations since the ambient lead concentrations have been well below the federal standard. For the San Diego monitoring stations, ambient lead levels were monitored through the end of 2004. Due to the scarcity of ambient lead data, Table 5.1-8 lists the federal air quality standard for airborne lead and the levels recorded in San Diego between 2003 and 2012 from the El Cajon monitoring station. Annual average levels are well below the federal standard.[8]

TABLE 5.1-8
Airborne Lead Levels in San Diego County, El Cajon-Redwood Avenue Monitoring Station, 2003–2012 (ng/m^3)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Annual Mean[b]	[a]	[a]	[a]	[a]	[a]	[a]	6.75	[a]	[a]	4.45
Annual Maximum	7.0	[a]	[a]	[a]	37	[a]	30	590	9.2	10
Number of Observations	5	0	0	0	17	0	31	18	22	29

[a]There were insufficient or no data available to determine the value.

[b]Means shown in CARB’s toxics pages are actually means of monthly means. Using the mean of monthly means compensates for the uneven distribution of samples over the 12 months of the year.

Source: CARB, 2014c

ng/m^3 = nanograms per cubic meter

5.1.3 Air Quality Agencies

EPA has responsibility for enforcing, on a national basis, the requirements of many of the country’s environmental and hazardous waste laws. California is under the jurisdiction of EPA Region 9, which has its offices in San Francisco. Region 9 is responsible for the local administration of EPA programs for California, Arizona, Nevada, Hawaii, and certain Pacific trust territories. EPA’s activities relative to the California air pollution control program focus principally on reviewing California’s submittals for the State Implementation Plan (SIP). The SIP is required by the federal Clean Air Act to demonstrate how all areas of the state will meet the national ambient air quality standards by the federally specified deadlines (42 USC §7409, 7411).

CARB was created in 1968 by the Mulford-Carrell Air Resources Act, through the merger of two other state agencies. CARB’s primary responsibilities are to develop, adopt, implement, and enforce the state’s motor vehicle pollution control program; to administer and coordinate the state’s air pollution research program;

[8] CARB no longer reports summary lead statistics on its website. The 3-month average statistic is not available on the EPA AirData website (EPA, 2014).

to adopt and update, as necessary, the state's ambient air quality standards; to review the operations of the local air pollution control districts; and to review and coordinate preparation of the SIP for achievement of the federal ambient air quality standards (California Health and Safety Code [H&SC] §39500 et seq.).

When the state's air pollution statutes were reorganized in the mid-1960s, local air pollution control districts (APCD) were required to be established in each county of the state (H&SC §4000 et seq.). There are three different types of districts: county, regional, and unified. In addition, special air quality management districts (AQMD), with more comprehensive authority over non-vehicular sources, as well as transportation and other regional planning responsibilities, have been established by the Legislature for several regions in California.

Air pollution control districts and air quality management districts in California have principal responsibility for:

- Developing plans for meeting the state and federal ambient air quality standard;
- Developing control measures for non-vehicular sources of air pollution necessary to achieve and maintain both state and federal air quality standards;
- Implementing permit programs established for the construction, modification, and operation of sources of air pollution; and
- Enforcing air pollution statutes and regulations governing non-vehicular sources and for developing employer-based trip reduction programs.

Each level of government (state, federal, and county/local air district) has adopted specific regulations that limit emissions from stationary combustion sources, several of which are applicable to this Amended CECP. The air agencies having permitting authority for the Amended CECP are shown in Table 5.1-9. The applicable federal LORS and compliance with these requirements are discussed in more detail in the following sections. The SDAPCD staff will treat the Petition to Amend (PTA) as an application for a Determination of Compliance.

TABLE 5.1-9
Air Quality Agencies

Agency	Authority	Contact
EPA Region 9	Permit issuance and oversight, enforcement	Gerardo Rios, Chief Permits Office EPA Region 9 75 Hawthorne Street San Francisco, CA 94105 (415) 744-1259
California Air Resources Board	Regulatory oversight	Cynthia Marvin, Chief Stationary Source Division California Air Resources Board 1001 I Street Sacramento, CA 95814 (916) 322-7236
San Diego Air Pollution Control District	Permit issuance, enforcement	Tom Weeks Chief, Engineering Division 10124 Old Grove Road San Diego, CA 92131 (858) 586-2600

5.1.3.1 Laws, Ordinances, Regulations, and Standards

Requirements of federal, state, and local jurisdictions are discussed in the following sections. Compliance with each of these requirements is addressed in Section 5.1.5.

5.1.3.1.1 Federal

EPA implements and enforces the requirements of many of the federal environmental laws. EPA Region 9, which has its offices in San Francisco, administers federal air programs in California. The federal Clean Air Act, as most recently amended in 1990, provides EPA with the legal authority to regulate air pollution from stationary sources such as the CECP. EPA has promulgated the following stationary source regulatory programs to implement the requirements of the federal Clean Air Act:

- Prevention of Significant Deterioration (PSD)
- New Source Review (NSR)
- Title IV: Acid Rain Program
- Title V: Operating Permits
- National Standards of Performance for New Stationary Sources (NSPS)
- National Emission Standards for Hazardous Air Pollutants (NESHAP)

Prevention of Significant Deterioration Program

Authority: Clean Air Act §160-169A, 42 USC §7470-7491; 40 CFR Parts 51 and 52

Requirements: Requires preconstruction review and permitting of new or modified major stationary sources of air pollution to prevent significant deterioration of ambient air quality. PSD applies to pollutants for which ambient concentrations do not exceed the corresponding NAAQS (i.e., attainment pollutants). For the SDAPCD, the PSD pollutants are SOx, NOx, CO, PM_{10}, $PM_{2.5}$, lead, and greenhouse gasses (GHG). The PSD program allows new sources of air pollution to be constructed, or existing sources to be modified, 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).

The PSD requirements apply to any project that is a new major stationary source or a major modification to an existing major stationary source. A major source is a listed facility (one of 28 PSD source categories listed in the federal Clean Air Act) that emits at least 100 tons per year (tpy), or any other facility that emits at least 250 tpy.

Effective July 1, 2011, a stationary source that emits more than 100,000 tpy of GHGs is also considered to be a major stationary source.

A major modification is any project at a major stationary source that results in a significant increase in emissions of any PSD pollutant.

A significant increase for a PSD pollutant is an increase above the significant emission rate for that pollutant (Table 5.1-10). It is important to note that once PSD is triggered by any pollutant, PSD requirements apply to any PSD pollutant with an emission increase above the significance level, regardless of whether the facility is major for that pollutant.

TABLE 5.1-10
PSD Significant Emission Thresholds

Pollutant	PSD Significant Emission Threshold (tpy)*
SO_2	40
PM_{10}	15
$PM_{2.5}$	10
NO_x	40
CO	100
Lead	0.6
GHGs	75,000

*40 CFR 52.21 (b)(1)(23).

The principal requirements for the PSD program include the following:

- Emissions of pollutants that are subject to PSD review must be controlled using Best Available Control Technology (BACT)
- Air quality impacts, in combination with other increment-consuming sources, must not exceed maximum allowable incremental increases
- Air quality impacts of all sources in the area plus ambient pollutant background levels cannot exceed NAAQS
- Pre- and/or post-construction air quality monitoring may be required
- The air quality impacts on soils, vegetation, and nearby PSD Class I areas (specific national parks and wilderness areas) must be evaluated

Air Quality Monitoring. At its discretion, the PSD permit issuer may require preconstruction and/or post-construction ambient air quality monitoring for PSD sources if representative monitoring data are not already available. Preconstruction monitoring data must be gathered over a 1-year period to characterize local ambient air quality. Post-construction air quality monitoring data must be collected as deemed necessary by the PSD permit issuer to characterize the impacts of project-related emissions on ambient air quality.

Best Available Control Technology. BACT must be applied to any new or modified major source to minimize the emissions increase of those pollutants exceeding the PSD emission thresholds. EPA defines BACT as an emissions limitation based on the maximum degree of reduction for each subject pollutant, considering energy, environmental, and economic impacts, that is achievable through the application of available methods, systems, and techniques. BACT must be as stringent as any emission limit required by an applicable NSPS or NESHAP.

Air Quality Impact Analysis. An air quality dispersion analysis must be conducted to evaluate impacts of significant emission increases from new or modified facilities on ambient air quality. PSD source emissions must not cause or contribute to an exceedance of any ambient air quality standard, and the increase in ambient air concentrations must not exceed the allowable increments shown in Table 5.1-11. Once PSD review is triggered for the project, all pollutants with emission increases above the PSD significance thresholds are subject to this requirement.

TABLE 5.1-11
PSD Increments and Significant Impact Levels

Pollutant	Averaging Time	SILs ($\mu g/m^3$)[a]	Maximum Allowable Class II Increments[b]
SO_2	Annual	1.0	20
	24-hr	5	91
	3-hr	25	512
	1-hr	7.8[c]	No 1-hr increment
PM_{10}	Annual	1.0	17
	24-hr	5	30
$PM_{2.5}$	Annual	0.3	4
	24-hr	1.2	9
NO_2	Annual	1.0	25
	1-hr	7.5[c]	No 1-hr increment
CO	8-hr	500	No CO increments
	1-hr	2,000	

[a]40 CFR 51.165 (b)(2).
[b]40 CFR 52.21 (c)
[c]EPA has not yet defined significance impact levels (SILs) for 1-hour NO_2 or SO_2 impacts. However, EPA has suggested that, until SILs have been promulgated, values of 4 ppb (7.5 $\mu g/m^3$) for NO_2 and 3 ppb (7.8 $\mu g/m^3$) for SO_2 may be used. These values will be used in this analysis wherever a SIL would be used for NO_2 or SO_2.

Protection of Class I Areas. The potential increase in ambient air quality concentrations for attainment pollutants (i.e., NO_2, PM_{10}, or SO_2) within Class I areas closer than approximately 100 km may need to be quantified if the new or modified PSD source were to have a sufficiently large emission increase as evaluated by the Class I area Federal Land Managers. In such a case, a Class I visibility impact analysis would also be performed.

Growth, Visibility, Soils, and Vegetation Impacts. Impairment to visibility, soils, and vegetation resulting from PSD source emissions as well as associated commercial, residential, industrial, and other growth must be analyzed. This analysis includes cumulative impacts to local ambient air quality.

While the PSD program historically has been implemented in San Diego by EPA Region 9, EPA is expected to delegate this program to the SDAPCD in the near future with SIP approval of the new SDAPCD Rule 20.3.1.

As discussed in more detail below, the Amended CECP includes the installation of six new simple-cycle gas turbine units (also referred to as combustion turbine generating [CTG] units) and the shutdown of the five existing boilers and an existing peaker gas turbine at the EPS. With the shutdown of the existing boilers/peaker gas turbine, the facility-wide net emission change is expected to be below PSD significance thresholds for all pollutants with the exception of GHG emissions. Hence, the Amended CECP will be subject to the PSD program for GHG emissions.

Administering Agency: EPA Region 9.

Nonattainment New Source Review

Authority: Clean Air Act §171-193, 42 USC §7501 et seq.; 40 CFR Parts 51 and 52

Requirement: Requires preconstruction review and permitting of new or modified major stationary sources of air pollution to allow industrial growth without interfering with the attainment and maintenance of NAAQS. Nonattainment new source review jurisdiction has been delegated to the SDAPCD for all nonattainment pollutants and is discussed further under local LORS and conformance below.

Administering Agency: SDAPCD, with EPA Region 9 oversight.

Acid Rain Program

Authority: Clean Air Act §401 (Title IV), 42 USC §7651

Requirement: Requires the monitoring and reporting of emissions of acidic compounds and their precursors. The principal source of these compounds is the combustion of fossil fuels. Therefore, Title IV established national standards to monitor, record, and in some cases limit SO_2 and NOx emissions from electrical power generating facilities. These standards are implemented at the local level with federal oversight.

Administering Agency: SDAPCD, with EPA Region 9 oversight.

Title V Operating Permits Program

Authority: Clean Air Act §501 (Title V), 42 USC §7661

Requirements: Requires the issuance of operating permits that identify all applicable federal performance, operating, monitoring, recordkeeping, and reporting requirements. Title V applies to major facilities, Phase II acid rain facilities, subject solid waste incinerator facilities, and any facility listed by EPA as requiring a Title V permit. SDAPCD has received delegation authority for this program.

Administering Agency: SDAPCD, with EPA Region 9 oversight.

National Standards of Performance for New Stationary Sources

Authority: Clean Air Act §111, 42 USC §7411; 40 CFR Part 60

Requirements: Establishes standards of performance to limit the emission of criteria pollutants (air pollutants for which EPA has established NAAQS) from new or modified facilities in specific source categories. These standards are implemented at the local level with federal oversight. The applicability of these regulations depends on the equipment size, process rate, and/or the date of construction, modification, or reconstruction of the affected facility.

The NSPS for Stationary Gas Turbines and for Stationary Compression Ignition Internal Combustion Engines will be applicable to the Amended CECP. Regarding the NSPS for Gas Turbines, NSPS Subpart KKKK, Standards of Performance for Stationary Gas Turbines sets limits on NOx and SO_2 emissions from gas turbines. Subpart KKKK limits NOx and SO_2 emissions from new gas turbines based on power output. The limits for gas turbines greater than 850 MMBtu/hr are 15 ppmv at 15% O_2/0.43 lb per MWh for NOx, and 0.90 lb per MWh SO_2 for SOx. For the size of engines proposed for the emergency fire pump and generator engines, NSPS Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines requires facilities to purchase engines meeting the EPA engine non-road certification level of Tier II or better depending on the year the engine is manufactured/purchased. This regulation also requires the engines to use ultra-low sulfur content diesel fuel.

On Sept. 20, 2013, the EPA issued a revised proposed NSPS to control GHG emissions from new power plants. The EPA proposed separate standards for natural gas-fired turbines and coal-fired units. The comment period for these revised standards ends on May 9, 2014. The GHG emission limits (a revision to NSPS Subpart KKKK) for new natural gas-fired combustion turbines subject to the regulation are 1,000 lb CO_2/MWh (new combustion turbines with a heat input rating greater than 850 MMBtu/hr) and 1,100 lb CO_2/MWh (new combustion turbines with a heat input rating equal to or less than 850 MMBtu/hr). New combustion turbines that supply less than one-third of their potential electric output (on a 3-year rolling average basis) to a utility distribution system are exempt from this regulation. Because the new gas turbines associated with the Amended CECP will supply less than one-third of their potential electric output to the local utility, the units will be exempt from this regulation. Consequently, there will be no further discussion of this GHG NSPS in this document.

Administering Agency: SDAPCD, with EPA Region 9 oversight.

National Emission Standards for Hazardous Air Pollutants

Authority: Clean Air Act §112, 42 USC §7412

Requirements: 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 major sources of HAPs in specific source categories.[9] These standards are implemented at the local level with federal oversight. Only the NESHAPs for gas turbines, which limit formaldehyde emissions from gas turbines, are potentially applicable to a new power plant project. However, as discussed further below, the gas turbine NESHAP is not expected to be applicable to the Amended CECP because the facility would not be a major source of HAPs (i.e., 10 tpy of one HAP or 25 tpy of all HAPs). Thus, NESHAPs requirements will not be addressed further.

Administering Agency: SDAPCD, with EPA Region 9 oversight.

Compliance Assurance Monitoring

Authority: 40 CFR 64 Compliance Assurance Monitoring (CAM)

Requirements: Requires compliance monitoring at emission units at major stationary sources that are required to obtain a Title V permit, and that use control equipment to achieve a specified emission limit. The rule is intended to provide "reasonable assurance" that the control systems are operating properly to

[9] A major source of HAPs is one that emits more than 10 tpy of any individual HAP, or more than 25 tpy of all HAPs combined.

maintain compliance with the emission limits. CAM is usually implemented through the Title V permit. The only equipment associated with the Amended CECP that may be affected by CAM are the oxidation catalysts that will be installed on the new gas turbines (if VOC control is claimed for use of oxidation catalysts).

Administering Agency: SDAPCD, with EPA Region 9 oversight.

5.1.3.1.2 State

CARB was created in 1968 by the Mulford-Carrell Air Resources Act, through the merger of two other state agencies. CARB's primary responsibilities are to develop, adopt, implement, and enforce the state's motor vehicle pollution control program; to administer and coordinate the state's air pollution research program; to adopt and update, as necessary, the CAAQS; to review the operations of the local APCDs; and to review and coordinate preparation of the SIP for achievement of the NAAQS. CARB has implemented the following state or federal stationary source regulatory programs in accordance with the requirements of the federal Clean Air Act and California H&SC:

- State Implementation Plan
- California Clean Air Act
- Toxic Air Contaminant Program
- Airborne Toxic Control Measure for Stationary Compression-Ignition Engines
- Nuisance Regulation
- Air Toxics "Hot Spots" Act
- CEC and CARB Memorandum of Understanding

State Implementation Plan

Authority: H&SC §39500 et seq.

Requirements: The SIP demonstrates the means by which all areas of the state will attain and maintain NAAQS within the federally mandated deadlines, as required by the federal Clean Air Act. CARB reviews and coordinates preparation of the SIP. Local districts must adopt new rules or revise existing rules to demonstrate that the resulting emission reductions, in conjunction with reductions in mobile source emissions, will result in attainment of the NAAQS. The relevant SDAPCD Rules and Regulations that have been incorporated into the SIP are discussed with the local LORS below.

Administering Agency: SDAPCD, with CARB and EPA Region 9 oversight.

California Clean Air Act

Authority: H&SC §40910–40930

Requirements: Established in 1989, the California Clean Air Act requires local districts to attain and maintain both national and state ambient air quality standards at the "earliest practicable date." Local districts must prepare air quality plans demonstrating the means by which the ambient air quality standards will be attained and maintained. The relevant components of the SDAPCD Air Quality Plan are discussed with the local LORS.

Administering Agency: SDAPCD, with CARB oversight.

Toxic Air Contaminant Program

Authority: H&SC §39650–39675

Requirements: Adopted in 1983, the Toxic Air Contaminant Identification and Control Act created a two-step process to identify toxic air contaminants (TAC) and control their emissions. CARB identifies and prioritizes the pollutants to be considered for identification as toxic air contaminants. CARB assesses the potential for human exposure to a substance, while the Office of Environmental Health Hazard Assessment evaluates the corresponding health effects. Both agencies collaborate in the preparation of a risk assessment report, which concludes whether a substance poses a significant health risk and should be identified as a toxic air contaminant. In 1993, the Legislature amended the program to include the 187[10] federally identified hazardous air pollutants as toxic air contaminants. CARB reviews the emission sources of an identified toxic air contaminant and, if necessary, develops air toxics control measures to reduce the emissions.

Administering Agency: CARB

Airborne Toxic Control Measure for Stationary Compression-Ignition Engines

Authority: Title 17, California Code of Regulations, §93115

Requirements: The purpose of the airborne toxic control measure (ATCM) is to reduce diesel particulate matter and criteria pollutant emissions from stationary diesel-fueled compression ignition engines. The ATCM applies to stationary compression-ignition engines with a rating greater than 50 brake horsepower. The ATCM requires the use of CARB-certified diesel fuel or equivalent, and limits emissions from, and operations of, compression ignition engines.

Administering Agency: SDAPCD and CARB

Nuisance Regulation

Authority: H&SC §41700

Requirements: Provides that "no person shall discharge from any source whatsoever such quantities of air contaminants or other material which causes injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public or which endanger the comfort, repose, health, or safety of any such persons or the public, or which cause, or have a natural tendency to cause injury or damage to business or property."

Administering Agency: SDAPCD and CARB

Air Toxic "Hot Spots" Act

Authority: H&SC §44300–44384; 17 CCR §93300–93347

Requirements: Adopted in 1987, the Air Toxics "Hot Spots" Information and Assessment Act supplements the toxic air contaminant program, by requiring the development of a statewide inventory of air toxics emissions from stationary sources. The program requires affected facilities to prepare (1) an emissions inventory plan that identifies relevant air toxics and sources of air toxics emissions; (2) an emissions inventory report quantifying air toxics emissions; and (3) a health risk assessment, if necessary, to characterize the health risks to the exposed public. Facilities whose air toxics emissions are deemed to pose a significant health risk must issue notices to the exposed population. In 1992, the Legislature amended the program to further require facilities whose air toxics emissions are deemed to pose a significant health risk to implement risk management plans to reduce the associated health risks. This program is implemented at the local level with state oversight.

Administering Agency: SDAPCD and CARB

CEC and CARB Memorandum of Understanding

Authority: California Public Resources Code §25523(a); 20 CCR §1752, 1752.5, 2300-2309 and Div. 2, Chap. 5, Art. 1, Appendix B, Part (k)

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[10] Methyl ethyl ketone was removed from the list on December 19, 2005 (http://www.epa.gov/ttn/atw/pollutants/atwsmod.html, accessed April 9, 2006).

Requirements: Provides for the inclusion of requirements in the CEC's decision on an AFC to assure protection of environmental quality; the application is required to include information concerning air quality protection.

Administering Agency: CEC

California Climate Change Regulatory Program

Authority: Stats. 2006, Ch. 488 and H&SC §38500–38599

Requirements: The State of California adopted the Global Warming Solutions Act of 2006 (Assembly Bill [AB] 32) on September 27, 2006, which requires sources within the state to reduce carbon emissions to 1990 levels by the year 2020. Pursuant to this statutory authority, CARB has adopted regulations to limit GHG emissions from electric power plants and other specific source categories through a cap-and-trade program. In addition, CARB has adopted regulations requiring the calculation and reporting of GHG emissions from subject facilities.

The annual GHG emission reports to CARB for subject facilities must include the project's emission rates of greenhouse gases (CO_2, CH_4, N_2O, and SF_6) from the stack, cooling towers, fuels and materials handling processes, delivery and storage systems, and from all on-site secondary emission sources.

On January 25, 2007, the Public Utilities Commission (PUC) and CEC jointly adopted a Greenhouse Gas Emissions Performance Standard in an effort to help mitigate climate change. The Emissions Performance Standard is a facility-based emissions standard requiring that all new long-term commitments for baseload generation to serve California consumers be with power plants that have emissions no greater than a combined-cycle gas turbine plant. That level is established at 1,100 pounds of CO_2 per megawatt-hour (or 0.50 MT CO_2 per megawatt-hour). As discussed under CCR Title 20, Chapter 11, Sections 2900, 2901(b), 2902(a), and 2905(a), this GHG Emissions Performance Standard applies only to baseload generating plants (a power plant that is designed and intended to provide electricity at an annualized plant capacity factor of at least 60 percent net generation available for sale). Because the Amended CECP's annual capacity factor will be below 60 percent, this Emissions Performance Standard is not applicable to the project. Consequently, there will be no further discussion of this GHG Emissions Performance Standard in this document.

Administering Agencies: CARB and CEC.

5.1.3.1.3 Local

When the state's air pollution statutes were reorganized in the mid-1960s, local districts were required to be established in each county of the state. There are three different types of districts: county (including the SDAPCD), regional, and unified. In addition, special AQMDs, with more comprehensive authority over non-vehicular sources, as well as transportation and other regional planning responsibilities, have been established by the Legislature for several regions in California. Local districts have principal responsibility for the following:

- Developing plans for meeting the NAAQS and CAAQS;
- Developing control measures for non-vehicular sources of air pollution necessary to achieve and maintain both state and federal air quality standards;
- Implementing permit programs established for the construction, modification, and operation of sources of air pollution;
- Enforcing air pollution statutes and regulations governing non-vehicular sources; and
- Developing programs to reduce emissions from indirect sources.

San Diego Air Quality Plans

Authority: H&SC §40914

Requirements: Air quality plans define the proposed strategies, including stationary source and transportation control measures and new source review rules that will be implemented to attain and maintain the state ambient air quality standards. The relevant stationary source control measures and new source review requirements are discussed with SDAPCD Rules and Regulations.

Administering Agency: SDAPCD with EPA Region 9 and CARB oversight.

San Diego Air Pollution Control District Rules and Regulations

Authority: H&SC §4000 et seq., H&SC §40200 et seq., indicated SDAPCD Rules

Requirements: Establishes procedures and standards for issuing permits; establishes standards and limitations on a source-specific basis.

Administering Agency: SDAPCD with EPA Region 9 and CARB oversight.

Authority to Construct. Rule 10 (Permits Required) specifies that any facility installing nonexempt equipment that causes or controls the emission of air pollutants must first obtain an Authority to Construct from the SDAPCD. Under Rule 20.5 (h) (Power Plants), the District's Final Determination of Compliance acts as an authority to construct for a power plant upon approval of the Amended CECP by the CEC.

Review of New or Modified Sources. Rule 20.3 (New Source Review – Major Stationary Sources and PSD Sources) implements the federal NSR and PSD programs, as well as the new source review requirements of the California Clean Air Act. The rule contains the following elements:

- BACT and Lowest Achievable Emission Rates (LAER);
- Emission offsets; and
- Air quality impact analysis (AQIA).

Best Available Control Technology. BACT must be applied to any new or modified source resulting in an emissions increase exceeding any SDAPCD BACT threshold shown in Table 5.1-12.

TABLE 5.1-12
SDAPCD BACT and LAER Emission Thresholds

Pollutant	BACT Threshold (lb/day)	LAER Major Source Threshold (tpy)	LAER Major Modification Threshold (tpy)
CO	N/A[a]	N/A[b]	N/A[b]
NOx	10	50	25
PM_{10}	10	100	15
SO_2	10	100	40
VOC	10	50	25

[a] SDAPCD regulates BACT for CO under the PSD component of Rule 20.3.

[b] CO is an attainment pollutant and therefore not subject to LAER requirements.

The SDAPCD defines BACT as the most stringent emission limitation or control technique that:

- Has been proven in field application and that is cost-effective <u>unless not achievable</u>; or
- Has been demonstrated, but not necessarily proven, in field applications, and that is cost-effective; or
- Is any control equipment, process modification, change in raw material including alternate fuels, and substitution of equipment or processes with any equipment or processes (or any combination of these) determined to be technologically feasible and cost-effective; or

- Is contained in any SIP approved by EPA for such emission unit category, unless demonstrated to not be proven in field application, not be technologically feasible, or not be cost-effective.

LAER must be applied to any federal nonattainment pollutants (or their precursors) at new major sources or major modifications exceeding any emission threshold shown in Table 5.1-12. LAER is more stringent than BACT because it does not contain restrictions for cost-effectiveness. Only NOx and VOCs are federal nonattainment precursors in SDAPCD and therefore potentially subject to LAER. The SDAPCD defines LAER as:

- The most stringent emission limitation that is achieved in practice by such class or category of emission unit; or
- The most stringent emission limitation, or most effective emission control device or technique, contained in any SIP approved by the EPA for such emission unit class or category unless demonstrated to not be achievable; or
- BACT.

Emission Offsets. A new or modified source resulting in emission increases above the major source or major modification emission thresholds, as shown in Table 5.1-13, must offset emission increases of federal nonattainment pollutants (and their precursors) at a ratio of 1.2 to 1. If existing equipment is shut down at a source as part of a facility modification, the reductions in emissions from those shutdowns are subtracted from the increases associated with the new equipment to determine the net emissions increase subject to offset requirements. San Diego County is classified as a federal nonattainment area for the 8-hour ozone standard. Therefore, emissions of NOx and VOCs, as precursors to ozone, are subject to the emission offset requirements. VOC emission reductions may be used to offset NOx emission increases at an offset ratio of 2 to 1.

TABLE 5.1-13
SDAPCD Offset Emission Thresholds

Pollutant	Major Source Threshold [a] (tpy)	Major Modification Threshold [b] (tpy)
NOx	50	25
SOx	N/A[c]	N/A[c]
CO	N/A[c]	N/A[c]
VOC	50	25
PM_{10}	N/A[c]	N/A[c]

[a]SDAPCD Regulation II, Rule 20.1, Table 20.1-6

[b]SDAPCD Regulation II, Rule 20.1, Table 20.1-5

[c]Not applicable because CO, SOx, and PM_{10} are federal attainment pollutants and therefore are not subject to offset requirements.

Air Quality Impact Analysis (AQIA). An AQIA must be conducted to evaluate impacts on ambient air quality of emission increases from new or modified projects exceeding any AQIA threshold shown in Table 5.1-14. Project emissions must not cause a new exceedance or contribute significantly to an existing exceedance of any ambient air quality standard.

TABLE 5.1-14
SDAPCD AQIA EMISSION Thresholds*

Pollutant	Emission Thresholds lb/hr	lb/day	tpy
CO	100	550	100
NOx	25	250	40
PM_{10}	N/A	100	15
SOx	25	250	40

*SDAPCD Regulation II, Rule 20.3, Table 20.3-1.

Toxic Risk Management. Rule 1200 (Toxic Air Contaminants – New Source Review) provides a mechanism for evaluating the potential impact of TAC (also called non-criteria pollutant) air emissions from new, modified, and relocated sources in the SDAPCD. The rule requires a demonstration that the source will not exceed the risk thresholds summarized in Table 5.1-15. As shown in this table, there are different acceptable risk levels depending upon whether a project uses Toxics-Best Available Control Technology (T-BACT). The Amended CECP will use T-BACT with the use of natural gas and installation of an oxidation catalyst system.

TABLE 5.1-15
SDAPCD Health Risk Thresholds

Risk Criterion	Risk Threshold
Cancer Risk with T-BACT	1×10^{-5}
Cancer Risk without T-BACT	1×10^{-6}
Acute Noncarcinogenic Health Hazard Index	1
Chronic Noncarcinogenic Health Hazard Index	1

CEC Review. Rule 20.5 establishes a procedure for coordinating SDAPCD review of power plant projects with the CEC's AFC, and Small Power Plant Exemption (SPPE) processes. Under this rule, the SDAPCD reviews the AFC/SPPE and issues a Determination of Compliance for a proposed project. Upon approval of the proposed project by the CEC, this Determination of Compliance is equivalent to an Authority to Construct. A Permit to Operate is issued following demonstration of compliance with all permit conditions.

Prevention of Significant Deterioration. Rule 20.3 (New Source Review – Major Stationary Sources and PSD Sources) implements the federal nonattainment NSR and PSD programs. Currently the PSD program in the SDAPCD is implemented by EPA Region 9 based on the federal version of the PSD regulations (40 CFR 52.21). On April 4, 2012, the SDAPCD approved a new PSD Regulation (Rule 20.3.1) that adopts the federal PSD regulations by reference. The SDAPCD expects that the EPA will approve Rule 20.3.1 in the near future. While the PSD program in the SDAPCD is implemented based on the federal PSD regulations (either by EPA Region 9 or by SDAPCD in the future under Rule 20.3.1), the SDAPCD will continue to require facilities to comply with the various requirements of Rule 20.3 (including those identified as PSD requirements).

Acid Rain Permit. Rule 1412 (Federal Acid Rain Program Requirements) adopts, by reference, the federal requirements of 40 CFR Part 72, which requires that certain subject facilities comply with maximum operating emissions levels for SO_2 and NOx, and monitor SO_2, NOx, and carbon dioxide emissions and exhaust gas flow rates. A Phase II acid rain facility, such as a new power plant project, must obtain an acid rain permit. A permit application must be submitted to the SDAPCD at least 24 months before operation of the new unit commences. The application must present all relevant Phase II sources at the facility, a compliance plan for each unit, applicable standards, and an estimated commencement date of operations. The Amended CECP will be a modification to an existing Phase II facility. Consequently, an application for a modification to the existing acid rain permit will be submitted according to the timeframe discussed above.

Federal Operating Permit. Rule 1414 (Applications) requires new or modified major facilities, NSPS sources, NESHAP sources, and/or Phase II acid rain facilities to obtain an operating permit containing the federally enforceable requirements mandated by Title V of the 1990 Clean Air Act Amendments. A permit application for a new or modified source must be submitted to the SDAPCD within 12 months of commencing operation. The application must present a process description identifying all new stationary sources at the facility, applicable regulations, estimated emissions, associated operating conditions, alternative operating scenarios, a facility compliance plan, and a compliance certification. The Amended CECP will be a modification to an existing Title V facility. Consequently, an application for a modification to the existing Title V permit will be submitted according to the timeframe discussed above.

New Source Performance Standards. Regulation X (Standards of Performance for New Stationary Sources) adopts, by reference, the federal standards of performance for new or modified stationary sources. The applicability of the New Source Performance Standards is discussed above under the federal regulations.

SDAPCD Prohibitory Rules

The general prohibitory rules of the SDAPCD applicable to the Amended CECP include the following:

Rule 50 – Visible Emissions. Prohibits visible emissions as dark as, or darker than, Ringelmann No. 1 for periods greater than three minutes in any hour.

Rule 51 – Nuisance. Prohibits the discharge from a facility of air pollutants that cause injury, detriment, nuisance, or annoyance to the public, or that damage business or property.

Rule 52 – Particulate Matter Emission Standards. Prohibits PM emissions in excess of 0.10 grains per dry standard cubic foot (gr/dscf). This rule does not apply to stationary internal combustion engines.

Rule 53 – Combustion Contaminants. Prohibits sulfur emissions, calculated as SO_2, in excess of 0.05% by volume on a dry basis (500 parts per million by volume [ppmv]), and combustion particulate emissions in excess of 0.10 gr/dscf at 12% CO_2.

Rule 55 – Fugitive Dust Control. Requires control of dust emissions during construction activities. It prohibits visible dust emissions beyond the property line for periods aggregating more than 3 minutes in any 60-minute period, and minimization and daily removal of roadway dust.

Rule 62 – Sulfur Content of Fuels. Prohibits the burning of gaseous fuel with a sulfur content of more than 10 gr/100 scf and liquid fuel with a sulfur content of more than 0.05% sulfur by weight.

Rule 69.3 – Stationary Gas Turbines. Limits NOx emissions from a gas turbine to 42 ppmv at 15% O_2. The limit does not apply during a startup or shutdown period not to exceed 120 minutes.

Rule 69.3.1 – Stationary Gas Turbines. Limits NOx emissions from stationary gas turbines rated greater than or equal to 10 MW with post-combustion controls to 9 x E/25 ppm at 15%O_2, where E is the unit's thermal efficiency.

Rule 69.4.1 – Stationary Reciprocating Internal Combustion Engines. Limits CO, NOx, and VOC emissions from stationary reciprocating internal combustion engines rated greater than or equal to 50 bhp. However, emergency equipment operating less than or equal to 52 hours per year for testing or maintenance purposes and less than or equal to 200 hours per year for any purpose are exempt from the emission limits of Rule 69.4.1.

All applicable LORS are summarized in Table 5.1-16 along with identification of the section that discusses compliance with each requirement.

TABLE 5.1-16

Laws, Ordinances, Regulations, Standards and Permits for Protection of Air Quality

LORS	Purpose	Regulating Agency	Permit or Approval	Schedule and Status of Permit	Conformance (Sections)
Federal					
Clean Air Act (CAA) §160-169A and implementing regulations, Title 42 United States Code (USC) §7470-7491 (42 USC §7470-7491), Title 40 Code of Federal Regulations (CFR) Parts 51 & 52 (Prevention of Significant Deterioration Program)	Requires prevention of significant deterioration (PSD) review and facility permitting for construction of new or modified major stationary sources of air pollution. PSD review applies to pollutants for which ambient concentrations are lower than NAAQS.	SDAPCD (expected delegation) with EPA oversight	PSD Permit for a New Major Source or major modification.	Proposed project will only trigger for GHG emissions.	5.1.3.1.1
CAA §171-193, 42 USC §7501 et seq. (New Source Review)	Requires new source review (NSR) facility permitting for construction or modification of specified stationary sources. NSR applies to pollutants for which ambient concentration levels are higher than NAAQS.	SDAPCD with EPA oversight	Determination of Compliance (DOC) with conditions limiting emissions.	Agency approval to be obtained before start of construction.	5.1.3.1.1
CAA §401 (Title IV), 42 USC §7651 (Acid Rain Program)	Requires reductions in NOx and SO_2 emissions.	SDAPCD with EPA oversight	Acid Rain program requirements included in Determination of Compliance, Permit to Operate, and Title V permit.	Meet compliance deadlines listed in regulations.	5.1.3.1.1
CAA §501 (Title V), 42 USC §7661 (Federal Operating Permits Program)	Establishes comprehensive permit program for major stationary sources.	SDAPCD with EPA oversight	Modified Title V permit after review of application.	Permit application to modify existing Title V permit will be submitted within 12 months after commencement of operation.	5.1.3.1.1
CAA §111, 42 USC §7411, 40 CFR Part 60 (New Source Performance Standards – NSPS)	Establishes national standards of performance for new stationary sources.	SDAPCD with EPA oversight	DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	5.1.3.1.1

TABLE 5.1-16
Laws, Ordinances, Regulations, Standards and Permits for Protection of Air Quality

LORS	Purpose	Regulating Agency	Permit or Approval	Schedule and Status of Permit	Conformance (Sections)
State					
H&SC §44300-44384; California Code of Regulations (CCR) §93300-93347 (Toxic "Hot Spots" Act)	Requires preparation and biennial updating of facility emission inventory of hazardous substances; risk assessments.	SDAPCD with CARB oversight	DOC with conditions limiting emissions.	Screening HRA submitted as part of PTA.	5.1.3.1.2
California Public Resources Code §25523(a); 20 CCR §§1752, 2300-2309 (CEC & CARB Memorandum of Understanding)	Requires that CEC's decision on PTA include requirements to assure protection of environmental quality; PTA required to address air quality protection.	CEC	Final Certification with conditions limiting emissions.	SDAPCD issuance of DOC precedes CEC approval of PTA.	5.1.3.1.2
17 CCR § 93115 (ATCM for Stationary Compression Ignition Engines)	Establishes emission and operational limits for diesel-fueled stationary compression ignition engines.	SDAPCD and CARB	DOC with conditions limiting emissions and operation.	Agency approval to be obtained before start of construction.	5.1.3.1.2
Local					
SDAPCD Rule 20.3 (New Source Review – Major Stationary Sources and PSD Sources)	NSR: Requires that preconstruction review be conducted for all proposed new or modified sources of air pollution, including BACT, emissions offsets, and air quality impact analysis.	SDAPCD with CARB oversight	DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	5.1.3.1.3
SDAPCD Rule 1200 (Toxics – New Source Review)	Requires that preconstruction review be conducted for all proposed new or modified sources of toxic air contaminants, including T-BACT, and a health risk assessment.	SDAPCD with EPA oversight	DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	5.1.3.1.3
SDAPCD Rule 1414 (Title V Applications)	Implements operating permits requirements of CAA Title V.	SDAPCD with EPA oversight	Issues modified Title V permit after review of application.	Agency approval to be obtained before start of construction.	5.1.3.1.3
SDAPCD Rule 1412 (Federal Acid Rain Program Requirements)	Implements acid rain regulations of CAA Title IV.	SDAPCD with EPA oversight	Title IV requirements included in DOC, Permit to Operate, and Title V permit.	Application to be made within 12 months of start of facility operation.	5.1.3.1.3

TABLE 5.1-16

Laws, Ordinances, Regulations, Standards and Permits for Protection of Air Quality

LORS	Purpose	Regulating Agency	Permit or Approval	Schedule and Status of Permit	Conformance (Sections)
SDAPCD Rule 50 (Visible Emissions)	Limits visible emissions to no darker than Ringelmann No. 1 for periods greater than 3 minutes in any hour.	SDAPCD with CARB oversight	DOC with conditions limiting emissions.	Agency approval to be obtained prior to commencement of operation.	5.1.3.1.3
SDAPCD Rule 51 (Nuisance)	Prohibits emissions in quantities that adversely affect public health, other businesses, or property.	SDAPCD with CARB oversight	DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	5.1.3.1.3
SDAPCD Rule 52 (Particulate Matter)	Limits PM emissions from stationary sources (does not apply to I/C engines including gas turbines).	SDAPCD with CARB oversight	DOC with conditions limiting emissions.	Proposed new equipment exempt from this regulation.	5.1.3.1.3
SDAPCD Rule 53 (Combustion Contaminants)	Limits SO_2 emissions from stationary sources.	SDAPCD with CARB oversight	DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	5.1.3.1.3
SDAPCD Rule 55 (Fugitive Dust)	Limits visible dust emissions from construction activities.	SDAPCD with CARB oversight	DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	5.1.3.1.3
SDAPCD Rule 62 (Sulfur Content of Fuels)	Limits the sulfur content of fuels combusted in stationary sources.	SDAPCD with CARB oversight	DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	5.1.3.1.3
SDAPCD Rule 69.3 (Stationary Gas Turbines)	Limits NOx emissions from stationary gas turbines.	SDAPCD with CARB oversight	DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	5.1.3.1.3
SDAPCD Rule 69.3.1 (Stationary Gas Turbines)	Limits NOx emissions from stationary gas turbines.	SDAPCD with CARB oversight	DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	5.1.3.1.3
SDAPCD Rule 69.4.1 (Stationary Reciprocating Internal Combustion Engines)	Limits CO, NOx, and VOC emissions from stationary reciprocating internal combustion engines (does not apply to limited use emergency engines).	SDAPCD with CARB oversight	DOC with conditions limiting emissions.	Proposed new engine is exempt from this regulation due to operating limits.	5.1.3.1.3

TABLE 5.1-16

Laws, Ordinances, Regulations, Standards and Permits for Protection of Air Quality

LORS	Purpose	Regulating Agency	Permit or Approval	Schedule and Status of Permit	Conformance (Sections)
SDAPCD Regulation X (New Source Performance Standards: Subpart KKKK, Stationary Gas Turbines)	Requires monitoring of fuel, other operating parameters; limits NOx and SO_2 and PM emissions, requires source testing, emissions monitoring, and recordkeeping.	SDAPCD with CARB oversight	DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	5.1.3.1.3
SDAPCD Regulation X (New Source Performance Standards: Subpart IIII, Stationary Compression Ignition Internal Combustion Engines)	Limits VOC, NOx, CO, and PM emissions and requires recordkeeping.	SDAPCD with CARB oversight	DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	5.1.3.1.3

Attainment Status. Table 5.1-17 summarizes the attainment status of the San Diego Air Basin based on the measured existing air quality described in Section 5.1.2.5, the ambient air quality standards presented in Table 5.1-1, and the responsibilities of EPA and CARB discussed in Sections 5.1.3.1.1 and 5.1.3.1.2, respectively.

TABLE 5.1-17
Ambient Air Quality Standard Attainment Status in San Diego Air Basin

Pollutant	Averaging Time	California	National
Ozone	1 hour	Nonattainment	No NAAQS
	8 hours	Nonattainment	Nonattainment
Carbon Monoxide	8 hours	Attainment	Unclassified/Attainment
	1 hour	Attainment	Unclassified/Attainment
Nitrogen Dioxide	Annual Average	Attainment	Unclassified/Attainment
	1 hour	Attainment	Unclassified/Attainment
Sulfur Dioxide	Annual Average	No CAAQS	No NAAQS
	24 hours	Attainment	No NAAQS
	3 hours	No CAAQS	No NAAQS
	1 hour	Attainment	Attainment
Respirable Particulate Matter (10 Microns)	Annual Arithmetic Mean	Nonattainment	Unclassified/Attainment
	24 hours	Nonattainment	Unclassified/Attainment
Fine Particulate Matter (2.5 Microns)	Annual Arithmetic Mean	Nonattainment	Unclassified/Attainment
	24 hours	No CAAQS	Unclassified/Attainment
Sulfates	24 hours	Attainment	No NAAQS
Lead	30 days	Attainment	No NAAQS
	Calendar Quarter	No CAAQS	Unclassified/Attainment
	Rolling 3-Month Average	No CAAQS	Unclassified/Attainment
Hydrogen Sulfide	1-hour	Unclassified/Attainment	No NAAQS
Visibility Reducing Particles	8-hour	Unclassified/Attainment	No NAAQS

Sources: CARB, 2014d and EPA, 2013

5.1.4 Environmental Analysis

Ambient air quality impact analyses for the Amended CECP have been conducted to satisfy the SDAPCD, EPA, and CEC requirements for analysis of impacts from criteria pollutants (NO_2, CO, PM_{10}, $PM_{2.5}$, and SO_2) and noncriteria pollutants during project construction and operation. The analyses cover each phase of the Amended CECP. Section 5.1.4.1 gives an overview of the analytical approach. Section 5.1.4.2 presents the emissions for operation of the CECP, and Section 5.1.4.3 gives the ambient air quality impacts of operation. Section 5.1.4.4 discusses the Screening Health Risk Assessment. Section 5.1.4.5 provides the demolition/construction impacts analysis. As shown in Tables 5.1-25, 5.1-40, and 5.1-41, there are significant net reductions criteria pollutant, GHGs, and total nitrogen emissions when comparing the Amended CECP to the Licensed CECP.

5.1.4.1 Overview of the Analytical Approach to Estimating Facility Impacts

The following sections describe the emission sources that have been evaluated, the results of the ambient impact analyses, and the evaluation of the Amended CECP compliance with the applicable air quality regulations, including the District's NSR requirements. These analyses are designed to confirm that the Amended CECP's design features lead to less-than-significant impacts even with the following conservative analysis assumptions and procedures: maximum allowable emission rates, project operating schedules that lead to maximum emissions, worst-case meteorological conditions, and the worst-observed existing air quality added to the highest potential ground-level impact from modeling—even when all of these situations could not physically occur at the same time.

5.1.4.1.1 Emitting Units

The new gas turbines proposed for the Amended CECP will be GE LMS 100 simple-cycle gas turbines equipped with evaporative cooling. Each unit will include an air-cooled fin-fan cooler and associated support equipment. The six units will provide a total nominal generating capacity of 632 MW net output.[11] Each gas turbine will be equipped with water injection and a selective catalytic reduction (SCR) system for NOx control. An oxidation catalyst will be used to reduce CO emissions. Particulate, SOx, and VOC emissions will be minimized through the use of natural gas as the fuel. Emission control systems will operate at all times except during startups and shutdowns. Specifications for the new gas turbines are summarized in Table 5.1-18.

As discussed above, the use of natural gas as the sole fuel will minimize emissions of VOCs, SOx, and PM. Table 5.1-19 summarizes a typical analysis for the natural gas fuel to be used by the gas turbines.

The Amended CECP will also include the installation of a new diesel emergency fire pump engine rated at 244 horsepower (maximum fuel consumption rate of 14.8 gallons per hour) and a new diesel emergency generator engine rated at 500 kw (maximum fuel consumption rate of 35.9 gallons per hour). The auxiliary equipment associated with the Amended CECP will also include the installation of one 20,000-gallon aqueous ammonia (19%) storage tank.

Facility Operations

Gas turbine performance specifications were developed for three ambient temperature scenarios: extreme hot temperature (96°F), annual average temperature (60°F), and extreme low temperature (44°F). The annual average temperature scenario was used to characterize maximum hourly emissions during normal operation because it has the highest hourly heat input and emission rates. The plant may be operated under a wide variety of conditions over its life. The worst-case hourly emissions assume all six gas turbines will undergo startups simultaneously with no operation of the emergency generator engines. Maximum daily operations are based on each gas turbine undergoing four startups/shutdowns with the units operating at full-load for the remaining hours of the day and each emergency engine operating for 30 minutes for testing purposes. Maximum annual emissions are based on each gas turbine operating approximately 2,700 hours per year (including up to 400 startups/shutdowns per year) at annual average full-load operation. Annual emissions include the emergency engines each operating a total of 200 hours per year.

[11] Rated at an average annual ambient temperature of 60.3 degrees Fahrenheit [°F] 79 percent relative humidity and with inlet air evaporative cooling.

TABLE 5.1-18
New Simple-Cycle Gas Turbine Design Specifications

Manufacturer	GE
Model	LMS 100PA
Fuel	Natural gas
Design Ambient Temperature*	60°F
Maximum Gas Turbine Heat Input Rate*	984 MMBtu/hr at HHV (each turbine)
Stack Exhaust Temperature*	781.7°F
Exhaust Flow Rate*	1,022,475 acfm
Exhaust O_2 Concentration, dry volume*	13.18%
Exhaust CO_2 Concentration, dry volume*	4.44%
Exhaust Moisture Content, wet volume*	6.94%
Emission Controls	Water injection and SCR; oxidation catalyst

*This ambient temperature at 100% load results in maximum heat input/power output; exhaust characteristics shown reflect this ambient temperature and load.

TABLE 5.1-19
Nominal Fuel Properties – Natural Gas

Component Analysis		**Chemical Analysis**	
Component	**Average Concentration, Volume**	**Constituent**	**Percent by Weight**
Methane (CH_4)	95.870 %	Carbon (C)	72.98 %
Ethane (C_2H_6)	1.808 %	Hydrogen (H)	23.86 %
Propane (C_3H_8)	0.336 %	Nitrogen (N)	1.05 %
Butane C_4H_{10})	0.122 %	Oxygen (O)	2.11 %
Pentane (C_5H_{12})	0.043 %	Sulfur (S)	0.75 gr/100 scf (short-term average) 0.25 gr/100 scf (long-term average)
Hexane (C_6H_{14})	0.026 %		
Nitrogen (N_2)	0.682 %	Higher Heating Value	1,020 Btu/scf 22,856 Btu/lb
Carbon Dioxide (CO_2)	1.113 %		
Sulfur (S)	<0.00 %		

Heat input levels for the gas turbines, as summarized in Table 5.1-20, correspond to the calculated unit and project emission levels.

TABLE 5.1-20
Maximum Proposed Project Fuel Use – CTGs (MMBtu)

Period	Gas Turbines (each)	Total Fuel Use (six units)
Per Hour	984	5,902
Per Day	23,606	141,638
Per Year	2,655,720	15,934,320

MMBtu = million Btu

Emissions and operating parameters for the gas turbines under various loads and ambient conditions are shown in Appendix 5.1B. Emissions and operating parameters for the emergency engines are also shown in Appendix 5.1B.

5.1.4.2 Emissions Calculations

This section presents calculations of emissions increases from the proposed Amended CECP generating and auxiliary equipment and of the emissions reductions from the shutdown of the existing boilers at the EPS for the purpose of demonstrating rule compliance. Tables containing the detailed calculations are included in Appendix 5.1B.

5.1.4.2.1 Criteria Pollutant Emissions: Amended CECP

The gas turbine and emergency engine emission rates have been calculated from vendor data, project design criteria, and established emission calculation procedures. The emission rates for the gas turbines and emergency engines are shown in the following tables. The detailed emission calculations for these units are shown in Appendix 5.1B.

Gas Turbine Emissions during Commissioning

The commissioning period begins when the gas turbines are prepared for first fire and ends upon successful completion of performance/compliance testing. The commissioning process entails several relatively short periods of operation prior to and following installation of the emission control systems. During these periods, NOx emissions will be higher than normal operating levels because the NOx emission control system would not be fully operational and because the gas turbine would not be tuned for optimum performance. CO emissions would also be higher than normal because turbine performance would not be optimized and the CO emissions control system would not be fully operational.

Gas turbine commissioning activities can be broken down into several separate test phases, as shown on the commissioning summary table included in Appendix 5.1B. The emission estimates shown in the detailed commissioning summary table in Appendix 5.1B are based on vendor-supplied emission rates. At the conclusion of the commissioning period, emissions rates will be at the normal operating levels discussed in the following paragraphs. While the required continuous emissions monitoring system (CEMS) for NOx and CO will be calibrated and operating during the commissioning test phases, the CEMS will be not certified until the end of the commissioning period.

The commissioning of the six new CTGs is expected to occur over approximately a four-month period. During this commissioning period, it will be necessary to continue to operate the existing EPS Units 1 through 5/peaker gas turbine. Consequently, as discussed in Section 5.1.4.3, the commissioning air quality modeling analysis performed for the Amended CECP includes the simultaneous operation of the new CTGs (commissioning tests) and the existing EPS units. Once the commissioning tests are complete and the new CTGs are available for commercial operation, the existing units will no longer be operated and will be removed from service.

Gas Turbine Emissions during Normal Operations

Emissions of NOx, CO, and VOC were calculated from emission limits (in ppmv at 15% O_2) and the exhaust flow rates. The NOx emission limit reflects the application of water injection and SCR. The VOC and CO emission limits reflect the use of good combustion practices and, for CO, an oxidation catalyst. SOx, PM_{10}, and $PM_{2.5}$ emission rates are based on the use of natural gas as the fuel and good combustion practices. Emissions are based on the heat input rates shown in Table 5.1-20.

SOx emissions were calculated from the heat input (in MMBtu) and a SOx emission factor (in lb/MMBtu). The short-term SOx emission factor of 0.0021 lb/MMBtu was derived from the maximum allowable (i.e., tariff limit) fuel sulfur content of 0.75 grains per 100 standard cubic feet (gr/100 scf). The annual average SOx emissions were based on the expected annual average sulfur grain loading of 0.25 gr/100 scf.

Maximum hourly PM_{10} emissions are based on vendor-supplied emission levels. $PM_{2.5}$ emissions were determined based on the assumption that all gas turbine exhaust particulate is less than 2.5 microns in diameter.

Emission rates for the CTGs are summarized in Table 5.1-21. The BACT analysis upon which the emission factors are based is presented in Appendix 5.1C and summarized in Section 5.1.2.6.3.

Gas Turbine Emissions During Startup and Shutdown

Maximum emission rates expected to occur during a gas turbine startup or shutdown are shown in Table 5.1-22. PM and SO_2 emissions are not included in this table because emissions of these pollutants will not be higher during startup and shutdown than during normal gas turbine operation. During a CTG startup, there are approximately 25 minutes with elevated emissions (emissions higher than during normal operation). Consequently, the hourly emission rates during CTG startups are based on 25 minutes of elevated emissions followed by 35 minutes of normal operating emission levels. During a CTG shutdown, there are approximately 13 minutes with elevated emissions (emissions higher than during normal operation). Consequently, the hourly emission rates during CTG shutdowns are based on 47 minutes of normal operating emission levels followed by 13 minutes of elevated emission levels.

TABLE 5.1-21
Maximum Hourly Emission Rates: CTGs

Pollutant	ppmvd at 15% O_2	lb/MMBtu	lb/hr
Each Gas Turbine[a]			
NOx	2.5	0.0091	9.00
SO_x (short term)	n/a	0.0021	2.07
SO_x (long term)	n/a	0.0007	0.69
CO	4.0	0.0088	8.80
VOC	2.0	0.0025	2.50
$PM_{10}/PM_{2.5}$[b]	n/a	0.0036	3.50

[a]Emission rates shown reflect the highest value at any operating load during normal operation (excluding startups/shutdowns).
[b]100 percent of PM_{10} emissions assumed to be emitted as $PM_{2.5}$.

TABLE 5.1-22
CTG Startup and Shutdown Emission Rates*

	NOx	CO	VOC
CTG Startup, lbs/hr, per gas turbine	20.0	12.5	3.5
CTG Shutdown, lbs/hr, per gas turbine	7.7	10.3	4.4
CTG Startup/Shutdown/Restart, lbs/hr, per gas turbine	28.2	17.3	6.2

*Startup and shutdown emission rates reflect the maximum hourly emissions during an hour in which a startup, shutdown, or both occur.

The Project Owner also expects that periodically there could be an hour when a startup, shutdown, and restart all occur. For this hour, there would be 25 minutes of elevated emissions due to the startup, 13 minutes of elevated emissions due a shutdown, followed by 22 minutes of elevated emissions due to the restart. While this situation is expected to occur very infrequently, from an hourly emission standpoint this would represent worst-case hourly emissions, and as such it is included in the ambient air impact analysis for the Amended CECP. The detailed CTG startup hourly emission calculations are shown in the startup/shutdown summary tables in Appendix 5.1B. Included in this appendix are the startup/shutdown emission levels supplied by the vendor for the gas turbines.

Criteria Pollutant Emissions Summary

The calculation of maximum project-related emissions shown in Table 5.1-23 is based on the CTG emission rates and heat input levels shown in the above tables and the following assumptions:

- Worst-case hour: All six gas turbines will undergo a startup/shutdown/restart sequence simultaneously in one hour. The emergency engines will not be operated during this hour.
- Worst-case day: Each gas turbine will undergo 4 startup hours (hours including a startup), 4 shutdown hours, and 16 hours of normal operation. The emergency engines will each be operated for 30 minutes for testing/maintenance purposes.
- Worst-case year: Each gas turbine will undergo 400 startups, 400 shutdowns, with a total of 2,700 hours of operation per year (including startup/shutdown periods). The emergency engines will each be operated a total of 200 hours.

The assumptions used in calculating maximum hourly, daily, and annual emissions from the new facility are shown in Appendix 5.1B.

The cooling towers proposed for the project will be a dry design. Therefore, there will be no emissions associated with this equipment. The only other source of criteria pollutant emissions for project operations will be fugitive leaks from the compressors used to increase the natural gas pressure required by the gas turbines. These leaks will result in a small amount of VOC emissions to the atmosphere. The gas compressor fugitive emission calculations are included in Appendix 5.1B.

The maximum hourly, daily, and annual emissions in Table 5.1-23 are used in the air dispersion modeling to calculate the maximum potential ground-level concentrations contributed by the Amended CECP to the ambient air.

5.1.4.2.2 Emissions for Existing Boilers at the Encina Power Station

The EPS consists of five natural-gas-fired steam boilers (Units 1 through 5), and one simple-cycle peaking gas turbine, rated at the following nominal levels: 113 MW, 109 MW, 115 MW, 293 MW, 315 MW, and 18 MW, respectively. As part of the Amended CECP, the existing boiler Units 1 through 5 and the peaker gas turbine at the EPS will be shut down and retired prior to commercial operation of the new equipment.

To determine the actual emissions associated with the operation of the existing EPS units, it is necessary to determine the baseline period. The three regulatory programs that discuss baseline periods for air quality purposes are CEQA, the SDAPCD NSR regulations, and the federal PSD regulations. These three baseline periods are summarized below:

- **CEQA** – Under the CEQA regulations there is no specific baseline period defined or required. The CEQA baseline period needs to reflect the actual conditions that exist at the start of the environmental review process for a project.

TABLE 5.1-23
Maximum Emissions From New Equipment

	Pollutant				
Emissions/Equipment	**NOx**	**CO**	**VOC**	**$PM_{10}/PM_{2.5}$**	**SOx**
Maximum Hourly Emissions[a]					
Gas Turbines[a]	169.4	103.9	37.0	21.0	12.4
Diesel Emergency Engines[b]	n/a	n/a	n/a	n/a	n/a
Gas Compressors	n/a	n/a	0.0	n/a	n/a
Total, pounds per hour =	**169.4**	**103.9**	**37.0**	**21.0**	**12.4**

TABLE 5.1-23
Maximum Emissions From New Equipment

	Pollutant				
Emissions/Equipment	**NOx**	**CO**	**VOC**	**$PM_{10}/PM_{2.5}$**	**SOx**
Maximum Daily Emissions[a]					
Gas Turbines	1,526.4	1,392.6	427.6	504.0	298.2
Diesel Emergency Engines	1.6	0.3	0.0	0.0	0.0
Gas Compressors	n/a	n/a	0.3	n/a	n/a
Total, pounds per day =	**1528.0**	**1392.9**	**427.9**	**504.0**	**298.2**
Maximum Annual Emissions[a]					
Gas Turbines	84.4	77.6	23.6	28.4	5.6
Diesel Emergency Engines	0.3	0.1	0.0	0.0	0.0
Gas Compressors	n/a	n/a	0.1	n/a	n/a
Total, tons per year =	**84.7**	**77.6**	**23.7**	**28.4**	**5.6**

[a]Maximum hourly, daily and annual gas turbine emission rates include emissions during startups/shutdowns.

[b]The diesel emergency engines will not be operated during a gas turbine startup and/or shutdown. Consequently, n/a is shown for all pollutants.

- **SDAPCD NSR** – Under SDAPCD NSR rules (Rule 20.1.d.2), the baseline period to establish the actual emissions for existing units is the most representative two-year period during the five years preceding the filing of a permit application with the SDAPCD.
- **Federal PSD** – Under the federal PSD regulations (40 CFR 52.21.b.48.1), the baseline period to establish the actual emissions for existing units is any consecutive 24-month period within the 5-year period preceding when actual construction of a new project begins. The EPA does allow the use of a different lookback period to calculate actual emissions if it is more representative of normal operation.

For CEQA purposes this analysis examines actual historical emissions for the existing EPS units averaged over the past 5 years, 10 years, and 12 years. The 12-year lookback period begins in 2002 which is consistent with the start of the baseline period used during the original permitting of the Licensed CECP. For both NSR and PSD purposes, the baseline emissions for the existing EPS units and the associated emissions reductions from the shutdown of these units are based on actual emissions during the most representative consecutive 2-year period during the 5 years preceding the filing of the PTA/SDAPCD permit application for the proposed project (2009 to 2013). The emission reductions associated with the shutdown of the existing units are shown in Table 5.1-24. The detailed calculation of the historical baseline emissions for the existing units at the EPS is included in Appendix 5.1B.

TABLE 5.1-24
Emissions for Existing Units (Maximum 2-Year Average for Period From 1/1/09 to 12/31/13)

	Pollutant (tpy)				
Emissions/Equipment	**NOx**	**CO**	**VOC**	**$PM_{10}/PM_{2.5}$**	**SOx**
Annual Emissions Encina Power Station					
Unit 1	5.5	33.7	3.3	4.6	0.4
Unit 2	6.5	39.7	3.5	4.9	0.4
Unit 3	6.5	18.7	4.0	5.5	0.4
Unit 4	15.6	10.8	8.3	11.5	0.9
Unit 5	23.9	75.8	12.0	16.5	1.3
Gas Turbine	0.3	0.4	0.0	0.1	0.0
Total	**58.3**	**179.1**	**31.1**	**43.0**	**3.4**

Net Changes in Criteria Pollutant Emissions for the Amended CECPt

Net emissions changes as a result of the proposed project are calculated on an annual basis for federal PSD, SDAPCD NSR, and CEQA purposes. These net emission changes are shown in Table 5.1-25. As shown on this table, there is significant net reduction in criteria pollutant emissions when comparing the Amended CECP to the Licensed CECP.

TABLE 5.1-25
Net Emissions Change for Amended CECP

	Pollutant (tpy)				
Emissions/Equipment	**NOx**	**CO**	**VOC**	**$PM_{10}/PM_{2.5}$**	**SOx**
Amended CECP vs. Shutdown of Existing Units					
Potential to Emit for New Equipment (Amended CECP)	84.7	77.6	23.7	28.4	5.6
Reductions from Shutdown of Existing Units	-58.3	-179.1	-31.1	-43.0	-3.4
Net Emission Change	**26.4**	**-101.5**	**-7.4**	**-14.6**	**2.2**
Amended CECP vs. Licensed CECP					
Potential to Emit for New Equipment (Amended CECP)	84.7	77.6	23.7	28.4	5.6
Potential to Emit for Licensed CECP*	163.1	641.5	52.8	96.0	10.0
Net Emission Change	**-78.4**	**-563.9**	**-29.1**	**-67.6**	**-4.4**

*This includes the emissions for the new equipment associated with the Licensed CECP (CEC June 2012 Approval of CECP, Air Quality Table-7) and the emissions for existing Units 4 and 5 (12-year lookback).

5.1.4.2.3 Non-Criteria Pollutant Emissions

Noncriteria pollutant emissions were estimated for the proposed gas turbines and emergency engines. These emissions are summarized in Table 5.1-26. The detailed noncriteria pollutant emissions calculations and the associated screening-level health risk assessment are included in Section 5.9, Public Health. Also shown below in Table 5.1-27 is a summary of the maximum potential to emit for noncriteria pollutants for the existing units at the facility. This information is provided for regulatory applicability purposes.

TABLE 5.1-26
Non-Criteria Pollutant Emissions for the New Equipment

Compound	Emissions (tpy)
Gas Turbines (six units)	
Ammonia (not a HAP)	54.73
Propylene (not a HAP)	4.33
Acetaldehyde	0.23
Acrolein	0.04
Benzene	0.07
1,3-Butadiene	0.00
Ethylbenzene	0.18
Formaldehyde	5.15
Hexane	1.45
Naphthalene	0.01
PAHs (other)	0.00
Propylene Oxide	0.17

TABLE 5.1-26
Non-Criteria Pollutant Emissions for the New Equipment

Compound	Emissions (tpy)
Toluene	0.75
Xylene	0.37
Subtotal HAPs	8.42
Subtotal All	67.48
Emergency Engines (two units)	
Diesel PM (not a HAP)	0.01
Acrolein	0.00
Subtotal HAPs	0.00
Subtotal All	0.01
Total HAPs (Proposed Project)	**8.42**
Total All Proposed Project)	**67.49**

TABLE 5.1-27
Non-Criteria Pollutant Emissions for the Existing Boiler Units 1, 2, 3, 4, 5, and Gas Turbine (Maximum 2-Year Avg. Over Past 5-Years)

Compound	Emissions (tpy)
Ammonia (not a HAP)	25.86
Benzene	0.01
Formaldehyde	0.44
Hexane	0.01
Naphthalene	0.00
Dichlorobenzene	0.01
Toluene	0.02
1,3-Butadiene	0.00
Acetaldehyde	0.00
Acrolein	0.00
Ethyl Benzene	0.00
PAHs (other)	0.00
Xylene	0.00
Total HAPs (Existing Facility)	**0.49**
Total All (Existing Facility)	**26.35**

5.1.4.2.4 Greenhouse Gas Emissions

Potential maximum annual GHG emissions for the operation of the Amended CECP were calculated using the calculation methods and emission factors from the EPA GHG Reporting Regulation.[12] Table 5.1-28 presents the estimated GHG emissions due to project operations in carbon dioxide equivalent [$CO2_e$]. Emissions of methane, nitrous oxide, and sulfur hexafluoride have been converted to carbon dioxide equivalents using GHG warming potentials of 25, 298, and 22,800 respectively. The estimated emissions include the combustion emissions for the six turbines and two emergency engines. They also include sulfur

[12] 40 CFR 98 (as revised on 11/29/13).

hexafluoride leakage emissions from eight new circuit breakers. The detailed GHG emission calculations are included in Appendix 5.1B.

TABLE 5.1-28
Project Greenhouse Gas Emissions

Unit	CO_2, metric tpy	CH_4, metric tpy	N_2O, metric tpy	SF_6, metric tpy	CO_2eq, metric tpy*	CO_2, metric tons/MWh
Gas Turbines	845,475	16	2	n/a		
Emergency Engines	102	0	0	n/a		
Circuit Breakers	n/a	n/a	n/a	5.41×10^{-3}		
Total =	845,577	16	2	0	846,574	0.48

*Includes CH_4, N_2O, and SF_6.

5.1.4.3 Air Quality Impact Analysis

The SDAPCD new source review regulations require the Applicant to prepare ambient air quality modeling analyses and other impact assessments. An ambient air quality impact assessment is also required by the CEC for CEQA review. These analyses are presented in this section.

5.1.4.3.1 Air Quality Modeling Methodology

An assessment of impacts from the Amended CECP on ambient air quality has been conducted using EPA-approved air quality dispersion models. These models use a mathematical description of atmospheric turbulent entrainment and dispersion to simulate the actual processes by which emissions are transported to ground-level areas.

Using conservative assumptions, the modeling was used to determine the maximum ground-level impacts of the Amended CECP. The results were compared with state and federal ambient air quality standards and PSD significance levels. If the standards are not exceeded in the analysis, then the modified facility will cause no exceedances under any operating or ambient conditions, at any location, under any meteorological conditions. In accordance with the air quality impact analysis guidelines developed by EPA[13] and CARB,[14] the ground-level impact analysis includes the following assessments:

- Impacts in simple, intermediate, and complex terrain;
- Aerodynamic effects (downwash) due to nearby building(s) and structures; and
- Impacts from inversion breakup (fumigation).

Simple, intermediate, and complex terrain impacts were assessed for all meteorological conditions that would limit the amount of final plume rise. Plume impaction on elevated terrain, such as on the slope of a nearby hill, can cause high ground-level concentrations, especially under stable atmospheric conditions. Another dispersion condition that can cause high ground-level pollutant concentrations is caused by building downwash. A stack plume can be impacted by downwash when wind speeds are high and a sufficiently tall building or structure is in close proximity to the emission stack. This can result in building wake effects where the plume is drawn down toward the ground by the lower pressure region that exists in the lee (downwind) side of the building or structure.

Fumigation conditions occur when the plume is emitted into a layer of stable air (inversion) that then becomes unstable from below, resulting in a rapid mixing of pollutants out of the stable layer and towards

[13] EPA. Guideline on Air Quality Models, 40 CFR Part 51, Appendix W.

[14] CARB. Reference Document for California Statewide Modeling Guideline, April 1989.

the ground in the unstable layer underneath. The low mixing height that results from this condition allows little diffusion of the stack plume before it is carried downwind to the ground. Although fumigation conditions are short-term, rarely lasting as long as an hour, relatively high ground-level concentrations may be reached during that period. Fumigation tends to occur under clear skies and light winds, and is more prevalent in summer.

Two types of fumigation are analyzed: inversion breakup and shoreline. Inversion breakup fumigation occurs under low-wind conditions when a rising morning mixing height caps a stack and "fumigates" the air below.

Shoreline fumigation occurs when a roughness boundary (generally a beach) causes turbulent dispersion to be much more enhanced near the ground, once again fumigating the air below. For shoreline fumigation, the lens-shape of the wedge of turbulent air rising from the beach is governed by several factors. SCREEN3 modeling was performed to evaluate shoreline fumigation associated with the Amended CECP following the methodology provided by EPA.[15]

The basic model equation used in this analysis assumes that the concentrations of emissions within a plume can be characterized by a Gaussian (statistical) distribution around the centerline of the plume. Concentrations at any location downwind of a point source such as a stack can be determined from the following equation:

$$C(x,y,z,H) = \left(\frac{Q}{2\pi\sigma_y\sigma_z u}\right) * \left(e^{-1/2(y/\sigma_y)^2}\right) * \left[\left\{e^{-1/2(z-H/\sigma_z)^2}\right\} + \left\{e^{-1/2(z+H/\sigma_z)^2}\right\}\right] \quad \text{(Eq. 1)}$$

where

C	=	pollutant concentration in the air
Q	=	pollutant emission rate
$\sigma_y\sigma_z$	=	horizontal and vertical dispersion coefficients, respectively, at downwind distance x
u	=	wind speed at the height of the plume center
x,y,z	=	variables that define the downwind, crosswind, and vertical distances from the center of the base of the stack in the model's three-dimensional Cartesian coordinate system
H	=	the height of the plume above the stack base (the sum of the height of the stack and the vertical distance that the plume rises due to the momentum and thermal buoyancy of the plume)

Gaussian dispersion models are approved by EPA for regulatory use and are based on conservative assumptions (i.e., the models tend to overpredict actual impacts by assuming steady-state conditions, no pollutant loss [through conservation of mass], no chemical reactions). The EPA models were used to determine if ambient air quality standards would be exceeded, and whether a more accurate and sophisticated modeling procedure would be warranted to make the impact determination. The following sections describe:

- Gas turbine screening modeling;
- Refined air quality impact analysis;
- Specialized modeling analyses;
- Results of the ambient air quality modeling analyses; and
- PSD significance levels.

[15] EPA, "Screening Procedures for Estimating the Air Quality Impact of Stationary Sources, Revised", 1992b.

Modeling for the Amended CECP was performed in accordance with the modeling protocol submitted to the SDAPCD and CEC. The SDACPD reviewed this protocol and made the following recommendations, which were incorporated into the modeling analysis performed for the CECP:

- Rather than a NO_2/NOx ratio of 10%, use NO_2/NOx ratios of 18% and 14% for the emergency fire pump engine and the emergency generator engine, respectfully (based on District test data);
- Rather than a 30-meter resolution, use U.S. Geological Survey National Elevation Dataset data at a horizontal resolution of 1/3 arc-second (approximately 10 meters); and
- Within 100 meters of points of potential maximum impacts, include an additional receptor grid with a resolution of 10 meters.

The modeling procedures used for each type of modeling analysis are described in more detail in the following sections.

Two different EPA guideline models were used for different meteorological conditions in the ambient air quality impact analysis: AERMOD[16] and SCREEN3.

The EPA-approved AERMOD model was used to evaluate impacts in simple, intermediate, and complex terrain. AERMOD is a Gaussian dispersion model capable of assessing impacts from a variety of source types in areas of simple, intermediate, and complex terrain. The model can account for settling and dry deposition of particulates; area, line, and volume source types; downwash effects; and gradual plume rise as a function of downwind distance. The model is capable of estimating concentrations for a wide range of averaging times (from 1 hour to 1 year), and was applied with 5 years of actual meteorological data recorded at the Camp Pendleton monitoring station.

The SCREEN3 model was used to evaluate gas turbine impacts under inversion breakup and shoreline fumigation conditions because these are special cases of meteorological conditions. The SCREEN3 model uses a range of meteorological conditions that could occur under inversion breakup and shoreline fumigation. Since the emissions from the emergency engines are so small compared to the gas turbine emissions, they are excluded from this single-source model used for the fumigation analysis. The fumigation analysis is discussed in more detail below.

Gas Turbine Screening Modeling

The screening and refined air quality impact analyses were performed using the AERMOD model. The screening modeling is performed to determine the combination of ambient temperature and gas turbine operating conditions that generates the highest ambient air quality levels for each pollutant and averaging period. The refined modeling uses the stack parameters that the screening-level modeling shows produced the highest ambient impacts (for each pollutant and averaging period).

Inputs required by AERMOD include the following:

- Model options
- Meteorological data
- Source data
- Receptor data

Standard AERMOD control parameters were used, including stack tip downwash, non-screening mode, non-flat terrain, and sequential meteorological data check. Stack-tip downwash, which adjusts the effective stack height downward following the methods of Briggs (1972) for cases where the stack exit velocity is less than 1.5 times the wind speed at stack top, were selected per EPA guidance. As approved by the District during its review of the modeling plan (see Appendix 5.1D), the rural default option was used by not invoking the

[16] The acronym AERMOD was derived from American Meteorological Society/Environmental Protection Agency Regulatory Model.

URBANOPT option.[17] The use of the rural default in modeling for the Amended CECP is consistent with District policy and guidance (SDAPCD, 1996) for past modeling using at this site.

The required emission source data inputs to both models used in this analysis include source locations, source elevations, stack heights, stack diameters, stack exit temperatures and velocities, and emission rates. The source locations are specified for a Cartesian (x,y) coordinate system where x and y are distances east and north in meters, respectively. The Cartesian coordinate system used is the Universal Transverse Mercator Projection (UTM). The stack height that can be used in the model is limited by federal Good Engineering Practice (GEP) stack height restrictions, discussed in more detail below. In addition, Building Profile Input Program – Plume Rise Model Enhancements (BPIP-PRIME, current version 04274) requires nearby building dimension data to calculate the impacts of building downwash.

For the purposes of modeling, a stack height beyond what is required by GEP is not allowed. However, this requirement does not place a limit on the actual constructed height of a stack. GEP as used in modeling is the height necessary to assure that emissions from the stack do not result in excessive concentrations of any air pollutant in the immediate vicinity of the source as a result of atmospheric downwash, eddies, or wakes that may be created by the source itself, nearby structures, or nearby terrain obstacles. In addition, the GEP modeling restriction assures that any required regulatory control measure is not compromised by the effect of that portion of the stack that exceeds the GEP. EPA guidance (EPA, 1985) for determining GEP stack height indicates that GEP is the greater of 65 meters or H_g, where H_g is calculated as follows:

$$H_g = H + 1.5L$$

where:

H_g = Good Engineering Practice stack height, measured from the ground-level elevation at the base of the stack

H = height of nearby structure(s) measured from the ground-level elevation at the base of the stack

L = lesser dimension, height or maximum projected width, of nearby structure(s)

In using this equation, the guidance document indicates that both the height and width of the structure are determined from the frontal area of the structure, projected onto a plane perpendicular to the direction of the wind.

For the new gas turbine stacks, the nearby (influencing) structures are the inlet air filter housings for the new units, which are 47.5 feet (14.5 m) high, 44.7 feet (13.6 m) long and 40.5 feet (12.3 m) wide. Thus H = L = 47.5 feet, and H_g = 2.5 * 47.5 = 119 feet (36.2 m). Since H_g is less than 65 m, the GEP stack height is 65 m. The proposed stack height of 90 feet (27.4 m) does not exceed GEP stack height of 65 m, and consequently satisfies the EPA requirement.

For regulatory applications, a building is considered sufficiently close to a stack to cause wake effects when the downwind distance between the stack and the nearest part of the building is less than or equal to five times the lesser of the height or the projected width of the building. Building dimensions for the buildings analyzed as downwash structures were obtained from plot plans. The building dimensions were analyzed using the BPIP-PRIME to calculate 36 wind-direction-specific building heights and projected building widths for use in building wake calculations. The building dimensions used in the GEP analysis are shown in Appendix 5.1E.

Screening Procedures and Unit Impact Modeling

Screening modeling was performed to select the worst-case gas turbine operating mode for each pollutant and averaging period. The modeling used emissions data based on an annual average temperature (60°F),

[17] The rural vs. urban option in AERMOD is primarily designed to set the fraction of incident heat flux that is transferred into the atmosphere. This fraction becomes important in urban areas having an appreciable "urban heat island" effect due to a large presence of land covered by concrete, asphalt, and buildings. This situation does not exist for the Amended CECP site.

maximum temperature (96°F), and minimum temperature (44°F), and at nominal minimum and maximum gas turbine operating load points of 25% and 100%. The determination of the worst-case gas turbine operating condition depends on how changes in emissions rates and stack characteristics (plume rise characteristics) interact with terrain features. For example, lower mass emissions resulting from lower load operations may cause higher concentrations than other operating conditions because lower final plume height may have a greater significant interaction with terrain features.

Initial AERMOD modeling runs were performed using normalized emission rates to assess the zone of impact and relative magnitude of the impacts. For the AERMOD gas turbine screening modeling, each gas turbine was modeled with a unit emission rate of 1 gram per second to obtain maximum 1-hour, 3-hour, 8-hour, 24-hour, and annual average concentration to emission rate (χ/Q in units of $\mu g/m^3$ per g/s) values. These χ/Q values were multiplied by the actual emission rate in grams per second from the gas turbine to calculate ambient impacts for NO_2, CO, SO_2, and $PM_{10}/PM_{2.5}$ in units of $\mu g/m^3$. Stack characteristics used in the screening modeling analysis are shown in Appendix 5.1E.

The results of the screening analysis are shown in Appendix 5.1E. The stack parameters and emission rates corresponding to the operating case that produced the maximum impacts in the gas turbine screening analysis for each pollutant and averaging period were used in the refined modeling analysis to evaluate the impacts of the new units. For the unit impacts analysis, the CEC staff's recommendation regarding receptor grid spacing has been followed.[18]

Refined Air Quality Impact Analysis

In simple, intermediate, and complex terrain, AERMOD was used to estimate project-related impacts. The AERMOD model was used to calculate 1-hour, 3-hour, 8-hour, 24-hour, and annual average concentrations.

Refined modeling was performed in two phases: coarse grid modeling and fine grid modeling. Preliminary modeling was performed with the coarse grid to locate the areas of maximum concentration. Fine grids were used to refine the location of the maximum concentrations.

The stack parameters and emission rates used to model combined impacts from all new equipment at the facility are shown in Appendix 5.1E. The model receptor grids were derived from U.S. Geological Survey 10-meter Digitized Elevation Map (DEM) data. CEC guidance was used to locate receptors.

A 250-meter resolution coarse receptor grid was developed and extended outwards at least 10 km. In addition, a nested grid was developed to fully represent the maximum impact area(s). The receptor grid was constructed as follows:

1. One row of receptors spaced 25 meters apart along the facility's fence line;
2. Four tiers of receptors spaced 25 meters apart, extending 100 meters from the fence line;
3. Additional tiers of receptors spaced 100 meters apart, extending from 100 meters to 1,000 meters from the fenceline; and
4. Additional tiers of receptors spaced 250 meters apart, out to at least 10 km from the most distant source modeled, not to exceed 50 km from the project site.
5. Additional refined receptor grids with 25-meter resolution were placed around the maximum first-high or maximum second-high coarse grid impacts and extended out 1,000 meters in all directions. In addition, refined receptor grids with 10-meter resolution were placed around the maximum first-high coarse grid impacts extending out 100 meters in all directions. Concentrations within the facility fenceline were not calculated.

[18] 25-meter resolution along the facility fenceline to 100 meters from the fenceline; 100 meter resolution from 100 meters to 1,000 meters from the fenceline; and 250-meter spacing out to at least 10 km from the site.

Terrain features were taken from the U.S. Geological Survey National Elevation Dataset (NED). The regions imported into the NED database are bounded by the following coordinates:

- South West corner: UTM Zone 11 (NAD 83) 465,500.0 m, 3,654,200.0 m; and
- North East corner: UTM Zone 11 (NAD 83) 483,000.0 m, 3,678,200.0 m.

These terrain data are included in the modeling DVD submitted to the SDAPCD and CEC as part of the PTA for the Amended CECP.

5.1.4.3.2 Specialized Modeling Analyses

Fumigation Modeling

Fumigation occurs when a stable layer of air lies a short distance above the release point of a plume and unstable air lies below. Under these conditions, an exhaust plume may cause high ground-level pollutant concentrations because the plume is unable to rise upwards normally due to the stable layer capping it from above, and be drawn to the ground by turbulence within the unstable layer. Although fumigation conditions rarely last as long as one hour, relatively high ground-level concentrations may be reached during that time. For this analysis, fumigation was assumed to occur for up to 90 minutes as required by EPA guidance.

The SCREEN3 model was used to evaluate maximum ground-level concentrations for short-term averaging periods (24 hours or less). Guidance from the EPA (EPA, 1992) was followed in evaluating fumigation impacts. This analysis is shown in more detail in Appendix 5.1E.

Shoreline Fumigation Modeling

Because land surfaces tend to both heat and cool more rapidly than water, shoreline fumigation tends to occur on sunny days when the denser cooler air over water displaces the warmer, lighter air over land. During an inland sea breeze, the unstable air over land gradually increases in depth with inland distance. The boundary between stable air over the water and unstable air over the land and the wind speed determine whether the plume will loop down before much dispersion of the pollutants has occurred.

SCREEN3 can examine sources within 3,000 meters of a large body of water, and was used to calculate the maximum shoreline fumigation impact. The model uses a stable onshore flow and a wind speed of 2.5 meters per second; the maximum ground-level shoreline fumigation concentration is assumed by the model to occur where the top of the stable plume intersects the top of the well-mixed thermal inversion boundary layer (TIBL). The model TIBL height was varied between 2 and 6 to determine the highest shoreline fumigation impact. The worst-case (highest) impact was used in determining facility impacts due to shoreline fumigation. Shoreline breakup fumigation was assumed to persist for up to 3 hours. The shoreline fumigation analysis is shown in more detail in Appendix 5.1E.

Gas Turbine Startup

Facility impacts were also evaluated during simultaneous startup of the six new gas turbines to evaluate short-term impacts under worst-case startup emissions. Gas turbine exhaust parameters used to characterize gas turbine exhaust during startup and the CO and NO_x emission rates are shown in Appendix 5.1E.

Ozone Limiting

1-hour NO_2 impacts during project operation were modeled using the Ozone Limiting Method (OLM) (Cole and Summerhays, 1979), implemented through the "OLMGROUP ALL" option in AERMOD (EPA, 2011a). AERMOD OLM was used to calculate the NO_2 concentration based on the OLM method and hourly ozone data. Hourly ozone data collected at the Camp Pendleton monitoring station during the years 2008-2012 were used in conjunction with OLM to calculate hourly NO_2 concentrations from hourly NOx concentrations.

Part of the NOx in the exhaust is converted to NO_2 during and immediately after combustion. The remaining percentage of the NOx emissions is assumed to be NO. For the new gas turbines, and as required by the SDAPCD, the analysis was performed using the following NO_2/NOx ratios:

- 13% during normal operating hours;
- 24% during hours in which a startup/shutdown occurs; and
- 24% during commissioning tests when the SCR system is not fully operational.

As approved by the SDAPCD, NO_2/NOx ratios of 18% and 14% were used for the diesel emergency fire pump and generator engines, respectfully.

As the exhaust leaves the stack and mixes with the ambient air, the NO reacts with ambient ozone (O_3) to form NO_2 and molecular oxygen (O_2). The OLM assumes that at any given receptor location, the amount of NO that is converted to NO_2 by this oxidation reaction is proportional to the ambient O_3 concentration. If the O_3 concentration is less than the NO concentration, the amount of NO_2 formed by this reaction is limited. However, if the O_3 concentration is greater than or equal to the NO concentration, all of the NO is assumed to be converted to NO_2.

Annual NO_2 concentrations were calculated using the Ambient Ratio Method (ARM), originally adopted in Supplement C to the Guideline on Air Quality Models (EPA, 1995) with a revision issued by EPA in March 2011. The Guideline allows a nationwide default of 80% for the conversion of nitric oxide (NO) to NO_2 on an annual basis and the calculation of NO_2/NOx ratios. This nationwide default conversion factor was used to model annual NO_2 impacts for the CECP.

Gas Turbine Commissioning

Gas turbine commissioning is the process of initial startup, tuning, and adjustment of the new CTGs and auxiliary equipment and of the emission control systems. The commissioning process for Amended CECP will consist of sequential test operation of each of the six gas turbines up through increasing load levels, and with successive application of the air pollution control systems. The total set of commissioning tests will require approximately 213 operating hours for each gas turbine with a total of approximately four calendar months required to complete the commissioning tests of the six new units. The detailed gas turbine commissioning schedule is included in Appendix 5.1B. While the total commissioning period for each gas turbine is expected to occur over a period of approximately 213 hours, because the gas turbine vendor requires 300 hours of equipment operation prior to the initial VOC/PM_{10} compliance test, in the permit application submitted to the SDAPCD the Applicant will be requesting that the District allow 300 hours of gas turbine operation prior to the initial VOC/PM_{10} compliance tests.

While it may not be possible to perform the commissioning tests on all six new units simultaneously due to several factors, including electrical interconnections and availability of commissioning crews, for the commissioning air quality modeling analysis it is assumed that all six new CTGs undergo commissioning simultaneously. During the commissioning phase of the Amended CECP, the existing boilers Units 1–5 and the peaking turbine at the EPS will remain available for operation and the commissioning modeling analysis accounts for the combined impacts for the new units (undergoing commissioning) and operation of the existing units. Once the commissioning tests are complete and the new CTGs are available for commercial operation, the existing EPS units will no longer be operated and will be removed from service.

Impacts during Normal Operation. Table 5.1-29 summarizes the maximum impacts during the normal operation of Amended CECP, calculated from the refined, startup/shutdown and fumigation modeling analyses described above.

Impacts During Gas Turbine Commissioning. During the gas turbine commissioning phase, NO_2 and CO impacts may be higher than under the operating conditions evaluated above. The commissioning period is comprised of various equipment tests. These tests and the associated emissions are summarized in Appendix 5.1B.

It is assumed that the maximum modeled impacts during commissioning will occur under the gas turbine operating conditions that are least favorable for dispersion. These conditions are expected to occur under low-load conditions.

As discussed above, during the commissioning of the new units it may be necessary to operate existing Units 1–5 and the existing peaking gas turbine. Therefore, the commissioning modeling analysis analyzed the combined impacts for the simultaneous commissioning of the six new units and the continued operation of the existing units. Emission rates and stack parameters for the new and existing units during the commissioning period are shown in Appendix 5.1E. Modeled short-term impacts (1-hour, 8-hour, and 24-hour average) during the commissioning period are summarized further below in Table 5.1-32. While SOx and PM_{10}/$PM_{2.5}$ emissions during the commissioning of the new gas turbines are not expected to be higher than during normal operation of these units, SO_2 and PM_{10}/$PM_{2.5}$ impacts are included in Table 5.1-32 to show the combined short-term impacts for the new/existing units.

Ambient Air Quality Impacts from the Proposed Project

To determine a project's air quality impacts, the modeled concentrations are added to the maximum background ambient air concentrations and then compared to the applicable ambient air quality standards. As discussed previously, the background PM_{10}/$PM_{2.5}$/and CO data were collected at the Escondido monitoring site (approximately 24 km from project site). The background NO_2 data was collected at the Camp Pendleton monitoring site (approximately 10 km from project site), and the background SO_2 data was collected at the San Diego-Beardsley Street monitoring site (approximately 50 km from project site). Because these are the nearest ambient monitoring stations to the project site, the data collected at these stations are considered representative of ambient concentrations in the vicinity of the Amended CECP.

TABLE 5.1-29
Normal Operation Air Quality Modeling Results for New Equipment

		Modeled Maximum Concentrations (µg/m³)			
Pollutant	**Averaging Time**	**Normal Operations AERMOD**	**Startup/Shutdown AERMOD**	**Fumigation SCREEN3**	**Shoreline Fumigation SCREEN3**
Combined Impacts Six Gas Turbines					
NO_2	1-hour	18.5	88.6	4.8	33.9
	98th percentile	12.3	63.5	–	—
	Annual	0.1	[a]	[c]	[c]
SO_2	1-hour	4.7	[b]	1.1	7.8
	3-hour	3.0	[b]	0.9	3.8
	24-hour	0.6	[b]	0.3	0.5
	Annual	0.0	[b]	[c]	[c]
CO	1-hour	20.0	60.3	4.6	32.7
	8-hour	7.2	20.7	2.6	6.2
$PM_{2.5}$/PM_{10}	24-hour	1.5	[b]	0.9	1.4
	Annual	0.04	[b]	[c]	[c]
Emergency Fire Pump Engine					
NO_2	1-hour	64.8	[d]	[e]	[e]
	98th percentile	63.4	[d]	[e]	[e]
	Annual	0.0	[d]	[e]	[e]
SO_2	1-hour	0.1	[d]	[e]	[e]
	3-hour	0.1	[d]	[e]	[e]
	24-hour	0.0	[d]	[e]	[e]
	Annual	0.0	[d]	[e]	[e]

TABLE 5.1-29
Normal Operation Air Quality Modeling Results for New Equipment

		Modeled Maximum Concentrations (µg/m³)			
Pollutant	**Averaging Time**	**Normal Operations AERMOD**	**Startup/Shutdown AERMOD**	**Fumigation SCREEN3**	**Shoreline Fumigation SCREEN3**
CO	1-hour	19.4	d	e	e
	8-hour	2.1	d	e	e
$PM_{2.5}$/PM_{10}	24-hour	0.1	d	e	e
	Annual	0.01	d	e	e
Emergency Generator Engine					
NO_2	1-hour	25.8	d	e	e
	98th percentile	19.6	d	e	e
	Annual	0.0	d	e	e
SO_2	1-hour	0.1	d	e	e
	3-hour	0.0	d	e	e
	24-hour	0.0	d	e	e
	Annual	0.0	d	e	e
CO	1-hour	4.2	d	e	e
	8-hour	0.3	d	e	e
$PM_{2.5}$/PM_{10}	24-hour	0.0	d	e	e
	Annual	0.00	d	e	e
Combined Impacts New Equipment					
NO_2	1-hour	64.8	f	f	f
	98th percentile	63.4	f	f	f
	Annual	0.2	f	f	f
SO_2	1-hour	4.7	f	f	f
	3-hour	3.0	f	f	f
	24-hour	0.6	f	f	f
	Annual	0.0	f	f	f
CO	1-hour	20.0	f	f	f
	8-hour	7.2	f	f	f
$PM_{2.5}$/PM_{10}	24-hour	1.5	f	f	f
	Annual	0.04	f	f	f

[a]Not applicable, because startup/shutdown emissions are included in the modeling for annual average.

[b]Not applicable, because emissions are not elevated above normal operation levels during startups/shutdowns.

[c]Not applicable, because inversion breakup is a short-term phenomenon and as such is evaluated only for short-term averaging periods.

[d]Not applicable, because engine will not operate during gas turbine startups/shutdowns.

[e]Not applicable, this type of modeling is not performed for small combustion sources with relatively short stacks.

[f]Impacts are the same as shown for gas turbines.

Table 5.1-30 presents the maximum concentrations of NO_2, CO, SO_2, PM_{10}, and $PM_{2.5}$ recorded between 2010 and 2012 from representative nearby monitoring stations, as required by Appendix B(g)(8)(G) of the CEC guidelines.

TABLE 5.1-30
Maximum Background Concentrations[a], Project Area, 2010–2012 (μg/m³)

Pollutant	Averaging Time	2010	2011	2012
NO_2 (Camp Pendleton)	1-hour	**152.4**	124.2	114.8
	Fed. 1-hour[c]	**105.3**	95.3	89.6
	Annual	**16.9**	*	15.1
SO_2 (San Diego)	1-hour	21.0	**34.1**	*
	Fed. 1-hour[d]	**35.8**	25.3	*
	24-hour	**7.9**	7.9	*
	Annual[b]	**7.9 (2009)**	2.6 (2010)	0.0 (2011)
CO (Escondido)	1-hour	4,468	4,009	**5,040**
	8-hour	2,818	2,635	**4,238**
PM_{10} (Escondido)	24-hour	**43**	40	33
	Annual	**22.8**	21.5	19.3
$PM_{2.5}$ (Escondido)	24-hour[e]	*	**26**	25
	Annual	12.7	**13.2**	10.8

Note: Reported values have been rounded to the nearest tenth of a μg/m³ except for PM_{10} which were already rounded to the nearest integer.

*There were insufficient data to determine the values.

[a]With the exception of federal 1-hr NO_2, federal 1-hr SO_2, and 24-hr $PM_{2.5}$, bolded values are the highest during the three years and are used to represent background concentrations.

[b]There were insufficient data to determine annual SO_2 for 2011 and 2012. Maximum 24-hour SO_2 values from 2009 to 2010 are presented in this table to represent "maximum" background concentrations.

[c]Federal 1-hour NO_2 is shown as the 3-year average 98th percentile, as that is the basis of the federal standard.

[d]Federal 1-hour SO_2 is shown as the 3-year average 99th percentile, as that is the basis of the federal standard.

[e]24-hour average $PM_{2.5}$ concentrations shown are 3-year average 98th percentile values, rather than highest values, because compliance with the ambient air quality standards is based on 98th percentile readings. Since the ambient standard is based on a 3-year average of the 98th percentile readings.

Source: CARB, 2014b and EPA, 2014.

The maximum modeled concentrations during normal operation shown in Table 5.1-29 are combined with the maximum background ambient concentrations in Table 5.1-30 and compared with the state and federal ambient air quality standards in Table 5.1-31. In Table 5.1-32, the maximum modeled concentrations during the commissioning period are compared with state and federal ambient air quality standards. Using the conservative assumptions described earlier, during normal operation the results indicate that the Amended CECP will not cause or contribute to violations of state or federal air quality standards, with the exception of the annual state PM_{10}/$PM_{2.5}$ standards and annual federal $PM_{2.5}$ standard. For these pollutants and averaging periods, existing background concentrations already exceed state/federal standards.

During commissioning activities the results indicate that once again the Amended CECP will not cause or contribute to violations of state or federal air quality standards, with the exception of the annual state PM_{10}/$PM_{2.5}$ standards and annual federal $PM_{2.5}$ standard (existing background concentrations already exceed state/federal standards).

TABLE 5.1-31
Modeled Maximum Proposed Project Impacts (Normal Operation)

Pollutant	Averaging Time	Maximum Project Impact (µg/m³)	Background (µg/m³)	Total Impact (µg/m³)	State Standard (µg/m³)	Federal Standard (µg/m³)
NO_2	1-hour	88.6	152.4	241	339	—
	98th percentile	63.5	105.3[a]	151	—	188
	Annual	0.2	16.9	17	57	100
SO_2	1-hour	7.8	34.1	42	655	—
	99th percentile	7.8	35.8[c]	44	—	196
	24-hour	0.6	7.9	9	105	—
CO	1-hour	60.3	5,040	5,100	23,000	40,000
	8-hour	20.7	4,238	4,259	10,000	10,000
PM_{10}	24-hour	1.5	43	45	50	150
	Annual	0.04	22.8	23	20	—
$PM_{2.5}$	24-hour	1.5	26[b]	28	—	35
	Annual	0.04	13.2	13	12	12

[a]1-hour NO_2 background concentration is shown as the 3-year average of the 98th percentile as that is the basis of the federal standard.

[b]24-hr $PM_{2.5}$ background concentration reflects 3-year average of the 98th percentile values based on form of standard.

[c]1-hr SO_2 background concentration reflects 3-year average of the 99th percentile values based on form of standard.

TABLE 5.1-32
Modeled Maximum Proposed Project Impacts (Commissioning Period)

Pollutant	Averaging Time	Maximum Project Impact[d] (µg/m³)	Background (µg/m³)	Total Impact (µg/m³)	State Standard (µg/m³)	Federal Standard (µg/m³)
NO_2	1-hour	176.9	152.4	329	339	—
	98th percentile	137.6	105.3[a]	152	—	188
SO_2	1-hour	7.6	34.1	42	655	—
	99th percentile	7.6	35.8[c]	43	—	196
	24-hour	1.0	7.9	9	105	—
CO	1-hour	868.9	5,040	5,909	23,000	40,000
	8-hour	297.6	4,238	4,536	10,000	10,000
PM_{10}	24-hour	2.0	43	45	50	150
$PM_{2.5}$	24-hour	2.0	26[b]	28	—	35

[a]1-hour NO_2 background concentration is shown as the 98th percentile as that is the basis of the federal standard.
[b]24-hr $PM_{2.5}$ background concentration reflects 3-year average of the 98th percentile values based on form of standard.
[c]1-hr SO_2 background concentration reflects 3-year average of the 99th percentile values based on form of standard.
dIncludes impacts from existing EPS units.

PSD Significance Levels

The PSD program was established to allow emission increases that do not result in significant deterioration of ambient air quality in areas where criteria pollutants have not exceeded the NAAQS. The net emission increase shown later in Table 5.1-35 shows that although the Amended CECP will be a major source, the net increases resulting from the Amended CECP will trigger PSD review only for GHG emissions due to the shutdown of existing Units 1–5 and the peaking gas turbine. While the Amended CECP will not trigger a PSD review for NO_2, CO, SO_2, PM_{10}, or $PM_{2.5,}$ an analysis was conducted to determine whether the ambient impacts of the Amended CECP exceed the PSD significance thresholds, as these thresholds are generally used as one measure of whether the project's ambient impacts will be significant. Modeled project impacts during normal operation are compared with the PSD significance thresholds in Table 5.1-33 below. As shown in this table, the maximum impacts for the Amended CECP during normal operation are below the PSD significance thresholds with the exception of 1-hour NO_2 and 24-hour $PM_{2.5}$ impacts.

TABLE 5.1-33
Comparison of Maximum Modeled Impacts and PSD Significant Impact Levels

Pollutant	Averaging Time	Significant Impact Level, µg/m³	Maximum Modeled Impact for CECP, µg/m³	Exceed Significant Impact Level?
NO_2	1-Hour	7.5*	88.6	Yes
	Annual	1	0.2	
SO_2	1-Hour	7.8	7.8	No
	3-Hour	25	3.8	
	24-Hour	5	0.6	
	Annual	1	0.0	
CO	1-Hour	2000	60.3	No
	8-Hour	500	20.7	
PM_{10}	24-Hour	5	1.5	No
	Annual	1	0.04	
$PM_{2.5}$	24-Hour	1.2	1.5	Yes
	Annual	0.3	0.04	

*EPA has not yet defined significance levels (SILs) for 1-hour NO_2 and SO_2 impacts. However, EPA has suggested that, until SILs have been promulgated, interim values of 4 ppb (7.5 µg/m³) for NO_2 and 3 ppb (7.8 µg/m³) for SO_2 may be used (EPA, 2010c and EPA, 2010d). These values will be used in this analysis as interim SILs.

5.1.4.4 Screening Health Risk Assessment

A screening health risk assessment (SHRA) was conducted to determine expected impacts on public health of the noncriteria pollutant emissions from the operation of the six gas turbines and emergency engines. The potential health risks and a detailed discussion of the approach used for the screening level risk assessment, including the detailed non-criteria-pollutant calculations, are provided in the Section 5.9, Public Health.

5.1.4.5 Demolition/Construction Impacts Analysis

The demolition/construction of the Amended CECP is scheduled to occur in the following two phases:

- Construction of the new equipment (24-month period); and
- Demolition of the existing EPS (22-month period).

There is no overlap between these two phases. The emissions were calculated for each phase. The demolition/construction emission estimates include emissions from vehicle and equipment exhaust and fugitive dust generated from material handling and paved/unpaved road travel. A dispersion modeling analysis and a screening health risk assessment were conducted based on these emissions. The detailed analysis of the demolition/construction emissions and ambient impacts is included in Appendix 5.1F.

5.1.5 Consistency with Laws, Ordinances, Regulations, and Standards

This section considers consistency separately for federal, state, and local requirements.

5.1.5.1 Consistency with Federal Requirements

The SDAPCD has been delegated authority by the EPA to implement and enforce most federal requirements that may be applicable to the Amended CECP, including new source performance standards and new source review for nonattainment pollutants. The Amended CECP will also be required to comply with the Federal Acid Rain requirements (Title IV). Because the SDAPCD is delegated authority to implement Title IV through its Title V permit program, the modified Title V Federal Operating Permit that will be issued as a result of the Amended CECP will include the necessary requirements for compliance with the Title IV Acid Rain provisions. In addition, the SDAPCD is in the processing of obtaining delegation from the EPA to implement the PSD program. Depending on the timing on the final PSD delegation to the SDAPCD, it may be necessary to submit a PSD permit application to EPA Region 9.

5.1.5.1.1 PSD Program

EPA has promulgated PSD regulations for areas that are in compliance with national ambient air quality standards (40 CFR 52.21). The PSD program allows new sources of air pollution to be constructed, or existing sources to be modified, while preserving the existing ambient air quality levels, protecting public health and welfare, and protecting Class I areas (e.g., specific national parks and wilderness areas). There are five principal areas of the PSD program: (1) Applicability; (2) Best Available Control Technology; (3) Preconstruction Monitoring; (4) Increments Analysis; and (5) Air Quality Impact Analysis. Although issuance of the PSD permit will be the responsibility of either the SDAPCD or EPA Region 9 (depending on the timing for PSD delegation to the SDAPCD), the protection of Class I areas is still the responsibility of the Federal Land Managers.

The federal 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 stationary source. (These terms are defined in federal regulations.) (40 CFR 52.21) Since the EPS is an existing major source, the determination of applicability is based on evaluating the emissions changes associated with the Amended CECP in addition to all other emissions changes at the facility over a 5-year lookback period. In Table 5.1-34, the net emission changes at the EPS, based on the emissions from the new Amended CECP equipment and the shutdown of the existing EPS units, are compared to the regulatory significance thresholds. As shown in this table, the net emission changes associated with the Amended CECP are below these significance thresholds for all pollutants with the exception of GHG, and thus the Amended CECP is subject to PSD review only for GHG emissions. While the PSD regulations include several requirements, including controlling PSD pollutants with BACT, ambient air quality modeling, visibility impact analyses, and ambient monitoring requirements, the only PSD requirement applicable to GHG emissions is the requirement to use BACT for GHG emissions. As discussed in the detailed BACT analysis included in Appendix 5.1C, the Amended CECP will meet GHG BACT requirements with the use of high efficient simple-cycle gas turbines.

TABLE 5.1-34
Net Emission Change and PSD Applicability

Pollutant	Facility Net Increase (tpy)	PSD Significance Levels (tpy)	Are Increases Significant?
NOx	26.4	40	No
SO_2	2.2	40	No
VOC	-7.4	N/A*	N/A*
CO	-101.5	100	No
PM_{10}	-14.6	15	No
$PM_{2.5}$	-14.6	10	No
GHG	257,844	75,000	Yes

*Because the project area is classified as a federal nonattainment for ozone, this pollutant is not subject to the PSD regulations.

5.1.5.2 Consistency with State Requirements

As discussed in Section 5.1.3.1.2, state law set up local air pollution control districts and air quality management districts with the principal responsibility for regulating emissions from stationary sources. The CECP is under the local jurisdiction of the SDAPCD; therefore, compliance with District regulations will assure compliance with state air quality requirements.

5.1.5.3 Consistency with Local Requirements: SDAPCD

The SDAPCD has been delegated responsibility for implementing local, state, and federal air quality regulations in the San Diego Air Basin. The Amended CECP is subject to District regulations that apply to new stationary sources, to the prohibitory regulations that specify emission standards for individual equipment categories, and to the requirements for evaluation of impacts from non-criteria pollutants. The following sections evaluate facility compliance with applicable District requirements.

5.1.5.3.1 New Source Review Requirements

Under the regulations that govern new sources of emissions, the Amended CECP is required to secure a preconstruction Determination of Compliance from the SDAPCD, as well as demonstrate continued compliance with regulatory limits when the new equipment becomes operational. The preconstruction review includes demonstrating that subject new equipment will use BACT, will provide any necessary emission offsets, and will perform an ambient air quality impact analysis. The requirements of each of these elements of the SDAPCD's new source review program are discussed below.

Best Available Control Technology

BACT must be applied to a new or modified emissions unit resulting in an emissions increase exceeding SDAPCD BACT threshold levels. In Table 5.1-35, the maximum daily emissions from each gas turbine and each emergency engine are compared with the BACT thresholds. As shown in this table, the CTGs are subject to BACT for NOx, VOC, SOx, and PM_{10}. However, emissions for the emergency engines are below the BACT trigger levels, so the engines are not required to use BACT.

TABLE 5.1-35
SDAPCD BACT Emission Thresholds

Pollutant	BACT Threshold (lbs/day)	Each CTG (lbs/day)	Fire Pump Engine (lbs/day)	Generator Engine (lbs/day)
PM_{10}	10	84.0	0.0	0.0
NO_x	10	254.4	0.5	1.2
SO_x	10	49.7	0.0	0.0
VOC	10	71.3	0.0	0.0

*SDAPCD Rule 20.3 does not include a BACT requirement for CO.

BACT for the applicable pollutants was determined by reviewing a number of BACT guideline documents, including the SDAPCD BACT Guidance, the South Coast Air Quality Management District BACT Guideline Manual, and the EPA's RACT/BACT/LAER Clearinghouse. The detailed BACT analysis is included in Appendix 5.1C. As discussed in this analysis, the Amended CECP gas turbines will comply with BACT using the following measures.

- BACT for NOx emissions from the gas turbine will be the use of low-NOx emitting equipment and add-on controls. The Amended CECP will use water injection and SCR to reduce NOx emissions to 2.5 ppmvd NOx, corrected to 15 percent O_2 (ppmc).
- BACT for CO emissions will be achieved by using good combustion practices and an oxidation catalyst to achieve CO emissions of 4.0 ppmc.

- BACT for VOC emissions will be achieved by use of good combustion practices in the gas turbines to achieve VOC emissions of 2.0 ppmc.
- BACT for PM_{10} and SOx is best combustion practices and the use of natural gas. The proposed CTGs will burn exclusively PUC-regulated natural gas with a maximum short-term sulfur content of 0.75 grains per 100 scf (gr/100 scf), and an annual average level of 0.25 gr/100 scf.

Emission Offsets

Because the EPS is an existing major facility, emission offsets are required for net emission increases that occur at the facility above SDAPCD offset threshold levels. Emission offsets are required only for federal nonattainment pollutants. Since the District is classified as a federal nonattainment area for ozone, the pollutants regulated under the emission offset section of the District new source review program are the ozone precursors NOx and VOC. As shown in Table 5.1-36, the net increase in VOC emissions associated with the installation of the new equipment and shutdown of existing units is below the emission offset trigger level. Therefore, the Amended CECP does not trigger the SDAPCD emission offset requirement for this pollutant. However, the net increase in NOx emissions is above the offset trigger level and as for the Licensed Project, NOx emission offsets must be provided for this pollutant. The detailed NOx emission offset calculations are included in Appendix 5.1B. As shown by these calculations, 31.7 tpy of NOx emission offset credits must be provided for the Proposed Project. As shown in the list included in Appendix 5.1G, the Applicant has obtained the necessary amount emission offsets (in the form of emission offset credits). These emission offsets credits will be surrendered to the SDAPCD prior to the initial operation of the new units.

TABLE 5.1-36
SDAPCD Nonattainment Pollutant Emission Offset Thresholds (tpy)

Pollutant	Emission Offset Trigger Level*	Facility Net Emission Change	Emission Offsets Required?
NOx	25	26.4	Yes
VOC	25	-7.4	No

*SDAPCD Rule 20.1, Table 20.1-5.

Air Quality Impact Analysis

Under the SDAPCD new source review regulations, an air quality impact analysis must be performed if new or modified emission units result in emission increases above specific trigger levels. This analysis must confirm that the above emission increases will not interfere with the attainment or maintenance of an applicable ambient air quality standard or cause additional violations of a standard anywhere the standard is already exceeded. As shown in Table 5.1-37, the emissions for the new equipment are above the air quality impact analysis trigger levels for NOx, CO, PM_{10}, and SOx. Consequently, an air quality impact analysis must be performed for these pollutants. The modeling analyses presented in Section 5.1.4.3 show that the Amended CECP will not interfere with the attainment or maintenance of the applicable air quality standards or cause additional violations of any standards.

TABLE 5.1-37
Air Quality Impact Analysis Trigger Levels

Pollutant	Emissions for New Equipment[a]	Trigger Level[b]	AQIA Required?
Hourly Emissions			
NOx	169 lbs/hr	25 lbs/hr	Yes
CO	104 lbs/hr	100 lbs/hr	Yes
PM_{10}	N/A	N/A	N/A
SOx	12 lbs/hr	25 lbs/hr	No
Daily Emissions			
NOx	1,528 lbs/day	250 lbs/day	Yes
CO	1,393 lbs/day	550 lbs/day	Yes
PM_{10}	504 lbs/day	100 lbs/day	Yes
SOx	298 lbs/day	250 lbs/day	Yes
Annual Emissions			
NOx	85 tpy	40 tpy	Yes
CO	78 tpy	100 tpy	No
PM_{10}	28 tpy	15 tpy	Yes
SOx	6 tpy	40 tpy	No

[a]Normal operating year.
[b]SDAPCD Rule 20.3, Table 20.3-1.

SDAPCD Prohibitory Rules

The general prohibitory rules of the SDAPCD applicable to the Amended CECP are summarized below.

Rule 50 – Visible Emissions. Prohibits visible emissions as dark as, or darker than, Ringelmann No. 1 for periods greater than three minutes in any hour. With the use of natural gas, the Amended CECP is expected to comply with this regulation.

Rule 51 – Nuisance. Prohibits a facility from discharging air pollutants that cause injury, detriment, nuisance, or annoyance to the public, or that damage business or property. The Amended CECP would not emit odorous pollutants, and the screening health risk assessment demonstrated that the potential health risks from the emissions are less than significant.

Rule 52 – Particulate Matter Emission Standards. Prohibits PM emissions in excess of 0.10 grains per dry standard cubic foot (gr/dscf). This rule does not apply to stationary internal combustion engines (including CTGs).

Rule 53 – Combustion Contaminants. Prohibits sulfur emissions, calculated as SO_2, in excess of 0.05% by volume (500 parts per million by volume [ppmv]), and combustion particulate emissions in excess of 0.10 gr/dscf at 12% CO_2. SO_x emissions from the Amended CECP will be below 0.5 ppmv, based on the fuel sulfur content levels of 0.75 gr/100 scf (short-term average) and 0.25 gr/100 scf (long-term average). The maximum particulate emissions for each CTG will be 3.5 lbs/hr. At low loads, the gas turbine exhaust flow rate will be approximately 189,845 dscfm at 3.43% CO_2 (see Appendix 5.1B), resulting in a particulate grain loading of 0.0022 gr/dscf. Corrected to 12% CO_2, this grain loading is 0.0077 gr/dscf at 12% CO_2 and complies with this regulation.

Rule 55 – Fugitive Dust Control. This rule requires control of dust emissions during construction activities and prohibits visible dust emissions beyond the property line for periods aggregating more than 3 minutes in any 60-minute period (also requires minimization of track-out onto public roadways). The proposed mitigation measures during construction of the Amended CECP are discussed in Appendix 5.1F. These mitigation measures will assure compliance with this regulation.

Rule 62 – Sulfur Content of Fuels. Prohibits the burning of gaseous fuel with a sulfur content of more than 10 gr/100 scf and liquid fuel with a sulfur content of more than 0.05% sulfur by weight. The natural gas that would be used in the Amended CECP will have a sulfur content that will be less than 0.75 gr S/100 scf (short-term average) and 0.25 gr S/100 scf (long-term average). The diesel fuel used in the emergency engines will comply with the current CARB fuel sulfur limit of 15 ppm, or 0.0015%, well below the limit of this rule.

Rule 69.3 – Stationary Gas Turbines. This rule limits NOx emissions from stationary gas turbines to 42 ppmv at 15% O_2. The rule does not apply during a startup or shutdown period (not to exceed 120 minutes). The NOx emissions for the Amended CECP gas turbines will be limited to 2.5 ppmc.

Rule 69.3.1 – Stationary Gas Turbines. Limits NOx emissions from stationary gas turbines rated greater than or equal to 10 MW with post-combustion controls to 9 ppmv (at 15% O_2, corrected for efficiency). The NOx emissions from the Amended CECP gas turbines will be limited to 2.5 ppmc.

Rule 69.4.1 – Stationary Reciprocating Internal Combustion Engines. Limits CO, NOx, and VOC emissions from stationary reciprocating internal combustion engines rated greater than or equal to 50 bhp. However, emergency equipment operating less than or equal to 52 hours per year for testing or maintenance purposes and less than or equal to 200 hours per year for any purpose are exempt from the emission limits of Rule 69.4.1. Therefore, with an annual operating limit of 200 hours per year for any purpose, the new emergency engines are exempt from these emission limits.

Rule 1200 – Toxic Air Contaminants. Requires preparation of a health risk assessment and demonstration that the project will not result in unacceptable health risks (cancer risk greater than 10 in a million, chronic health index greater than 1, acute health index greater than 1). As discussed in Section 5.9, Public Health, the Amended CECP will comply with these requirements.

Regulation XIV – Title V Operating Permits. This regulation implements the Title V federal operating permit program discussed above under Federal LORS. An application for a Title V permit modification will be submitted within 12 months of the start of operation of the new equipment.

40 CFR Part 60, Subpart KKKK (Standards of Performance for Stationary Combustion Turbines). This new source performance standard applies to gas turbines with a heat input in excess of 1 MMBtu/hr that commence construction after February 18, 2005, and therefore is applicable to the Amended CECP CTGs. Subpart KKKK limits NOx and SO_2 emissions from new gas turbines with a heat input greater than 850 MMBtu/hr to limits of 15 ppmv at 15% O_2 (ppmc) for NOx and 0.90 lbs/MWh for SOx. As shown in Table 5.1-38, the proposed CTGs at the Amended CECP will comply with these limits.

TABLE 5.1-38
Compliance with 40 CFR 60 Subpart KKKK

	Project Emission Levels			
Pollutant	**ppmc**	**lb/hr**	**lb/MWh**	**Subpart KKKK Limits**
NOx	2.5	—	—	15 ppmc
SOx	—	2.07	0.02	0.90 lb/MWh

Compliance with the NSPS limits must be demonstrated through an initial performance test. Because the Amended CECP gas turbines will be equipped with a NOx continuous emissions monitoring system (CEMS) that will comply with NSPS requirements, the initial performance test will be met as part of the initial NOx CEMS certification testing process and ongoing annual performance testing will not be required under the NSPS.

40 CFR Part 60, Subpart IIII (Standards of Performance for Stationary Compression Ignition Internal Combustion Engines). The new emergency diesel engines will be subject to this NSPS. For engines in this size range, the NSPS requires manufacturers to provide engines that are certified to meet the NSPS emission standards (depending on the year an engine is manufactured). The Amended CECP will comply with the emission limitations of the NSPS by purchasing engines certified to meet the required standards.

The NSPS also requires engines in this size range to use fuel with a sulfur content not to exceed 15 ppm. The new emergency engines will comply with this requirement by using only CARB diesel fuel.

5.1.6 Cumulative Impacts

An analysis of potential cumulative air quality impacts that may result from the Amended CECP and other reasonably foreseeable projects is required by the SDAPCD and the CEC.

5.1.6.1 Criteria Pollutant Cumulative Impacts Analysis

Cumulative air quality impacts from the Amended CECP and other reasonably foreseeable projects will be both regional and localized in nature. Regional air quality impacts are possible for pollutants such as ozone, which is formed through a photochemical process that can take hours to occur, and $PM_{2.5}$, which is a mixture of locally generated pollutants and aerosols formed in the atmosphere. Carbon monoxide, NOx, and SOx impacts are generally localized in the area in which they are emitted. PM_{10} can create a local air quality problem in the vicinity of its emission source, but can also be a regional issue when it is formed in the atmosphere from VOC, SOx, and NOx.

The cumulative impacts analysis considers the potential for both regional and localized impacts due to emissions from proposed operation of Amended CECP. Regional impacts are evaluated by comparing maximum daily and annual emissions from Amended CECP with emissions of ozone and PM precursors in San Diego County. Localized impacts are evaluated by looking at other local sources of pollutants that are not included in the background air quality data to determine whether these sources in combination with Amended CECP would be expected to cause significant cumulative air quality impacts.

5.1.6.1.1 Regional Impacts

Regional impacts are evaluated by assessing the Amended CECP's contribution to regional emissions. Although the relative importance of VOC and NOx emissions in ozone formation differs from region to region and from day to day, reductions in emissions of both precursors are typically necessary to reduce overall ozone levels. The change in the sum of emissions of these pollutants, equally weighted, provides a rough estimate of the impact of the Amended CECP on regional ozone levels. Similarly, a comparison of the emissions of PM_{10} and $PM_{2.5}$ precursor emissions from the Amended CECP with regional PM_{10}/$PM_{2.5}$ precursor emissions provides an estimate of the impact of this project on regional PM_{10}/$PM_{2.5}$ levels.

Table 5.1-39 summarizes these comparisons; detailed calculations for the Amended CECP and the emission reductions for the shutdown of the existing units are shown in Appendix 5.1B. Amended CECP emissions are compared with regional emissions in 2015 (the Amended CECP is expected to begin operation in 2017). San Diego County emissions projections for 2015 were taken from CARB's web-based emission inventory projection software, available at *www.arb.ca.gov/app/emsinv/emssumcat.php.*

The emission reductions for the shutdown of the existing units at the EPS examine a 5-year, 10-year, and 12-year lookback period (12-year lookback starts in 2002, which matches the beginning of the baseline period used for the Licensed CECP permitting process). These comparisons show that the total ozone and PM_{10}/$PM_{2.5}$ precursor emissions reductions from the shutdown of the existing units at the EPS will be larger (with the exception of the 5-year lookback for ozone precursors) than the maximum potential emissions for the Amended CECP. Therefore, the Amended CECP will have an overall positive impact on regional ozone and PM_{10}/$PM_{2.5}$ formation.

TABLE 5.1-39
Comparison of Amended CECP Emissions to Regional Precursor Emissions in 2015: Annual Basis[a]

Ozone Precursors – Annual Basis	
Total San Diego County Ozone Precursors, tpy	98,842
Total CECP Ozone Precursor Emissions, tpy	108
CECP Ozone Precursor Emissions as Percent of Regional Total	0.11%
Reductions from Shutdown of Existing Units (5-Year Lookback), tpy[b]	-66
Reductions from Shutdown of Existing Units (10-Year Lookback), tpy[c]	-123
Reductions from Shutdown of Existing Units (12-Year Lookback), tpy[d]	-152
CECP Net Ozone Precursor Emissions with Shutdown of Existing Units (5-Year Lookback), tpy	42
CECP Net Ozone Precursor Emissions with Shutdown of Existing Units (10-Year Lookback), tpy	-15
CECP Net Ozone Precursor Emissions with Shutdown of Existing Units (12-Year Lookback), tpy	-44
CECP Net Ozone Precursor Emissions as Percent of Regional Total, with Shutdown of Existing Units	Net Benefit
PM_{10}/$PM_{2.5}$ Precursors – Annual Basis	
Total San Diego County PM_{10} Precursors, tpy	145,489
Total San Diego County $PM_{2.5}$ Precursors, tpy	112,822
Total CECP PM_{10}/$PM_{2.5}$ Precursor Emissions, tpy	142
CECP PM_{10} Precursor Emissions as Percent of Regional Total	0.10%
CECP $PM_{2.5}$ Precursor Emissions as Percent of Regional Total	0.13%
Reductions from Shutdown of Existing Units (5-Year Lookback), tpy[b]	-100
Reductions from Shutdown of Existing Units (10-Year Lookback), tpy[c]	-190
Reductions from Shutdown of Existing Units (12-Year Lookback), tpy[d]	-235
CECP Net PM_{10}/$PM_{2.5}$ Precursor Emissions with Boiler Shutdowns (5-Year Lookback), tpy	42
CECP Net PM_{10}/$PM_{2.5}$ Precursor Emissions with Boiler Shutdowns (10-Year Lookback), tpy	-47
CECP Net PM_{10}/$PM_{2.5}$ Precursor Emissions with Boiler Shutdowns (12-Year Lookback), tpy	-92
CECP Net PM_{10}/$PM_{2.5}$ Precursor Emissions as Percent of Regional Total, with Shutdown of Existing Units	Net Benefit

[a]County-wide emissions calculated as 365 times daily emissions.
[b]Based on average emissions during past 5 years (2009 to 2013).
[c]Base on average emissions during past 10 years (2004 to 2013).
[d]Base on average emissions during past 12 years (2002 to 2013).

5.1.6.1.2 Localized Impacts

To evaluate potential cumulative impacts of Amended CECP in combination with other projects in the area, projects within a radius of 6 km of the Amended CECP were examined for the cumulative localized impacts analysis.

Within this search area, three categories of projects with combustion sources were used as criteria for identification:

- Existing projects that have been in operation since at least 2012;
- Projects for which air pollution permits to construct have been issued and/or that began operation after the beginning of 2012; and
- Projects for which air pollution permits to construct have not been issued, but that are reasonably foreseeable.

Existing projects that have been in operation since at least 2012 are reflected in the ambient air quality data that have been used to represent background concentrations for the Amended CECP; consequently, no further analysis of the emissions from this category of facilities was performed.

Projects for which air pollution permits to construct have been issued but that were not operational in 2012 were identified through a request of permit records from the SDAPCD. The SDAPCD performed a search of its permit computer tracking system for permits issued after January 1, 2012, for projects located within six miles of the CECP. This search also included permit application packages the SDAPCD is currently processing for projects located within six miles of the CECP. Enclosed as Appendix 5.1H is a copy of the list of projects provided by the SDAPCD. As shown on this list, other than the EPS there is only one project with CO, NOx, SOx, PM_{10}, or $PM_{2.5}$ emissions above the CEC-established *de minimis* level of 5 tpy: a 212 bhp digester gas fired engine at the CHP Clean Energy LLC facility located in Oceanside, CA (roughly 3.5 miles from the project site). For this facility, the only pollutant with emissions above 5 tpy is CO (maximum emissions of approximately 10 tpy).

As shown previously in Table 5.1-33, the maximum impacts for the Amended CECP remain below the federal significant impact levels (SIL) for CO. The primary purpose of federal SILs is to identify a level of ambient impact that is sufficiently low relative to an ambient air quality standard or increment such that the impact can be considered de minimis. Hence, EPA considers a source whose individual impact falls below a SIL to have a de minimis impact on air quality concentrations that already exist. If a project's impacts are below a federal SIL, these impacts are not considered to cause or contribute to a violation of an ambient air quality standard and/or increment.[19]

Consequently, since Amended CECP's CO impacts are below federal SILs, the Project Owner concludes that the impacts of the Amended CECP will be de minimis and that there is no need to perform a further CEQA cumulative analysis for this pollutant.

The following project are not included in the list of new/future projects provided by the SDAPCD:

- Carlsbad Seawater Desalination Plant
- Vista/Carlsbad Interceptor Agua Hedionda Lift Station
- Interstate 5 North Coast Corridor Project
- Los Angeles to San Diego (LOSSAN) Double-Tracking Project

The proposed Carlsbad Seawater Desalination Plant will be located adjacent to the CECP. According to the Final Environmental Impact Report (EIR) for this project,[20] the equipment associated with operation of the desalination plant includes the desalination plant intake water pump station, pretreatment facilities, reverse osmosis system, product water pump station, membrane cleaning system, chemical feed equipment, solids handling equipment, service facilities (i.e., HVAC, lighting), and the Oceanside pump station. All of this equipment will utilize electric power, will not utilize any combustion or other fuel sources, and will not generate any air emissions during their operation.

The proposed Vista/Carlsbad Interceptor Agua Hedionda Lift Station will also be located adjacent to the CECP. As with the Carlsbad Seawater Desalination Plant, the equipment associated with the Lift Station is expected to be electric powered and will not generate air emissions.

The proposed I-5 North Coast Corridor Project includes proposed improvements to maintain or improve the existing and future traffic operations on the I-5 freeway from La Jolla Village Drive in San Diego to Harbor Drive in Oceanside/Camp Pendleton that is scheduled to occur over approximately a 20-year period. This project was considered during the original permitting of the Licensed CECP and, as summarized below, the CEC concluded that there would not be significant cumulative impacts.[21]

[19] 75 FR 64891: "Accordingly, a source that demonstrates that the projected ambient impact of its proposed emissions increase does not exceed the SIL for that pollutant at a location where a NAAQS or increment violation occurs is not considered to cause or contribute to that violation."

[20] Final EIR for the Poseidon Carlsbad Desalination Project, 12/2005, Section 4.2, page 4.2-17 (http://carlsbaddesal.com/Websites/carlsbaddesal/images/eir/EIR_4_2.pdf).

[21] Commission Decision, Carlsbad Energy Center Project, 07-AFC-06, June 2012, pages 6.2-22 to 6.2-23.

Regarding cumulative operational impacts, the DEIR/DEIS states that the proposed project would reduce particulate emissions compared to the current baseline, and that toxic emissions from freeway traffic would also likely be reduced by the widening project. (DEIR/DEIS, pp. 3.14-6, 3.14-9.) These would be reductions from the current baseline conditions currently included in the Staff's air quality analysis. Moreover, the CECP operation and the I-5 freeway widening impacts will be in different locations due to the different types of emission sources and the relative buoyancy of CECP turbine emissions, which will be dispersed much further downwind. Therefore, significant cumulative impacts from the CECP operation and the I-5 widening project should not occur.

A review of the October 2013 FEIR/EIS for the I-5 North Coast Corridor Project indicates that the project may result in a slight increase in overall PM_{10} emissions (mainly associated with paved road travel fugitive dust emissions) compared to existing baseline levels due to increased traffic volumes. However, there will be an expected decrease in overall $PM_{2.5}$ emissions due to a reduction in Diesel truck exhaust emissions.[22] There will also be an expected decrease in CO ambient impacts[23] and mobile source air toxic (MSAT) pollutants compared to existing baseline conditions.[24] Therefore, with the continued conclusion in the FEIR/EIS that there will generally be a decrease in emissions associated with the I-5 North Coast Corridor Project, there are no expected significant cumulative impacts from the Amended CECP and the I-5 project.

The LOSSAN Double-Tracking Project includes the proposed double-tracking of the main line/bridges, curve realignment, and the addition of crossovers to increase capacity and enhance reliability of the railroad corridor from Los Angeles to San Diego scheduled to occur over approximately a 20-year period. While the Final Program EIR/EIS for the LOSSAN Double-Tracking Project[25] concludes that the project will increase regional rail emissions in San Diego County due to rail traffic increases once the double track is installed (FEIR/EIS, Table 3.3-6), the FEIR/EIS admits that the analysis did not account for the benefits associated with decreases in locomotive idling and/or decreases in automotive idling at crossings due to debottlenecking with the double-track design (FEIR/EIS, page 3.3-19). In addition, the FEIR/EIS admits that the analysis did not account for the benefits associated with the phase-in of the EPA Tier III locomotive engines and did not account for the benefits associated with the SCAQMD Locomotive Fleet Agreement (FEIR/EIS, page 3.3-16). The FEIR/EIS concludes that these benefits would need to be determined as part of project-specific analyses prepared for the LOSSAN project. The double-tracking of the main line that passes by the CECP is referred to as the South Carlsbad Double Track Project. This project includes the double-tracking of a 1.9-mile section of main line from Carlsbad Village southward past Cannon Road and was completed in February 2012.[26] According to a Federal Railroad Administration Categorical Exclusion Worksheet prepared by AMTRAK, the South Carlsbad Double Track Project is not expected to result in any changes that would impact operational air emissions.[27] This determination is based on an air quality impact analysis performed for this project[28] that concludes that the project will result in lower operational NOx, VOC, CO, and PM_{10} emissions due to a reduction in locomotive idling time. Therefore, there are no expected significant cumulative impacts from the Amended CECP and the LOSSAN Double-Tracking Project.

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[22] Interstate 5 North Coast Corridor Project, FEIR/EIS, Section 3.14, page 3.14-18. (http://www.dot.ca.gov/dist11/Env_docs/I-5NCC/Final/i-5_part3_chp3.pdf)

[23] Interstate 5 North Coast Corridor Project, FEIR/EIS, Section 3.14, Table 3.14.6.

[24] Interstate 5 North Coast Corridor Project, FEIR/EIS, Section 3.14, page 3.14-23.

[25] Final Program EIR/EIS for the LOSSAN – Los Angeles to San Diego Proposed Rail Corridor Improvements in the State of California, 09/2007.

[26] http://www.keepsandiegomoving.com/Lossan/lossan-carlsbad-double-track.aspx.

[27] Federal Railroad Administration Categorical Exclusion Worksheet, 12/7/2009, FRA Project ID 20103221, AMTRAK, Section III.G.

[28] Air Quality Impact Analysis for Carlsbad Double Track Project, 11/2/2009, Tom Dodson and Associates, Operational Impacts, pages 23 to 26.

5.1.6.2 Greenhouse Gas Cumulative Impacts Analysis

In the absence of established thresholds of significance or methodologies for assessing impacts, this analysis of GHG emission impacts consists of quantifying project-related GHG emissions, determining their significance in comparison to the goals of AB 32, and discussing the potential impacts of climate change within the state as well as strategies for minimizing those impacts.

As the CEC's 2009 Integrated Energy Policy Report (CEC, December 2009) noted:

> *The Energy Commission's 'Framework for Evaluating Greenhouse Gas Implications of natural Gas-Fired Power Plants in California' found that as California's integrated electricity system evolves to meet GHG emissions reduction targets, the operational characteristics associated with increasing renewable generation will increase the need for flexible generation to maintain grid reliability. The report asserts that natural gas-fired power plants are generally well-suited for this role and that California cannot simply replace all natural gas fired power plants with renewable energy without endangering the safety and reliability of the electric system. The report acknowledges that California will need to modernize its natural gas generating fleet to reduce environmental impacts, however. Overall, the report found that the future of natural gas plants will likely fill five auxiliary roles: 1) intermittent generation support, 2) local capacity requirements, 3) grid operations support, 4) extreme load and system emergencies support, and 5) general energy support. The question remains as to the quantity, type, and location of natural gas-fired generation to fill remaining electricity needs once preferred resource targets are achieved. (p. 110)*

Most renewable energy facilities such as wind and solar are "intermittent resources," meaning these resources are not available to generate in all hours and thus have limited operating capacity. For example, intermittent resources can be limited by meteorological conditions on an hourly, daily, and seasonal basis. Further, most renewable resources have no ability to provide regulation—the ability to ramp up and down quickly at the system operator's direction to ensure electric system reliability. In addition, the availability of intermittent resources is often unrelated to the load profile they serve. For example, some photovoltaic resources reach peak production around 12:00 noon, while the electrical demand sometimes peaks between 5:00 p.m. and 7:00 p.m. "Firming" involves the use of fast-starting, flexible generation that is always available under all operating conditions to ramp up or ramp down, as necessary, to balance load and generation. Firming power is the cornerstone of system reliability. Thus, in the context of the California Environmental Quality Act, the CEC's Integrated Energy Policy Report, and other state GHG policy documents, the project would not be expected to cause a significant cumulative impact with respect to GHGs. Instead, the project supports the State's strategy to reduce fuel use and GHG emissions.

The project can be operated without the limitations affecting intermittent renewable resources. The project will provide fast-starting, flexible generating resources that will supplement and support intermittent renewable resources without affecting electric system reliability. Accordingly, as a fast-starting, flexible generating resource, Amended CECP will enhance the reliability of existing and future intermittent renewable resources and thus further California's Renewable Portfolio Standard (RPS) and GHG goals. As directed by SB 97, the Resources Agency adopted Amendments to the CEQA Guidelines for GHG emissions (GHG CEQA Guidance) on December 30, 2009. On March 18, 2010, those amendments became effective.

The GHG CEQA Guidance included the following elements:

- Quantification of GHG emissions;
- Determination of whether the project may increase or decrease GHG emissions as compared to existing environmental setting;
- Determination of whether the project emissions exceed a threshold of significance determined by the lead agency;

- The extent to which the project complies with state, regional, or local plans for reduction or mitigation of GHGs; and
- Mitigation measures.

Certain GHG reduction strategies will require increases in natural gas consumption; for example, some fraction of electric generation from coal-fired power plants will need to be replaced by natural gas fired generation. As the 2007 Integrated Energy Policy Report (IEPR) and a 2009 CEC Siting Committee Report (CEC, March 2009) acknowledged, "new gas-fired power plants are more efficient than older power plants, and they displace these older facilities in the dispatch order." The CEC's 2009 Framework report (CEC, May 2009) further discussed the role of new gas-fired power plants in displacing GHG emissions, and furthering the State's efforts to reduce GHG emissions. The 2009 Framework report concludes that as California expands renewable energy generation to achieve its GHG emissions reduction goals, it cannot simply retire natural-gas fired power plants: rather, new natural-gas fired power plants may be needed. Net GHG emissions for the integrated electric system will decline when new gas-fired power plants are added that (1) serve load growth or capacity needs more efficiently than the existing fleet; (2) improve the overall efficiency of the electric system; and/or (3) permit increased penetration of renewable generation (CEC, May 2009). Because of its location and operational characteristics, Amended CECP will contribute to the reduction of GHG emissions because it will achieve all of these goals.

In the Presiding Member's Proposed Decision for the Avenal Energy Project (CEC-800-2009 006-PMPD), the Committee has established a three-part test to ensure that new natural gas fired power plants approved by the CEC will support the goals and policies of AB 32 and the related parts of California's GHG framework. The elements of this test are listed below.

1. The project must not increase the overall system heat rate for natural gas plants.
2. The project must not interfere with generation from existing renewable facilities nor with the integration of new renewable generation.
3. Taking into account the factors listed in (1) and (2), the project must reduce system-wide GHG emissions and support the goals and policies of AB 32.

As a fast-starting, highly efficient facility, Amended CECP will meet all three of these criteria. The proposed high efficiency simple-cycle units would have a gross heat rate of approximately 7,947 Btu/kWh (LHV), which leads to an estimated GHG emission rate of 0.48 MT CO_2/MWh. The project's capability for fast response will provide firming capability that will support the integration of new renewable generation. By displacing older, less efficient units, the project will reduce system-wide GHG emissions.

In addition, GHG emissions for the Amended CECP will be offset in part by the shutdown of EPS Units 1–5 and the peaker gas turbine. The net GHG emission change is shown below in Table 5.1-40 looking at a 5-year, 10-year, and 12-year[29] lookback period for the existing EPS units. The detailed GHG emission calculations for the proposed new units and the existing EPS units are included in Appendixes 5.1B and 5.1C, respectively.

Table 5.1-40 demonstrates that all three baseline periods for the existing EPS units result in a significant reduction in GHG emissions, with the 12-year lookback period resulting in an overall net reduction in GHG emissions with the shutdown of the existing Units 1–5/peaker gas turbine. Table 5.1-40 also shows that there is a significant net reduction in GHG emissions when comparing the Amended CECP to the Licensed CECP.

[29] The 12-year lookback begins in 2002, which matches the beginning of the baseline period used for the original CECP permitting process.

TABLE 5.1-40
Net GHG Emissions Change for Amended CECP

Equipment	Total MT CO_2e [a]
Amended CECP vs. Shutdown of Existing Units	
Reductions from Shutdown of Existing Units	
Units 1–5 and Peaker Gas Turbine (5-Year Lookback)[b]	-450,922
Units 1–5 and Peaker Gas Turbine (10-Year Lookback)[c]	-805,745
Units 1–5 and Peaker Gas Turbine (12-Year Lookback)[d]	-912,085
New Equipment (Amended CECP)	
Gas Turbines and Emergency Engines[e]	846,574
Net Emission Change (5-Year Lookback) =	395,652
Net Emission Change (10-Year Lookback) =	40,829
Net Emission Change (12-Year Lookback) =	-65,511
Amended CECP vs. Licensed CECP	
Licensed CECP	
New Equipment and Existing Units 4 and 5[f]	-1,561,264
New Equipment (Amended CECP)	
Gas Turbines and Emergency Engines[e]	846,574
Net Emission Change =	-714,690

[a]Metric tons of carbon dioxide equivalent.
[b]Based on average emissions during past 5 years (2009 to 2013).
[c]Base on average emissions during past 10 years (2004 to 2013).
[d]Base on average emissions during past 12 years (2002 to 2013).
[e]Includes SF_6 from circuit breakers.
[f]This includes the emissions for the new equipment associated with the Licensed CECP (CEC June 2012 Approval of CECP, Greenhouse Gas Table-1) and the emissions for existing Units 4 and 5 for 12-year lookback.

5.1.6.2.1 Nitrogen Emission Analysis

Nitrogen deposition is the input of NOx and ammonia (NH_3) derived pollutants, primarily nitric acid (HNO_3), from the atmosphere to the biosphere. Nitrogen deposition can lead to adverse impacts on sensitive species including direct toxicity, changes in species composition among native plants, and enhancement of invasive species.

The total nitrogen emission levels (based on NOx and NH_3 emissions) for the Amended CECP will be offset in part by the shutdown of EPS Units 1–5 and the peaker gas turbine. The net nitrogen emission change is shown below in Table 5.1-41 looking at 5-year, 10-year, and 12-year lookback periods for the existing EPS units. The detailed nitrogen emission calculations for the proposed new units and the existing EPS units are included in Appendix 5.1B.

Table 5.1-41 demonstrates that all three baseline periods for the existing EPS units result in a significant reduction in total nitrogen emissions, with the 12-year lookback period resulting in an overall net reduction in nitrogen emissions with the shutdown of the existing Units 1–5/peaker gas turbine. Table 5.1-41 also shows that there is a significant net reduction in nitrogen emissions when comparing the Amended CECP to the Licensed CECP.

TABLE 5.1-41
Net Nitrogen Emissions Change for Proposed Project

Equipment	Total Nitrogen Emissions (tpy)[a]
Amended CECP vs. Shutdown of Existing Units	
Reductions from Shutdown of Existing Units	
Units 1–5 and Peaker Gas Turbine (5-Year Lookback)[b]	-29
Units 1–5 and Peaker Gas Turbine (10 -Year Lookback)[c]	-50
Units 1–5 and Peaker Gas Turbine (12 -Year Lookback)[d]	-65
New Equipment (Amended CECP)	
Gas Turbines and Emergency Engines	62
Net Emission Change (5-Year Lookback) =	34
Net Emission Change (10-Year Lookback) =	12
Net Emission Change (12-Year Lookback) =	-3
Amended CECP vs. Licensed CECP	
Licensed CECP	
New Equipment and Existing Units 4 and 5[e]	-119
New Equipment (Amended CECP)	
Gas Turbines and Emergency Engines	62
Net Emission Change =	-56

[a]Includes nitrogen associated with NOx and NH_3 emissions.

[b]Based on average emissions during past 5 years (2009 to 2013).

[c]Base on average emissions during past 10 years (2004 to 2013).

[d]Base on average emissions during past 12 years (2002 to 2013).

[e]This includes the emissions for the new equipment associated with the Licensed CECP (CEC June 2012 Approval of CECP, Air Quality Table-7) and the emissions for existing Units 4 and 5 for 12-year lookback.

5.1.7 Laws, Ordinances, Regulations, and Standards

A discussion of the air quality LORS applicable to the Amended CECP is included in Sections 5.1.3.1 and 5.1.5.

5.1.8 Conditions of Certification

In the June 2012 approval of the CECP, the CEC imposed a number of air quality COCs on the project based on the SDAPCD's FDOC that was issued on August 4, 2009. The Amended CECP will require the submittal of a new permit application to the SDAPCD requesting a new FDOC for the CECP. When issued, the new FDOC will likely include a number of new and/or revised equipment descriptions, emission limits, and operating restrictions. Since the new FDOC is not yet issued, it is currently impossible to provide an accurate markup of the existing air quality COCs showing the necessary changes to match the new FDOC.

5.1.9 Mitigation

Mitigation will be provided for all emissions increases from the Amended CECP in the form of emission reductions from the shutdown of existing units at the EPS, NOx emission reduction credits, and the installation of BACT for the new equipment, as required under District regulations. The demonstration of compliance with the BACT requirement is provided in Appendix 5.1C.

As discussed in Section 5.1.5.3.1, the emissions increases from the Amended CECP will be offset through the reductions achieved by shutting down the existing boiler Units 1–5 and the peaker gas turbine at the EPS and by providing NOx emission reduction credits. Table 5.1-34 demonstrated that the Amended CECP will result in a net reduction in emissions of CO, PM_{10}, and VOC; an increase in SOx emissions (no SDAPCD offset

requirement for this pollutant); and an increase in NOx emissions (as shown in Table 5.1-36, this increase triggers SDAPCD offset requirements). The NOx emission offsets required by the SDAPCD have been purchased and will be surrendered to the SDAPCD prior to the initial operation of the new units.
Table 5.1-41 demonstrated that when a 10- or 12-year lookback is used to develop the baseline emissions for the existing EPS units, the Amended CECP will result in a net reduction in emissions of ozone and PM_{10}/$PM_{2.5}$ precursors with the shutdown of the existing Units 1–5/peaker gas turbine. Therefore, no further mitigation will be needed for the Amended CECP.

5.1.10 Permits Required and Permit Schedule

Under Rule 20.5, the SDAPCD regulates the construction and operation of new and modified power plants. As part of the application review process, the District will conduct a Determination of Compliance (DOC) review upon receipt of the PTA for the Amended CECP. The SDAPCD considers the PTA to be equivalent to an application for an Authority to Construct (ATC). The DOC review will consist of a review identical to that which would be performed if an application for an ATC had been received for a power plant and will confirm that the project will meet all applicable District rules and regulations.

A preliminary DOC (PDOC) is expected to be issued within approximately 180 days after the District determines that the PTA is complete. The PDOC will be circulated for public comment, and a final DOC (FDOC) will be issued by the SDAPCD after comment has been considered and addressed. Upon approval of the Amended CECP by the CEC, the FDOC confers the same rights and privileges as an ATC. The ATC allows for the construction of the new air pollution sources and services as a temporary Permit to Operate (PTO). Once the project has completed construction, begun operating, and performed the initial set of emission compliance tests, the SDAPCD will verify that the Amended CECP conforms to the FDOC/ATC and, following such verification, will issue a PTO.

The SDAPCD has received delegation from EPA to administer the federal Title IV and Title V programs for sources within its jurisdiction. The project will be subject to Acid Rain program requirements (federal Title IV). With regards to Title V, within 12 months of the initial operation of the new equipment a Title V permit application will be submitted to the District to modify the existing Title V permit for the EPS to include the operation of the new equipment. As discussed above, the SDAPCD expects that in the near future the EPA will delegate authority to the SDAPCD to issue PSD permits. If this is the case, the ATC will serve as the PSD permit as well. If this PSD delegation to the SDAPCD does not occur in a timely manner, a separate PSD permit application will be submitted to EPA Region 9 for a PSD review/permit for GHG emissions.

5.1.11 References

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5.9 Public Health

This section provides the Project Owner's evaluation of how the Amended CECP could impact public health and how the Amended CECP would comply with laws, ordinances, regulations, and standards (LORS) applicable to public health. Consistent with this PTA, this section focuses on changes to the impact or compliance of the project as it was previously evaluated and approved in the original Application for Certification process. Any proposed changes to Conditions of Certification (COCs) are provided.

This section presents the methodology and results of a human health risk assessment performed to assess potential impacts and public exposure associated with airborne emissions from the construction and operation of the Amended CECP.

Generally, the Amended CECP is not likely to create any new significant impacts to public health that were not previously identified and/or mitigated in the original permitting process. As with the Licensed CECP, the COCs will ensure project compliance with LORS and less-than-significant impacts.

5.9.1 Amendment Overview

As discussed in detail in Section 2.0, Project Description, the Amended CECP would be different than the project as approved in the Final Decision. For that reason, an evaluation of environmental impacts including the potential for changes or additions to COCs for the project is required. This PTA proposes implementing the following general changes to the Licensed CECP:

- Change in generation equipment and technology from Siemens fast response, combined-cycle to GE LMS 100 simple-cycle turbines to allow better support of renewable energy integration and local and regional demand. The Amended CECP will have six natural-gas-fired combustion GE LMS 100 turbines with approximately 632 MW[1] net output of simple-cycle electrical generating capacity.
- Add retirement and demolition of Encina Power Station (EPS). Units 1 through 5 of EPS will be retired and all above-grade elements of the EPS power and support buildings will be demolished.

As previously discussed in the Project Description, the Amended CECP would continue to occupy a portion of the Cabrillo Parcel, which is located in a City of Carlsbad Public Utility zone (as depicted in Figure 2.0-1). The CECP will continue to be situated adjacent to EPS, in the eastern portion of the Cabrillo Parcel, between the existing railroad tracks and I-5, but the Amended CECP will have a larger footprint occupying most of that area. Construction equipment/material laydown and construction worker parking areas for the project will continue to be located immediately north of the CECP facility, as well as in various areas west of the existing railroad tracks. No offsite parking or laydown areas (outside of use of the 95-acre Cabrillo Parcel) are anticipated to be necessary for the construction of the Amended CECP.

The Amended CECP will continue to interconnect to the electrical transmission system via 138-kilovolt (kV) and 230-kV lines that connect to the respective San Diego Gas and Electric Company (SDG&E) switchyards situated on and adjacent to the Cabrillo Parcel. Natural gas will be delivered to the Amended CECP from the existing SDG&E transmission pipeline (Line TL 2009, "Rainbow line") via an approximate 1,100-foot-long interconnection pipeline west of the Amended CECP site that runs parallel to the existing railroad tracks. At the facility, the natural gas will flow through a flow-metering station, gas scrubber/filtering equipment, a gas pressure control station, and a fuel gas compressor station prior to injection into the combustion turbines. Similar to the Licensed CECP, with the exception of short, onsite interconnections, no offsite gas supply lines are required for the Amended CECP. The Amended CECP will use reclaimed water and/or potable water from the City of Carlsbad, or ocean water, and will connect to an existing City of Carlsbad (Encina Wastewater Authority) sanitary sewer line.

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[1] Rated at an average annual ambient temperature of 60.3 degrees Fahrenheit [°F] 79 percent relative humidity and with inlet air evaporative cooling

Upon completion of construction of the CECP and achievement of commercial operations, EPS will be retired and the above grade elements of the main EPS power building and also of all support buildings, will be demolished. Upon completion of demolition of EPS, portions of the western areas of the Cabrillo Parcel will be removed from CEC jurisdiction and made available for redevelopment plans along with any other available adjacent lands. Some portions of the western areas of the Cabrillo Parcel will remain dedicated to the CECP, such as for transportation access, electrical interconnection, and water or gas supply.

Air will be the dominant pathway for potential public exposure to non-criteria pollutants released by the Amended CECP. Emissions to the air will consist primarily of combustion by-products produced by the simple-cycle gas turbine units and Diesel emergency engines. Potential health risks from combustion emissions will occur almost entirely by direct inhalation. To be conservative and as required by the San Diego Air Pollution Control District (SDAPCD), additional pathways for dermal absorption, soil ingestion, mother's milk ingestion, home-grown produce ingestion, and fish ingestion were included in the health risk modeling. The health risk assessment for the Amended CECP was conducted in accordance with guidance established by the California Office of Environmental Health Hazard Assessment (OEHHA, 2003), the California Air Resources Board (CARB, 2014), and the SDAPCD (2006).

The Amended CECP will use new, efficient simple-cycle technology to minimize emissions of pollutants per unit of electric energy generated, thus reducing potential effects on public health. It is beyond the scope of this analysis to describe the public health benefits that derive from the generated electric power that is provided to homes, businesses, hospitals, and other societal institutions.

Combustion byproducts with established national and California ambient air quality standards (referred to as "criteria pollutants") are addressed in Section 5.1, Air Quality. Discussion of the potential health risks associated with these criteria pollutants is presented in this section. Human health risks potentially associated with accidental releases of stored hazardous materials at the Amended CECP (aqueous ammonia) are discussed in Section 5.5, Hazardous Materials.

5.9.2 Affected Environment

The California Energy Commission (CEC) defines sensitive receptors as infants and children, the elderly, the chronically ill, and any other members of the general population who are more susceptible to the effects of exposure to environmental contaminants than the population at large. For the purpose of this analysis, sensitive receptors are defined as the locations occupied by groups of individuals who may be more susceptible to health risks from a chemical exposure: schools (public and private), day-care facilities, convalescent/nursing homes, retirement homes, health clinics, and hospitals. Because sensitive individuals may be located at any residential site, risk-based standards apply to existing residences and places where residences may be built without a change in zoning as well as sensitive receptors. If project impacts are protective of sensitive individuals at the point of maximum impact, they are protective at all locations. Identification of sensitive receptors is typically done to ensure that notice of possible impacts is provided to the community.

In accordance with guidance from the CEC, a search was conducted for sensitive receptors within 3 miles of the CECP site. Daycare, hospital, park, preschool, and school receptors found within 3 miles are listed in Appendix 5.9A. The nearest sensitive receptor to the CECP site is located approximately 1.5 km to the northeast.

The nearest residence to the CECP site is approximately 0.7 km southwest of the project site.

Air quality and health risk data presented by CARB in the 2009 Almanac of Emissions (the most recent CARB Almanac of Emissions available containing toxic air contaminants [TACs) and Air Quality for the San Diego Air Basin show that over the period 1990 through 2007, the average concentrations for the top ten TACs have been substantially reduced, and the associated health risks for the San Diego Air Basin are showing a steady downward trend as well. CARB-estimated emissions inventory values for the top ten TACs for 2008 and ambient levels and associated potential risks for 2007 are presented in Table 5.9-1 for the air basin.

TABLE 5.9-1
Top Ten TACs Emitted by All Sources in the San Diego Air Basin

TAC	2008 Emissions (tons/year)	2007 Levels and Risks	
		Concentration (ppbv)	Potential Carcinogenic Risk (in 1 million)
Acetaldehyde	524	0.88	4
Benzene	770	0.37	35
1,3-Butadiene	233	0.07	27
Carbon tetrachloride	0.09	0.09 (2003)	25 (2003)
Chromium, hexavalent	0.06	0.03 ng/m^3	5
Para-Dichlorobenzene	122	0.15 (2006)	10 (2006)
Formaldehyde	1,282	2.2	16
Methylene chloride	359	0.14	<1
Perchloroethylene	422	0.03	1
Diesel PM	1,607	1.4 µg/m^3 (2000)	420 (2000)

Source: CARB, 2009
µg/m^3 = micrograms per cubic meter
ng/m^3 = nanograms per cubic meter
ppbv = parts per billion by volume

Concerning the current incidence of cancer and respiratory illnesses and diseases in the vicinity of the proposed project, the County of San Diego Health and Human Services Agency offers the following information. The number of annual asthma hospitalizations in the north coastal portion of San Diego County, which includes the project area, has remained within the narrow range of 210 to 253 during the period of 2007 through 2011, the most recent period for which data are available (County of San Diego Health and Human Services Agency, 2013). This area accounts for approximately 10 percent of the total county asthma hospitalizations. Lung cancer deaths during this same period have also remained within a narrow range, from 154 to 165 per 100,000 population (County of San Diego Health and Human Services Agency, 2011), which is a slightly lower incidence rate than in the entire county. The contribution of the Carlsbad area to the north coastal total range was 35 to 37.

5.9.3 Environmental Analysis

This section discusses the sources and different kinds of air emissions associated with the construction and operation of the Amended CECP (see Section 5.1, Air Quality, for additional information on these emissions sources), the methodology used in performing the screening level health risk assessment, and the results of this risk assessment. Other potential public health risks associated with the proposed project are discussed in different sections of the PTA as follows:

- Potential exposure to wastes generated by the proposed project is discussed in Section 5.14, Waste Management.
- Potential exposure to the hypothetical accidental release of aqueous ammonia onsite or during offsite transport is discussed in Section 5.5, Hazardous Materials.
- Potential safety and health impacts relative to the work environment of project employees are discussed in Section 5.15, Worker Health and Safety.

Emissions associated with the operation of the Amended CECP will consist of combustion byproducts from the natural gas-fired turbines and from routine testing of the diesel emergency engines. After dispersion to ground-level, inhalation is the main pathway by which air pollutants can potentially cause public health impacts. Other pathways, including ingestion of soil, fish, homegrown produce, and mother's milk, and dermal absorption, also were evaluated.

5.9.3.1 Significance Criteria

Significance criteria exist for both carcinogenic and non-carcinogenic risks, and are discussed separately.

5.9.3.1.1 Cancer Risk

Cancer risk is the probability or chance of contracting cancer over a human life span (assumed to be 70 years). Carcinogens are assumed to have no threshold below which there would be no human health impact. In other words, any exposure to a carcinogen is assumed to have some probability of causing cancer; the lower the exposure, the lower the cancer risk (i.e., a linear, no-threshold model). Under state and SDAPCD regulations, an incremental cancer risk greater than 10-in-1 million is considered to be a significant impact on public health for equipment using Toxics Best Available Control Technology (T-BACT), which is the case for the Amended CECP.[2] The 10-in-one-million risk level is also used by the Air Toxics "Hot Spots" (AB 2588) program and California's Proposition 65 as the public notification level for air toxic emissions from existing sources.

5.9.3.1.2 Non-Cancer Risk

Non-cancer health effects can be either long-term (chronic) or short-term (acute). In determining potential non-cancer health risks from air toxics, it is assumed there is a dose of the TAC below which there would be no impact on human health. The air concentration corresponding to this dose is called the Reference Exposure Level (REL). A non-cancer health risk is measured in terms of a health hazard quotient, which is the calculated maximum exposure (concentration) of each TAC divided by its REL. Health hazard quotients for TACs affecting the same target organ are typically summed with the resulting totals expressed as health hazard indices for each organ system.

Chronic toxicity is defined as adverse health effects from prolonged chemical exposure, caused by chemicals accumulating in the body. Because chemical accumulation to toxic levels typically occurs slowly, symptoms of chronic effects usually do not appear until long after exposure commences. The lowest no-effect chronic exposure level for a non-carcinogenic air toxic is the chronic REL. Below this threshold, the body is capable of eliminating or detoxifying the chemical rapidly enough to prevent its accumulation. The chronic hazard index was calculated using the hazard quotients calculated with annual concentrations.

Acute toxicity is defined as adverse health effects caused by a brief chemical exposure of no more than 24 hours. For most chemicals, the air concentration required to produce acute effects is higher than the level required to produce chronic effects because the duration of exposure is shorter. Because acute toxicity is predominantly manifested in the upper respiratory system at threshold exposures, all acute health hazard quotients are typically summed to calculate the acute health hazard index. The maximum 1-hour average concentration of each TAC with acute health effects is divided by the TAC's acute REL to obtain a health hazard index for health effects caused by relatively high, short-term exposure to air toxics. An additional conservative procedure in this health risk assessment is that the health hazard quotients for all TACs having potential acute impacts were summed regardless of target organ. This method leads to an upper bound assessment. RELs used in the hazard index calculations were those published in the CARB/OEHHA listings dated January 30, 2014.

5.9.3.2 Demolition/Construction Impacts

The demolition/construction of the proposed project is scheduled to occur in the following two phases:

- Construction of the new equipment (24-month period); and
- Demolition of the existing Encina Power Station (22-month period).

[2] The threshold would be 1-in-one-million if the emitting units were determined not to be applying T-BACT.

There is no overlap between these phases. The emissions were calculated for each phase. The demolition/construction emission estimates include emissions from vehicle and equipment exhaust and fugitive dust generated from material handling and paved/unpaved road travel. A dispersion modeling analysis and a screening health risk assessment were conducted based on these emissions. The detailed analysis of the demolition/construction emissions and ambient impacts is included in Appendix 5.1F.

5.9.3.3 Operations Impacts

Potential human health impacts associated with the Amended CECP stem from exposure to air emissions from operation of the natural gas-fired simple-cycle units, and routine testing of the emergency Diesel engines. The non-criteria pollutants emitted from the proposed project include certain volatile organic compounds and polycyclic aromatic hydrocarbons (PAHs) from the combustion of natural gas, ammonia from the SCR NO_x control systems, and DPM from combustion of diesel fuel in the emergency engines. These pollutants are listed in Table 5.9-2, and the detailed emission summaries and calculations are presented in Appendix 5.9B.

For criteria pollutants, the proposed project will include the use of Best Available Control Technology (BACT) as required under SDAPCD rules.

TABLE 5.9-2
Pollutants Emitted to the Air from the Amended CECP

Criteria Pollutants	Non-criteria Pollutants (Continued)	
Carbon monoxide	Formaldehyde	Ammonia
Oxides of nitrogen	Hexane	Acetaldehyde
Particulate matter	Naphthalene	Acrolein
Oxides of sulfur	Propylene	1,3-Butadiene
Volatile organic compounds	Propylene oxide	Benzene
	Toluene	Dichlorobenzene
	Xylene	Diesel Exhaust Particulate Matter
	Hexane	Ethylbenzene
	PAHs	
	Benzo(α)anthracene	
	Benzo(α)pyrene	
	Benzo(β)fluoranthene	
	Benzo(k)fluoranthene	
	Chrysene	
	Dibenz(a,h)anthracene	
	Indeno(1,2,3-cd)pyrene	

Air dispersion modeling results (see Section 5.1.4) indicate that the Amended CECP will not cause or contribute to violations of state or federal air quality standards, with the exception of the annual state PM_{10}/$PM_{2.5}$ standards and annual federal $PM_{2.5}$ standard. For these pollutants and averaging periods, existing background concentrations already exceed state/federal standards. These standards are intended to protect the general public with a wide margin of safety. Therefore, the proposed project will not have a significant impact on public health from emissions of criteria pollutants

5.9.3.4 Public Health Impact Study Method

As discussed above, the health risk assessment was conducted in accordance with guidance established by OEHHA, CARB, and the SDAPCD.

Emissions of non-criteria pollutants from the proposed project were estimated using emission factors approved by the SDAPCD, CARB, and the U.S. Environmental Protection Agency (EPA). Included in Appendix 5.9B are the detailed non-criteria pollutant emission calculations for the proposed new gas turbines and emergency engines and the existing units at the Encina Power Station. In addition to an analysis of the acute/chronic/cancer risk impacts during the normal operation of the new equipment (gas turbines/emergency engines), the SDAPCD requires an analysis of the acute impacts during gas turbine startups/shutdowns and during the commissioning phase of the new gas turbines. Therefore, the detailed non-criteria pollutant calculations in Appendix 5.9B include separate non-criteria emission calculations for each of these three cases (normal operation, startups/shutdown, commissioning).

As shown in the calculations in Appendix 5.9B, compared to normal operating levels the hourly non-criteria pollutant emission levels will be higher during gas turbine startups/shutdowns and during the commissioning period. Hourly non-criteria pollutant emissions will be elevated during these two operating cases because the oxidation catalyst system (which controls organic compounds including non-criteria pollutants) may not be operating at all times during these periods. During a gas turbine startup/shutdown, the oxidation catalyst system may not be fully functional during the entire hour in question because the proper catalyst operating temperature was not reached for a portion of the hour. During the commissioning phase of a new gas turbine, there will be test runs performed prior to the installation/operation of the oxidation catalyst system. The health risk assessment performed for the proposed project includes an analysis of the impacts during gas turbine startups/shutdowns and the commissioning period. Because it will be necessary to continue to operate the existing Units 1-5 and the peaker gas turbine at the Encina Power Station during the commissioning period of the new gas turbines, the health risk assessment for the commissioning period also includes the impacts for the existing Encina units.

The SDAPCD also requires new power plant projects to analyze the long-term impacts (chronic/cancer risk) associated with commissioning activities. Although the Amended CECP is a newly proposed configuration of a licensed facility, the Project Owner has included this analysis to ensure the thoroughness of its evaluation of the Amended CECP's impacts on public health. This analysis is for comparison purposes only (to compare long-term normal operating impacts against commissioning impacts), and the results are not added to the normal operating impacts. For this analysis, it is assumed that the gas turbine commissioning activities (approximately 213 hours per gas turbine per year) occur each year for 70 years. The detailed non-criteria pollutant emission calculations in Appendix 5.9B show the resulting annual emissions for this long-term commissioning case. The health risk assessment performed for the proposed project includes the chronic/cancer risk results for the long-term commissioning case.

The health risk assessment was performed using the CARB's Hotspots Analysis and Reporting Program (HARP) computer program (Version 1.4f, May 2012 using the latest HARP Health Database table updated in November 2013), and associated guidance. Also used was the CARB software program that allows AERMOD dispersion modeling data to be imported into the HARP model, called HARP On-Ramp. The same approach for modeling of criteria pollutants (discussed in Section 5.1.4) was also used to model non-criteria pollutant impacts using the AERMOD model. The HARP model was used to assess cancer risk as well as non-cancer chronic and acute health hazards. In addition to inhalation, the HARP modeling included the additional pathways for dermal absorption, soil ingestion, mother's milk ingestion, home-grown produce ingestion, and fish ingestion.

Health risks were evaluated for a hypothetical maximum exposed individual (MEI) located at the Point of Maximum Impact (PMI). In addition, health risks were evaluated at the Maximally Exposed Individual Resident (MEIR). The MEIR is an individual assumed to be located at an actual residential receptor where the highest concentrations of air pollutants associated with facility emissions are predicted to occur, based on air dispersion modeling.

Evaluation of potential non-cancer health effects from exposure to short-term and long-term concentrations in air was performed by comparing modeled concentrations with the RELs. An REL is a concentration in air at or below which no adverse health effects are anticipated. RELs are based on the most sensitive adverse effects reported in the medical and toxicological literature. Potential non-cancer effects were evaluated by calculating a ratio of the modeled concentration in air and the REL. This ratio is referred to as a hazard quotient. The inhalation cancer potency factors and RELs used to characterize health risks associated with modeled concentrations in air are embedded in the risk module of HARP and in the *Consolidated Table of OEHHA/ARB Approved Risk Assessment Health Values* (CARB, 2014), and are presented in Table 5.9-3.

TABLE 5.9-3
Toxicity Values Used to Characterize Health Risks

Toxic Air Contaminant	Inhalation Cancer Potency Factor $(mg/kg\text{-}d)^{-1}$	Chronic Inhalation REL ($\mu g/m^3$)	Acute Inhalation REL ($\mu g/m^3$)
Acetaldehyde	0.010	140	—
Acrolein	—	0.35	2.5
Ammonia	—	200	3,200
Benzene	0.10	60	1,300
1,3-Butadiene	0.60	2.0	660
Diesel PM	1.1	5.0	—
Ethylbenzene	—	2,000	—
Formaldehyde	0.021	9.0	55
Hexane	—	7,000	—
Naphthalene	0.12	9.0	—
PAHs (as BaP for HRA)	3.9	—	—
Propylene	—	3,000	—
Propylene oxide	0.013	30	3,100
Toluene	—	300	37,000
Xylene	—	700	22,000

Source: CARB, 2014.

5.9.3.5 Characterization of Risks from Toxic Air Pollutants

The estimated potential maximum cancer risks associated with the operation of the proposed project are shown in Table 5.9-4. The maximum carcinogenic risk is below the 10×10^{-6} SDAPCD threshold of significance.

TABLE 5.9-4
Summary of Potential Health Risks

Receptor	Carcinogenic Risk [a] (per million)	Cancer Burden	Acute Health Hazard Index	Chronic Health Hazard Index
New Equipment Normal Operation (gas turbines/emergency engines)				
Maximally Exposed Individual (MEI) at PMI	2.9		2.7×10^{-2}	1.5×10^{-3}
Maximally Exposed Individual Resident (MEIR)	7.8×10^{-2}	0	1.6×10^{-2}	4.7×10^{-4}
Maximally Exposed Individual Worker [b] (MEIW)	4.5×10^{-1}		2.7×10^{-2}	—
Gas Turbine Startups/Shutdowns				
MEI (acute impact only)	N/A	N/A	9.0×10^{-2}	N/A

TABLE 5.9-4
Summary of Potential Health Risks

Receptor	Carcinogenic Risk [a] (per million)	Cancer Burden	Acute Health Hazard Index	Chronic Health Hazard Index
Gas Turbine Commissioning Period (includes impacts for existing Encina units)				
MEI (acute impact only)	N/A	N/A	7.8×10^{-2}	N/A
Gas Turbine Long-Term Commissioning Case				
MEI (cancer risk/chronic impacts only)	7.4×10^{-3}	0	n/a	9.0×10^{-5}
Significance Level	10	1.0	1.0	1.0

[a] Based on High Point Method which results in the maximum cancer risk.

[b] The worker is assumed to be exposed at the work location 8 hours per day, instead of 24, 245 days per year, instead of 365, and for 40 years, instead of 70.

Cancer risks potentially associated with the project also were assessed in terms of cancer burden. Cancer burden is a hypothetical upper-bound estimate of the additional number of cancer cases that could be associated with emissions from the project. Cancer burden is calculated as the maximum product of any potential carcinogenic risk greater than 1 in 1 million and the number of individuals at that risk level. Because the area with a MEI cancer risk above 1 in 1 million extends for only approximately 100 meters to the east and west of the project fenceline where the rail tracks to the west and I-5 to the east are located, the potential cancer burden is zero due to a lack of residences in those areas.

The maximum potential acute non-cancer health hazard index associated with operation of the proposed project is shown in Table 5.9-5. The acute non-cancer health hazard index for all target organs falls below 1.0, the SDAPCD threshold of significance.

Similarly, the maximum potential chronic non-cancer health hazard index associated with operation of the proposed project is also shown in Table 5.9-5. The chronic non-cancer health hazard index falls below 1.0, the SDAPCD threshold of significance.

Included in Section 5.1, Air Quality (Section 5.1.4) are comparisons between the criteria pollutant and GHG emissions for the Amended CECP versus the Licensed CECP. These comparisons show a significant net reduction in emissions for the Amended CECP when compared to the Licensed CECP. Because of the direct correlation between criteria/GHG emissions and non-criteria emissions (both based on fuel combustion and/or activity levels), the same conclusion can be reached that there is an expected net reduction in non-criteria pollutant emissions for the Amended CECP when compared to the Licensed CECP.

A separately transmitted DVD containing the HARP modeling input and output files will be submitted to the CEC and SDAPCD.

5.9.4 Cumulative Effects

An analysis of potential cumulative air quality impacts that may result from the Amended CECP and other reasonably foreseeable projects is required by the CEC. As discussed in Section 5.1.4, a cumulative impact analysis was performed for criteria pollutants. This conclusion was reached because the emissions for the nearby new projects were *de minimis*, or there were no expected operational emissions associated with these projects, or the nearby projects did not result in an increase in emissions compared to baseline conditions. This analysis concluded, therefore, that there are no expected significant cumulative impacts for the Amended CECP and other nearby reasonably foreseeable projects. Because of the direct correlation between criteria and non-criteria emissions (both based on fuel combustion and/or activity levels), the same conclusion can be reached that there are no expected significant cumulative impacts for non-criteria pollutant for the Amended CECP and other reasonably foreseeable projects.

5.9.5 Laws, Ordinances, Regulations, and Standards

An overview of the regulatory process for public health issues is presented in this section. Table 5.9-5 summarizes the relevant LORS that affect public health that are applicable to the Amended CECP, along with the compliance of the proposed project with each of the applicable LORS. The LORS identified below for the Amended CECP are consistent with the LORS listed for the Licensed CECP. The only new LORS listed below is SDAPCD Rule 51 – Nuisance.

TABLE 5.9-5
Laws, Ordinances, Regulations, and Standards Applicable to Public Health

LORS	Requirements/ Applicability	Administering Agency	PTA Section Explaining Conformance
Federal			
Clean Air Act (CAA) §160-169A and implementing regulations, Title 42 United States Code (USC) §7470-7491 (42USC 7470-7491), Title 40 Code of Federal Regulations (CFR)	Protect public health by limiting emissions and resulting exposure to air pollutants	SDAPCD, with CARB and EPA oversight	Based on a health risk assessment that follows CARB/OEHHA and SDAPCD guidelines, project emissions of non-criteria pollutants do not result in a significant health risk (see Section 5.9.3.5). Based on an ambient air quality modeling analysis performed in accordance with SDAPCD and EPA guidance, project criteria pollutant impacts would not exceed primary ambient air quality standards established to protect public health.
40 CFR Part 68 (Risk Management Plan)	Public exposure to acutely hazardous materials	EPA, San Diego Dept of Environmental Health	As discussed in Section 5.5, Hazardous Materials, an RMP will be developed prior to commencement of facility operations
State			
California Health and Safety Code (H&SC) 25249.5 et seq. (Safe Drinking Water and Toxic Enforcement Act of 1986—Proposition 65)	Inform public at a facility of potential exposure to chemicals known to cause cancer or reproductive toxicity	OEHHA	Based on a health risk assessment that follows CARB/OEHHA and SDAPCD guidelines, non-criteria pollutant emission rates and resulting doses and carcinogenic risks (see Section 5.9.3.5) will not exceed thresholds that require Proposition 65 exposure warnings.
H&SC, Sections 25531 to 25541; CCR Title 19 (Public Safety), Division 2 (Office of Emergency Services), Chapter 4.5 (California Accidental Release Prevention Program)	Public exposure to regulated substances	San Diego County Department of Environmental Health	As discussed in Section 5.5, Hazardous Materials, an RMP will be prepared prior to commencement of facility operations.
California Public Resources Code §25523(a); 20 CCR 1752.5, 2300-2309, and Division 2 Chapter 5, Article 1, Appendix B, Part (1)	Ensure protection of environmental quality; requires a quantitative HRA	CEC	Based on a health risk assessment that follows CARB/OEHHA and SDAPCD guidelines, project emissions of non-criteria pollutants do not result in a significant health risk (Section 5.9.3.5).
California Clean Air Act, TAC Program, HSC §39650, et seq.	Requires quantification of TAC emissions, use of BACT, and preparation of an HRA	SDAPCD with CARB oversight	Based on a health risk assessment that follows CARB/OEHHA and SDAPCD guidelines, project emissions of non-criteria pollutants do not result in a significant health risk (Section 5.9.3.5).

TABLE 5.9-5
Laws, Ordinances, Regulations, and Standards Applicable to Public Health

LORS	Requirements/ Applicability	Administering Agency	PTA Section Explaining Conformance
HSC §41700	Prohibits emissions in quantities that adversely affect public health, other businesses, or property	SDAPCD with CARB oversight	Based on a health risk assessment that follows CARB/OEHHA and SDAPCD guidelines, project emissions of non-criteria pollutants do not result in a significant health risk (Section 5.9.3.5).
Local			
SDAPCD Regulation XII – Toxic Air Contaminants, Rule 1200 - Toxic Air Contaminants New Source Review	Limit public exposure to toxic air contaminants based on specified cancer and non-cancer risk thresholds	SDAPCD	The project health risk assessment in Section 5.9.3 confirms that project design features and application of T-BACT will assure that potential health risks are less than Rule 1200 thresholds.
SDAPCD Regulation IV – Rule 51 – Nuisance	Prevents creation of a public nuisance	SDAPCD with CARB oversight	Based on a health risk assessment that follows CARB/OEHHA and SDAPCD guidelines, project emissions of non-criteria pollutants do not result in a significant health risk (Section 5.9.3.5).

5.9.6 Conditions of Certification

In the June 2012 approval of the CECP, the CEC imposed a single public health COC on the project. The Amended CECP will not require any additional COCs, but will require that the existing COC be revised due to the retirement and demolition of the EPS. Also, the COC was revised to clarify that natural gas will be the fuel for the CECP gas turbines. The emergency engines proposed as part of the Amended CECP will be fueled with CARB certified Diesel. The proposed changes to this condition are provided below using strikethrough/underline format:

PUBLIC HEALTH-1: The project owner shall only use pipeline quality natural gas in the Carlsbad Energy Center Project gas turbines~~, Encina Unit 4, Encina Unit 5, and Encina EGT.~~

Verification: The project owner shall provide a statement to the CPM in the yearly compliance report that only natural gas has been used to fuel the CECP gas turbines ~~and the Encina Power Station~~.

5.9.7 Mitigation Measures

No mitigation measures are needed for the Amended CECP TAC emissions because the potential air quality and public health impacts are less than significant.

5.9.8 Involved Agencies and Agency Contacts

Table 5.9-6 provides contact information for agencies involved with public health.

TABLE 5.9-6
Agency Contacts for Public Health

Issue	Agency	Contact
Public exposure to air pollutants	CARB	Cynthia Marvin, Chief Stationary Source Division California Air Resources Board 1001 I Street Sacramento, CA 95814 (916) 322-7236
	San Diego Air Pollution Control District	Tom Weeks Chief, Engineering Division 10124 Old Grove Road San Diego, CA 92131 (858) 586-2715
Public exposure to chemicals known to cause cancer or reproductive toxicity	Cal-EPA, Office of Environmental Health and Hazard Assessment (OEHHA)	Cynthia Oshita or Susan Luong Office of Environmental Health Hazard Assessment 1001 I Street, Sacramento, CA 95814 (916) 322-2068 (Oshita) (916) 327-3015 (Luong)
Public exposure to accidental releases of hazardous materials	California Office of Emergency Services	Trevor Anderson Governor's Office of Emergency Services 3650 Schriever Avenue Mather, CA 95655 (916) 845-8788
	San Diego County Department of Environmental Health	Dave Cammall, Supervisor, Hazardous Incident Response Team County of San Diego Department of Environmental Health 5500 Overland Avenue #170 San Diego, CA 92123 (858) 505-6974

5.9.9 Permits Required and Permit Schedule

Agency-required permits related to public health are listed in Table 5.9-7; these include a Risk Management Plan for hazardous materials, and the SDAPCD Determination of Compliance (DOC). Upon approval of the Amended CECP by the CEC, the DOC serves as the SDAPCD Authority to Construct. These requirements are discussed in detail in Sections 5.1, Air Quality) and 5.5, Hazardous Materials.

TABLE 5.9-7
Permits and Permit Schedule for Public Health

Permit	Agency	Schedule
Determination of Compliance / Authority to Construct	San Diego Air Pollution Control District	District must issue a Preliminary DOC within 180 days after issuing the Application Completeness Determination Letter.
Risk Management Plan (CalARP)	San Diego County Department of Environmental Health	RMP application must be approved before arrival of hazardous materials on site.

5.9.10 References

California Air Resources Board (CARB). 2009. The California Almanac of Emissions and Air Quality, 2009 Edition. Available online at: http://www.arb.ca.gov/aqd/almanac/almanac07/almanac2009all.pdf

California Air Resources Board (CARB). 2014. Consolidated Table of OEHHA/ARB Approved Risk Assessment Health Values. January 30. Available online at: http://arbis.arb.ca.gov/toxics/healthval/contable.pd).

California Air Resources Board (CARB). HARP Model, Version 1.4f, http://www.arb.ca.gov/toxics/harp/harp.htm.

County of San Diego Health and Human Services Agency. 2011. County of San Diego Community Profiles by Region and Subregional Area, North Coastal Region, p. 38. Available online at: http://www.sdcounty.ca.gov/hhsa/programs/phs/documents/CHS-Community_Profiles_Chronic_Disease_2011.pdf

County of San Diego Health and Human Services Agency. 2013. Asthma Hospitalizations among San Diego County Residents. Available online at: http://www.sdcounty.ca.gov/hhsa/programs/phs/documents/CHS-NonCommunicableProfile_2013.pdf

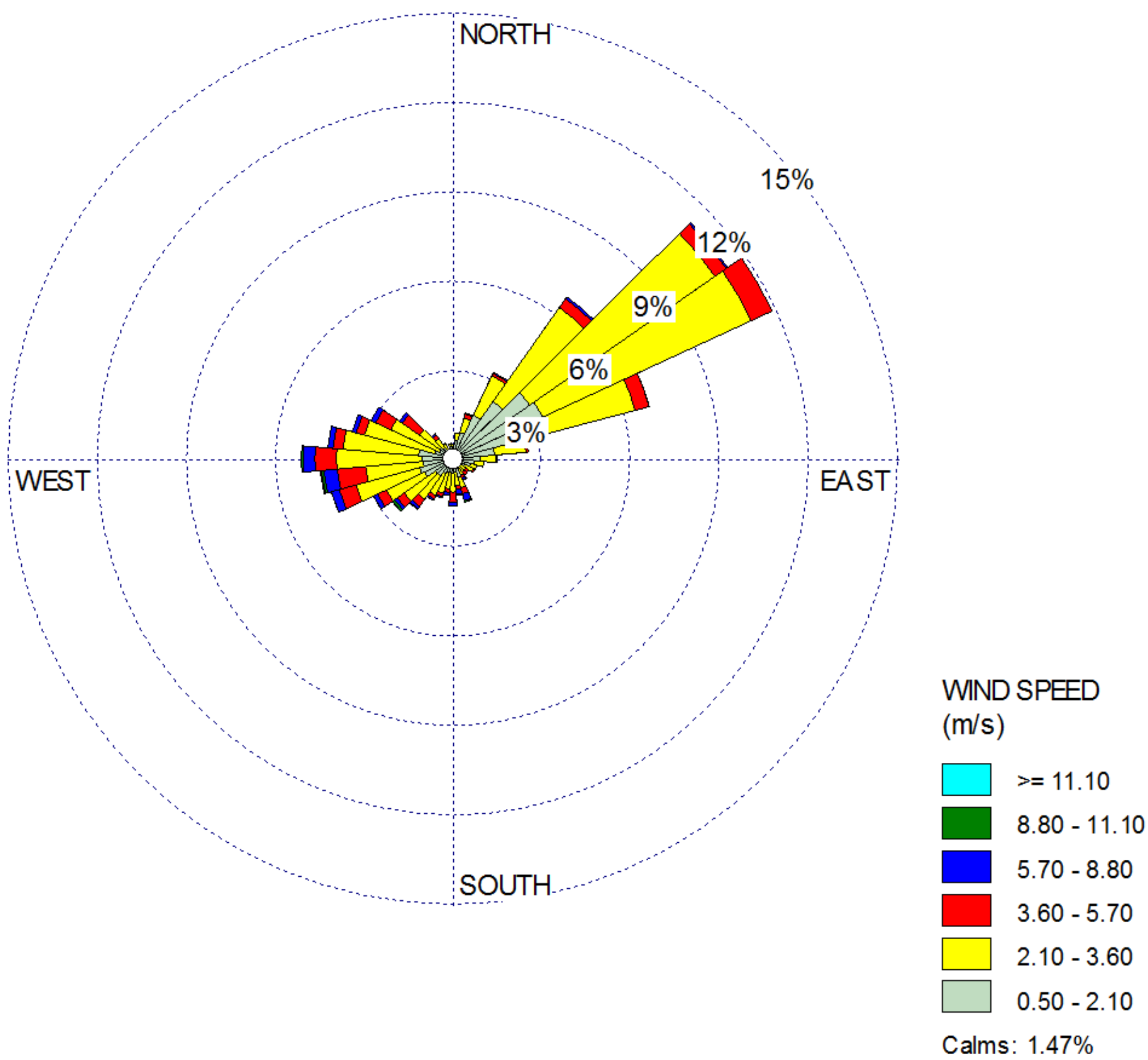
Office of Environmental Health Hazard Assessment (OEHHA). 2003. Air Toxics Hot Spots Program Risk Assessment Guidelines, The Air Toxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments, California Environmental Protection Agency.

San Diego Air Pollution Control District (SDAPCD). 2006. Supplemental Guidelines for Submission of Air Toxics “Hot Spots” Program Health Risk Assessments (HRAs). June.

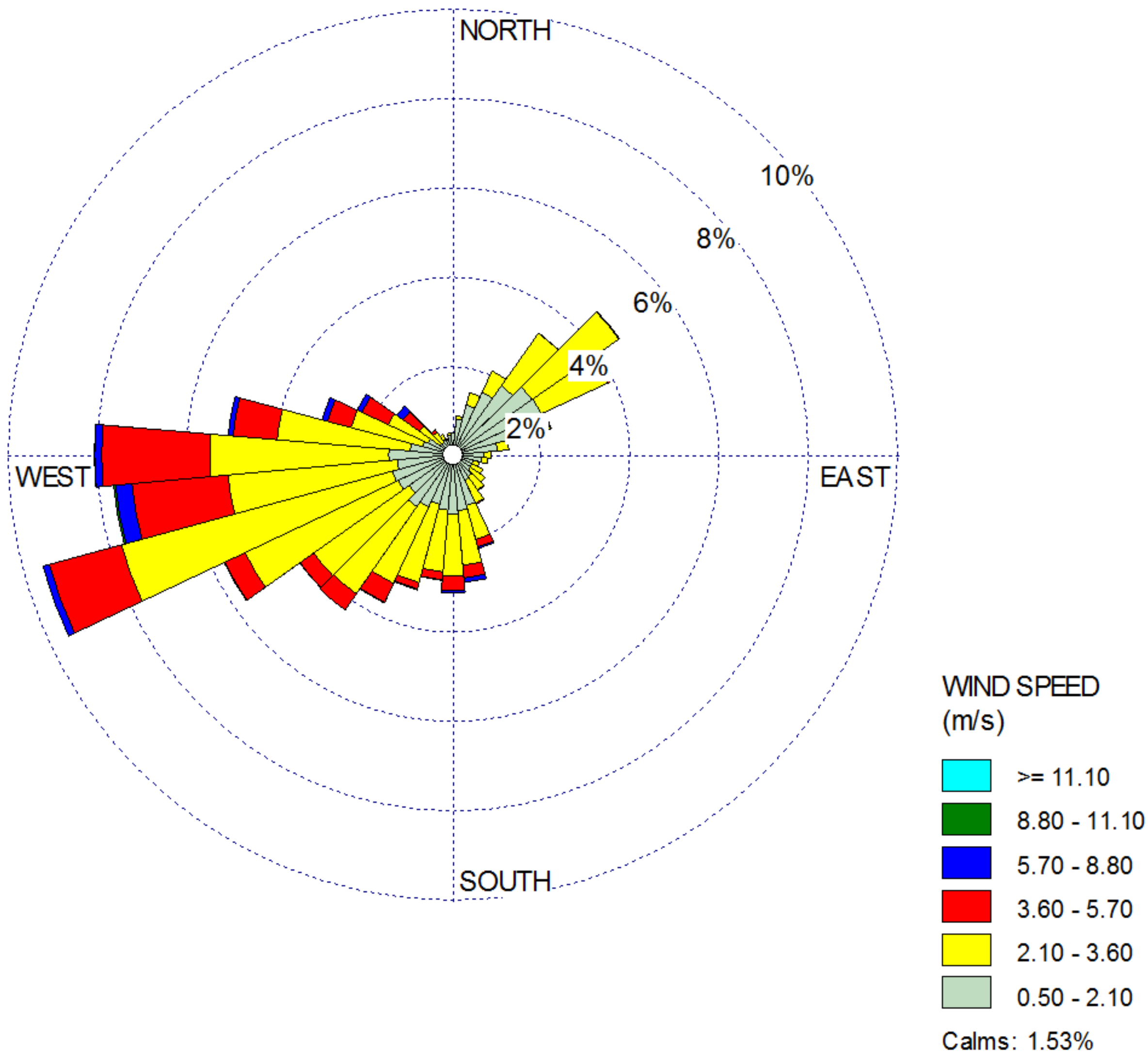
Appendix 5.1A
Wind Roses

Composite Quarterly and Annual Wind Roses for Camp Pendleton, CA 2008 – 2012

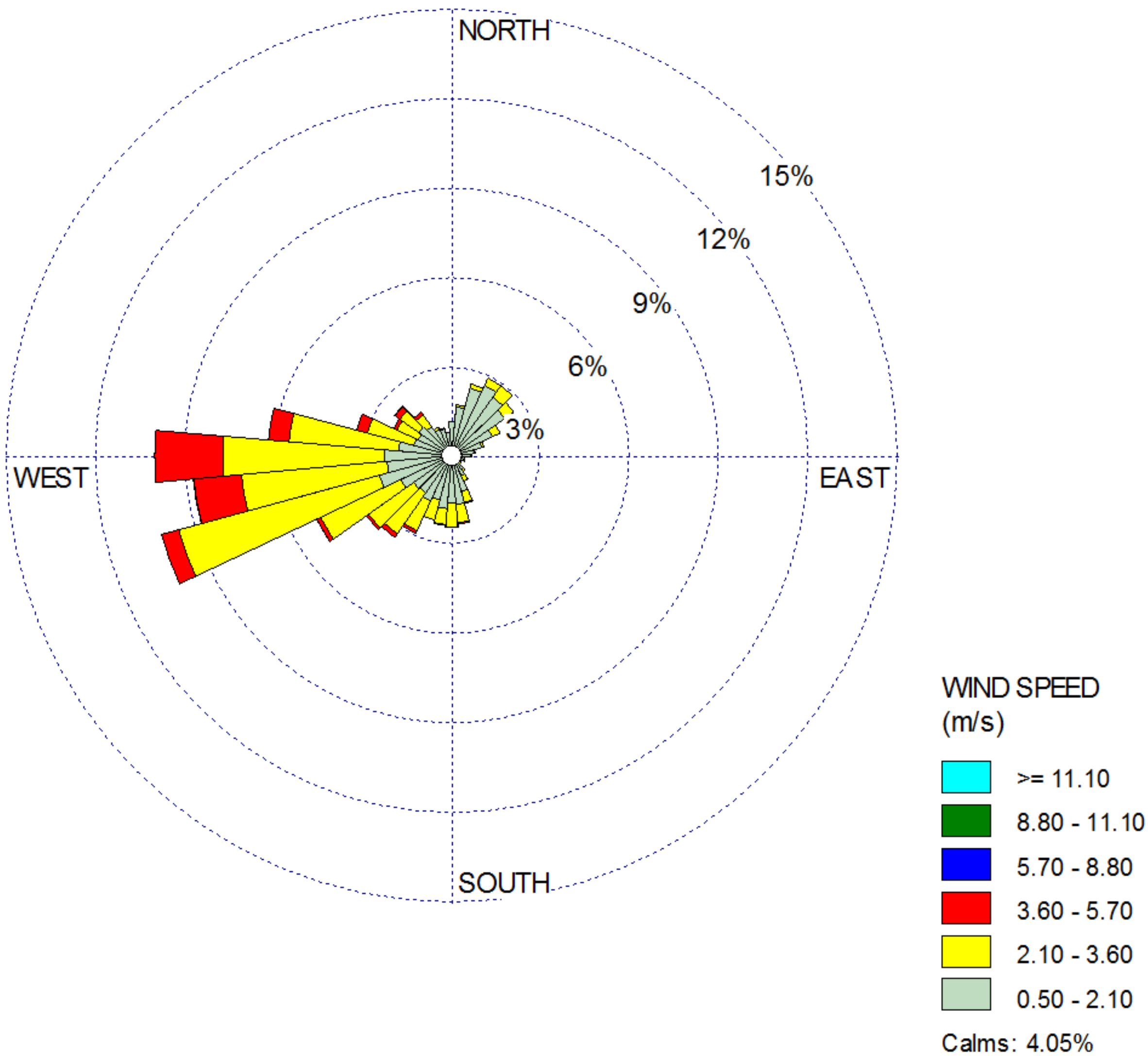
First Quarter, 2008 – 2012



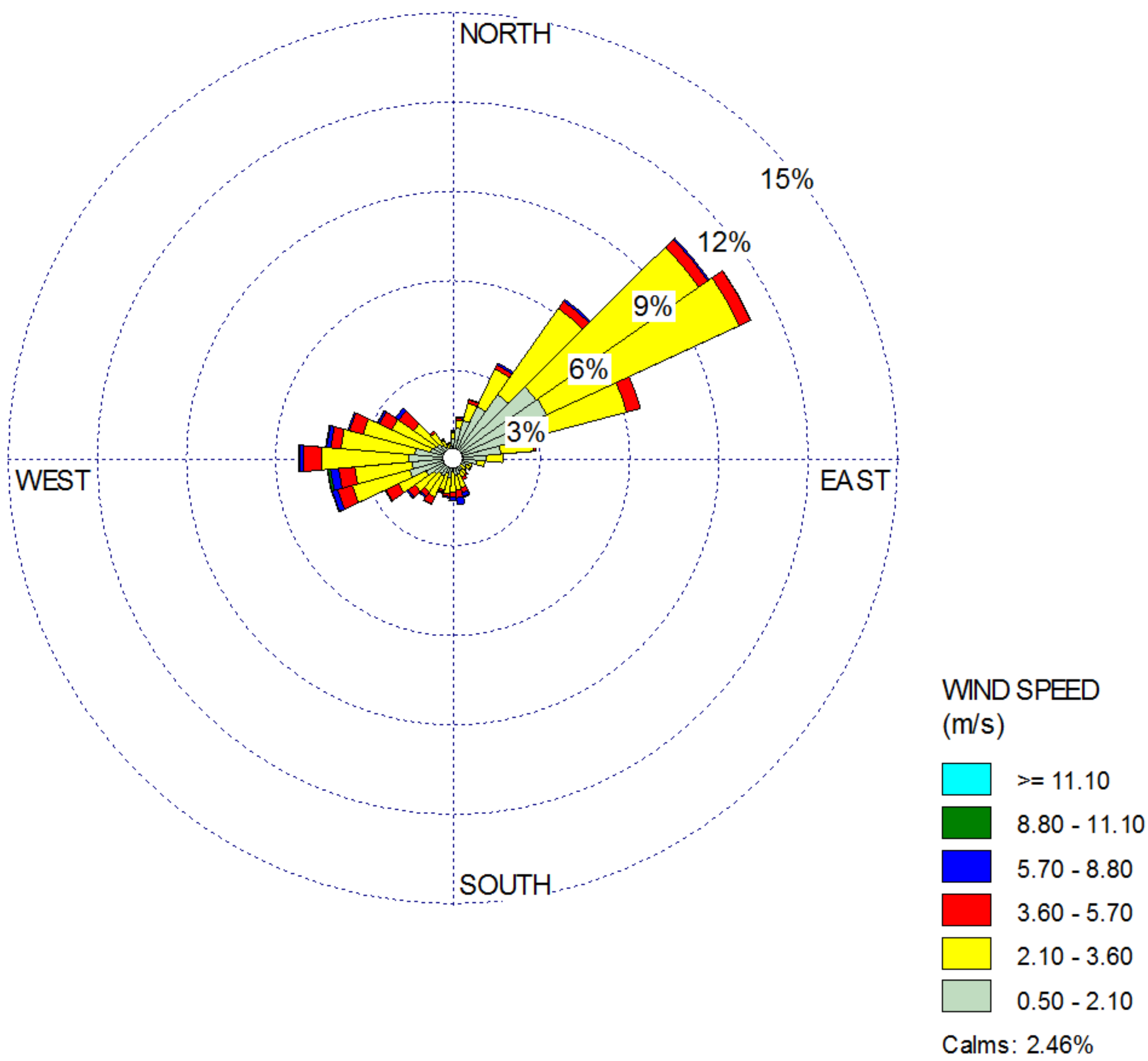
Second Quarter, 2008 – 2012



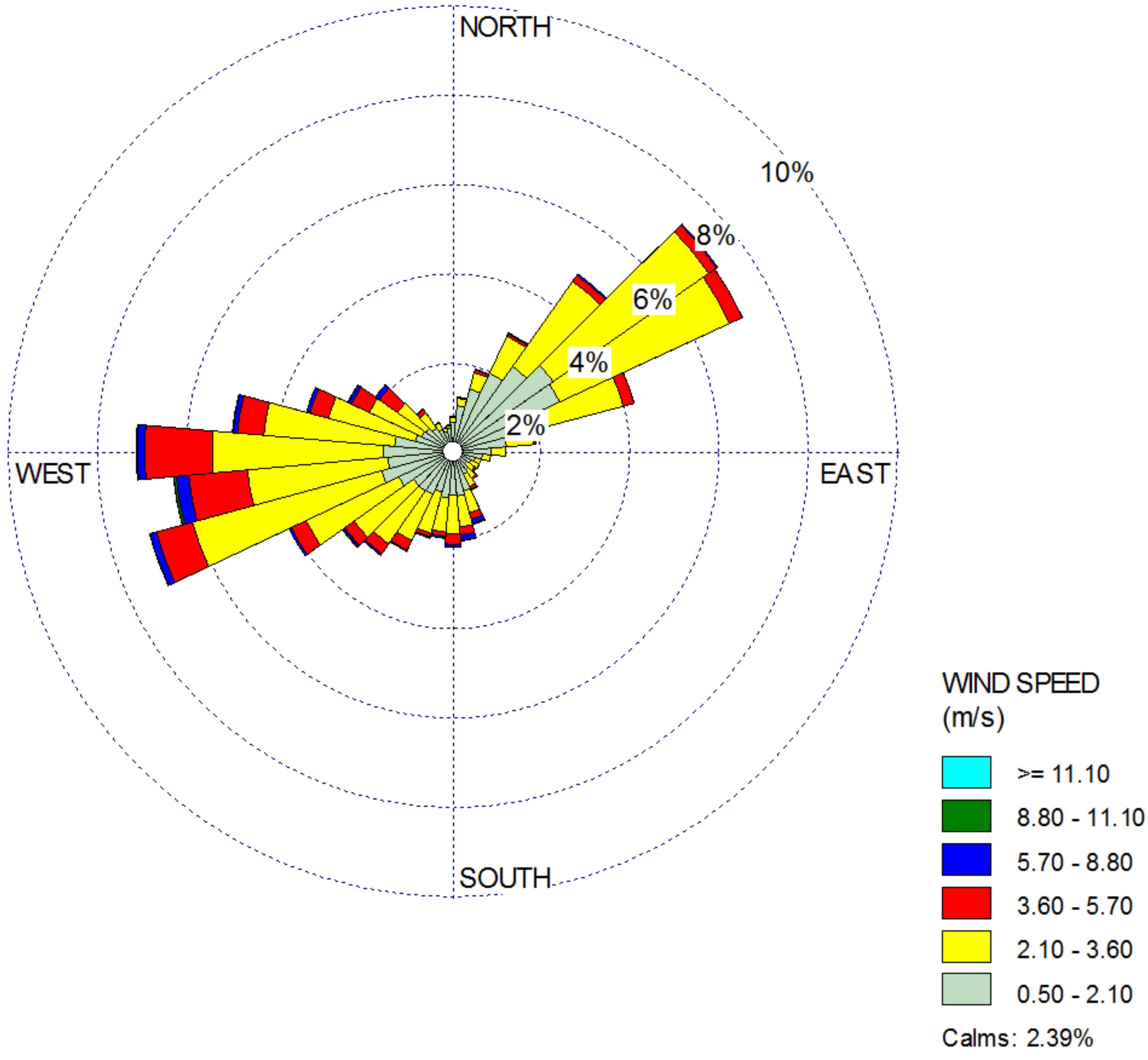
Third Quarter, 2008 – 2012



Fourth Quarter, 2008 – 2012



Annual, 2008 – 2012



Appendix 5.1B
Detailed Emission Calculations

Table 5.1B -1
CECP Amendment
Gas Turbine Emissions

			Standard Conditions:	68 F		29.92		
			Reference O2:	15.00%				
Case	Cold 100% Load	Cold 25% Load	Hot 100% Load w/Evap.	Hot 100% load w/o Evap.	Hot 25% Load	Avg. 100% Load w/Evap.	Avg. 100% Load w/o Evap.	Avg. 25% Load
Ambient Temperature (F)	44.5	44.5	96	96	96	60.3	60.3	60.3
Ambient Humidity (%)	86.1%	86.1%	36.0%	36.0%	36.0%	79.1%	79.1%	79.1%
Inlet Air Cooler	Off	Off	On	Off	Off	On	Off	Off
Water Injection (lbs/hr)	23723	5635	19625	19790	4559	23572	23671	5053
Turbine Fuel Flow Rates								
scfm (margined)	15,850	6,170	14,844	14,408	5,751	16,061	16,089	6,170
Heat Input (margined) (LHV)	874	340	819	795	317	886	887	340
Heat Input (margined) (HHV)	969	377	908	881	352	982	984	377
Gas Turbine Output (kw)	107,665	26,913	98,584	94,357	23,591	108,728	108,837	27,209
Exhaust Gas Parameters								
Exhaust Flow Rate (wacfm)	1,012,885	524,635	985,287	948,559	499,004	1,023,515	1,022,475	523,114
Exhaust Flow Rate (dscfm)	386,192	190,908	349,921	340,745	170,750	382,041	381,368	189,845
Stack Temperature (F)	763.7	856.7	813.1	821.1	920.2	779.1	781.7	854.2
Diluent Concentrations								
O2 (%), dry basis	13.39%	15.00%	13.14%	13.16%	14.75%	13.21%	13.18%	14.96%
CO2 (%), dry basis	4.32%	3.41%	4.47%	4.45%	3.55%	4.43%	4.44%	3.43%
Reference O2 (%), dry basis	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Pollutant Concentrations at Ref. O2								
VOC as CH4, ppmvd	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
CO (short term), ppmvd	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00
CO (long term), ppmvd	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00
NOx (short term), ppmvd	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50
NOx (long term), ppmvd	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50
SOx (short term), ppmvd	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42
SOx (long term), ppmvd	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
NH3, ppmvd	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00
Emission Rates (lbs/hour)								
VOC as CH4	2.50	1.00	2.30	2.20	0.90	2.50	2.50	1.00
CO	8.60	3.40	8.10	7.80	3.10	8.70	8.80	3.40
NOx	8.90	3.40	8.30	8.10	3.20	9.00	9.00	3.50
SOx (short term)	2.04	0.79	1.91	1.85	0.74	2.07	2.07	0.79
SOx (long term)	0.68	0.26	0.64	0.62	0.25	0.69	0.69	0.26
NH3	6.60	2.60	6.10	6.00	2.40	6.60	6.70	2.60
PM10	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50

Table 5.1B-2
GE Performance Runs

Estimated Average Engine Performance NOT FOR GUARANTEE, REFER TO PROJECT F&ID FOR DESIGN
Predicted Intercooler Performance not to be utilized for Balance of Plant design. Please contact GE.

GE Power & Water

Performance By: **Kessler, Daniel**
Project Info: **NRG Carlsbad - Avg. Ambient Load Sweep R0**

Engine: **LMS100 PA**
Deck Info: **G0179E - 8k1.scp**
Generator: **BDAX 82-445ER 60Hz, 13.8kV, 0.9PF (EffCurve#: 35404; CapCurve#: 35407)**
Fuel: **Site Gas Fuel#900-4103, 20598 Btu/lb,LHV**

Date: **2/1/2014**
Time: **3:44:53 PM**
Version: **3.9.8**

Case #	**100**	**101**	**109**
Ambient Conditions			
Dry Bulb, °F	60.3	60.3	60.3
Wet Bulb, °F	56.4	56.4	56.4
RH, %	79.1	79.1	79.1
Altitude, ft	20.9	20.9	20.9
Ambient Pressure, psia	14.685	14.685	14.685
Engine Inlet			
Comp Inlet Temp, °F	57.0	60.3	60.3
RH, %	96.6	79.1	79.1
Conditioning	EVAP	NONE	NONE
Tons(Chilling) or kBtu/hr(Heating)	0	0	0
Pressure Losses			
Inlet Loss, inH20	5.00	5.00	2.90
Exhaust Loss, inH20	10.00	10.00	3.80
Partload %	**100**	**100**	**25**
kW, Gen Terms	**108728**	**108837**	**27209**
Est. Btu/kW-hr, LHV	**7947**	**7953**	**12200**
Guar. Btu/kW-hr, LHV	**7947**	**7953**	--
Fuel Flow			
MMBtu/hr, LHV	864.1	865.6	331.9
lb/hr	41949	42023	16116
Fuel Flow (Margined)			
MMBtu/hr, LHV	885.7	887.2	340.2
MMBtu/hr, HHV	981.9	983.6	377.2
lb/hr	42998	43073	16519
NOx Control	**Water**	**Water**	**Water**
Water Injection			
lb/hr	23572	23671	5053
Temperature, °F	100.0	100.0	100.0
Intercooler	**Dry Fin Fan Cooling**	**Dry Fin Fan**	**Dry Fin Fan**
Humidification	OFF	OFF	OFF
IC Heat Extraction, btu/s	31011	31068	8665
KOD Water Extraction, lb/s	0.9	0.5	0.0
Exhaust Parameters			
Temperature, °F	779.1	781.7	854.2
lb/sec	494.1	493.5	247.3
lb/hr	1778916	1776560	890332
Energy, Btu/s- Ref 0 °R	157619	157788	82872
Cp, Btu/lb-R	0.2742	0.2743	0.2726
Estimated Maximum Emissions (at GT Exhaust) *			
NOx ppmvd Ref 15% O2	25	25	25
NOx as NO2, lb/hr	90	90	35
CO ppmvd Ref 15% O2	113	113	139
CO, lb/hr	247	248	117
VOC, ppmvd Ref 15% O2	2.0	2.0	2.0
VOC, lb/hr	2.51	2.51	0.96
PM-10, lb/hr	3.5	3.5	NS
****Gas Fuel Sulfur contents of </+ 0.25 grains/ 100 scf***			
Estimated Maximum Emissions (at Stack) *			
NOx ppmvd Ref 15% O2	2.5	2.5	2.5
NOx as NO2, lb/hr	9.0	9.0	3.5
CO ppmvd Ref 15% O2	4.0	4.0	4.0
CO, lb/hr	8.7	8.8	3.4
VOC, ppmvd Ref 15% O2	2.0	2.0	2.0
VOC, lb/hr	2.5	2.5	1.0
NH3, ppmvd Ref 15% O2	5.0	5.0	5.0
NH3, lb/hr	6.6	6.7	2.6
PM-10, lb/hr	3.5	3.5	NS
****Gas Fuel Sulfur contents of </+ 0.25 grains/ 100 scf***			

Estimated Average Engine Performance NOT FOR GUARANTEE, REFER TO PROJECT F&ID FOR DESIGN
Predicted Intercooler Performance not to be utilized for Balance of Plant design. Please contact GE.

GE Power & Water

Performance By: **Kessler, Daniel**
Project Info: **NRG Carlsbad - Avg. Ambient Load Sweep R0**

Engine: **LMS100 PA**
Deck Info: **G0179E - 8k1.scp**
Generator: **BDAX 82-445ER 60Hz, 13.8kV, 0.9PF (EffCurve#: 35404; CapCurve#: 35407)**
Fuel: **Site Gas Fuel#900-4103, 20598 Btu/lb,LHV**

Date: **2/1/2014**
Time: **3:44:53 PM**
Version: **3.9.8**

Case #	100	101	109
Exh Wght % Wet (NOT FOR USE IN ENVIRONMENTAL PERMITS) (GT Exhaust)			
AR	1.2320	1.2318	1.2464
N2	72.2646	72.2525	73.1044
O2	13.3917	13.3600	15.4929
CO2	6.1695	6.1891	4.8793
H20	6.9373	6.9618	5.2726
SO2	0.0000	0.0000	0.0000
CO	0.0014	0.0014	0.0016
HC	0.0002	0.0002	0.0001
NOX	0.0033	0.0033	0.0026
Exh Mole % Dry (NOT FOR USE IN ENVIRONMENTAL PERMITS) (GT Exhaust)			
AR	0.9731	0.9732	0.9642
N2	81.3931	81.4047	80.6425
O2	13.2054	13.1782	14.9625
CO2	4.4233	4.4387	3.4262
H20	0.0000	0.0000	0.0000
SO2	0.0000	0.0000	0.0000
CO	0.0015	0.0015	0.0018
HC	0.0003	0.0003	0.0003
NOX	0.0033	0.0033	0.0025
Exh Mole % Wet (NOT FOR USE IN ENVIRONMENTAL PERMITS) (GT Exhaust)			
AR	0.8677	0.8674	0.8842
N2	72.5749	72.5551	73.9537
O2	11.7747	11.7456	13.7215
CO2	3.9441	3.9562	3.1420
H20	10.8341	10.8711	8.2944
SO2	0.0000	0.0000	0.0000
CO	0.0014	0.0014	0.0017
HC	0.0003	0.0003	0.0002
NOX	0.0029	0.0029	0.0023

Aero Energy Fuel Number	**900-4103 (Steve Rose Sample 59F)**	
	Volume %	**Weight %**
Hydrogen	0.0000	0.0000
Methane	95.8700	91.1296
Ethane	1.8080	3.2212
Ethylene	0.0000	0.0000
Propane	0.3360	0.8779
Propylene	0.0000	0.0000
Butane	0.1220	0.4201
Butylene	0.0000	0.0000
Butadiene	0.0000	0.0000
Pentane	0.0430	0.1838
Cyclopentane	0.0000	0.0000
Hexane	0.0260	0.1328
Heptane	0.0000	0.0000
Carbon Monoxide	0.0000	0.0000
Carbon Dioxide	1.1130	2.9025
Nitrogen	0.6820	1.1321
Water Vapor	0.0000	0.0000
Oxygen	0.0000	0.0000
Hydrogen Sulfide	0.0000	0.0000
Ammonia	0.0000	0.0000

Btu/lb, LHV	20598
Btu/scf, LHV	918.4
Btu/scf, HHV	1018.2
Btu/lb, HHV	22836
Fuel Temp, °F	59.0
NOx Scalar	0.978
Specific Gravity	0.58
Wobbe	52.834

Estimated Average Engine Performance NOT FOR GUARANTEE, REFER TO PROJECT F&ID FOR DESIGN
Predicted Intercooler Performance not to be utilized for Balance of Plant design. Please contact GE.

GE Power & Water

Performance By: **Vu, Christopher**
Project Info: **NRG Carlsbad - Avg. Ambient Load Sweep R0**

Engine: **LMS100 PA**
Deck Info: **G0179E - 8k1.scp**
Generator: **BDAX 82-445ER 60Hz, 13.8kV, 0.9PF (EffCurve#: 35404; CapCurve#: 35407)**
Fuel: **Site Gas Fuel#900-4103, 20598 Btu/lb,LHV**

Date: **2/6/2014**
Time: **3:44:53 PM**
Version: **3.9.8**

Case #	**300**	**308**
Ambient Conditions		
Dry Bulb, °F	44.5	44.5
Wet Bulb, °F	42.6	42.6
RH, %	86.1	86.1
Altitude, ft	20.9	20.9
Ambient Pressure, psia	14.685	14.685
Engine Inlet		
Comp Inlet Temp, °F	44.5	44.5
RH, %	86.1	86.1
Conditioning	NONE	NONE
Tons(Chilling) or kBtu/hr(Heating)	0	0
Pressure Losses		
Inlet Loss, inH20	5.00	5.00
Exhaust Loss, inH20	10.00	10.00
Partload %	**100**	**25**
kW, Gen Terms	**107665**	**26913**
Est. Btu/kW-hr, LHV	**7920**	**12334**
Guar. Btu/kW-hr, LHV	**7920**	--
Fuel Flow		
MMBtu/hr, LHV	852.7	331.9
lb/hr	41398	16115
Fuel Flow (Margined)		
MMBtu/hr, LHV	874.0	340.2
MMBtu/hr, HHV	969.0	377.2
lb/hr	42432	16518
NOx Control	**Water**	**Water**
Water Injection		
lb/hr	23723	5635
Temperature, °F	100.0	100.0
Intercooler	**Dry Fin Fan Cooling**	**Dry Fin Fan**
Humidification	OFF	OFF
IC Heat Extraction, btu/s	28202	7474
KOD Water Extraction, lb/s	0.0	0.0
Exhaust Parameters		
Temperature, °F	763.7	856.7
lb/sec	497.5	248.0
lb/hr	1791150	892660
Energy, Btu/s- Ref 0 °R	156191	83059
Cp, Btu/lb-R	0.2728	0.2720

Estimated Maximum Emissions (at GT Exhaust) *		
NOx ppmvd Ref 15% O2	25	25
NOx as NO2, lb/hr	89	34
CO ppmvd Ref 15% O2	113	139
CO, lb/hr	244	117
VOC, ppmvd Ref 15% O2	2.0	2.0
VOC, lb/hr	2.47	0.96
PM-10, lb/hr	3.5	NS

** Gas Fuel Sulfur contents of </+ 0.25 grains/ 100 scf*

Estimated Maximum Emissions (at Stack) *		
NOx ppmvd Ref 15% O2	2.5	2.5
NOx as NO2, lb/hr	8.9	3.4
CO ppmvd Ref 15% O2	4.0	4.0
CO, lb/hr	8.6	3.4
VOC, ppmvd Ref 15% O2	2.0	2.0
VOC, lb/hr	2.5	1.0
NH3, ppmvd Ref 15% O2	5.0	5.0
NH3, lb/hr	6.6	2.6
PM-10, lb/hr	3.5	NS

** Gas Fuel Sulfur contents of </+ 0.25 grains/ 100 scf*

Estimated Average Engine Performance NOT FOR GUARANTEE, REFER TO PROJECT F&ID FOR DESIGN
Predicted Intercooler Performance not to be utilized for Balance of Plant design. Please contact GE.

GE Power & Water

Performance By: **Vu, Christopher**
Project Info: **NRG Carlsbad - Avg. Ambient Load Sweep R0**

Engine: **LMS100 PA**
Deck Info: **G0179E - 8k1.scp**
Generator: **BDAX 82-445ER 60Hz, 13.8kV, 0.9PF (EffCurve#: 35404; CapCurve#: 35407)**
Fuel: **Site Gas Fuel#900-4103, 20598 Btu/lb,LHV**

Date: **2/6/2014**
Time: **3:44:53 PM**
Version: **3.9.8**

Case #	**300**	**308**
Exh Wght % Wet (NOT FOR USE IN ENVIRONMENTAL PERMITS) (GT Exhaust)		
AR	1.2355	1.2500
N2	72.4649	73.3121
O2	13.6292	15.5746
CO2	6.0464	4.8667
H20	6.6193	4.9923
SO2	0.0000	0.0000
CO	0.0013	0.0016
HC	0.0001	0.0001
NOX	0.0032	0.0026
Exh Mole % Dry (NOT FOR USE IN ENVIRONMENTAL PERMITS) (GT Exhaust)		
AR	0.9722	0.9640
N2	81.3145	80.6281
O2	13.3895	14.9962
CO2	4.3189	3.4071
H20	0.0000	0.0000
SO2	0.0000	0.0000
CO	0.0015	0.0018
HC	0.0003	0.0002
NOX	0.0032	0.0025
Exh Mole % Wet (NOT FOR USE IN ENVIRONMENTAL PERMITS) (GT Exhaust)		
AR	0.8715	0.8882
N2	72.8949	74.2857
O2	12.0031	13.8166
CO2	3.8717	3.1391
H20	10.3544	7.8663
SO2	0.0000	0.0000
CO	0.0013	0.0017
HC	0.0003	0.0002
NOX	0.0029	0.0023

Aero Energy Fuel Number	**900-4103 (Steve Rose Sample 59F)**	
	Volume %	**Weight %**
Hydrogen	0.0000	0.0000
Methane	95.8700	91.1296
Ethane	1.8080	3.2212
Ethylene	0.0000	0.0000
Propane	0.3360	0.8779
Propylene	0.0000	0.0000
Butane	0.1220	0.4201
Butylene	0.0000	0.0000
Butadiene	0.0000	0.0000
Pentane	0.0430	0.1838
Cyclopentane	0.0000	0.0000
Hexane	0.0260	0.1328
Heptane	0.0000	0.0000
Carbon Monoxide	0.0000	0.0000
Carbon Dioxide	1.1130	2.9025
Nitrogen	0.6820	1.1321
Water Vapor	0.0000	0.0000
Oxygen	0.0000	0.0000
Hydrogen Sulfide	0.0000	0.0000
Ammonia	0.0000	0.0000
Btu/lb, LHV	20598	
Btu/scf, LHV	918.4	
Btu/scf, HHV	1018.2	
Btu/lb, HHV	22836	
Fuel Temp, °F	59.0	
NOx Scalar	0.978	
Specific Gravity	0.58	
Wobbe	52.834	

Estimated Average Engine Performance NOT FOR GUARANTEE, REFER TO PROJECT F&ID FOR DESIGN
Predicted Intercooler Performance not to be utilized for Balance of Plant design. Please contact GE.

GE Power & Water

Performance By: **Vu, Christopher**
Project Info: **NRG Carlsbad - Avg. Ambient Load Sweep R0**

Engine: **LMS100 PA**
Deck Info: **G0179E - 8k1.scp**
Generator: **BDAX 82-445ER 60Hz, 13.8kV, 0.9PF (EffCurve#: 35404; CapCurve#: 35407)**
Fuel: **Site Gas Fuel#900-4103, 20598 Btu/lb,LHV**

Date: **2/6/2014**
Time: **3:44:53 PM**
Version: **3.9.8**

Case #	**400**	**401**	**409**
Ambient Conditions			
Dry Bulb, °F	96.0	96.0	96.0
Wet Bulb, °F	74.1	74.1	74.1
RH, %	36.0	36.0	36.0
Altitude, ft	20.9	20.9	20.9
Ambient Pressure, psia	14.685	14.685	14.685
Engine Inlet			
Comp Inlet Temp, °F	77.4	96.0	96.0
RH, %	86.0	36.0	36.0
Conditioning	EVAP	NONE	NONE
Tons(Chilling) or kBtu/hr(Heating)	0	0	0
Pressure Losses			
Inlet Loss, inH20	5.00	5.00	5.00
Exhaust Loss, inH20	10.00	10.00	10.00
Partload %	**100**	**100**	**25**
kW, Gen Terms	**98584**	**94357**	**23591**
Est. Btu/kW-hr, LHV	**8101**	**8215**	**13115**
Guar. Btu/kW-hr, LHV	**8101**	**8215**	--
Fuel Flow			
MMBtu/hr, LHV	798.6	775.1	309.4
lb/hr	38772	37632	15021
Fuel Flow (Margined)			
MMBtu/hr, LHV	818.6	794.5	317.1
MMBtu/hr, HHV	907.5	880.8	351.6
lb/hr	39741	38573	15396
NOx Control	**Water**	**Water**	**Water**
Water Injection			
lb/hr	19625	19790	4559
Temperature, °F	100.0	100.0	100.0
Intercooler	**Dry Fin Fan Cooling**	**Dry Fin Fan**	**Dry Fin Fan**
Humidification	OFF	OFF	OFF
IC Heat Extraction, btu/s	28292	28726	8649
KOD Water Extraction, lb/s	0.7	0.0	0.0
Exhaust Parameters			
Temperature, °F	813.1	821.1	920.2
lb/sec	454.6	441.0	223.8
lb/hr	1636482	1587556	805535
Energy, Btu/s- Ref 0 °R	150043	146286	79368
Cp, Btu/lb-R	0.2770	0.2768	0.2763
Estimated Maximum Emissions (at GT Exhaust) *			
NOx ppmvd Ref 15% O2	25	25	25
NOx as NO2, lb/hr	83	81	32
CO ppmvd Ref 15% O2	113	113	113
CO, lb/hr	228	222	88
VOC, ppmvd Ref 15% O2	2.0	2.0	2.0
VOC, lb/hr	2.32	2.25	0.90
PM-10, lb/hr	3.5	3.5	NS
***Gas Fuel Sulfur contents of </+ 0.25 grains/ 100 scf**			
Estimated Maximum Emissions (at Stack) *			
NOx ppmvd Ref 15% O2	2.5	2.5	2.5
NOx as NO2, lb/hr	8.3	8.1	3.2
CO ppmvd Ref 15% O2	4.0	4.0	4.0
CO, lb/hr	8.1	7.8	3.1
VOC, ppmvd Ref 15% O2	2.0	2.0	2.0
VOC, lb/hr	2.3	2.2	0.9
NH3, ppmvd Ref 15% O2	5.0	5.0	5.0
NH3, lb/hr	6.1	6.0	2.4
PM-10, lb/hr	3.5	3.5	NS
***Gas Fuel Sulfur contents of </+ 0.25 grains/ 100 scf**			

Estimated Average Engine Performance NOT FOR GUARANTEE, REFER TO PROJECT F&ID FOR DESIGN
Predicted Intercooler Performance not to be utilized for Balance of Plant design. Please contact GE.

GE Power & Water

Performance By: **Vu, Christopher**
Project Info: **NRG Carlsbad - Avg. Ambient Load Sweep R0**

Engine: **LMS100 PA**
Deck Info: **G0179E - 8k1.scp**
Generator: **BDAX 82-445ER 60Hz, 13.8kV, 0.9PF (EffCurve#: 35404; CapCurve#: 35407)**
Fuel: **Site Gas Fuel#900-4103, 20598 Btu/lb,LHV**

Date: **2/6/2014**
Time: **3:44:53 PM**
Version: **3.9.8**

Case #	400	401	409
Exh Wght % Wet (NOT FOR USE IN ENVIRONMENTAL PERMITS) (GT Exhaust)			
AR	1.2237	1.2264	1.2405
N2	71.7735	71.9324	72.7561
O2	13.2250	13.2816	15.1780
CO2	6.1804	6.1750	5.0245
H20	7.5926	7.3798	5.7963
SO2	0.0000	0.0000	0.0000
CO	0.0015	0.0015	0.0019
HC	0.0002	0.0002	0.0001
NOX	0.0033	0.0033	0.0027
Exh Mole % Dry (NOT FOR USE IN ENVIRONMENTAL PERMITS) (GT Exhaust)			
AR	0.9735	0.9733	0.9653
N2	81.4231	81.4123	80.7351
O2	13.1350	13.1604	14.7455
CO2	4.4631	4.4487	3.5491
H20	0.0000	0.0000	0.0000
SO2	0.0000	0.0000	0.0000
CO	0.0017	0.0017	0.0021
HC	0.0003	0.0003	0.0003
NOX	0.0033	0.0033	0.0026
Exh Mole % Wet (NOT FOR USE IN ENVIRONMENTAL PERMITS) (GT Exhaust)			
AR	0.8585	0.8615	0.8775
N2	71.8054	72.0538	73.3943
O2	11.5835	11.6476	13.4048
CO2	3.9359	3.9373	3.2264
H20	11.8120	11.4952	9.0925
SO2	0.0000	0.0000	0.0000
CO	0.0015	0.0015	0.0019
HC	0.0003	0.0003	0.0003
NOX	0.0029	0.0029	0.0024

Aero Energy Fuel Number	**900-4103 (Steve Rose Sample 59F)**	
	Volume %	**Weight %**
Hydrogen	0.0000	0.0000
Methane	95.8700	91.1296
Ethane	1.8080	3.2212
Ethylene	0.0000	0.0000
Propane	0.3360	0.8779
Propylene	0.0000	0.0000
Butane	0.1220	0.4201
Butylene	0.0000	0.0000
Butadiene	0.0000	0.0000
Pentane	0.0430	0.1838
Cyclopentane	0.0000	0.0000
Hexane	0.0260	0.1328
Heptane	0.0000	0.0000
Carbon Monoxide	0.0000	0.0000
Carbon Dioxide	1.1130	2.9025
Nitrogen	0.6820	1.1321
Water Vapor	0.0000	0.0000
Oxygen	0.0000	0.0000
Hydrogen Sulfide	0.0000	0.0000
Ammonia	0.0000	0.0000

Btu/lb, LHV	20598
Btu/scf, LHV	918.4
Btu/scf, HHV	1018.2
Btu/lb, HHV	22836
Fuel Temp, °F	59.0
NOx Scalar	0.978
Specific Gravity	0.58
Wobbe	52.834

Table 5.1B-3
CECP Amendment
Gas Turbine Hourly Emissions - Startup/Shutdown Emissions

Gas Turbine - Hourly Startup Emissions (per GT)

	Time (minutes)	NOx Emissions (lbs/hr)	CO Emissions (lbs/hr)	VOC Emissions (lbs/hr)	PM10 Emissions (lbs/hr)	SOx Emissions (lbs/hr)	NOx Emissions (lbs)	CO Emissions (lbs)	VOC Emissions (lbs)	PM10 Emissions (lbs)	SOx Emissions (lbs)
Maximum Startup Emissions	25	N/A	N/A	N/A	3.5	0.8	14.7	7.4	2.0	1.5	0.3
Maximum Normal Operation Emissions	35	9.0	8.8	2.5	3.5	2.1	5.3	5.1	1.5	2.0	1.2
Total =	60						20.0	12.5	3.5	3.5	1.5

Gas Turbine - Hourly Shutdown Emissions (per GT)

	Time (minutes)	NOx Emissions (lbs/hr)	CO Emissions (lbs/hr)	VOC Emissions (lbs/hr)	PM10 Emissions (lbs/hr)	SOx Emissions (lbs/hr)	NOx Emissions (lbs)	CO Emissions (lbs)	VOC Emissions (lbs)	PM10 Emissions (lbs)	SOx Emissions (lbs)
Maximum Shutdown Emissions	13	N/A	N/A	N/A	3.5	0.8	0.6	3.4	2.4	0.8	0.2
Maximum Normal Operation Emissions	47	9.0	8.8	2.5	3.5	2.1	7.1	6.9	2.0	2.7	1.6
Total =	60						7.7	10.3	4.4	3.5	1.8

Gas Turbine - Hourly Startup/Shutdown/Restart Emissions (per GT)

	Time (minutes)	NOx Emissions (lbs/hr)	CO Emissions (lbs/hr)	VOC Emissions (lbs/hr)	PM10 Emissions (lbs/hr)	SOx Emissions (lbs/hr)	NOx Emissions (lbs)	CO Emissions (lbs)	VOC Emissions (lbs)	PM10 Emissions (lbs)	SOx Emissions (lbs)
Maximum Startup Emissions	25	N/A	N/A	N/A	3.5	0.8	14.7	7.4	2.0	1.5	0.3
Maximum Shutdown Emissions	13	N/A	N/A	N/A	3.5	0.8	0.6	3.4	2.4	0.8	0.2
Maximum Restart Emissions*	22	N/A	N/A	N/A	3.5	0.8	12.9	6.5	1.8	1.3	0.3
Total =	60						28.2	17.3	6.2	3.5	0.8

Note: * Calculated based on maximum startup emissions reduced for 22 minute period.

Table 5.1B-4
GE Startup/Shutdown Information

LMS100 PA Estimated Startup Stack Emissions - Gas Fuel Operation

Event	Duration (min)	Heat Input (MMBTU - HHV)	NOx (lb)	CO (lb)	VOC (lb)
Startup	25	293.57	14.7	7.4	2.0

**** Fuel Must Meet GE Gas Fuel Spec (MID-TD-0000-1 LATEST REVISION)**

Based on a Ramp to 100% Load. 60.3°F, 79.1%RH, No Inlet Conditioning, Inlet/Exhaust Loss (inH2O) 5.0/10.0, at 20.9ft. AMSL, Gas Fuel900-4103 (Steve Rose Sample 59F) Btu/lb (LHV/HHV) (20,598/22,836), Water Injected to 0 ppmvdc, Dry Secondary Cooler, G0179

VOC's are defined as non-methane, non-ethane, 50% saturated. VOC mass rates reported as methane.

LMS100 PA Estimated Shutdown STACK Emissions - Gas Fuel Operation

Event	Duration (min)	Heat Input (MMBTU - HHV)	NOx (lb)	CO (lb)	VOC (lb)
Shutdown	13	48.63	0.6	3.4	2.4

*Fuel Must Meet GE Gas Fuel Spec (MID-TD-0000-1 LATEST REVISION)

Based on a Ramp to 100% Load. 60.3°F, 79.1%RH, No Inlet Conditioning, Inlet/Exhaust Loss (inH2O) 5.0/10.0, at 20.9ft. AMSL, Gas Fuel900-4103 (Steve Rose Sample 59F) Btu/lb (LHV/HHV) (20,598/22,836), Water Injected to 25 ppmvdc, Dry Secondary Cooler, G017

VOC's are defined as non-methane, non-ethane, 50% saturated. VOC mass rates reported as methane.

Table 5.1B-5
CECP Amendment
Gas Turbine Commissioning Schedule

Description	Power Level	Operating Hours	% Output	Fuel Rate MMBtu/hr	Fuel Use MMBtu	Total Estimated Emissions				Calculated Hourly Emission Rates			
						NOx lbs	CO lbs	VOC lbs	PM10 lbs	NOx lbs/hr	CO lbs/hr	VOC lbs/hr	PM10 lbs/hr
Estimated Non-Fired Hours During Commissioning													
(1) Dry fire GTG	Non-Fired	12	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Estimated Fired Hours During Commissioning													
(2) **First Fire the unit & then shutdown to check for leaks, etc**													
First fire the unit & then shutdown to check for leaks, etc	Core / Sync Idle	16	CI	128.7	2059	753.0	1834.0	126.0	56.0	47.1	114.6	7.9	3.5
Sub-Total													
(3) **Synch & Check E-Stop**													
Fire the unit and bring to synchronous load… … do a system check out (check E-stop, etc)	Sync Idle	12	SI	128.7	1544	565.0	1375.0	95.0	42.0	47.1	114.6	7.9	3.5
(4) **Additional AVR Commissioning**													
Sync to the grid… continue commissioning of the AVR		12	10%	243.8	2926	428.0	1303.0	90.0	42.0	35.7	108.6	7.5	3.5
(5) **Break-In Run**													
Controlled “Break-In Run”		8	10%	243.8	1951	285.0	869.0	60.0	28.0	35.6	108.6	7.5	3.5
(6) **Dynamic Commissioning of AVR & Water Injection**													
Bring back up to synchronous speed… … begin dynamic commissioning of the AVR													
Load Step 1		3	10%	243.8	732	107.0	326.0	22.0	11.0	35.7	108.7	7.3	3.5
Load Step 2		3	20%	339.3	1018	93.0	315.0	2.6	11.0	31.0	105.0	0.9	3.5
Load Step 3		3	30%	431.8	1296	118.0	326.0	3.3	11.0	39.3	108.7	1.1	3.5
Load Step 4		3	40%	516.6	1550	142.0	390.0	4.0	11.0	47.3	130.0	1.3	3.5
Load Step 5		3	50%	583.5	1751	160.0	441.0	4.5	11.0	53.3	147.0	1.5	3.5
Load Step 6		3	60%	661.6	1985	182.0	500.0	5.1	11.0	60.7	166.7	1.7	3.5
Load Step 7		3	70%	736.3	2209	202.0	556.0	5.6	11.0	67.3	185.3	1.9	3.5
Load Step 8		3	80%	812.2	2437	223.0	613.0	6.2	11.0	74.3	204.3	2.1	3.5
Load Step 9		3	90%	894.9	2685	246.0	676.0	6.8	11.0	82.0	225.3	2.3	3.5
Load Step 10		3	100%	983.6	2951	270.0	743.0	7.5	11.0	90.0	247.7	2.5	3.5

Table 5.1B-5
CECP Amendment
Gas Turbine Commissioning Schedule (cont.)

(7) **Base load AVR Commissioning / Burnout for Exhaust Prior to Catalyst Installation**													
Once at base load, complete AVR commissioning		12	100%	983.6	11804	1080.0	2971.0	30.0	42.0	90.0	247.6	2.5	3.5
(8) **Emissions Control System (ECS) Tuning (m)**													
Controlled "Break-In Run" (n)	100%	2	100%	983.6	1968	36.0	99.0	4.0	7.0	18.0	49.5	2.0	3.5
Control System initial Start-up & Troubleshooting (o)	50%	4	50%	583.5	2335	43.0	117.0	5.0	14.0	10.8	29.3	1.3	3.5
Control System Tuning	0-100%												
Load Step 1	0%	1.5	0%	128.7	193	14.0	5.0	4.7	5.0	9.3	3.3	3.1	3.3
Load Step 2	10%	1.5	10%	243.8	366	11.0	5.0	4.5	5.0	7.3	3.3	3.0	3.3
Load Step 3	20%	1.5	20%	339.3	509	9.0	5.0	1.0	5.0	6.0	3.3	0.7	3.3
Load Step 4	30%	1.5	30%	431.8	648	12.0	6.0	1.3	5.0	8.0	4.0	0.9	3.3
Load Step 5	40%	1.5	40%	516.6	775	14.0	7.0	1.6	5.0	9.3	4.7	1.1	3.3
Load Step 6	50%	1.5	50%	583.5	876	16.0	8.0	1.8	5.0	10.7	5.3	1.2	3.3
Load Step 7	60%	1.5	60%	661.6	993	18.0	9.0	2.0	5.0	12.0	6.0	1.3	3.3
Load Step 8	70%	1.5	70%	736.3	1105	20.0	10.0	2.3	5.0	13.3	6.7	1.5	3.3
Load Step 9	80%	1.5	80%	812.2	1219	22.0	11.0	2.5	5.0	14.7	7.3	1.7	3.3
Load Step 10	90%	1.5	90%	894.9	1343	25.0	12.0	2.7	5.0	16.7	8.0	1.8	3.3
Load Step 11	100%	1.5	100%	983.6	1476	27.0	13.0	3.0	5.0	18.0	8.7	2.0	3.3
(9) **GE Performance Test**													
Baseload: installation, preliminary testing, and official test.		8	100%	983.6	7869	72.0	70.0	20.0	28.0	9.0	8.8	2.5	3.5
(10) **PPA Performance Test**													
Baseload: installation, preliminary testing, and official test.		8	100%	983.6	7869	72.0	70.0	20.0	28.0	9.0	8.8	2.5	3.5
(11) **Reliability Test**													
Once at base load, complete Reliability Test		72	100%	983.6	70821	648.0	631.0	181.0	252.0	9.0	8.8	2.5	3.5
Total =		213				5913	14316	726	704				
					max =	1080.0	2971.0	181.0	252.0	90.0	247.7	7.9	3.5

Table 5.1B-6
GE Commissioning Schedule

ESTIMATED Fired Hours, Fuel Usage, Emissions and Exhaust Parameters - NOT FOR GUARANTEE - NOT FOR PERMIT USE

for Commissioning Estimates [a] [b] [c] [d] [e] [f] [g] [h] [i] [j] [k] [l] [m] [n] [o]

GAS FUEL LMS100 PA Water Injected, 60HZ

	Description	Power Level	Estimated Operating Hours	% Output	Estimated kW Output	Estimated Fuel Rate MMBtu/hr HHV	Estimated Fuel Usage MMBtu's	Total Estimated Emission per Event NOx lbs	CO lbs	VOC lbs	PM10 lbs
	Estimated Non-Fired Hours During Commissioning										
(1)	Dry fire GTG	Non-Fired	12	0	NA	NA	NA	NA	NA	NA	NA
	Estimated Fired Hours During Commissioning										
(2)	**First Fire the unit & then shutdown to check for leaks, etc**										
	First fire the unit & then shutdown to check for leaks, etc	Core / Sync Idle	16	CI	0	128.7	2059	753	1834	126	56
	Sub-Total		**16**								
(3)	**Synch & Check E-Stop**										
	Fire the unit and bring to synchronous load…	Sync Idle	12	SI	0	128.7	1544	565	1375	95	42
	… do a system check out (check E-stop, etc)										
	Sub-Total		**12**								
(4)	**Additional AVR Commissioning**										
	Sync to the grid… continue commissioning of the AVR		12	10%	10884	243.8	2926	428	1303	90	42
	Sub-Total		**12**								
(5)	**Break-In Run**										
	Controlled "Break-In Run"		8	10%	10884	243.8	1951	285	869	60	28
	Sub-Total		**8**								
(6)	**Dynamic Commissioning of AVR & Water Injection**										
	Bring back up to synchronous speed…										
	… begin dynamic commissioning of the AVR										
	Load Step 1		3.0	10%	10884	243.8	732	107	326	22	11
	Load Step 2		3.0	20%	21766	339.3	1018	93	315	2.6	11
	Load Step 3		3.0	30%	32651	431.8	1296	118	326	3.3	11
	Load Step 4		3.0	40%	43535	516.6	1550	142	390	4.0	11
	Load Step 5		3.0	50%	54420	583.5	1751	160	441	4.5	11
	Load Step 6		3.0	60%	65302	661.6	1985	182	500	5.1	11
	Load Step 7		3.0	70%	76186	736.3	2209	202	556	5.6	11
	Load Step 8		3.0	80%	87070	812.2	2437	223	613	6.2	11
	Load Step 9		3.0	90%	97953	894.9	2685	246	676	6.8	11
	Load Step 10		3.0	100%	108837	983.6	2951	270	743	7.5	11
	Sub-Total		**30**								
(7)	**Base load AVR Commissioning / Burnout for Exhaust Prior to Catalyst Installation**										
	Once at base load, complete AVR commissioning		12	100%	108837	983.6	11804	1080	2971	30	42
	Sub-Total		**12**								

ESTIMATED Fired Hours, Fuel Usage, Emissions and Exhaust Parameters - NOT FOR GUARANTEE - NOT FOR PERMIT USE

for Commissioning Estimates (a) (b) (c) (d) (e) (f) (g) (h) (i) (j) (k) (l) (m) (n) (o)

GAS FUEL LMS100 PA Water Injected, 60HZ

	Description	Power Level	Estimated Operating Hours	% Output	Estimated kW Output	Estimated Fuel Rate MMBtu/hr HHV	Estimated Fuel Usage MMBtu's	Total Estimated Emission per Event NOx lbs	CO lbs	VOC lbs	PM10 lbs
(8)	**Emissions Control System (ECS) Tuning [m]**										
	Controlled "Break-In Run" [n]	100%	**2**	100%	108837	983.6	1968	36	99	4	7
	Control System initial Start-up & Troubleshooting [o]	50%	**4**	50%	54420	583.5	2335	43	117	5	14
	Control System Tuning	0-100%									
	Load Step 1	0%	1.5	0%	0	128.7	193	14	5	4.7	5
	Load Step 2	10%	1.5	10%	10884	243.8	366	11	5	4.5	5
	Load Step 3	20%	1.5	20%	21766	339.3	509	9	5	1.0	5
	Load Step 4	30%	1.5	30%	32651	431.8	648	12	6	1.3	5
	Load Step 5	40%	1.5	40%	43535	516.6	775	14	7	1.6	5
	Load Step 6	50%	1.5	50%	54420	583.5	876	16	8	1.8	5
	Load Step 7	60%	1.5	60%	65302	661.6	993	18	9	2.0	5
	Load Step 8	70%	1.5	70%	76186	736.3	1105	20	10	2.3	5
	Load Step 9	80%	1.5	80%	87070	812.2	1219	22	11	2.5	5
	Load Step 10	90%	1.5	90%	97953	894.9	1343	25	12	2.7	5
	Load Step 11	100%	1.5	100%	108837	983.6	1476	27	13	3.0	5
	Sub-Total		**17**								
	Sub-Total		**23**								
(9)	**GE Performance Test**										
	Baseload: installation, preliminary testing, and official test.		8	100%	108837	983.6	7869	72	70	20	28
	Sub-Total		**8**								
(10)	**PPA Performance Test**										
	Baseload: installation, preliminary testing, and official test.		8	100%	108837	983.6	7869	72	70	20	28
	Sub-Total		**8**								
(11)	**Reliability Test**										
	Once at base load, complete Reliability Test		72	100%	108837	983.6	70821	648	631	181	252
	Sub-Total		**72**								

Estimated Fired Hours without Catalyst in Operation	**125**
Estimated Fired Hours with Catalyst in Operation	**88**
Total Estimated Comissioning Hours	**213**

	Estimated Fuel Usage MMBtu HHV	NOx lbs	CO lbs	VOC lbs	PM10 lbs
Without Catalyst in Operation	**38898**	**4853**	**13237**	**468**	**315**
With Catalyst in Operation	**100365**	**1059**	**1077**	**257**	**387**
Total	**139263**	**5912**	**14314**	**725**	**702**

Assumptions:

a) Site Conditions are 60.3F, 79.1% RH, Sea Level, 5/12 Inch H20 Losses, Dry Secondary Cooler, Gas Fuel as stated below
b) All commissioning activities except (9)(10)(11) take place without exhaust treatment in operation
c) Core idle (CI) and sync idle (SI) are assumed to have same mass rates
d) All data is based on this estimated commissioning schedule, which will vary between sites and engines. Schedule and data is estimated only.
e) VOC's are defined as non-methane, non-ethane, 50% saturated. Mass rate reported as Methane.
f) Calculations executed using the gas below with GCV = 22836 Btu/lb and margined heat input
g) Fuel composition <5% C3+
h) Sulfur < 0.25 grains/100 SCF
i) Assumes water is used to maintain 25 ppmvdc NOX
j) Not for guarantee and not for permit use
k) Other commissioning activities not stated here are not included in this estimate
l) It is assumed that NOX water tuning and AVR tuning can be concurent
m) After the break-in period - during ECS tuning - the CO catalyst is assumed to be fully function and an average reduction of 80% from the SCR
n) The "controlled break in" run after catalyst installation is to check seals and installation - assume 80% NOX reduction, 80% CO reduction, 20% VOC reduction
o) Assumed 80% NOX and CO reduction; 20% VOC reduction.

Table 5.1B-7
CECP Amendment
Emergency Firepump Engine

Rating (bhp) =	327				
Fuel =	Diesel				
Fuel Consumption (gal/hr) =	14.8				
Exhaust Temperature (F) =	842				
Exhaust Diameter (inches) =	6				
Exhaust Flow Rate (acfm) =	1,867				
Exhaust Velocity (ft/sec) =	158				
	NOx	**CO**	**VOC**	**PM10**	**SOx**
Emission Factor (g/bhp-hr) =	2.60	0.70	0.10	0.11	0.00
Hourly Emissions (lbs/hr)(1) =	9.37E-01	2.52E-01	3.60E-02	3.96E-02	1.77E-03

Notes:
(1) Assumes testing at 50% load.

Table 5.1B-8
CECP Amendment
Emergency Generator Engine

Rating (bhp) =	779				
Fuel =	Diesel				
Fuel Consumption (gal/hr) =	35.9				
Exhaust Temperature (F) =	1263				
Exhaust Diameter (inches) =	5.5				
Exhaust Flow Rate (acfm) =	3,185				
Exhaust Velocity (ft/sec) =	322				
	NOx	**CO**	**VOC**	**PM10**	**SOx**
Emission Factor (g/bhp-hr) =	2.70	0.39	0.03	0.03	0.00
Hourly Emissions (lbs/hr)(1) =	2.32E+00	3.35E-01	2.58E-02	2.58E-02	4.21E-03

Notes:
(1) Assumes testing at 50% load.

TABLE 5.1B-9
EMERGENCY FIREPUMP VENDOR INFORMATION

Rating Specific Emissions Data - John Deere Power Systems

Nameplate Rating Information

Clarke Model	JW6H-UFADF0
Power Rating (BHP / kW)	327 / 244
Certified Speed (RPM)	1760

Rating Data

Rating	6090HFC47A
Certified Power (kW)	315
Rated Speed	1760
Vehicle Model Number	Clarke Fire Pump

Units	g/kW-hr	g/hp-hr
NOx	3.5	2.6
HC	0.1	0.1
NOx + HC	3.7	2.7
Pm	0.14	0.11
CO	0.9	0.7

Certificate Data

Engine Model Year	2013
EPA Family Name	DJDXL09.0114
EPA JD Name	450HAB
EPA Certificate Number	DJDXL09.0114-005
CARB Executive Order	Not Applicable
Parent of Family	6090HFG84A

Units	g/kW-hr
NOx	3.8
HC	0.1
NOx + HC	3.9
Pm	0.13
CO	0.9

* The emission data listed is measured from a laboratory test engine according to the test procedures of 40 CFR 89 or 40 CFR 1039, as applicable. The test engine is intended to represent nominal production hardware, and we do not guarantee that every production engine will have identical test results. The family parent data represents multiple ratings and this data may have been collected at a different engine speed and load. Emission results may vary due to engine manufacturing tolerances, engine operating conditions, fuels used, or other conditions beyond our control.

CLARKE
Fire Protection Products, Inc.

JW6H-UFADF0
INSTALLATION & OPERATION DATA (I&O Data)
USA Produced

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 - in³ (L)	549 (9)
Compression Ratio	16.0:1
Valves per cylinder	
Intake	2
Exhaust	2
Combustion System	Direct Injection
Engine Type	In-Line, 4 Stroke Cycle
Fuel Management Control	Electronic, High Pressure Common Rail
Firing Order (CW Rotation)	1-5-3-6-2-4
Aspiration	Turbocharged
Charge Air Cooling Type	Raw Water Cooled
Rotation, viewed from front of engine, Clockwise (CW)	Standard
Engine Crankcase Vent System	Open
Installation Drawing	D627
Weight - lb (kg)	2094 (950)

Power Rating	**1760**	**2100**
Nameplate Power - HP (kW)	327 (244)	311 (232)

Cooling System - [C051387]	**1760**	**2100**
Engine Coolant Heat - Btu/sec (kW)	73 (77)	80 (84.4)
Engine Radiated Heat - Btu/sec (kW)	74 (78.1)	70 (73.9)
Heat Exchanger Minimum Flow		
60°F (15°C) Raw H_20 - gal/min (L/min)	38 (144)	40 (151)
95°F (35°C) Raw H_20 - gal/min (L/min)	47 (178)	50 (189)
Heat Exchanger Maximum Cooling Raw Water		
Inlet Pressure - psi (bar)	60 (4.1)	
Flow - gal/min (L/min)	80 (303)	
Typical Engine H_20 Operating Temp - °F (°C)[1]	180 (82.2) - 195 (90.6)	
Thermostat		
Start to Open - °F (°C)	180 (82.2)	
Fully Opened - °F (°C)	201 (93.9)	
Engine Coolant Capacity - qt (L)	27 (25.6)	
Coolant Pressure Cap - lb/in² (kPa)	15 (103)	
Maximum Engine Coolant Temperature - °F (°C)	221 (105)	
Minimum Engine Coolant Temperature - °F (°C)	160 (71.1)	
High Coolant Temp Alarm Switch - °F (°C)[2]	235 (113) - 241 (116)	

Electric System - DC	**Standard**		**Optional**	
System Voltage (Nominal)	12		24	
Battery Capacity for Ambients Above 32°F (0°C)				
Voltage (Nominal)	12	[C07633]	24	[C07633]
Qty. Per Battery Bank	1		2	
SAE size per J537	8D		8D	
CCA @ 0°F (-18°C)	1400		1400	
Reserve Capacity - Minutes	430		430	
Battery Cable Circuit, Max Resistance - ohm	0.0017		0.0017	
Battery Cable Minimum Size				
0-120 in. Circuit Length[3]	00		00	
121-160 in. Circuit Length[3]	000		000	
161-200 in. Circuit Length[3]	0000		0000	
Charging Alternator Maximum Output - Amp,	40	[C071363]	55	[C071365]
Starter Cranking Amps, Rolling - @60°F (15°C)	440	[RE520634]	326	[C07820]

NOTE: This engine is intended for indoor installation or in a weatherproof enclosure. [1]Engine H_2O temperature is dependent on raw water temperature and flow. [2]High Coolant Switch threshold varies with engine load. [3]Positive and Negative Cables Combined Length.

CLARKE Fire Protection Products, Inc.

JW6H-UFADF0
INSTALLATION & OPERATION DATA (I&O Data)
USA Produced

Exhaust System	**1760**	**2100**
Exhaust Flow - ft.³/min (m³/min)	1867 (52.9)	2214 (62.7)
Exhaust Temperature - °F (°C)	842 (450)	826 (441)
Maximum Allowable Back Pressure - in H_20 (kPa)	30 (7.5)	30 (7.5)
Minimum Exhaust Pipe Dia. - in (mm)[4]	6 (152)	6 (152)

Fuel System	**1760**	**2100**
Fuel Consumption - gal/hr (L/hr)	14.8 (56)	16.8 (63.6)
Fuel Return - gal/hr (L/hr)	50.2 (190)	48.2 (182)
Fuel Supply - gal/hr (L/hr)	65 (246)	65 (246)
Fuel Pressure - lb/in² (kPa)	2 (13.8) - 9 (62.1)	
Minimum Line Size - Supply - in.	.50 Schedule 40 Steel Pipe	
Pipe Outer Diameter - in (mm)	0.848 (21.5)	
Minimum Line Size - Return - in.	.375 Schedule 40 Steel Pipe	
Pipe Outer Diameter - in (mm)	0.675 (17.1)	
Maximum Allowable Fuel Pump Suction Lift with clean Filter - in H_20 (mH_20)	80 (2)	
Maximum Allowable Fuel Head above Fuel pump, Supply or Return - ft (m)	6.6 (2)	
Fuel Filter Micron Size	2 (Secondary)	

Heater System	**Standard**	**Optional**
Engine Coolant Heater		
Wattage (Nominal)	2500	2500
Voltage - AC, 1 Phase	115 (+5%, -10%)	230 (+5%, -10%)
Part Number	[C122191]	[C122195]

Air System	**1760**	**2100**	
Combustion Air Flow - ft.³/min (m³/min)	698 (19.8)	949 (26.9)	
Air Cleaner	**Standard**		**Optional**
Part Number	[C03244]		[C03330]
Type	Indoor Service Only, with Shield		Canister, Single-Stage
Cleaning method	Washable		Disposable
Air Intake Restriction Maximum Limit			
Dirty Air Cleaner - in H_20 (kPa)	14 (3.5)		14 (3.5)
Clean Air Cleaner - in H_20 (kPa)	7 (1.7)		7 (1.7)
Maximum Allowable Temperature (Air To Engine Inlet) - °F (°C)[5]	130 (54.4)		

Lubrication System	
Oil Pressure - normal - lb/in² (kPa)	37 (255) - 41 (283)
Low Oil Pressure Alarm Switch - lb/in² (kPa)[6]	21 (145) to 41 (283)
In Pan Oil Temperature - °F (°C)	190 (87.8) - 220 (104)
Total Oil Capacity with Filter - qt (L)	30.1 (28.5)

Lube Oil Heater	**Optional**	**Optional**
Wattage (Nominal)	150	150
Voltage	120V (+5%, -10%)	240V (+5%, -10%)
Part Number	C04430	C04431

Performance	**1760**	**2100**
BMEP - lb/in² (kPa)	268 (1850)	214 (1480)
Piston Speed - ft/min (m/min)	1569 (478)	1873 (571)
Mechanical Noise - dB(A) @ 1m	C133383	
Power Curve	C132971	

[4]Based on Nominal System. Back pressure flow analysis must be done to assure maximum allowable back pressure is not exceeded. (Note: minimum exhaust Pipe diameter is based on: 15 feet of pipe, one 90° elbow, and a silencer pressure drop no greater than one half of the maximum allowable back pressure.) [5]Review for horsepower derate if ambient air entering engine exceeds 77°F (25°C). [6]Low Oil Pressure Switch threshold varies w/engine speed. [ ] indicates component reference part number.

TABLE 5.1B-10
EMERGENCY GENERATOR ENGINE VENDOR INFORMATION

DIESEL GENERATOR SET

Image shown may not reflect actual package

Standby
500 ekW 625 kVA
60 Hz 1800 rpm 480 Volts

Caterpillar is leading the power generation Market place with Power Solutions engineered to deliver unmatched flexibility, expandability, reliability, and cost-effectiveness.

FUEL/EMISSIONS STRATEGY
- EPA Tier 4 Interim

DESIGN CRITERIA
- The generator set accepts 100% rated load in one step per NFPA 110 and meets ISO 8528-5 transient response.

UL 2200
- UL 2200 packages available. Certain restrictions may apply. Consult with your Cat® dealer.

FULL RANGE OF ATTACHMENTS
- Wide range of bolt-on system expansion attachments, factory designed and tested
- Flexible packaging options for easy and cost effective installation

SINGLE-SOURCE SUPPLIER
- Fully prototype tested with certified torsional vibration analysis available

WORLDWIDE PRODUCT SUPPORT
- Cat dealers provide extensive post sale support including maintenance and repair agreements
- Cat dealers have over 1,800 dealer branch stores operating in 200 countries.
- The Caterpillar S•O•S℠ program effectively detects internal engine component condition, even the presence of unwanted fluids and combustion by products.

CAT® C15 ATAAC DIESEL ENGINE
- Reliable, rugged, durable design
- Field proven in thousands of applications worldwide
- Four-stroke diesel engine combines consistent performance and excellent fuel economy with minimum weight

CAT GENERATOR
- Matched to the performance and output characteristics of Cat engines
- Single point access to accessory connections
- UL 1446 Recognized Class H insulation

CAT EMCP 4 CONTROL PANELS
- Simple user friendly interface and navigation
- Scalable system to meet a wide range of customer needs
- Integrated Control System and Communications Gateway

SPECIFICATIONS

CAT GENERATOR
Frame …………………..…………………….. 6124F
Excitation ………………………………………..….IE
Pitch……………………………………………0.6667
Number of poles……………………………………4
Number of leads……………………………………..12
Number of bearings ………………….………….Single
Insulation ………………………………………Class H
IP rating ………………………………..Drip proof IP23
Over speed capability - % of rated………………125%
Wave form deviation…………………………….....2 %
Voltage regulator…………. 3 phase sensing with load adjustable module
Voltage regulation….Less than ±1/2% (steady state)
Less than ±1/2% (3% speed change)
Telephone Influence Factor …………….Less than 50
Harmonic Distortion ……………………..Less than 5%

CAT DIESEL ENGINE
C15 ATAAC, L-6, 4 stroke, water-cooled diesel

Bore …………….…….……… ...137.20 mm (5.4 in)
Stroke ……………………………171.4 mm (6.75 in)
Displacement …………………...15.20 L (927.56 in^3)
Compression ratio…………….………………..16:1
Aspiration…………………….….….….………ATAAC
Fuel system…………………………….………..MEUI
Governor Type………………………….. ADEM™ A4

CAT EMCP 4 CONTROL PANELS
EMCP 4 controls including:
- Run / Auto / Stop Control
- Speed & Voltage Adjust
- Engine Cycle Crank
- Emergency stop pushbutton

EMCP 4.2 controller features:
- 24-volt DC operation
- Environmental sealed front face
- Text alarm/event descriptions

Digital indication for:
- RPM
- DC volts
- Operating hours
- Oil pressure (psi, kPa or bar)
- Coolant temperature
- Volts (L-L & L-N), frequency (Hz)
- Amps (per phase & average)
- Power Factor (per phase & average)
- kW (per phase, average & percent)
- kVA (per phase, average & percent)
- kVAr (per phase, average & percent)
- kW-hr & kVAr-hr (total)

Warning/shutdown with common LED indication of shutdowns for:
- Low oil pressure
- High coolant temperature
- Overspeed
- Emergency stop
- Failure to start (overcrank)
- Low coolant temperature
- Low coolant level

Programmable protective relaying functions:
- Generator phase sequence
- Over/Under voltage (27/59)
- Over/Under Frequency (81 o/u)
- Reverse Power (kW) (32)
- Reverse Reactive Power (kVAr) (32RV)
- Overcurrent (50/51)

Communications
- Customer data link (Modbus RTU)
- Accessory module data link
- Serial annunciator module data link

- 6 programmable digital inputs
- 4 programmable relay outputs (Form A)
- 2 programmable relay outputs (Form C)
- 2 programmable digital outputs

Compatible with the following optional modules:
- Digital I/O module
- Local Annunciator
- Remote annunciator
- RTD module
- Thermocouple module

STANDBY 500 ekW 625 kVA

60 Hz 1800 rpm 480 Volts

TECHNICAL DATA

Open Generator Set - 1800 rpm/60 Hz/480 Volts	STANDBY EM0177	
Genset Package Performance		
Power rating @ 0.8 pf	625 kVA	
Power rating w/fan	500 ekW	
Fuel Consumption[1]		
100% load with fan	136.6 L/hr	35.9 Gal/hr
75% load with fan	108.0 L/hr	28.6 Gal/hr
50% load with fan	78.0 L/hr	20.5 Gal/hr
Cooling System[2]		
Ambient air temperature	51°C	123 °F
Air flow restriction (system)	0.12 kPa	0.5 in water
Air flow (max @rated speed)	819.6 m^3/min	28958 cfm
Engine coolant Capacity with radiator arrangement)	68 L	18.0 US Gal
Engine coolant capacity	27 L	7.1 US Gal
Radiator coolant capacity	41 L	10.9 US Gal
Inlet Air		
Combustion air inlet flow rate	35.2 m^3/min	1243 cfm
Exhaust System		
Exhaust stack gas temperature	683.8 °C	1263 °F
Exhaust gas flow rate	90.2 m^3/min	3185 cfm
Exhaust flange size (internal diameter)	139 mm	5.5 in
Exhaust system backpressure (minimum allowable) [3]	1 kPa	4 in. water
Exhaust system backpressure (maximum allowable) [3]	10 kPa	40 in. water
Heat Rejection		
Heat rejection to coolant (total)	253 kW	14375 Btu/min
Heat rejection to exhaust (total)	430 kW	24457 Btu/min
Heat rejection to atmosphere from engine	95.6 kW	5436 Btu/min
Heat rejection to atmosphere from generator	29.1 kW	1655 Btu/min
Alternator[4]		
Motor starting capability @ 30% voltage dip	1712 skVA	
Frame	LC6124F	
Temperature Rise	130°C	234°F
Lube System [5]		
Lube oil refill with filter change for standard sump	60 L	15.9 US Gal
Emissions (Nominal)[6]		
NO_x	3.6 g/kW-hr	2.7 g/hp-hr
CO	0.52 g/kW-hr	.39 g/hp-hr
HC	0.04 g/kW-hr	0.03 g/hp-hr
PM	0.04 g/kW-hr	0.03 g/hp-hr

[1] EPA Tier 4 Interim diesel engines required the use of Ultra Low Sulfur Diesel (ULSD) fuel in order to protect emissions control systems, help comply with emissions standards, and meet published maintenance intervals. ULSD fuel will have ≤ 15 ppm (0.0015%) sulfur using the ASTM D5453, ASTM 2622, or SIN 51400 test methods.

[2] For ambient and altitude capabilities consult your Cat dealer. Air flow restriction (system) is added to existing restriction from factory.

[3] Backpressure allowance is total backpressure available for the customer.

[4] Generator temperature rise is based on a 40 degree C ambient per NEMA MG1-32.
Some packages may have oversized generators with a different temperature rise and motor starting characteristics.

[5] Requires the use of CJ4 oil in order to meet published maintenance intervals.

[6] Emissions data measurement procedures are consistent with those described in EPA CFR 40 Part 89, Subpart D & E and ISO8178-1 for measuring HC, CO, PM, NO_x. Data shown is based on steady state operating conditions of 77°F, 28.42 in HG and number 2 diesel fuel with 35° API and LHV of 18,390 btu/lb. The nominal emissions data shown is subject to instrumentation, measurement, facility and engine to engine variations. Emissions data is based on 100% load and thus cannot be used to compare to EPA regulations which use values based on a weighted cycle.

Table 5.1B-11
CECP Amendment
Natural Gas Compressor Fugitive Emissions (three fuel compressors)

Fitting	Number	Emission factor (kg/hr/unit)(1)	Organic Compound Emissions (kg/hr)	Organic Compound Emissions (lb/day)	VOC Emissions(2) (lb/day)	CH4 Emissions(3) (lb/day)
Valves	50	4.50E-03	0.225	2.45	0.23	2.23
Connectors	112	2.00E-04	0.0224	0.24	0.02	0.22
Compressor Seals	3	8.80E-03	0.0264	0.29	0.03	0.26
TOTAL =				2.98	0.28	2.72

Notes:
(1) EPA's Protocol for Equipment Leak Emission Estimates, November 1995, Table 2-4 (Oil and Gas Production Operations).
(2) Based on a VOC fraction of total organic compound of 9.46%wt (based on gas composition specified by SDAPCD for Pio Pico Energy Center with high VOC due to LNG).
(3) Based on CH4 fraction (91.2%wt) of site specific gas composition.

Table 5.1B-12
CECP Amendment
Hourly Emissions

Hourly Mass Emission Rates, lbs/hr (Commissioning Period)	NOx	CO	VOC	PM10	SOx	NH3(1)
Single GT Normal Operation	9.00	8.80	2.50	3.50	2.07	6.70
Single GT Startups	19.95	12.53	3.46	3.50	1.54	6.70
Single GT Shutdowns	7.65	10.29	4.36	3.50	1.79	6.70
Single GT Startup/Shutdown/Restart	28.24	17.31	6.16	3.50	0.79	6.70
Single GT Commissioning	90.00	247.67	7.92	3.50	2.07	6.70
Single GT Maximum =	90.00	247.67	7.92	3.50	2.07	6.70
Six GTs Maximum =	**540.00**	**1486.00**	**47.50**	**21.00**	**12.42**	**40.20**
Emergency Firepump Engine	N/A(2)	N/A(2)	N/A(2)	N/A(2)	N/A(2)	N/A
Emergency Generator Engine	N/A(2)	N/A(2)	N/A(2)	N/A(2)	N/A(2)	N/A
Natural Gas Compressors	N/A	N/A	0.01	N/A	N/A	N/A
Total New Equipment =	**540.00**	**1486.00**	**47.51**	**21.00**	**12.42**	**40.20**
Total Emergency Engines =	N/A(2)	N/A(2)	N/A(2)	N/A(2)	N/A(2)	N/A

Hourly Mass Emission Rates, lbs/hr (Non-Commissioning Period)	NOx	CO	VOC	PM10	SOx	NH3(1)
Single GT Normal Operation	9.00	8.80	2.50	3.50	2.07	6.70
Single GT Startups	19.95	12.53	3.46	3.50	1.54	6.70
Single GT Shutdowns	7.65	10.29	4.36	3.50	1.79	6.70
Single GT Startup/Shutdown/Restart	28.24	17.31	6.16	3.50	0.79	6.70
Single GT Maximum =	28.24	17.31	6.16	3.50	2.07	6.70
Six GTs Maximum =	**169.42**	**103.87**	**36.96**	**21.00**	**12.42**	**40.20**
Emergency Firepump Engine	N/A(2)	N/A(2)	N/A(2)	N/A(2)	N/A(2)	N/A
Emergency Generator Engine	N/A(2)	N/A(2)	N/A(2)	N/A(2)	N/A(2)	N/A
Natural Gas Compressors	N/A	N/A	0.01	N/A	N/A	N/A
Total New Equipment =	**169.42**	**103.87**	**36.97**	**21.00**	**12.42**	**40.20**
Total Emergency Engines =	N/A(2)	N/A(2)	N/A(2)	N/A(2)	N/A(2)	N/A

Notes:
(1) Set startup/shutdown hourly emission rate to 100% load normal emission level to determine worst case daily emissions for AQ modeling purposes.
(2) Emergency engines will not be operated during commissioning testing of new gas turbines and/or during startups/shutdowns of gas turbines.

Table 5.1B-13
CECP Amendment
Daily Emissions

Daily Emission Rates, lbs/day (Commissioning Period)														
	Operating	Hourly Emission Rate (lbs/hr)						Daily Emissions (lbs/day)					
	Hours	NOx	CO	VOC	PM10	SOx	NH3	NOx	CO	VOC	PM10	SOx	NH3
GT Normal Operation	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
GT Startups	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
GT Shutdowns	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
GT Commissioning	various	various	various	various	various	various	various	1,080.0	2,971.0	181.0	84.0	49.7	160.8
Single GT Total =								**1,080.0**	**2,971.0**	**181.0**	**84.0**	**49.7**	**160.8**
Six GT Total =								**6,480.0**	**17,826.0**	**1,086.0**	**504.0**	**298.2**	**964.8**
Emergency Firepump Engine	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Emergency Generator Engine	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Natural Gas Compressors	24									0.3			
Total New Equipment =								**6,480.0**	**17,826.0**	**1,086.3**	**504.0**	**298.2**	**964.8**
Total Emergency Engines =								**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

Daily Emission Rates, lbs/day (Non-Commissioning Period)													
	Operating	Hourly Emission Rate (lbs/hr)						Daily Emissions (lbs/day)					
	Hours	NOx	CO	VOC	PM10	SOx(1)	NH3(1)	NOx	CO	VOC	PM10	SOx	NH3
GT Normal Operation	16	9.00	8.80	2.50	3.50	2.07	6.70	144.0	140.8	40.0	56.0	33.1	107.2
GT Startups	4	19.95	12.53	3.46	3.50	2.07	6.70	79.8	50.1	13.8	14.0	8.3	26.8
GT Shutdowns	4	7.65	10.29	4.36	3.50	2.07	6.70	30.6	41.2	17.4	14.0	8.3	26.8
Single GT Total =								**254.4**	**232.1**	**71.3**	**84.0**	**49.7**	**160.8**
Six GT Total =								**1,526.4**	**1,392.6**	**427.6**	**504.0**	**298.2**	**964.8**
Emergency Firepump Engine	0.5	0.94	0.25	0.04	0.04	0.00		0.5	0.1	0.0	0.0	0.0	
Emergency Generator Engine	0.5	2.32	0.33	0.03	0.03	0.00		1.2	0.2	0.0	0.0	0.0	
Natural Gas Compressors	24									0.3			
Total New Equipment =								**1,528.0**	**1,392.9**	**427.9**	**504.0**	**298.2**	**964.8**
Total Emergency Engines =								**1.6**	**0.3**	**0.0**	**0.0**	**0.0**	

Notes:

(1) Set startup/shutdown hourly emission rate to 100% load normal emission level to determine worst case daily emissions for AQ modeling purposes.

Table 5.1B-14
CECP Amendment
Annual Emissions - Commissioning Year

	Hours per Year	NOx (lbs/hr)	CO (lbs/hr)	VOC (lbs/hr)	PM10 (lbs/hr)	SOx(1) (lbs/hr)	NH3(1) (lbs/hr)	NOx (lbs/year)	CO (lbs/year)	VOC (lbs/year)	PM10 (lbs/year)	SOx (lbs/year)	NH3 (lbs/year)
Single GT Commissioning	213	various	various	various	various	various	various	5,913	14,316	726	704	147	1,424
Single GT Start-Up	400	19.95	12.53	3.46	3.50	0.69	2.60	7,980	5,013	1,383	1,400	276	1,040
Single GT Normal Operation	1,200	9.00	8.80	2.50	3.50	0.69	6.70	10,800	10,560	3,000	4,200	828	8,040
Single GT Shutdown	400	7.65	10.29	4.36	3.50	0.69	2.60	3,060	4,117	1,743	1,400	276	1,040
Single GT Total =	**2,213**							**27,753**	**34,007**	**6,853**	**7,704**	**1,527**	**11,544**
Six GT Total =								**166,518**	**204,040**	**41,116**	**46,224**	**9,162**	**69,263**
Emergency Firepump Engine	200	0.94	0.25	0.04	0.04	0.00	0.00	187	50	7	8	0	
Emergency Generator Engine	200	2.32	0.33	0.03	0.03	0.00	0.00	464	67	5	5	1	
Natural Gas Compressors										103			
Total New Equipment Annual Emissions (lb/year) =								**167,169**	**204,157**	**41,231**	**46,237**	**9,164**	**69,263**
Total New Equipment Annual Emissions (tons/year) =								**83.6**	**102.1**	**20.6**	**23.1**	**4.6**	**34.6**
Total Gas Turbines Annual Emissions (tons/year) =								**83.3**	**102.0**	**20.6**	**23.1**	**4.6**	**34.6**
Total Emergency Engines Annual Emissions (tons/year) =								**0.3**	**0.1**	**0.0**	**0.0**	**0.0**	
Total Gas Compressors Annual Emissions (tons/year) =										**0.1**			

Notes:

(1) Set hourly startup/shutdown emission rate to 100% load normal emission level to determine worst case annual emissions for AQ modeling purposes.

Table 5.1B-15
CECP Amendment
Annual Emissions - Non-Commissioning Year

	Hours per Year	NOx (lbs/hr)	CO (lbs/hr)	VOC (lbs/hr)	PM10 (lbs/hr)	SOx(1) (lbs/hr)	NH3(1) (lbs/hr)	NOx (lbs/year)	CO (lbs/year)	VOC (lbs/year)	PM10 (lbs/year)	SOx (lbs/year)	NH3 (lbs/year)
Single GT Start-Up	400	19.95	12.53	3.46	3.50	0.69	2.60	7,980	5,013	1,383	1,400	276	1,040
Single GT Normal Operation	1,900	9.00	8.80	2.50	3.50	0.69	6.70	17,100	16,720	4,750	6,650	1,311	12,730
Single GT Shutdown	400	7.65	10.29	4.36	3.50	0.69	2.60	3,060	4,117	1,743	1,400	276	1,040
Single GT Total =	**2,700**							**28,140**	**25,851**	**7,877**	**9,450**	**1,864**	**14,810**
Six GT Total =								**168,840**	**155,104**	**47,260**	**56,700**	**11,181**	**88,860**
Emergency Firepump Engine	200	0.94	0.25	0.04	0.04	0.00		187	50	7	8	0	
Emergency Generator Engine	200	2.32	0.33	0.03	0.03	0.00		464	67	5	5	1	
Natural Gas Compressors										103			
Total New Equipment Annual Emissions (lb/year) =								**169,491**	**155,221**	**47,375**	**56,713**	**11,182**	**88,860**
Total New Equipment Annual Emissions (tons/year) =								**84.7**	**77.6**	**23.7**	**28.4**	**5.6**	**44.4**
Total Gas Turbines Annual Emissions (tons/year) =								**84.4**	**77.6**	**23.6**	**28.4**	**5.6**	**44.4**
Total Emergency Engines Annual Emissions (tons/year) =								**0.3**	**0.1**	**0.0**	**0.0**	**0.0**	
Total Gas Compressors Annual Emissions (tons/year) =										**0.1**			

Notes:
(1) Set hourly startup/shutdown emission rate to 100% load normal emission level to determine worst case annual emissions for AQ modeling purposes.

Table 5.1B-16
CECP Amendment
Hourly Emissions for Existing Units 1 - 5 and Peaking Gas Turbine

Device	Unit 1	Unit 2	Unit 3	Unit 4	Unit 5	Gas Turbine
Fuel	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
Maximum Power Rating (MW)	113	109	115	323	342	15
Maximum Heat Input (MMBtu/hr)	1013	1013	1128	3245	3475	317
Natural Gas F-factor (dscf/MMBtu)	8710	8710	8710	8710	8710	8710
Natural Gas F-factor (wscf/MMBtu)	10610	10610	10610	10610	10610	10610
Reference O2	3.0%	3.0%	3.0%	3.0%	3.0%	15.0%
Actual O2	7.9%	4.8%	4.5%	3.3%	2.1%	15.7%
Exhaust Temperature (F)	310	310	310	310	310	981
Exhaust Rate (dscfm @ ref. O2)	171,700	171,700	191,192	550,015	589,000	163,012
Exhaust Rate (wacfm @ actual O2)	418,696	339,751	370,708	992,604	996,771	609,032

	Emission Factors					
	NOx	CO	VOC	PM10	SOx	NH3
Pollutant	(lb/MMscf)[1]	(lb/MMscf)[1]	(lb/MMscf)[2]	(lb/MMscf)[2]	(lb/MMscf)[4]	(lb/MMscf)[3]
Unit 1	9.13	55.96	5.50	7.60	2.14	4.58E+00
Unit 2	10.24	62.19	5.50	7.60	2.14	4.58E+00
Unit 3	8.99	25.99	5.50	7.60	2.14	4.58E+00
Unit 4	10.34	7.14	5.50	7.60	2.14	4.58E+00
Unit 5	10.99	34.87	5.50	7.60	2.14	4.58E+00
Gas Turbine[5]	24.14	30.60	2.14	7.60	2.14	0

	Hourly Emissions					
	NOx	CO	VOC	PM10	SOx	NH3
Unit	(lbs/hr)	(lbs/hr)	(lbs/hr)	(lbs/hr)	(lbs/hr)	(lbs/hr)
Unit 1	9.07	55.58	5.46	7.55	2.13	4.55
Unit 2	10.17	61.77	5.46	7.55	2.13	4.55
Unit 3	9.94	28.75	6.08	8.41	2.37	5.07
Unit 4	32.91	22.71	17.50	24.18	6.82	14.57
Unit 5	37.44	118.80	18.74	25.90	7.30	15.60
Gas Turbine	7.50	9.51	0.67	2.36	0.67	0.00

Notes:
1. For NOx , based on a 2-Year average of CEMS data 2011 to 2012. For CO, based on a 2-Year average of stack test reports 2011 and 2012.
2. Based on emission factors from AP-42, Table 1.4-2, 7/98.
3. Based on SDACPD permit limit of 10 ppm @ 3% O2 ammonia slip.
4. Based on maximum natural gas sulfur content of 0.75 gr/100 scf.
5. NOx based emission factor from 4/10/13 source test data, other factors from AP-42, Table 3.1-1, water-injected natural gas turbine.

Table 5.1B-17-1
Encina Power Station - Baseline NOx emissions (tons/year)

Unit	2002*	2003*	2004*	2005*	2006*	2007*	2008*	2009**	2010**	2011**	2012+	2013+	5-Yr Avg	10-Yr Avg.	12-Yr Avg.
U1	39.99	27.70	46.00	31.73	16.17	10.20	0.70	3.41	2.13	3.45	7.56	2.10			
U2						7.70	3.60	2.15	0.64	4.24	8.83	1.88			
U3						13.00	5.90	3.72	1.33	3.73	9.20	2.88			
U4	101.90	75.70	86.50	53.20	35.50	38.60	28.50	14.60	4.85	7.05	24.24	8.83			
U5	113.70	87.40	80.90	37.20	37.50	59.20	57.20	22.68	12.27	13.50	34.27	15.21			
Peaker GT++								0.08	0.18	0.07	0.55	0.45			
Total =	255.59	190.80	213.40	122.13	89.17	128.70	95.90	46.64	21.39	32.04	84.65	31.36	43.22	86.54	109.31
2-Year Average =									34.02	26.72	58.34	58.00			

Notes:
* From SDAPCD approved inventory reports.
**, + Based on hourly CEMS data.
++ Based emission factor from 4/10/13 source test data and annual fuel use.

Table 5.1B-17-2
Encina Power Station - Baseline CO emissions (tons/year)

Unit	2002*	2003*	2004*	2005*	2006*	2007*	2008*	2009**	2010**	2011**	2012**	2013+	5-Yr Avg	10-Yr Avg.	12-Yr Avg.
U1	494.59	344.03	266.73	144.25	94.43	14.40	1.80	24.41	36.16	47.25	20.20	5.82			
U2						32.80	28.40	9.14	2.57	60.23	19.18	4.45			
U3						19.10	16.80	14.42	3.52	15.48	21.93	6.25			
U4	804.50	416.60	570.90	384.10	108.40	53.90	74.50	29.99	2.11	5.78	15.81	6.47			
U5	922.10	481.00	533.80	268.70	67.80	45.90	83.00	58.51	4.47	151.53	0.05	0.02			
Peaker GT++								0.10	0.23	0.09	0.70	0.57			
Total =	2221.19	1241.63	1371.43	797.05	270.63	166.10	204.50	136.57	49.06	280.35	77.86	23.58	113.48	337.71	570.00
2-Year Average =									92.81	164.71	179.11	50.72			

Notes:

* From SDAPCD approved inventory reports.

** Emissions Calculated using emission factor from source test for each year and actual fuel use from CEMS.

+ Units 1, 2, and 5 Emissions calculated based on 2012 source test and actual fuel use. Units 3 and 4 based on 2013 source tests.

++Based on emission factor (from AP-42 Table 3.1-1, water-injected natural gas turbine) and annual fuel use.

Table 5.1B-17-3
Encina Power Station - Baseline VOC emissions (tons/year)

Unit	2002*	2003*	2004*	2005*	2006*	2007*	2008*	2009**	2010**	2011**	2012**	2013**	5-Yr Avg	10-Yr Avg.	12-Yr Avg.
U1	16.18	14.83	22.14	15.41	8.11	1.90	0.20	1.80	1.15	2.17	4.46	1.29			
U2						1.40	1.20	1.23	0.38	2.36	4.66	1.08			
U3						2.40	2.00	1.95	0.80	2.40	5.51	1.90			
U4	26.40	27.30	37.40	25.10	16.30	7.20	9.90	7.81	2.57	3.83	12.81	4.71			
U5	30.20	31.50	35.00	17.60	17.40	11.00	19.80	11.53	6.52	6.39	17.52	7.43			
Peaker GT++								0.01	0.02	0.01	0.05	0.04			
Total =	72.78	73.63	94.54	58.11	41.81	23.90	33.10	24.33	11.42	17.15	45.02	16.45	22.87	36.58	42.69
2-Year Average =									17.87	14.29	31.09	30.73			

Notes:
* From SDAPCD approved inventory reports.
** Emissions calculated based on AP-42 table 1.4-1 (5.5 lb/MMScf) and annual fuel usage from CEMS (table 3-5)
++Based on emission factor (from AP-42 Table 3.1-1, water-injected natural gas turbine) and annual fuel use.

Table 5.1B-17-4
Encina Power Station - Baseline PM10 emissions (tons/year)

Unit	2002*	2003*	2004*	2005*	2006*	2007*	2008*	2009**	2010**	2011**	2012**	2013**	5-Yr Avg	10-Yr Avg.	12-Yr Avg.
U1	34.97	27.66	45.28	33.58	15.97	3.70	0.50	2.48	1.59	2.99	6.17	1.78			
U2						2.80	2.50	1.70	0.52	3.26	6.44	1.49			
U3						4.20	3.90	2.69	1.11	3.32	7.62	2.62			
U4	58.20	53.50	70.50	47.70	31.10	11.70	16.40	10.79	3.55	5.29	17.70	6.51			
U5	66.00	46.70	54.00	28.40	28.20	21.30	38.60	15.93	9.00	8.83	24.22	10.27			
Peaker GT++								0.02	0.05	0.02	0.15	0.13			
Total =	159.17	127.86	169.78	109.68	75.27	43.70	61.90	33.63	15.81	23.71	62.30	22.80	31.65	61.86	75.47
2-Year Average =									24.72	19.76	43.00	42.55			

Notes:
* From SDAPCD approved inventory reports.
** Calculated based on AP42, Table 1.4-2, 7/98 PM emission factor and actual fuel use from CEMS.
++Based on emission factor (from AP-42 Table 3.1-1, water-injected natural gas turbine) and annual fuel use.

Table 5.1B-17-5
Encina Power Station - Baseline SOx emissions (tons/year)

Unit	2002*	2003*	2004*	2005*	2006*	2007*	2008*	2009**	2010**	2011**	2012**	2013**	5-Yr Avg	10-Yr Avg.	12-Yr Avg.
U1	9.53	12.51	2.41	3.69	2.59	0.20	0.10	0.20	0.13	0.24	0.49	0.14			
U2						0.20	0.10	0.13	0.04	0.26	0.51	0.12			
U3						0.30	0.20	0.21	0.09	0.26	0.60	0.21			
U4	5.40	3.00	4.10	2.70	4.40	0.80	1.10	0.85	0.28	0.42	1.40	0.51			
U5	5.60	3.40	3.80	1.90	3.80	1.20	2.20	1.26	0.71	0.70	1.91	0.81			
Peaker GT++								0.01	0.03	0.01	0.08	0.07			
Total =	20.53	18.91	10.31	8.29	10.79	2.70	3.70	2.66	1.27	1.88	4.99	1.86	2.53	4.84	7.32
2-Year Average =									1.97	1.58	3.43	3.42			

Notes:
* From SDAPCD approved inventory reports.
** Emissions calculated based on AP-42 table 1.4-1 (0.6 lb/MMScf) and annual fuel usage from CEMS.
++Based on emission factor (from AP-42 Table 3.1-1, water-injected natural gas turbine) and annual fuel use.

Table 5.1B-17-6
Encina Power Station - GHG Emissions CO2e (MT)

Unit	Fuel	2002*	2003*	2004*	2005*	2006*	2007*	2008*	2009**	2010**	2011**	2012**	2013**	5-Yr Avg	10-Yr Avg	12-Yr Avg.
U1	natural gas								35,388	22,584	42,648	87,835	25,304			
U1	fuel oil								0	0	0	0	0			
U2	natural gas	315,791	295,421	443,422	308,148	161,081	111,632	69,162	24,281	7,386	46,468	91,739	21,276			
U2	fuel oil								0	0	0	0	0			
U3	natural gas								38,321	15,767	47,268	108,503	37,365			
U3	fuel oil								0	0	0	0	0			
U4	natural gas	514,177	536,871	735,711	494,941	319,055	520,222	210,377	153,684	50,546	75,353	252,108	92,789			
U4	fuel oil	8,436	0	0	0	844	744	0	0	0	0	0	0			
U5	natural gas	589,580	619,833	687,945	346,268	340,694	689,514	361,481	226,950	128,248	125,699	344,905	146,218			
U5	fuel oil	7,467	0	0	0	627	971	0	0	0	0	0	0			
Peaker GT	natural gas								352	800	304	2,488	2,032			
Total =		1,435,451	1,452,125	1,867,078	1,149,356	822,302	1,323,082	641,021	478,975	225,332	337,740	887,578	324,984	450,922	805,745	912,085
2-Year Average =										352,154	281,536	612,659	606,281			

Notes:

* For Units 1-3 for 2002 to 2008, based on annual GHG emissions shown in CEC FSA for CECP project. For Units 4 and 5 for 2002 to 2008 calculated based on fuel use (converted to MMBtu based on natural gas HHV of 1,019 Btu/scf and fuel oil HHV of 152,400 Btu/gal) and following emission factors:

For natural gas - CO2 emission factor of 53.06 kg/MMBtu, CH4 emission factor of 1 x 10-3 kg/MMBtu with GWP of 25, N2O emission factor of 1 x 10-4 kg/MMBtu with GWP of 298 per 40 CFR 98, Subparts A/C, Tables A-1 an

For fuel oil - CO2 emission factor of 75.10 kg/MMBtu, CH4 emission factor of 3 x 10-3 kg/MMBtu with GWP of 25, N2O emission factor of 6 x 10-4 kg/MMBtu with GWP of 298 per 40 CFR 98, Subparts A/C, Tables A-1, C-1, C

** calculated based on fuel use (converted to MMBtu based on natural gas HHV of 1,019 Btu/scf and fuel oil HHV of 152,400 Btu/gal) and following emission factors:

For natural gas - CO2 emission factor of 53.06 kg/MMBtu, CH4 emission factor of 1 x 10-3 kg/MMBtu with GWP of 25, N2O emission factor of 1 x 10-4 kg/MMBtu with GWP of 298 per 40 CFR 98, Subparts A/C, Tables A-1 an

For fuel oil - CO2 emission factor of 75.10 kg/MMBtu, CH4 emission factor of 3 x 10-3 kg/MMBtu with GWP of 25, N2O emission factor of 6 x 10-4 kg/MMBtu with GWP of 298 per 40 CFR 98, Subparts A/C, Tables A-1, C-1, C

Table 5.1B-18
CECP Amendment
Net Emission Changes and Required ERCs
Based on Maximum 2-year Average during Past 5 Years

	Emissions (tons/year)						
	NOx Emissions	CO Emissions	VOC Emissions	PM10 Emissions	SOx Emissions	GHG CO2e, metric tonnes	GHG CO2e, short tons
Emissions New Equipment =	84.7	77.6	23.7	28.4	5.6	846,574	933,178
Emission Reductions Units 1-5 and Peaker GT =	58.3	179.1	31.1	43.0	3.4	612,659	675,334
Net Emission Change =	26.4	-101.5	-7.4	-14.6	2.2	233,915	257,844
Major Modification Thresholds[1] =	25	100	25	15	40	N/A	75,000
Major Modification?	yes	no	no	no	no	N/A	yes
ERC Requirement Triggered?	yes	N/A	no	N/A	N/A	N/A	N/A
Offset Ratio[2] =	1.2	N/A	1.2	N/A	N/A	N/A	N/A
ERCs Required =	31.7	N/A	0.0	N/A	N/A	N/A	N/A
ERCs Purchased[3]=	49.6	0	0	0	0	N/A	N/A
Surplus/Shortfall =	-17.9	N/A	0	N/A	N/A	N/A	N/A

Notes:
1. Based on SDAPCD Rule 20.1.c.33.
2. Based on SDAPCD Rule 20.3.d.8.i.B.
3. Based on ERCs listed in 8/4/2009 FDOC for CECP, page 43 of 63.

Table 5.1B-19
CECP Amendment
Greenhouse Gas Emissions Calculations New Equipment

Unit	Total Number of Units	Per Unit Heat Input (MMBtu/hr)	Per Unit Gross Output (MW)	Operating Hours per year	Annual Fuel Use (MMBtu/yr)	Estimated Annual Gross MWh	Maximum Emissions, metric tonnes/yr				Facility-Wide Emissions, MT/yr CO2e	Facility-Wide Emissions, tons/yr CO2e	Facility-Wide CO2 MT/MWh
							CO2	CH4	N2O	SF6			
Gas Turbines	6	984	108.8	2,700	15,934,320	1,763,159	845,475	16	2	--			
Emergency Firepump Engine	1	2.0		200	403	n/a	30	0	0	--			
Emergency Generator Engine	1	4.9		200	976	n/a	72	0	0	--			
Circuit breakers	8	--		8760	0	n/a	--	--	--	5.4E-03			
Total =				--	15,935,699	1,763,159	845,577	16	2	5.4E-03			
CO2-Equivalent =							845,577	398	475	123	846,574	933,178	0.48

Fuel	Emission Factors, kg/MMBtu			Emission
	CO2 (1)	CH4 (2)	N2O (2)	SF6 (4)
Natural Gas	*53.060*	*1.00E-03*	1.00E-04	n/a
Diesel Fuel	*73.960*	3.00E-03	6.00E-04	n/a
Global Warming Potential (3)	1	25	298	22,800

Notes:
1. 40 CFR 98, Table C-1 (revised 11/29/13).
2. 40 CFR 98, Table C-2 (revised 11/29/13).
3. 40 CFR 98, Table A-1 (revised 11/29/13).

4. Sulfur hexafluoride (SF6) will be used as an insulating medium in eight circuit breakers. The SF6 contained in six of the circuit breakers is approximately 230 lbs/breaker and the remaining two breakers will contain approximately 500 lbs/breaker. The IEC standard for SF6 leakage is less than 0.5%; the NEMA leakage standard for new circuit breakers is 0.1%. A maximum leakage rate of 0.5% per year is assumed.

Table 5.1B-20
CECP Amendment
Nitrogen Emission Rates - New Equipment

Gas Turbines		
NOx emission rate =	14.07	tpy per turbine
N/NO2 molecular weight ratio (14/46) =	0.3043478	
N emission rate from NOx =	4.28	tpy per turbine
	0.12	g/s per turbine
NH3 emission rate =	7.41	tpy per turbine
N/NH3 molecular weight ratio (14/17) =	0.8235294	
N emission rate from NH3 =	6.10	tpy per turbine
	0.18	g/s per turbine
Total N emission rate for each CTG (N from NOx plus N from ammonia) =	10.38	tpy per turbine
Total N emission rate for each CTG (N from NOx plus N from ammonia) =	0.30	g/s per turbine
Emergency Engines		
NOx emission rate =	0.33	tpy both units
N/NO2 molecular weight ratio (14/46) =	0.3043478	
N emission rate from NOx =	0.10	tpy both units
Total N emission rate for six CTGs and engines (N from NOx plus N from ammonia) =	62.38	tpy

Table 5.1B-21
CECP Amendment
Nitrogen Emission Rates - Existing Units 1-5 and Peaker GT

NOx emission rate for Units 1-5/Peaker GT, 5-year avg. (tpy)=	43.22	tpy
NOx emission rate for Units 1-5/Peaker GT, 10-year avg. (tpy)=	86.54	tpy
NOx emission rate for Units 1-5/Peaker GT, 12-year avg. (tpy) =	109.31	tpy
N/NO2 molecular weight ratio (14/46) =		0.3043478
N emission rate from NOx, 5-year avg. (tpy) =	13.15	tpy
N emission rate from NOx, 10-year avg. (tpy) =	26.34	tpy
N emission rate from NOx, 12-year avg. (tpy) =	33.27	tpy
NH3 emission rate for Units 1-5/Peaker GT, 5-year avg. (tpy) =	19.03	tpy
NH3 emission rate for Units 1-5/Peaker GT, 10-year avg. (tpy) =	29.03	tpy
NH3 emission rate for Units 1-5/Peaker GT, 12-year avg. (tpy) =	38.44	tpy
N/NH3 molecular weight ratio (14/17) =		0.8235294
N emission rate from NH3, 5-year avg. (tpy) =	15.67	tpy
N emission rate from NH3, 10-year avg. (tpy) =	23.91	tpy
N emission rate from NH3, 12-year avg (tpy) =	31.66	
Total N emission rate for Units 1-5/GT (N from NOx plus N from ammonia), 5-yr avg. =	28.82	tpy
Total N emission rate for Units 1-5/GT (N from NOx plus N from ammonia), 10-yr avg. =	50.24	tpy
Total N emission rate for Units 1-5/GT (N from NOx plus N from ammonia), 12-yr avg. =	64.93	tpy

Appendix 5.1C
BACT Analysis

APPENDIX 5.1C

Evaluation of Best Available Control Technology

The gas turbines proposed for the Amended CECP are required to use best available control technology (BACT) in accordance with the requirements of San Diego Air Pollution Control District (SDAPCD, or District) rules and the federal Prevention of Significant Deterioration (PSD) regulations. BACT is defined in SDAPCD Rule 20-1:

> *(11) "**Best Available Control Technology (BACT)**" means and is applied as follows:*
>
> *(i) The lowest emitting of any of the following:*
>
> *(A) the most stringent emission limitation, or the most effective emission control device or control technique, which has been proven in field application and which is cost-effective for such class or category of emission unit, unless the applicant demonstrates to the satisfaction of the Air Pollution Control Officer that such limitation, device or control technique is not technologically feasible, or*
>
> *(B) any emission control device, emission limitation or control technique which has been demonstrated but not necessarily proven in field application and which is cost-effective for such class or category of emission unit, as determined by the Air Pollution Control Officer, unless the applicant demonstrates to the satisfaction of the Air Pollution Control Officer that such limitation, device or control technique is not technologically feasible, or*
>
> *(C) any control equipment, process modifications, changes in raw material including alternate fuels, and substitution of equipment or processes with any equipment or processes, or any combination of these, determined by the Air Pollution Control Officer on a case-by-case basis to be technologically feasible and cost-effective, including transfers of technology from another category of source, or*
>
> *(D) the most stringent emission limitation, or the most effective emission control device or control technique, contained in any State Implementation Plan (SIP) approved by the federal EPA for such emission unit category, unless the applicant demonstrates to the satisfaction of the Air Pollution Control Officer that such limitation or technique has not been proven in field application, that it is not technologically feasible or that it is not cost-effective for such class or category of emission unit.*

LAER must be applied to any federal nonattainment pollutants (or their precursors) at new major sources or major modifications exceeding any emission threshold shown in Table 5.1-11. LAER is more stringent than BACT because it does not contain restrictions for cost-effectiveness. Only NOx and VOCs are federal nonattainment precursors in SDAPCD and, therefore, potentially subject to LAER. The SDAPCD defines LAER as:

> *(32) "**Lowest Achievable Emission Rate (LAER)**" means and is applied as follows:*
>
> *(i) The lowest emitting of any of the following:*
>
> *(A) the most stringent emission limitation, or most effective emission control device or control technique, contained in any SIP approved by the federal EPA for such emission unit class or category, unless the applicant demonstrates to the satisfaction of the Air Pollution Control Officer that such emission limitation, device or technique is not achievable, or*
>
> *(B) the most stringent emission limitation which is achieved in practice by such class or category of emission unit, or*
>
> *(C) Best Available Control Technology (BACT).*

As discussed in Section 5.1.3, the CECP gas turbines will trigger PSD BACT requirements for greenhouse gases (GHG). In addition, as discussed in Section 5.1.4, the District NSR rules require BACT for NOx; sulfur oxides (SO_x); CO; volatile organic compounds (VOC); particulate (PM_{10} and $PM_{2.5}$); and ammonia. The BACT/LAER analyses required under both New Source Review (NSR) and PSD programs are similar, and are presented here. The emission rates and control technologies determined to be BACT for this project are discussed in detail in the following sections. For the CTGs, separate determinations are provided for normal operation and startup/shutdown operation.

5.1 Steps in a Top-Down BACT Analysis

5.1.1 Step 1 – Identify All Possible Control Technologies

The first step in a top-down analysis is to identify, for the emissions unit and pollutant in question, all available control options. Available control options are those air pollution control technologies or techniques, including alternate basic equipment or processes, with a practical potential for application to the emissions unit in question. The control alternatives should include not only existing controls for the source category in question, but also, through technology transfer, controls applied to similar source categories and gas streams.

BACT must be at least as stringent as what has been achieved in practice (AIP) for a category or class of source. Additionally, EPA guidelines require that a technology that is determined to be AIP for one category of source be considered for transfer to other source categories. There are two types of potentially transferable control technologies: (1) exhaust stream controls, and (2) process controls and modifications. For the first type, technology transfer must be considered between source categories that produce similar exhaust streams. For the second type, technology transfer must be considered between source categories with similar processes.

Candidate control options that do not meet basic project requirements (i.e., alternative basic designs that “redefine the source”) are eliminated at this step.

5.1.2 Step 2 – Eliminate Technologically Infeasible Options

To be considered, the candidate control option must be technologically feasible for the application being reviewed.

5.1.3 Step 3 – Rank Remaining Control Options by Control Effectiveness

All feasible options are ranked in the order of decreasing control effectiveness for the pollutant under consideration. In some cases, a given control technology may be listed more than once, representing different levels of control (e.g., the use of SCR for control of NOx may be evaluated at 2 and 2.5 parts per million by volume, dry [ppmvd]). Any control option less stringent than what has been already achieved in practice for the category of source under review must also be eliminated at this step.

5.1.4 Step 4 – Evaluate Most Effective Control Technology Considering Environmental, Energy, and Cost Impacts

To be required as BACT, the candidate control option must be cost effective, considering energy, environmental, economic, and other costs. The most stringent control technology for control of one pollutant may have other undesirable environmental or economic impacts. The purpose of Step 4 is to either validate the suitability of the top control option or provide a clear justification as to why that option should not be selected as BACT.

Once all of the candidate control technologies have been ranked, and other impacts have been evaluated, the most stringent candidate control technology is deemed to be BACT, unless the other impacts are unacceptable.

5.1.5 Step 5 – Determine BACT/Present Conclusions

BACT is determined to be the most effective control technology subject to evaluation, and not rejected as infeasible or having unacceptable energy, environmental, or cost impacts.

5.2 BACT for the Simple-Cycle CTGs: Normal Operations

5.3 NOx Emissions

5.3.1 Step 1 – Identify All Possible Control Technologies

The emissions unit for which BACT is being considered is a nominal 109 MW simple-cycle gas turbine.

Potential control technologies were identified by searching the following sources for determinations pertaining to combustion gas turbines:

- SDAPCD BACT Guidance;
- SCAQMD BACT Guidelines;
- San Joaquin Valley Air Pollution Control District (SJVAPCD) BACT Clearinghouse;
- Bay Area Air Quality Management District (BAAQMD) BACT Guidelines;
- EPA Reasonably Available Control Technology (RACT)/BACT/ Lowest Achievable Emission Rate (LAER) Clearinghouse;
- Other district and state BACT Guidelines; and
- BACT/LAER requirements in New Source Review permits issued by a local air district[1] or other air pollution control agency.

Outlined below are the technologies for control of NOx that were identified.

- A Selective Catalytic Reduction (SCR) system capable of continuously complying with a limit of 2.5 ppmvd at15% oxygen (O_2) (1-hour average).
- An EMx (formerly SCONOx) system capable of continuously complying with a limit of 2.5 ppmvd at15% O_2 (1-hour average).
- Alternative Basic Equipment:
  - Renewable Energy Source (e.g., solar, wind, etc.)
  - Combined-Cycle Turbine

It should be noted that the use of renewable energy in lieu of a simple-cycle gas turbine would "redefine the source." Renewable energy facilities require significantly more land to construct, and need to be located in areas with very specific characteristics. Wind and solar facilities have power generation profiles that cannot match demand; conventional power plants are needed in order to follow demand. The capital costs for wind or solar facilities are substantially higher than for a comparable conventional facility, making financing of such a project significantly different. Because these technologies would redefine the source, they are eliminated in this step of the analysis. Even if they were not eliminated in Step 1, solar and wind facilities require much more land than is available at the project site, and renewable energy alternatives would be eliminated in Step 2 as technologically infeasible.

The remaining technologies—combined cycle turbines, SCR and EMx—are further considered in Step 2 below.

[1] Any Air Quality Management District or Air Pollution Control District in California.

5.3.2 Step 2 – Eliminate Technologically Infeasible Options

5.3.2.1 Alternate Equipment

The use of a combined-cycle turbine instead of the proposed simple-cycle turbines would be technically infeasible for the project. The simple-cycle turbines are needed to effectively handle variable loads and perform multiple startups/shutdowns per day. While advanced combined-cycle turbines can start relatively quickly (within approximately 12 minutes to reach 100% rated capacity of the gas turbine generator), they may need as much as 2 hours to reach full combined cycle output (combined output of gas turbine and steam turbine generators). [2] While operating in simple cycle mode (while waiting for the steam system to warm up), fast-start combined cycle units will have efficiencies that are no better than, and are likely worse than, those achieved with advanced simple cycle turbines such as the LMS100. Further, such units cannot perform up to four starts per day – as required for this project – without substantially shortening the life of the unit. Therefore, combined-cycle turbines are eliminated because they do not meet the basic project requirements.

5.3.2.2 Exhaust Stream Controls

The most recent NOx BACT listings for aeroderivative simple-cycle combustion turbines in this size range are summarized in Table 5.1C-1. The most stringent NOx limit in these recent BACT determinations is a 2.5 ppm[3] limit averaged over a 1-hour averaging period, excluding startups and shutdowns. This level is achieved using water injection and SCR.

EMx is a NOx reduction system distributed by EmeraChem. This system uses a single catalyst to oxidize both NO and CO, a second catalyst system to absorb NO_2, and then a regeneration system to convert the NO_2 to N_2 and water vapor. The EMx system does not use ammonia as a reagent. The EMx process has been demonstrated in practice on smaller gas turbines, including Redding Electric Utility's (REU) Units 5 and 6 which are comprised of a 43-MW Alstom GTX100 and a 45 MW Siemens SGT 800 combined-cycle gas turbine, respectively. While the technology has never been demonstrated on a gas turbine the size of the GE LMS 100 or on a simple-cycle gas turbine, the technology is considered by the manufacturer to be scalable.

The SCR system uses ammonia injection to reduce NOx emissions. SCR systems have been widely used in simple-cycle gas turbine applications of all sizes. The SCR process involves the injection of ammonia into the flue gas stream via an ammonia injection grid upstream of a reducing catalyst. The ammonia reacts with the NOx in the exhaust stream to form N_2 and water vapor. The catalyst does not require regeneration, but must be replaced periodically; typical SCR catalyst lifetimes are in excess of three years.

Either SCR or EMx technology is capable of achieving a NOx emission level of 2.5 ppmvd at 15% O_2. Neither has been demonstrated to consistently achieve lower emission levels in simple-cycle turbines in demand-response service. Both technologies are evaluated further in Step 3.

5.3.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Both SCR and EMx technologies, each in combination with combustion controls, are capable of achieving a NOx emission level of 2.5 ppmvd at 15% O_2. They are therefore ranked together in terms of control effectiveness, and the evaluation of these technologies continues in Step 4.

[2] El Segundo Energy Center LLC, 00-AFC-014C: Petition to Amend, 4/23/13, Section 2.2.7

[3] All turbine/HRSG exhaust emissions concentrations shown are by volume, dry corrected to 15% O_2.

TABLE 5.1C-1
Recent NOx BACT Determinations for Simple-Cycle Combustion Turbines[a]

Facility	District	NOx Limit[b]	Averaging Period	Control Method Used	Date Permit Issued	Source
El Colton	SCAQMD	3.5 ppmvd	3 hrs	Water injection and SCR	1/10/03	SCAQMD website
MID Ripon	SJVAPCD	2.5 ppmvd	3 hrs	Water injection and SCR	2004	ATC
San Francisco Electric Reliability Project	BAAQMD	2.5 ppmvd	1 hr	Water injection and SCR	2/8/06 (FDOC)	CEC Siting Div website
EIF Panoche	SJVAPCD	2.5 ppmvd	1 hr	Water injection and SCR	7/13/07 (FDOC)	CEC Siting Div website
Starwood Midway Firebaugh/Panoche	SJVAPCD	2.5 ppmvd	1 hr	Water injection and SCR	9/5/07 (FDOC)	CEC Siting Div website
Walnut Creek Energy	SCAQMD	2.5 ppmvd	1 hr	Water injection and SCR	2/27/08	FDOC
Miramar Energy Facility II	SDCAPCD	2.5 ppmvd	3 hrs	Water injection and SCR	11/4/08	ATC
Orange Grove Energy, LLP	SDAPCD	2.5 ppmvd	1 hr	Water injection and SCR	12/4/08	CEC Siting Div website
El Cajon Energy, LLC	SDAPCD	2.5 ppmvd	1 hr	Water injection and SCR	12/11/09	ATC
TID Almond 2 Power Plant	SJVAPCD	2.5 ppmvd	1 hr	Water injection and SCR	2/16/2010	FDOC
CPV Sentinel	SCAQMD	2.5 ppmvd	1 hr	Water injection and SCR	12/1/2010	FDOC
Pio Pico Energy Center	SDAPCD	2.5 ppmvd	1 hr	Water injection and SCR	9/12/2012	FDOC

Notes:

[a] All projects listed here utilize GE LM6000-model units except Starwood Midway, which utilizes P&W FT8-3 SwiftPacs; and EIF Panoche, CPV Sentinel, Walnut Creek Energy, and Pio Pico Energy Center, which use GE LMS 100 CTGs.

[b] All concentrations expressed as parts per million by volume dry, corrected to 15% O_2.

5.3.4 Step 4 – Evaluate the Most Effective Control Technology Considering Environmental, Energy, and Cost Impacts

The use of SCR will result in ammonia emissions due to an allowable ammonia slip limit of 5 ppmvd at 15% O_2. A health risk screening analysis of the proposed project using air dispersion modeling will be prepared to demonstrate that both the acute health hazard index and the chronic health hazard index are much less than 1, based on an ammonia slip limit of 5 ppmv at 15% O_2. In accordance with the District's Toxics program and currently accepted practice, a hazard index below 1.0 is not considered significant. Therefore, the toxic impact of the ammonia slip resulting from the use of SCR is deemed to be not significant, and is not a sufficient reason to eliminate SCR as a control alternative.

A second potential environmental impact that may result from the use of SCR involves the storage and transport of aqueous or anhydrous ammonia.[4] Although ammonia is toxic if swallowed or inhaled and can irritate or burn the skin, eyes, nose, or throat, it is a commonly used material that is typically handled safely and without incident. The project operator will be required to develop and maintain a Risk Management Plan (RMP) and to implement a Risk Management Program to prevent accidental releases of ammonia. The RMP provides information on the hazards of the substance handled at the facility and the programs in place to prevent and respond to accidental releases. The accident prevention and emergency response requirements reflect existing safety regulations and proven industry safety codes and standards. Thus, the potential environmental impact due to aqueous ammonia use at the Project is minimal and does not justify the elimination of SCR as a control alternative.

Regeneration of the EMx catalyst is accomplished by passing hydrogen gas over an isolated catalyst module. The hydrogen gas is generated by reforming steam, so steam would be required. This would require installation of an auxiliary boiler, which is not currently proposed for this project. There would also be additional natural gas consumption, and increased emissions, per megawatt hour of electricity produced.

5.3.4.1 "Achieved in Practice" Criteria

In general, the method for determining when emission control technologies are achieved in practice (AIP) is similar in each District. SCAQMD has established formal criteria for determining when emission control technologies should be considered AIP for the purposes of BACT determinations. The criteria include the elements outlined below.

- Commercial Availability: At least one vendor must offer this equipment for regular or full-scale operation in the United States. A performance warranty or guarantee must be available with the purchase of the control technology, as well as parts and service.
- Reliability: All control technologies must have been installed and operated reliably for at least six months. If the operator did not require the basic equipment to operate daily, then the equipment must have at least 183 cumulative days of operation. During this period, the basic equipment must have operated: (1) at a minimum of 50% design capacity; or (2) in a manner that is typical of the equipment in order to provide an expectation of continued reliability of the control technology.
- Effectiveness: The control technology must be verified to perform effectively over the range of operation expected for that type of equipment. If the control technology will be allowed to operate at lesser effectiveness during certain modes of operation, then those modes of operation must be identified. The verification shall be based on a performance test or tests, when possible, or other performance data.

Each of these criteria is discussed separately below for SCR and for EMx.

[4] The project proposes to use the less concentrated, safer aqueous form of ammonia.

SCR Technology – SCR has been achieved in practice at numerous combustion turbine installations throughout the world. There are numerous aeroderivative simple-cycle gas turbine projects that limit NOx emissions to 2.5 ppmc using SCR technology, as shown in Table 5.1C-1. An evaluation of the proposed AIP criteria as applied to the achievement of 2.5 ppmc, and to extremely low NOx levels (below 2.5 ppmc) using SCR technology, is summarized below.

- Commercial Availability: Turbine-out NOx from aeroderivative gas turbines is generally guaranteed at 25 ppmc. Achieving a controlled NOx limit below 2.5 ppmc would require SCR technology to achieve reductions greater than 90 percent. Furthermore, because of the relatively high temperature of exhaust from simple-cycle turbines compared with combined-cycle units, there is a more limited selection of SCR technology available. Consequently, it is not clear that this criterion is satisfied for limits below 2.5 ppmc for aeroderivative gas turbines. As shown in Table 5.1C-1 above, this criterion is satisfied for aeroderivative gas turbines at a 2.5 ppmc permit level.
- Reliability: SCR technology has been shown to be capable of achieving NOx levels consistent with a 2.5 ppmc permit limit during extended, routine operations at several commercial power plants. There are no reported adverse effects of operation of the SCR system at these levels on overall plant operation or reliability. There has been no demonstration of operation at levels below 2.5 ppmc during extended, routine operation of simple-cycle aeroderivative gas turbines; consequently, this criterion is not satisfied for NOx limits below 2.5 ppmc.
- Effectiveness: SCR technology has been demonstrated to achieve NOx levels of 2.5 ppmc with aeroderivative turbines, but not at lower limits for this generating technology. Short-term excursions have resulted in NOx concentrations above the permitted level of 2.5 ppmc; however, these excursions are not frequent, and have not been associated with diminished effectiveness of the SCR system. Rather, these excursions typically have been associated with SCR inlet NOx levels in excess of those for which the SCR system was designed, or with malfunctions of the ammonia injection system. Consequently, this criterion is satisfied at a NOx limit of 2.5 ppmc, but not at lower NOx limits.
- Conclusion: SCR technology capable of achieving NOx levels of 2.5 ppmc is considered to be achieved in practice. The permit limits for the proposed project CTGs include a NOx limit of 2.5 ppmc. This proposed limit is consistent with the available data. The AIP criteria are not met for SCR on simple-cycle aeroderivative gas turbines at NOx limits lower than 2.5 ppmc.

EMx Technology – EMx has been demonstrated in service in five applications: the Sunlaw Federal cogeneration plant, the Wyeth BioPharma cogeneration facility, the Montefiore Medical Center cogeneration facility, the University of California San Diego facility, and the City of Redding Power Plant. The combustion turbines at these facilities are much smaller than for the proposed project turbine, and none of the existing installations are simple-cycle turbines. The largest installation of the EMx system is at the Redding Power Plant. The Redding Power Plant includes two combined-cycle combustion turbines—a 43 MW Alstom GTX100 with a permitted NOx emission rate of 2.5 ppmc (Unit 5), and a 45 MW Siemens SGT 800 with a permitted NOx emission rate of 2.0 ppmc (Unit 6).

A review of NOx continuous emissions monitoring (CEM) data obtained from the EPA's Acid Rain program website[5] indicates a <u>mean</u> NOx level for the Redding Unit 5 of less than 1.0 ppm during the period from 2002 to 2007, but not continuous compliance with a 2.5 ppmc limit. After the first year of operation, Unit 5 experienced only a few hours of non-compliance per year (fewer than 0.1% of the annual operating hours exceed that plant's NOx permit limit of 2.5 ppmc). The experience at the City of Redding Plant indicates the ability of the EMx system to control NOx emissions to levels of 2.5 ppmc. These data do not indicate the ability to consistently achieve NOx levels below 2.0 ppm, notwithstanding the lower annual average emission rate. This is due to the cyclical nature of EMx NOx levels between plant shutdowns and scheduled

[5] Available at *http://camddataandmaps.epa.gov/gdm/index.cfm?fuseaction=prepackaged.results*.

catalyst cleanings. Redding Unit 6 started up on October 2011 and has had an average of 1,476 hours per year of operation since startup.

Based on this information, the following paragraphs evaluate the proposed AIP criteria as applied to the achievement of low NOx levels (2.5 ppmc) using EMx technology.

- Commercial Availability: While a proposal has not been sought, presumably EmeraChem would offer standard commercial guarantees for the proposed project. Consequently, this criterion is expected to be satisfied. However, no EMx units are currently in operation on simple-cycle units.
- Reliability: Redding Unit 5 was originally permitted with a 2.0 ppmc permit limit. It was subsequently found that the unit could not maintain compliance with a 2.0 ppmc limit on a consistent basis, and the limit was eventually changed to 2.5 ppmc. As discussed above, based on a review of the CEM data for Redding Unit 5, the EMx system complied with the 2.5 ppmc NOx permit limit but with a few hours each year of excess emissions (approximately 3% of annual operating hours following the first year, and approximately 2% following the second year, dropping to approximately 0.1% after 4 years). This level of performance was also associated with some significant operating and reliability issues. According to a June 23, 2005 letter from the Shasta County Air Quality Management District,[6] repairs to the EMx system began shortly after initial startup and have continued during several years of operation. Redesign of the EMx system was required due to a problem with the reformer reactor combustion production unit that led to sulfur poisoning of the catalyst, despite the sole use of low-sulfur, pipeline quality natural gas as the turbine fuel. In addition, the EMx system catalyst washings had to occur at a frequency several times higher than anticipated during the first three years of operation, which resulted in substantial downtime of the combustion turbine. Redding Unit 6 began operation in October 2011 and had very limited operation in 2012. Since the REU installation is the most representative of all of the EMx-equipped combustion turbine facilities for comparison to the proposed Project, the problems encountered at REU bring into question the reliability of the EMx system for the proposed project. In addition, the EMx unit has not been demonstrated in use in a simple cycle application.
- Effectiveness: The EMx system at REU Unit 5 has recently been able to demonstrate compliance with a NOx level of 2.0 ppmc, and the new REU Unit 6 has been permitted with a 2.0 ppmc NOx limit. As discussed above, there have been no known excursions beyond the permit limit for Unit 6 in the recent limited operation; however, there are no EMx-equipped facilities on simple-cycle facilities in demand-response service. In addition, this is a combined-cycle unit. Consequently, due to the lack of actual performance data in a comparable installation, there is some question regarding the effectiveness of the EMx systems on simple-cycle, demand-response combustion turbine projects.
- Conclusion: EMx systems are capable of achieving NOx levels of 2.5 ppmc and less. However, the operating history at the Redding Power Plant does not support a conclusion that this technology is achieved in practice for simple-cycle, demand-response turbines, based on the above guidelines.

5.3.4.2 Summary of Achieved in Practice Evaluation

SCR's capability to consistently achieve 2.5 ppmc NOx (1-hour average) in large turbines has been demonstrated by numerous installations. EMx's ability to consistently achieve 2.5 ppmc in large turbines has not been demonstrated, nor has the technology been demonstrated in simple-cycle, demand-response service. An emission level of 2.5 ppmc NOx has therefore been achieved in practice, and any BACT determination must be at least as stringent as that.

5.3.4.3 Technologically Feasible/Cost Effective Criterion

No candidate technology with lower emission levels than those achieved in practice has been identified.

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[6] Letter dated June 23, 2005, from Shasta County Air Quality Management District to the Redding Electric Utility regarding Unit 5 demonstration of compliance with its NOx permit limit.

5.3.5 Step 5 – Determine BACT/Present Conclusions

BACT must be at least as stringent as the most stringent level achieved in practice, federal NSPS, or district prohibitory rule. Based upon the results of this analysis, the NOx BACT determinations of 2.5 ppmc on a 1-hour average basis made for recently permitted simple-cycle turbine projects in SCAQMD and SDAPCD reflect the most stringent NOx emission limit that has been achieved in practice. No more stringent level has been suggested as being technologically feasible. Therefore, BACT/LAER for NOx for this application is any technology capable of achieving 2.5 ppmc on a 1-hour average basis.

Both SCR and EMx are expected to achieve the proposed BACT NOx emission limit of 2.5 ppmc averaged over one hour. However, concerns remain regarding the long-term effectiveness of EMx as a control technology because the technology has not been demonstrated on the type of turbine used in this project—a simple-cycle demand-response application. For this reason, SCR has been selected as the NOx control technology to be used for the Project.

The project facility will be designed to meet a NOx level of 2.5 ppmc on a 1-hour average basis using SCR.

5.4 CO Emissions

While BACT for CO is not required by the District NSR regulations and/or federal PSD requirements, the following discussion was included for informational purposes to show that the CECP gas turbines will also meet BACT for CO.

5.4.1 Step 1 – Identify All Possible Control Technologies

CO emitted from natural gas-fired turbines is the result of incomplete combustion of fuel. Use of an oxidation catalyst is generally considered BACT for CO; however, combined-cycle turbines are also a possible control technology and are discussed further in step 2, along with oxidation catalysts. Other alternative basic equipment—including renewable energy sources, such as solar and wind—was already discussed above (Step 1 for NOx BACT on the CTGs). For the same reasons, solar, wind and other renewable energy sources are rejected as CO BACT for this application.

5.4.2 Step 2 – Eliminate Technologically Infeasible Options

5.4.2.1 Alternate Equipment

The use of a combined-cycle turbine instead of the proposed simple-cycle turbines would be technically infeasible for the project. The simple-cycle turbines are needed to effectively handle variable loads and perform multiple startups/shutdowns per day. While advanced combined-cycle turbines can start relatively quickly (within approximately 12 minutes to reach 100% rated capacity of the gas turbine generator), they may need as much as 2 hours to reach full combined cycle output (combined output of gas turbine and steam turbine generators). [7] While operating in simple cycle mode (while waiting for the steam system to warm up), fast-start combined cycle units will have efficiencies that are no better than, and are likely worse than, those achieved with advanced simple cycle turbines such as the LMS100. Further, such units cannot perform up to four starts per day – as required for this project – without substantially shortening the life of the unit. Therefore, combined-cycle turbines are eliminated because they do not meet the basic project requirements.

5.4.2.2 Exhaust Stream Controls

The only technology remaining under consideration is use of an oxidation catalyst in combination with combustion controls. This combination of technologies has been demonstrated to be feasible in many applications. No other technologies have been identified that are capable of achieving the same level of

[7] El Segundo Energy Center LLC, 00-AFC-014C: Petition to Amend, 4/23/13, Section 2.2.7

control. As a result, the goal of the rest of this analysis is to determine the appropriate emission limit that constitutes BACT for this application.

The California Air Resources Board's (CARB's) BACT guidance document for electric generating units rated at greater than 50 MW[8] indicates that BACT for the control of CO emissions for simple-cycle power plants is 6 ppmvd at 15% O_2.

The BAAQMD's BACT guidelines specify that, for natural gas-fired simple-cycle combustion gas turbines larger than 40 MW, a CO limit of 6 ppmvd at 15% O_2 has been "achieved in practice."

The SJVAPCD's BACT guidelines contain a determination for gas turbines rated at larger than 47 MW with variable load and without heat recovery. The SJVAPCD concluded that a CO exhaust concentration of 0.024 lb/MMBtu (11 ppmvd at 15% O_2) constituted BACT that is considered technologically feasible.

A summary of recent CO BACT determinations is shown in Table 5.1C-2. Published prohibitory rules from the BAAQMD, Sacramento Metropolitan Air Quality Management District (SMAQMD), San Diego County Air Pollution Control District (SDCAPCD), SJVAPCD, and SCAQMD were reviewed to identify the CO standards that govern existing natural gas-fired simple-cycle combustion gas turbines. The SJVAPCD prohibitory rule is the only one that includes an emission limit for CO (200 ppmv at 15% O_2). The applicable NSPS (40 CFR 60 Subpart KKKK) does not include a CO limit.

TABLE 5.1C-2
Recent CO BACT Determinations for Simple-Cycle Combustion Turbines[a]

Facility	District	CO Limit[b]	Averaging Period	Control Method Used	Date Permit Issued	Source
San Francisco Electric Reliability Project	BAAQMD	4.0 ppmc	3 hr	Oxidation Catalyst	2/8/06 (FDOC)	CEC Siting Div website
EIF Panoche	SJVAPCD	6.0 ppmc	3 hr	Oxidation Catalyst	7/13/07 (FDOC)	CEC Siting Div website
Starwood Midway Firebaugh/Panoche	SJVAPCD	6.0 ppmc	3 hr	Oxidation Catalyst	9/5/07 (FDOC)	CEC Siting Div website
Walnut Creek Energy	SCAQMD	4.0 ppmc	1 hr	Oxidation Catalyst	2/27/08	FDOC
Orange Grove Energy, LLP	SDAPCD	6.0 ppmc	3 hr	Oxidation Catalyst	12/4/08	CEC Siting Div website
El Cajon Energy, LLC	SDAPCD	6.0 ppmc	3 hr	Oxidation Catalyst	12/11/09	ATC
TID Almond 2 Power Plant	SJVAPCD	4.0 ppmc	3 hr	Oxidation Catalyst	2/16/2010	FDOC
CPV Sentinel	SCAQMD	4.0 ppmc	1 hr	Oxidation Catalyst	12/1/2010	FDOC
Pio Pico Energy Center	SDAPCD	4.0 ppmc	1 hr	Oxidation Catalyst	9/12/2012	FDOC

Notes:

[a] All projects listed here utilize GE LM6000-model units except Starwood Midway, which utilizes P&W FT8-3 SwiftPacs; and EIF Panoche, Walnut Creek Energy, CPV Sentinel, and Pio Pico, all of which use GE LMS 100 CTGs.

[b] All concentrations expressed as parts per million by volume dry, corrected to 15% O_2 (ppmc).

[8] CARB, "Guidance for Power Plant Siting and Best Available Control Technology," September 1999.

5.4.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The control technologies under consideration are ranked as follows:

- Oxidation catalyst unit capable of achieving 4 ppmc
- Oxidation catalyst unit capable of achieving 6 ppmc

5.4.4 Step 4 – Evaluate the Most Effective Control Technology Considering Environmental, Energy, and Cost Impacts

This step evaluates any source-specific environmental, energy, or economic impacts that demonstrate that the top alternative listed in the previous step is inappropriate as BACT.

The Applicant has proposed to meet a 4 ppmc limit on a 1-hour average basis. Because the Applicant has proposed to use the highest ranked technology under consideration, the analysis ends at this step.

5.4.5 Step 5 – Determine BACT/Present Conclusions

BACT must be at least as stringent as the most stringent achieved in practice, required in a federal NSPS or district prohibitory rule, or considered technologically feasible. Based upon the results of this analysis, the CO emission limit of 4.0 ppmc is considered to be BACT for the proposed project.

5.5 VOC Emissions

5.5.1 Step 1 – Identify All Possible Control Technologies

Most VOCs emitted from natural gas-fired turbines are the result of incomplete combustion of fuel. Therefore, most of the VOCs are methane and ethane, which are not effectively controlled by an oxidation catalyst. However, oxidation catalyst technology designed to control CO can also provide some degree of control of VOC emissions, especially the more complex and toxic compounds formed in the combustion process. Therefore, the use of good combustion practices is generally considered BACT for VOC, with some additional benefit provided by an oxidation catalyst.

Alternative basic equipment—including renewable energy sources, such as solar and wind—was already discussed above (Step 1 for NOx BACT on the CTGs). For the same reasons, solar, wind and other renewable energy sources are rejected as VOC BACT for this application.

5.5.2 Step 2 – Eliminate Technologically Infeasible Options

The only technology under consideration is combustion controls, with some additional benefit provided by an oxidation catalyst. This combination of technologies has been demonstrated to be feasible in many applications. No other technologies have been identified that are capable of achieving the same level of control. As a result, the goal of the rest of this analysis is to determine the appropriate emission limit that constitutes BACT for this application.

As shown in Table 5.1C-3, CARB's BACT guidance document for electric generating units rated at greater than 50 MW indicates that BACT for the control of VOC emissions for simple-cycle power plants is 2 ppmvd at 15% O_2.

The BAAQMD's BACT guidelines do not include a BACT determination for simple-cycle turbines greater than 40 MW.

TABLE 5.1C-3
CARB BACT Guidance For Power Plants

Pollutant	BACT
Nitrogen Oxides	2.5 ppmv at 15% O2 (1-hour average) 2.0 ppmv at 15% O2 (3-hour average)
Sulfur Dioxide	Fuel sulfur limit of 1.0 grains/100 scf
Carbon Monoxide	Nonattainment areas: 6 ppmv at 15% O2 (3-hour average) Attainment areas: District discretion
VOC	2 ppmv at 15% O2 (3-hour average)
NH_3	5 ppmv at 15% O2 (3-hour average)
PM_{10}	Fuel sulfur limit of 1.0 grains/100 scf

The SJVAPCD's BACT guidelines contain a determination for gas turbines rated at larger than 50 MW with variable load and without heat recovery. The SJVAPCD concluded that a VOC exhaust concentration of 0.007 lb/MMBtu (6 ppmvd at 15% O_2) constituted BACT that had been achieved in practice.

Published prohibitory rules from the BAAQMD, SMAQMD, SDCAPCD, SJVAPCD, and SCAQMD were reviewed to identify the VOC standards that govern existing natural gas-fired simple-cycle combustion gas turbines. None of the prohibitory rules for combustion gas turbines specify an emission limit for VOC. The applicable NSPS (40 CFR 60 Subpart KKKK) does not include a VOC limit.

This "top-down" VOC BACT analysis will consider the following VOC emission limitations:

- 2 ppmvd at 15% O_2

A summary of recent VOC BACT determinations is shown in Table 5.1C-4.

TABLE 5.1C-4
Recent VOC BACT Determinations for Simple-Cycle Combustion Turbines[a]

Facility	District	VOC Limit[b]	Averaging Period	Control Method Used	Date Permit Issued	Source
San Francisco Electric Reliability Project	BAAQMD	2.0 ppmc	1 hr	Oxidation Catalyst	2/8/06 (FDOC)	CEC Siting Div website
EIF Panoche	SJVAPCD	2.0 ppmc	1 hr	Oxidation Catalyst	7/13/07 (FDOC)	CEC Siting Div website
Starwood Midway Firebaugh/Panoche	SJVAPCD	2.0 ppmc	1 hr	Oxidation Catalyst	9/5/07 (FDOC)	CEC Siting Div website
Walnut Creek Energy	SCAQMD	2.0 ppmc	1 hr	Oxidation Catalyst	2/27/08	FDOC
Orange Grove Energy, LLP	SDAPCD	2.0 ppmc	1 hr	Oxidation Catalyst	12/4/08	CEC Siting Div website
El Cajon Energy, LLC	SDAPCD	2.0 ppmc	1 hr	Oxidation Catalyst	12/11/09	ATC
TID Almond 2 Power	SJVAPCD	2.0	1 hr	Oxidation	2/16/2010	FDOC

TABLE 5.1C-4
Recent VOC BACT Determinations for Simple-Cycle Combustion Turbines[a]

Facility	District	VOC Limit[b]	Averaging Period	Control Method Used	Date Permit Issued	Source
Plant		ppmc		Catalyst		
CPV Sentinel	SCAQMD	2.0 ppmc	1 hr	Oxidation Catalyst	12/1/2010	FDOC
Pio Pico Energy Center	SDAPCD	2.0 ppmc	1 hr	Oxidation Catalyst	9/12/2012	FDOC

Notes:

[a] All projects listed here utilize GE LM6000-model units except Starwood Midway, which utilizes P&W FT8-3 SwiftPacs; and EIF Panoche, Walnut Creek Energy, CPV Sentinel, and Pio Pico, all of which use GE LMS 100 CTGs.

[b] All concentrations expressed as parts per million by volume dry, corrected to 15% O_2 (ppmc).

5.5.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The control technologies under consideration are ranked as follows:

- 2 ppmvd at 15% O_2

5.5.4 Step 4 – Evaluate the Most Effective Control Technology Considering Environmental, Energy, and Cost Impacts

This step evaluates any source-specific environmental, energy, or economic impacts that demonstrate that the top alternative listed in the previous step is inappropriate as BACT.

The Applicant has proposed to meet a 2 ppmvd limit on a 1-hour average basis. This level meets BACT.

5.5.5 Step 5 – Determine BACT/Present Conclusions

BACT must be at least as stringent as the most stringent achieved in practice, required in a federal NSPS or district prohibitory rule, or considered technologically feasible. Based upon the results of this analysis, the VOC emission limit of 2.0 ppmc is considered to be BACT for the proposed project.

5.6 Sulfur Oxide Emissions

5.6.1 Step 1 – Identify All Possible Control Technologies

Natural gas fired combustion turbines have inherently low SOx emissions due to the small amount of sulfur present in the fuel. With typical pipeline quality natural gas sulfur content well below 1 grain/100 scf, the SOx emissions for natural gas fired combustion turbines are orders of magnitude less than oil-fired turbines. Firing by natural gas, and the resulting control of SOx emissions, has been used by numerous combustion turbines throughout the world. Due to the prevalence of the use of natural gas to control SOx emissions from combustion turbines, only an abbreviated discussion of post-combustion controls will be addressed in this section.

Post-combustion SOx control systems include dry and wet scrubber systems. These types of systems are typically installed on high SOx emitting sources such as coal-fired power plants. Post-combustion control systems for combustion turbines also include ESx catalyst systems. These systems trap the sulfur in the exhaust stream on an ESx catalyst. During a regeneration process, the sulfur is removed from the ESx catalyst and is either reintroduced back into the exhaust stream or sent to a sulfur scrubbing system. If the sulfur removed from the ESx catalyst is reintroduced back into the exhaust stream, there is no SOx control associated with the system.

5.6.2 Step 2 – Eliminate Technically Infeasible Options

All of the control options discussed above are technically feasible.

5.6.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The typical SOx control level for a well-designed wet or dry scrubber installed on a coal fired boiler ranges from approximately 70% to 90%,[9] with some installations achieving even higher control levels. According to EmeraChem literature,[10] the ESx system is capable of removing approximately 95% of the SOx emissions from the exhaust stream of natural gas fired combustion turbines. With the sulfur scrubber option, during the regeneration cycle of the ESx system the sulfur captured on the ESx catalyst is sent to a sulfur scrubbing unit. A high-efficiency sulfur scrubbing unit would achieve a control level similar to that of the wet/dry scrubbers discussed above.

5.6.4 Step 4 – Evaluate Most Effective Controls and Document Results

The use of low sulfur content pipeline natural gas has been achieved in practice at numerous combustion turbine installations throughout the world, and the use of this fuel minimizes SOx emissions. While it would be theoretically feasible to install some type of post-combustion control such as a dry/wet scrubber system or an ESx catalyst with a sulfur scrubber on a natural gas fired turbine, due to the inherently low SOx emissions associated with the use of natural gas, these systems are not cost effective and regulatory agencies do not require them. Consequently, no further discussion of post-combustion SOx control is necessary.

5.6.5 Step 5 – Determine BACT/Present Conclusions

BACT for this project is the use of pipeline-quality natural gas. The SOx control method for the proposed Amended CECP project is the use of pipeline-quality natural gas. Consequently, the proposed project is consistent with BACT requirements.

5.7 PM/PM_{10}/$PM_{2.5}$ Emissions

5.7.1 Step 1 – Identify All Possible Control Technologies

Alternative basic equipment—including renewable energy sources, such as solar and wind—has also been identified as a technology for the control of PM/PM_{10}/$PM_{2.5}$ emissions. Such alternative basic equipment was already discussed above (Step 1 for NOx BACT on the CTGs/HRSGs). For the same reasons, solar, wind and other renewable energy sources are rejected as PM_{10}/$PM_{2.5}$ BACT for this application.

5.7.2 Achievable Controlled Levels and Available Control Options

PM emissions from natural gas-fired turbines primarily result from carryover of noncombustible trace constituents in the fuel. PM emissions are minimized by using clean-burning pipeline quality natural gas with low sulfur content.

The CARB BACT Clearinghouse, as well as the BAAQMD and SJVAPCD BACT guidelines, identify the use of natural gas as the primary fuel as "achieved in practice" for the control of PM_{10}/$PM_{2.5}$ for combustion gas turbines.

[9] Air Pollution Control Manual, Air and Waste Management Association, Second Edition, page 206.

[10] High Performance EMx Emissions Control Technology for Fine Particles, NOx, CO, and VOCs from Combustion Turbines and Stationary IC Engines, by Steven DeCicco and Thomas Girdlestone, EmeraChem Power, June 2008, page 19.

CARB's BACT guidance document for stationary gas turbines used for power plant configurations[11] indicates that BACT for the control of PM emissions is an emission limit corresponding to natural gas with a fuel sulfur content of no more than 1 grain/100 standard cubic foot.

Title 40 CFR Part 60 Subpart KKKK contains the applicable NSPS for combustion gas turbines. Subpart KKKK does not regulate $PM_{10}/PM_{2.5}$ emissions.

Published prohibitory rules from the SCAQMD, SJVAPCD, SMAQMD, and SDCAPCD were reviewed to identify the PM_{10} standards that govern natural gas-fired combustion gas turbines. These prohibitory rules do not regulate $PM_{10}/PM_{2.5}$ emissions.

In the recently issued PSD permit for the Pio Pico project, EPA performed an extensive BACT analysis for PM. This analysis included a review of data specifically for the GE LMS100 simple cycle turbines, the same model proposed for CECP. EPA considered what PM limit would be technically feasible to meet on an ongoing basis, in addition to reviewing source test data from GE LMS100 turbines installed at other locations and reviewing permit limits for other installations with the same model and size turbine, operated in simple-cycle mode. The most recent approved BACT $PM_{10}/PM_{2.5}$ limit for an LMS100 gas turbine is 5.0 lb/hr for Pio Pico Energy Center, as approved on February 28, 2014.[12] This is the lowest BACT $PM_{10}/PM_{2.5}$ limit approved for GE LMS100 simple-cycle turbines. CECP is proposing a limit lower than that approved for Pio Pico.

This "top-down" $PM_{10}/PM_{2.5}$ BACT analysis will consider the following emission limitations:

- 3.5 lb/hr

5.7.3 Step 2 – Eliminate Technologically Infeasible Options

As discussed above, solar, wind and other renewable energy alternatives are not considered technologically feasible for this application.

5.7.4 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

No control technology other than use of clean natural gas fuel has been identified for this application.

5.7.5 Step 4 – Evaluate the Most Effective Control Technology Considering Environmental, Energy, and Cost Impacts

No control technology other than use of clean natural gas fuel has been identified for this application.

5.7.6 Step 5 – Determine BACT/Present Conclusions

Based upon the results of this analysis, the use of natural gas as the primary fuel source constitutes BACT for $PM_{10}/PM_{2.5}$ emissions from combustion gas turbines. Through the use of natural gas, the turbine is expected to be able to meet the proposed emission limit of 3.5 lbs/hr.

5.8 GHG Emissions

5.8.1 Step 1 – Identify All Possible Control Technologies

EPA has indicated in its guidance on BACT for GHGs[13] that the following types of controls must be considered in determining BACT for GHGs:

- Inherently lower-emitting processes/practices/designs;
- Add-on controls; and

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[11] Ibid, Table I-2.

[12] EPA PSD Permit for PPEC, http://www.regulations.gov/#!documentDetail;D=EPA-R09-OAR-2011-0978-0034

[13] EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases*, March 2011, p. 28

- Combinations of inherently lower emitting processes/practices/designs and add-on controls.[14]

EPA further acknowledges that the requirement to consider inherently lower-emitting processes/practices/designs does not require a fundamental redesign of the nature of the source. This indicates that lower-emitting process/practices/designs that do not achieve the goals, objectives, or purposes of the project may be considered technologically infeasible as BACT for a project.

The following control technologies were identified as potentially "available" for CECP:

- Renewable energy technology (solar or wind);
- Alternative generating technologies;
- Alternative fuels;
- Energy efficiency; and
- Carbon capture and storage.

5.8.1.1 Alternative Basic Equipment: Renewable Energy Technology and Combined Cycle Turbines

Combined cycle gas turbines have the potential to produce fewer GHG emissions, and are carried forward to Step 2. The remaining alternative technologies, and the basis for eliminating them from the BACT analysis, are discussed above under the NOx BACT evaluation.

5.8.2 Step 2 – Eliminate Technologically Infeasible Options

EPA considers a technology to be technically feasible if it has been demonstrated in practice on a similar facility, or is available and applicable to the source type under review. EPA considers a technology to be "available" where it can be obtained through commercial channels or is otherwise available within the common meaning of the term (e.g., it has been demonstrated in practice on a comparable, but not necessarily similar, facility). A technology is applicable if it may reasonably be expected to be successfully applied to the source type under review.

5.8.2.1 Alternate Equipment – Combined-Cycle Turbines

The use of a combined-cycle turbine instead of the proposed simple-cycle turbines would be technically infeasible for the project. The simple-cycle turbines are needed to effectively handle variable loads and perform multiple startups/shutdowns per day. While advanced combined-cycle turbines can start relatively quickly (within approximately 12 minutes to reach 100% rated capacity of the gas turbine generator), they may need as much as 2 hours to reach full combined cycle output (combined output of gas turbine and steam turbine generators).[15] While operating in simple cycle mode (while waiting for the steam system to warm up), fast-start combined cycle units will have efficiencies that are no better than, and are likely worse than, those achieved with advanced simple cycle turbines such as the LMS 100. Further, such units cannot perform up to four starts per day – as required for this project – without substantially shortening the life of the unit. Therefore, combined-cycle turbines are eliminated because they do not meet the basic project requirements.

5.8.2.2 Alternative Fossil Fuel Generating Technologies

Alternative fossil fuel generating technologies such as reciprocating internal combustion engines and boilers may be considered as potentially technologically feasible alternatives to the proposed use of simple-cycle combustion turbine technology. Reciprocating engine technology is generally well-suited to demand-response applications such as the proposed project, so can be considered technologically feasible for this application; boilers, on the other hand, have very high thermal inertia, so are not quick-starting or fast

[14] Ibid, p.27.

[15] El Segundo Energy Center LLC, 00-AFC-014C: Petition to Amend, 4/23/13, Section 2.2.7

ramping. Boiler technology is generally used for baseload power and not for highly variable demand-response power applications. Because boiler technology cannot meet the objectives of the project, it is not considered a technologically feasible alternative.

5.8.2.3 Alternative Fuels

Biomass fuel can only be used with boiler technology and must be gasified for use in turbines. As discussed previously, boiler technology is not considered a technologically feasible alternative. Therefore, there are no alternative fuels that are considered technologically feasible without redefining the project.

5.8.2.4 Energy Efficiency

There are two potential applications of energy efficiency as potential BACT for the proposed project: (1) demand-side management and similar electric load reduction programs to minimize or eliminate the need for the proposed project altogether; and (2) use of the most efficient generating technology that meets the objectives of the project.

Implementation of energy efficiency programs is beyond the scope of this project. The purpose of this project is to help meet the energy demands that will remain after utility energy efficiency programs are implemented.

Utilization of the most efficient generating technology that meets the objectives of the project is technologically feasible.

5.8.2.5 Carbon Capture and Storage

Carbon capture and storage (CCS) technology may be considered to be “available” in the sense that commercial facilities have been built on a scale comparable to CECP (e.g., a natural gas processing operation[16] in Wyoming captures 3.6 million tons per year of CO_2, compared to the 0.9 million tons per year that would be emitted from CECP). However, the technology cannot yet be considered “applicable.” The Interagency Task Force on Carbon Capture and Storage (ITF) found the following:

> *It is unclear how transferable the experience with natural gas processing is to separation of power plant flue gases, given the significant differences in the chemical make-up of the two gas steams. In addition, integration of these technologies with the power cycle at generating plants present significant cost and operating issues that will need to be addressed.*[17]

CCS has not yet reached the licensing and commercial sales stage of development. It is an emerging technology that has had limited successful application on an industrial scale, and no successful applications on a comparably sized natural gas power plant. There are no CCS systems commercially available for natural gas power plants in the United States. The Department of Energy expects commercial deployment in 2025.[18] CCS does not appear to be commercially available for this application.

5.8.3 Step 3 – Rank Remaining Control Technologies

Absent post-combustion removal or sequestration, CO_2 and other GHG emissions are a direct function of the amount of natural gas fuel burned. GHG emissions will be minimized by minimizing heat rate and maximizing generating efficiency. The remaining technologies are ranked by their overall heat rate for consideration as BACT for this project, as shown in Table 5.1C-5.

CO_2 is not the byproduct of incomplete combustion or contaminants in the fuel supply. It is an essential product of the combustion of natural gas. Therefore, the only way to reduce the amount of CO_2 generated is

[16] Interagency Task Force on Carbon Capture and Storage, *Report of the Interagency Task Force on Carbon Capture and Storage*¸ August 2010. p. 28.

[17] Ibid.

[18] 73 FR 44370

to minimize the amount of fuel combustion required to produce the desired amount of electricity. This is achieved by operating the unit efficiently and conducting regular maintenance to ensure continued good combustion. Good combustion practices are a well-established and widely used technique to minimize emissions from combustion sources. Good combustion operation and maintenance will maintain the thermal efficiency of the selected generating technology and therefore must also be considered a component of BACT to minimize GHG emissions.

TABLE 5.1C-5
Ranking of Potential Generating Technologies/Controls by Heat Rate

Technology	Heat Rate Range (HHV basis)	Technologically Feasible for This Project?
Renewable energy sources	n/a	No
Biomass and other biofuels	n/a	No
Demand-side management	n/a	No
CCS	n/a	Maybe
Reciprocating IC engines	~8,583 Btu/kWh[e]	Yes
Simple-cycle gas turbines	~8,770 to 10,000 Btu/kWh[a,b,c,d]	Yes
Boilers	>10,000 Btu/kWh[a,b,c]	No

Notes:

[a] CEC FSA, Sentinel Energy Project. *http://www.energy.ca.gov/sitingcases/sentinel/index.html*

[b] CEC FSA, TIC Almond 2 Power Plant Project. *http://www.energy.ca.gov/sitingcases/almond/index.html*

[c] CEC FSA, Walnut Creek Energy Project. *http://www.energy.ca.gov/sitingcases/walnutcreek/index.html*

[d] *CECP air quality analysis, Appendix 5.1B-2 (operating case 100) of PTA*

[e] *Quail Brush AFC, Table F.1-2, Case 8, August 2011 (Wartsila gas engine, model 20V34SG)*

5.8.4 Step 4 – Evaluate the Most Effective Control Technology Considering Environmental, Energy, and Cost Impacts

5.8.4.1 Reciprocating IC Engines

Reciprocating IC engines are fast-starting, but the largest natural gas-fired IC engine currently available is the approximately 18 MW Wärtsilä18V50SG.[19] The 632 MW net output size of the proposed project would require about 36 of these engines, which would result in a more complex plant and control system. In addition, there is insufficient room at the CECP site for a 36-engine plant. The heat rate for an engine of this type is approximately 8,583 Btu/kWh (HHV), as provided in the most recent CEC AFC for the Quail Brush project.[20] In comparison, the heat rate for the CECP GE LMS 100 gas turbines is approximately 8,770 Btu/kWh (HHV), which is similar to the heat rate for the IC engines. Furthermore, BACT for NOx from engines of this type has been determined to be 4 ppm (technologically feasible)[21], so NOx emissions from a comparable reciprocating engine plant would be approximately 60% higher than the NOx emissions from the proposed simple-cycle gas turbine project. Reciprocating IC engines would result in a more complex plant, provide comparable heat rates, could result in higher NOx emissions, and would not be able to be

[19] *Wartsila "Power Plant Solutions 2013" 3rd Edition, pp.119, http://www.wartsila.com/file/Wartsila/en/1278518335887a1267106724867-Power-Plants-Solutions-2013---3rd-Edition.pdf*

20 *Quail Brush AFC, Table F.1-2, Case 8, August 2011 (Wartsila gas engine, model 20V34SG)*

[21] BAAQMD BACT Guideline, Section 2, natural gas fired IC Engine-Spark Ignition >=50 HP

located within the project footprint; therefore, reciprocating IC engine technology is not considered BACT for this project.

5.8.4.2 Carbon Capture and Storage

CCS technology applicable to natural gas-fired projects refers to post-combustion capture. EPA's Interagency Task Force on Carbon Capture and Storage[22] found the following:

> *Post-combustion CO_2 capture … is challenging for the following reasons:*
>
> - *A high volume of gas must be treated because the CO_2 is dilute (13 to 15 percent by volume in coal-fired systems, three to four percent in natural-gas-fired systems);*
> - *The flue gas is at low pressure (near atmosphere);*
> - *trace impurities (particulate matter [PM], sulfur oxides [SOx], nitrogen oxides [NOx], etc.) can degrade the CO_2 capture materials; and*
> - *Compressing captured CO_2 from near atmospheric pressure to pipeline pressure (about 2,000 pounds per square inch absolute) requires a large auxiliary power load…Installing current amine post-combustion CO_2 capture technology on new conventional subcritical, supercritical, and ultra-supercritical coal-fired power plants would increase the COE by about 80 percent. Further, the large quantity of energy required to regenerate the amine solvent and compress the CO_2 to pipeline conditions would result in about a 30 percent energy penalty.*

The International Energy Agency estimates that "CCS can reduce CO_2 emissions from power plants…by more than 85%, and power plant efficiency by about 8-12 percentage points."[23] Although this energy penalty is for coal-fired plants and is not directly applicable to natural gas firing, it is expected to be reasonably representative of the energy penalty for a natural gas-fired system because the lower content of CO_2 in gas turbine exhaust would not necessarily result in an efficiency savings (separation is still required, and there are no data to suggest that the differences in CO_2 concentrations between coal exhaust and gas turbine exhaust would result in lower separation costs). Assuming a minimum 8% energy penalty for CCS, the project would have to generate 8% more electricity to provide energy for CCS without reducing the electricity supply provided by the facility. Criteria pollutant and GHG emissions would also be 8% higher. Considering the energy and emissions penalties, the cost, and the lack of commercial availability, CCS is not considered BACT for the proposed project.

5.8.5 Step 5 – Determine BACT/Present Conclusions

As shown in Table 5.1C-5, simple-cycle gas turbines typically have heat rates that range between approximately 8,770 and 10,000 Btu/kWh (HHV). CECP proposes to use a newer, more energy efficient simple-cycle turbine technology, the GE LMS100, which incorporates intercooling to promote enhanced energy efficiency. The heat rate of the GE LMS100 is approximately 8,770 Btu/kWh (HHV), at the low end of the range of heat rates shown above for typical simple-cycle gas turbines. The use of this highly efficient simple-cycle gas turbine technology, combined with good combustion operation and maintenance to maintain optimum efficiency, is determined to be BACT for GHG.

Recent BACT determinations for criteria pollutants from similar gas turbine projects are summarized in Tables 5.1C-6 through 5.1C-8.

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[22] EPA, "Report of the Interagency Task Force on Carbon Capture and Storage," 2010, pp. 29-30, *http://www.epa.gov/climatechange/downloads/CCS-Task-Force-Report-2010.pdf.*

[23] IEA Energy Technology Essentials, December 2006. *http://www.iea.org/techno/essentials.htm.*

TABLE 5.1C-6
Simple-Cycle Gas Turbine BACT Determinations (EPA RBLC Clearinghouse)

Facility/Location	Date Permit Issued	Equipment/Rating	NOx Limit/Control Technology	CO Limit/Control Technology	VOC Limit/Control Technology
TEC/Polk Power Energy Station Polk Co., FL	October 2007	Unspecified 2 turbines, 330 MW total	9.0 ppm Dry low-NOx burners	No BACT determination	No BACT determination
Rawhide Energy Station Larimer Co., CA	June 2009	GE Frame 7FA 1 turbine, 150 MW total	9.0 ppm Dry low-NOx burners	No BACT determination	No BACT determination
Shady Hills Generating Station Pasco Co., FL	January 2010	GE Frame 7FA 2 turbines, 340 MW total	9.0 ppm Dry low-NOx burners and water injection	6.5 ppm (3 hour)	No BACT determination

TABLE 5.1C-7
Summary of BACT Determinations (CARB BACT Clearinghouse)

Facility/District	Permit No./Date	Equipment/Rating	NOx Limit/ Control Technology	CO Limit/Control Technology	VOC Limit/Control Technology
Los Angeles Dept. of Water and Power Los Angeles Co., CA	May 2001	GE LM6000 1 turbine, 47.4 MW total	5.0 ppm SCR	6.0 ppm Oxidation catalyst	2.0 ppm Oxidation catalyst
CalPeak Power El Cajon San Diego Co., CA	June 2001	Pratt & Whitney FT-8 DLN Twin Pac 2 turbines 49.5 MW total	3.5 ppm SCR	50 ppm Oxidation catalyst	2.0 ppm Oxidation catalyst
Indigo Energy Facility Los Angeles Co., CA	July 2001	LM6000 (Enhanced Sprint) 1 turbine, 45 MW total	5.0 ppm SCR	6.0 ppm Oxidation catalyst	2.0 ppm Oxidation catalyst
Lambie Energy Center Solano Co., CA	December 2002	GE LM6000 Sprint PC 1 turbine, 49.9 MW total	2.5 ppm SCR	6.0 ppm Oxidation catalyst	2.0 ppm Oxidation catalyst
El Colton, LLC San Bernardino Co., CA	January 2003	LM6000 (Enhanced Sprint) 1 turbine, 48.7 MW total	3.5 ppm SCR	6.0 ppm Oxidation catalyst	2.0 ppm Oxidation catalyst

TABLE 5.1C-8
Summary of BACT Determinations (CEC Decisions)

Facility/District	Decision Date	Equipment/Rating	NOx Limit/ Control Technology	CO Limit/Control Technology	VOC Limit/Control Technology
San Francisco Electric Reliability Project Power Plant San Francisco Co., CA	October 2006	GE LM6000 Sprint PC 3 turbines, 145 MW total	2.5 ppm Water injection & SCR	4.0 ppm (3 hour) Oxidation catalyst	2.0 ppm Oxidation catalyst
Inland Empire Energy Center Imperial County, CA	October 2006	GE LM6000 Sprint PC 2 turbines, 93 MW total	2.5 ppm Dry low-NOx burners & SCR	6.0 ppm (3 hour) Oxidation catalyst	2.0 ppm Oxidation catalyst
Panoche Energy Project Fresno Co., CA	December 2007	GE LMS100 4 turbines, 400 MW total	2.5 ppm Water injection & SCR	6.0 ppm (3 hour) Oxidation catalyst	2.0 ppm Oxidation catalyst
Starwood Power-Midway Fresno Co., CA	January 2008	Pratt & Whitney FT8-3 SwiftPac 2 turbines, 120 MW total	2.5 ppm Water injection & SCR	6.0 ppm (3 hour) Oxidation catalyst	2.0 ppm Oxidation catalyst
Walnut Creek Energy Los Angeles County, CA	February 2008	GE LMS100 5 turbines, 500 MW total	2.5 ppm Water injection & SCR	4.0 ppm (1 hour) Oxidation catalyst	2.0 ppm Oxidation catalyst
Orange Grove Energy, LLP	December 2008	GE LM6000 Sprint PC 2 turbines, 96 MW total	2.5 ppm Water injection & SCR	6.0 ppm (3 hour) Oxidation catalyst	2.0 ppm Oxidation catalyst
Canyon Power Plant Orange Co., CA	March 2010	GE LM6000 Sprint PC 4 turbines, 200 MW total	2.5 ppm Ultra-low NOx burners, water injection & SCR	4.0 ppm (3 hour) Oxidation catalyst	2.0 ppm Oxidation catalyst
CPV Sentinel Riverside County, CA	December 2010	GE LMS100 8 turbines, 850 MW total	2.5 ppm Water injection & SCR	4.0 ppm (1 hour) Oxidation catalyst	2.0 ppm Oxidation catalyst
TID Almond 2 Power Plant Ceres, CA	December 2010	GE LM6000 Sprint PG 3 turbines, 174 MW	2.5 ppm Ultra-low NOx burners, water injection & SCR	4.0 ppm (3 hour) Oxidation catalyst	2.0 ppm Oxidation catalyst
Pio Pico Energy Center	September 2012	GE LMS100 3 turbines, 300 MW total	2.5 ppm Water injection & SCR	4.0 ppm (1 hour) Oxidation catalyst	2.0 ppm Oxidation catalyst

5.9 BACT for the Simple-Cycle CTGs: Startup/Shutdown

Startup and shutdown periods are a normal part of the operation of simple-cycle power plants such as CECP. BACT must also be applied during the startup and shutdown periods of gas turbine operation. The BACT limits discussed in the previous section apply to steady-state operation, when the turbines have reached stable operations and the emission control systems are fully operational.

5.10 NOx Emissions

5.10.1 Step 1 – Identify All Possible Control Technologies

The following technologies for control of NOx during startups and shutdowns have been identified:

- A Selective Catalytic Reduction (SCR) system capable of continuously complying with a limit of 2.5 ppmc (1-hour average);
- Fast-start technologies; and
- Operating practices to minimize the duration of startup and shutdown.

The LMS 100 turbine proposed for this project is controlled by SCR, which will operate at all times that the stack temperature is in the proper operating range.

5.10.2 Step 2 – Eliminate Technologically Infeasible Options

During gas turbine startup, there are equipment and process requirements that must be met in sequential order to protect the equipment.

For all turbine technologies, incomplete combustion at low loads results in higher CO and VOC emission rates. Furthermore, the post-combustion controls that are used to achieve additional emissions reductions (SCR and oxidation catalyst) require that specific exhaust temperature ranges be reached to be fully effective. The use of SCR to control NOx is not technically feasible when the surface of the SCR catalyst is below the manufacturer’s recommended operating range. When catalyst surface temperatures are low, ammonia will not react completely with the NOx, resulting in excess NOx emissions or excess ammonia slip or both. The oxidation catalyst is not effective at controlling CO emissions when exhaust temperature is below the optimal temperature range. Therefore, exhaust gas controls used to achieve BACT for normal operations are not feasible control techniques during startups and shutdowns.

This “top-down” BACT analysis will consider the following NOx emission limitations:

- Operating practices to minimize emissions during startup and shutdown; and
- Design features to minimize the duration of startup and shutdown.

5.10.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

5.10.3.1 Operating Practices to Minimize Emissions during Startup and Shutdown

There are basic principles of operation, or Best Management Practices, that minimize emissions during startups and shutdowns. These Best Management Practices are outlined below.

- During a startup, bring the gas turbine to the minimum load necessary to achieve compliance with the applicable NOx and CO emission limits as quickly as possible, consistent with the equipment manufacturers’ recommendations and safe operating practices.
- During a startup, initiate ammonia injection to the SCR system as soon as the SCR catalyst temperature and ammonia vaporization system have reached their minimum operating temperatures.

- During a shutdown, once the turbine reaches a load that is below the minimum load necessary to maintain compliance with the applicable NOx and CO emission limits, reduce the gas turbine load to zero as quickly as possible, consistent with the equipment manufacturers' recommendations and safe operating practices.
- During a shutdown, maintain ammonia injection to the SCR system as long as the SCR catalyst temperature and ammonia vaporization system remain above their minimum operating temperatures.

A key underlying consideration of these Best Management Practices is the overall safety of the plant staff by promoting operation within the limitations of the equipment and systems, and allowing for operator judgment and response times to respond to alarms and trips during the startup sequence.

5.10.3.2 Design Features to Minimize the Duration of Startup and Shutdown

An additional technique to reduce startup emissions is to minimize the amount of time the gas turbine spends in startup. The use of simple-cycle gas turbine technology inherently minimizes this time, in that simple-cycle gas turbines generally start up and shut down much more quickly than combined-cycle turbines.

5.10.4 Step 4 – Evaluate the Most Effective Control Technology Considering Environmental, Energy, and Cost Impacts

Utilizing best operating practices to minimize emissions during startups and shutdowns has no adverse environmental or energy impacts, nor does it require additional capital expenditure.

The approach of reducing startup/shutdown duration has no adverse environmental or energy impacts, and the use of simple-cycle generating technology minimizes startup/shutdown duration.

5.10.5 Step 5 - Determine BACT/Present Conclusions

BACT for NOx during startups/shutdowns is the use of operating systems/practices that reduce the duration of startups and shutdowns to the greatest extent feasible, and the use of operational techniques to initiate ammonia injection as soon as possible during a startup. Therefore, BACT is determined to be the use of simple-cycle gas turbine technology and the application of operating systems/practices that minimize startup and shutdown durations, in combination with the use of operational techniques to initiate ammonia injection as soon as possible during a startup.

5.11 CO Emissions

5.11.1 Step 1 – Identify All Possible Control Technologies

The CO control technologies under consideration for startups and shutdowns are ranked as follows:

- Oxidation catalyst unit capable of achieving 4 ppmc
- Operating practices to minimize the duration of startup and shutdown

5.11.2 Step 2 – Eliminate Technologically Infeasible Options

None of the proposed alternatives is infeasible for this application.

5.11.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Ranking for the control technologies is as indicated in Step 1.

5.11.4 Step 4 – Evaluate the Most Effective Control Technology Considering Environmental, Energy, and Cost Impacts

Similar to the discussion above for NOx, CO emissions during startup and shutdown are minimized by minimizing the length of time that the turbine fires while the oxidation catalyst is not in its operating temperature range.

5.11.5 Step 5 – Determine BACT/Present Conclusions

BACT for CO during startups/shutdowns is the use of simple-cycle gas turbine technology and operating practices that reduce the duration of startups and shutdowns to the greatest extent feasible.

5.12 VOC Emissions

5.12.1 Step 1 – Identify All Possible Control Technologies

The VOC control technologies under consideration for startups and shutdowns are ranked as follows:

- Operating practices to minimize the duration of startup and shutdown

5.12.2 Step 2 – Eliminate Technologically Infeasible Options

None of the proposed alternatives is infeasible for this application.

5.12.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The only proposed control technology is operating practices to minimize the duration of startups and shutdowns.

5.12.4 Step 4 – Evaluate the Most Effective Control Technology Considering Environmental, Energy, and Cost Impacts

VOC emissions during startup and shutdown are minimized by minimizing the duration of startup and shutdown.

5.12.5 Step 5 – Determine BACT/Present Conclusions

BACT for VOC during startups/shutdowns is the use of simple-cycle gas turbine technology and operating practices that reduce the duration of startups and shutdowns to the greatest extent feasible.

5.13 Sulfur Oxide Emissions

5.13.1 Step 1 – Identify All Possible Control Technologies

The SOx control technologies under consideration for startups and shutdowns are ranked as follows:

- Use of natural gas as a fuel
- Operating practices to minimize the duration of startup and shutdown

5.13.2 Step 2 – Eliminate Technologically Infeasible Options

None of the proposed alternatives is infeasible for this application.

5.13.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Ranking for the control technologies is as indicated in Step 1.

5.13.4 Step 4 – Evaluate the Most Effective Control Technology Considering Environmental, Energy, and Cost Impacts

SOx emissions during startup and shutdown are minimized by minimizing duration of startup and shutdown.

5.13.5 Step 5 – Determine BACT/Present Conclusions

BACT for SOx during startups/shutdowns is the use of simple-cycle gas turbine technology and operating practices that reduce the duration of startups and shutdowns to the greatest extent feasible.

5.14 PM/PM_{10}/$PM_{2.5}$ Emissions

5.14.1 Step 1 – Identify All Possible Control Technologies

The analysis for particulate is identical to the analysis for SOx.

5.14.2 Step 2 – Eliminate Technologically Infeasible Options

The analysis for particulate is identical to the analysis for SOx.

5.14.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The analysis for particulate is identical to the analysis for SOx.

5.14.4 Step 4 – Evaluate the Most Effective Control Technology Considering Environmental, Energy, and Cost Impacts

The analysis for particulate is identical to the analysis for SOx.

5.14.5 Step 5 – Determine BACT/Present Conclusions

BACT for particulate during startups/shutdowns is the use of simple-cycle gas turbine technology and operating practices that reduce the duration of startups and shutdowns to the greatest extent feasible.

5.15 GHG Emissions

5.15.1 Step 1 – Identify All Possible Control Technologies

The GHG control technologies under consideration for startups and shutdowns are ranked as follows:

- Operating practices to minimize the duration of startups and shutdowns

5.15.2 Step 2 – Eliminate Technologically Infeasible Options

None of the proposed alternatives is infeasible for this application.

5.15.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The only proposed control technology is operating practices to minimize the duration of startups and shutdowns.

5.15.4 Step 4 – Evaluate the Most Effective Control Technology Considering Environmental, Energy, and Cost Impacts

GHG emissions during startup and shutdown are minimized by minimizing the length of time during startup and shutdown.

5.15.5 Step 5 – Determine BACT/Present Conclusions

BACT for GHG during startups/shutdowns is the use of simple-cycle gas turbine technology and operating practices that reduce the duration of startups and shutdowns to the greatest extent feasible.

5.16 Summary

Proposed BACT determinations for the Amended CECP simple-cycle gas turbines are summarized in Table 5.1C-9.

TABLE 5.1C-9
Proposed BACT Determinations for Amended CECP Simple-Cycle Gas Turbines

Pollutant	Proposed BACT Determination
Nitrogen Oxides	Water injection and SCR system, 2.5 ppmc[a], 1-hour average, with exemptions for startup/shutdown conditions; no CCS
Sulfur Dioxide	Natural gas fuel (sulfur content not to exceed 0.75 grain/100 scf short-term average, 0.25 grains/100 scf long-term average)
Carbon Monoxide	Good combustion practices and oxidation catalyst, 4.0 ppmc, 1-hour average
VOC	Good combustion practices, 2.0 ppmc, 1-hour average
PM_{10}	Natural gas fuel, 3.5 PM_{10} lbs/hr
$PM_{2.5}$	Natural gas fuel, 3.5 $PM_{2.5}$ lbs/hr
GHGs	GE LMS100 simple-cycle gas turbine technology, good combustion practices
Ammonia	5 ppm ammonia slip
Startup/Shutdown	Best operating practices to minimize startup/shutdown times and emissions

Note:

[a] ppmc: parts per million by volume, corrected to 15% O_2.

Appendix 5.1D
Air Quality Modeling Protocol

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research

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January 29, 2014

Ralph DeSiena
Modeling and Meteorology Group
San Diego County Air Pollution Control District
10124 Old Grove Road
San Diego, CA 92131

Subject: Modeling Protocol for Reconfigured CECP

Dear Mr. DeSiena:

On behalf of Carlsbad Energy Center LLC, Sierra Research is pleased to submit the enclosed modeling protocol for the proposed reconfigured Carlsbad Energy Center Project (CECP). This protocol includes the proposed approach for demonstrating compliance with the one-hour nitrogen dioxide (NO_2) National Ambient Air Quality Standard (NAAQS).

If you have any questions or need any additional information, please do not hesitate to contact me at 916-273-5139.

Sincerely,

Tom Andrews
Principal Engineer

Enclosure

cc: Steve Moore, SDAPCD

sierra research

Air Dispersion Modeling and Health Risk Assessment Protocol

Reconfigured Carlsbad Energy Center Project

Carlsbad, California

Submitted to:

San Diego County Air Pollution Control District (for an Application for an Authority to Construct and PSD Permit)

California Energy Commission (for a Petition to Amend)

prepared for:

Carlsbad Energy Center LLC

January 2014

prepared by:

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Air Dispersion Modeling and Health Risk Assessment Protocol
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Air Dispersion Modeling and Health Risk Assessment Protocol
Reconfigured Carlsbad Energy Center Project

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1. INTRODUCTION

This protocol describes the modeling procedures that will be used to determine the ambient air impacts from the reconfigured Carlsbad Energy Center Project (also referred to herein as the Project). These procedures will be used in the ambient air quality impact assessment and screening health risk assessment that will be submitted to the San Diego County Air Pollution Control District (SDAPCD, or District) as part of an application for Final Determination of Compliance, Authority to Construct, and PSD permit, and to the California Energy Commission as part of a Petition to Amend.

2. FACILITY DESCRIPTION AND SOURCE INFORMATION

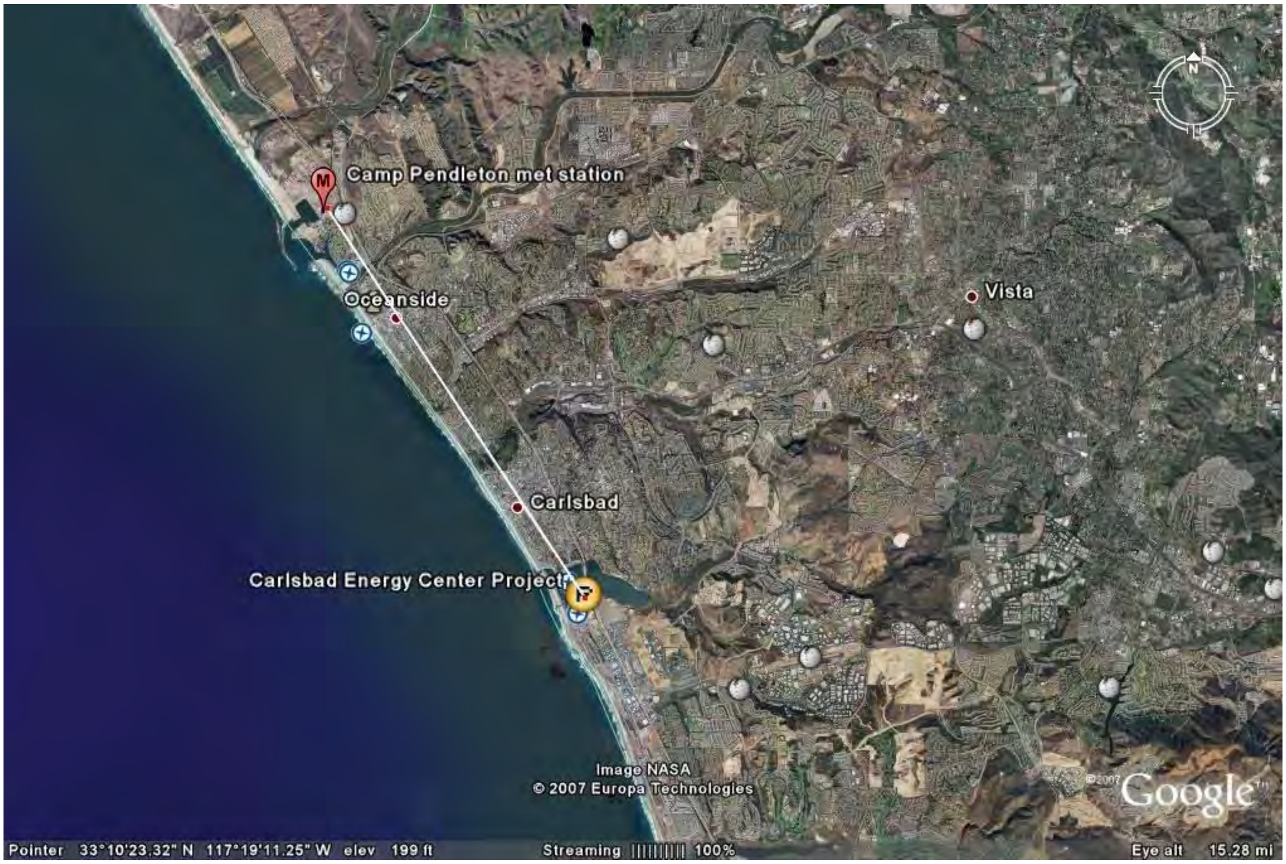
The reconfigured Carlsbad Energy Center Project will replace the existing Units 1-5 steam boiler plant with approximately 630 MW of new natural-gas fired turbine capacity at the existing Encina Power Station. The new gas turbine capacity will be comprised of six new GE LMS100 advanced simple-cycle units. The new equipment will also include a Diesel emergency firepump engine, and a Diesel emergency generator. Existing Boilers 1-5 and the existing 16 MW simple-cycle combustion gas turbine will be shut down. The new emitting units will be installed on the existing property of the Encina Power Station, located at 4600 Carlsbad Boulevard, Carlsbad, California. Figure 1 shows the general location of the power station.

The proposed new gas turbine units will be fitted with Best Available Control Technology (BACT). BACT will include water injection, selective catalytic reduction (SCR), an oxidation catalyst, and use of clean-burning natural gas fuel. The operating schedule of the new gas turbine units will vary and may range from no operation during the winter months to potentially 24 hours of operation per day during the summer months. The modeling analysis will be performed for the worst-case (maximum expected equipment operation) operating hour, operating day, and operating year. The modeling analysis will include a complete description of the new equipment, including the worst-case hourly, daily, and annual operating schedules used for the analysis.

The Proposed Project is not expected to trigger a Prevention of Significant Deterioration (PSD) review for any criteria pollutants. However, because of the relatively low applicability threshold for GHG emissions under the PSD program, the Proposed Project may be subject to PSD review for GHG emissions. The SDAPCD permit application will address applicable PSD modeling requirements based on the final determination of PSD applicability in the application documents.[1]

[1] The SDAPCD is in the process of obtaining delegation from EPA to implement PSD permitting for criteria air pollutants and GHG. Depending on the timing of this delegation, it may be necessary to file a separate PSD permit application for GHG to EPA Region 9.

Figure 1
Location of the Proposed Project



3. DISPERSION MODELING PROCEDURES

The air quality modeling analysis will follow the March 2009 U.S. Environmental Protection Agency (USEPA) AERMOD Implementation Guide, USEPA's "Guideline on Air Quality Models." (USEPA, 2005)

3.1 AERMOD Modeling

The following USEPA air dispersion models are proposed for use to quantify pollutant impacts on the surrounding environment based on the emission sources' operating parameters and their locations:

- American Meteorological Society/Environmental Protection Agency Regulatory Model Improvement Committee (AERMIC) model, also known as AERMOD (Version 13350);
- Building Profile Input Program – Plume Rise Model Enhancements (BPIP-PRIME, Version 04274); and
- SCREEN3 (Version 96043).

The main air dispersion modeling will be conducted with the latest version (Version 13350) of AERMOD, USEPA's preferred/recommended dispersion model for new source review and PSD air quality impact assessments. AERMOD can account for building downwash effects on dispersing plumes. Stack locations and heights and building locations and dimensions will be input to BPIP-PRIME. The first part of BPIP-PRIME determines and reports on whether a stack is being subjected to wake effects from a structure or structures; the second part calculates direction-specific building dimensions for each structure, which are used by AERMOD to evaluate wake effects. The BPIP-PRIME output is formatted for use in AERMOD input files.

AERMOD requires hourly meteorological data consisting of wind direction and speed (with reference height), temperature (with reference height), Monin-Obukhov length, surface roughness length, heights of the mechanically and convectively generated boundary layers, surface friction velocity, convective velocity scale, and vertical potential temperature gradient in the 500-meter layer above the planetary boundary layer.

Standard AERMOD control parameters will be used, including stack tip downwash, non-screening mode, non-flat terrain, and sequential meteorological data check. The stack-tip downwash algorithm will be used to adjust the effective stack height downward following the methods of Briggs (1972) for cases where the stack exit velocity is less than 1.5 times the wind speed at stack top. As approved by the District for the previous modeling performed for the CECP, the rural option will be used by not invoking the URBANOPT option.[2]

If more detailed evaluation of impacts at receptors in terrain above stack-top height is required, the screening version of the USEPA guideline Complex Terrain Dispersion Model PLUS (CTDMPLUS)—Complex Terrain Screening Model (CTSCREEN)—would be used. The CTSCREEN model is discussed in more detail in Appendix A.

3.1.1 Ambient Ratio Method and Ozone Limiting Method

Annual nitrogen dioxide (NO_2) concentrations will be calculated using the Ambient Ratio Method (ARM), originally adopted in Supplement C to the Guideline on Air Quality Models (USEPA, 1995) with a revision issued by EPA in March 2011[3]. The Guideline allows a nationwide default of 80% for the conversion of nitric oxide (NO) to NO_2 on an annual basis and the calculation of NO_2/NOx (nitrogen oxide) ratios.

If NO_2 concentrations need to be examined in more detail, the Ozone Limiting Method (OLM) (Cole and Summerhays, 1979), implemented through the "OLMGROUP ALL" option in AERMOD (USEPA, 2011a), will be used. AERMOD OLM will be used to calculate the NO_2 concentration based on the OLM method and hourly ozone data. Contemporaneous hourly ozone data collected at the nearby Camp Pendleton Marine Base monitoring station will be used in conjunction with OLM to calculate hourly NO_2 concentrations from modeled hourly NOx concentrations.

Part of the NOx in the exhaust is converted to NO_2 during and immediately after combustion. The remaining percentage of the NOx emissions is assumed to be NO. For the new gas turbines, and as required by the SDAPCD, we will use the same NO_2/NOx ratios as used during the SDAPCD permitting of the Pio Pico Project (13% during normal operating hours, 24% during startup/shutdown periods, and 24% during commissioning tests when SCR is not fully operational). For the Diesel emergency firepump engine and Diesel emergency generator, we will use a NO_2/NOx ratio of 10% (see Appendix B).

As the exhaust leaves the stack and mixes with the ambient air, the NO reacts with ambient ozone (O_3) to form NO_2 and molecular oxygen (O_2). The OLM assumes that at any given receptor location, the amount of NO that is converted to NO_2 by this oxidation reaction is proportional to the ambient O_3 concentration. If the O_3 concentration is less than the NO concentration, the amount of NO_2 formed by this reaction is limited. However, if the O_3

[2] The rural vs. urban option in AERMOD is primarily designed to set the fraction of incident heat flux that is transferred into the atmosphere. This fraction becomes important in urban areas having an appreciable "urban heat island" effect due to a large presence of land covered by concrete, asphalt, and buildings. This situation does not exist for the project site.

[3] "Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 NAAQS", Office of Air Quality Planning and Standards, Research Triangle Park, NC, March 1, 2011.

concentration is greater than or equal to the NO concentration, all of the NO is assumed to be converted to NO_2.

A detailed discussion of OLM modeling and how OLM modeling results and monitored background NO_2 will be combined is provided in Sections 3.6.1.3 and 3.6.1.4.

3.1.2 $PM_{2.5}$

$PM_{2.5}$ impacts will be modeled in accordance with USEPA guidance (USEPA, 2010a). A detailed discussion of how modeled $PM_{2.5}$ impacts will be evaluated is provided in Section 3.6.

3.2 Fumigation Modeling

The SCREEN3 model will be used to evaluate inversion breakup fumigation and shoreline fumigation impacts for short-term averaging periods (24 hours or less), as appropriate. The methodology in "Screening Procedures for Estimating the Air Quality Impact of Stationary Sources, Revised" (USEPA, 1992b) will be followed for these analyses. Combined impacts for all sources under fumigation conditions will be evaluated, based on USEPA modeling guidelines.

3.3 Health Risk Assessment Modeling

A health risk assessment (HRA) will be performed according to California Air Resources Board (CARB) guidance. The HRA modeling will be prepared using CARB's Hotspots Analysis and Reporting Program (HARP) computer program (Version 1.4f, May 2012 using the latest HARP Health Database table updated in November 2013) and AERMOD with the CARB "on-ramp."[4] HARP will be used to assess cancer risk as well as non-cancer chronic and acute health hazards.

3.4 Meteorological Data

The District will provide a five-year meteorological dataset (2008–2012) processed in AERMET to generate AERMOD-compatible meteorological data for air dispersion modeling. The surface meteorological data were recorded at the District's Camp Pendleton monitoring station, and the upper air data were recorded at the San Diego Miramar Station (No. 03190). Figure 1 above shows the relative locations of the project site and the meteorological monitoring station at Camp Pendleton.

EPA defines the term "on-site data" to mean data that would be representative of atmospheric dispersion conditions at the source and at locations where the source may

[4] HARP has not yet been revised to utilize AERMOD, but CARB has developed "on-ramp" software that allows HARP to incorporate AERMOD output files. Therefore, HARP is now compatible with AERMOD.

have a significant impact on air quality. Specifically, the meteorological data requirement originates in the Clean Air Act at Section 165(e)(1), which requires an analysis "of the ambient air quality at the proposed site and in areas which may be affected by emissions from such facility for each pollutant subject to regulation under [the Act] which will be emitted from such facility."

This requirement and EPA's guidance on the use of on-site monitoring data are also outlined in the "On-Site Meteorological Program Guidance for Regulatory Modeling Applications" (USEPA, 1987a). The representativeness of the data depends on (a) the proximity of the meteorological monitoring site to the area under consideration, (b) the complexity of the topography of the area, (c) the exposure of the meteorological sensors, and (d) the period of time during which the data are collected.

Representativeness has also been defined in "The Workshop on the Representativeness of Meteorological Observations" (Nappo et. al., 1982) as "the extent to which a set of measurements taken in a space-time domain reflects the actual conditions in the same or different space-time domain taken on a scale appropriate for a specific application." Representativeness is best evaluated when sites are climatologically similar, as are the project site and the Camp Pendleton meteorological monitoring station.

Representativeness has additionally been defined in the PSD Monitoring Guideline (USEPA, 1987b) as data that characterize the air quality for the general area in which the Proposed Project would be constructed and operated. Because of the close proximity of the Camp Pendleton meteorological data site to the project site (distance between the two locations is approximately 10 km, or 6.4 miles), the same large-scale topographic features that influence the meteorological data monitoring station also influence the project site in the same manner.

Based on all of the above, the District has determined that the meteorological data from this monitoring station are representative of conditions at the Project site.

3.5 Receptor Grids

Receptor and source base elevations will be determined from USGS National Elevation Dataset (NED) data in the GeoTIFF format at a horizontal resolution of 1 arc-second (approximately 30 meters). All coordinates will be referenced to UTM North American Datum 1983 (NAD83), Zone 11. The AERMOD receptor elevations will be interpolated among the DEM nodes according to standard AERMAP procedure. For determining concentrations in elevated terrain, the AERMAP terrain preprocessor receptor-output (ROU) file option will be chosen.

Cartesian coordinate receptor grids will be 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 impact locations.
A 250-meter resolution coarse receptor grid will be developed and will extend outwards at least 10 km (or more if necessary to establish the significant impact area).

For the full impact analyses, a nested grid will be developed to fully represent the maximum impact area(s). The receptor grid will be constructed as follows:

1. One row of receptors spaced 25 meters apart along the facility's fence line;
2. Four tiers of receptors spaced 25 meters apart, extending 100 meters from the fence line;
3. Additional tiers of receptors spaced 100 meters apart, extending from 100 meters to 1,000 meters from the fenceline; and
4. Additional tiers of receptors spaced 250 meters apart, out to at least 10 km from the most distant source modeled, not to exceed 50 km from the project site.

Additional refined receptor grids with 25-meter resolution will be placed around the maximum first-high or maximum second-high coarse grid impacts and extended out 1,000 meters in all directions. Concentrations within the facility fenceline will not be calculated.

The regions to be imported in Geographical Coordinates for the USGS National Elevation Dataset (NED) data are bounded as follows:

- South West corner: UTM Zone 11 (NAD 83) 465,500.0 m, 3,654,200.0 m; and
- North East corner: UTM Zone 11 (NAD 83) 483,000.0 m, 3,678,200.0 m.

3.6 Ambient Air Quality Impact Analyses (AQIA)

Emissions from the Proposed Project will result from combustion of fuel in the gas turbines and Diesel emergency firepump and emergency generator engines, and from the cooling system (if a wet cooling system is used for support systems such as intercooling of gas turbine combustion air and/or turbine lube oil cooling). These emission sources will be modeled as point sources. The expected emission rates will be based on vendor data and additional conservative assumptions of equipment performance.

The purpose of the ambient air quality impact analysis is to demonstrate compliance with applicable ambient air quality standards. Both USEPA and the District have regulations that prohibit construction of a project that will cause or contribute to violations of applicable standards.

According to EPA, if, for a given pollutant and averaging time, the project's impact is below the Significant Impact Levels (SILs) shown in Table 1, the project's impact is deemed to be *de minimis*, and no further analysis is required. However, if the modeled impacts exceed any of the significance thresholds displayed in Table 1, the project has the potential to cause or contribute to a violation of the ambient air quality standard at the times and locations where the threshold is exceeded. In that case, the analysis must consider the contribution of other sources to the ambient concentration. If the analysis indicates that there will be a violation of an ambient air quality standard, and the project's impact at the time and place of the violation is significant, then the project may not be approved unless the project's impact is reduced.

Table 1
Significant Impact Levels for Air Quality Impacts in Class II Areas ($\mu g/m^3$)

Pollutant	Averaging Period				
	Annual	**24-hour**	**8-hour**	**3-hour**	**1-hour**
NO_2	1	--	--	--	7.5[5]
SO_2	1	5	--	25	7.8[5]
CO	--	--	500	--	2000
PM_{10}	1	5	--	--	--
$PM_{2.5}$	0.3	1.2	--	--	--

An air quality impact analysis is required for certification by the CEC and to support the air quality impact analysis, PSD analysis, and screening health risk assessment that are required by the District. Each agency has its own criteria for preparation of the air quality impact analysis; however, the criteria used by the CEC and the District are similar enough that the same basic analysis, with some variations, will satisfy both.

3.6.1.1 Step 1: Project Impact

The first step in the compliance demonstration is to determine, for each pollutant and averaging period, whether the proposed new equipment for the project has the potential to cause a significant ambient impact at any location, under any operating or meteorological conditions. As indicated in the NSR Workshop Manual,[6] "[i]f the significant net emissions increase from a proposed source would not result in a significant ambient impact anywhere, the application is usually not required to go beyond a preliminary analysis in order to make the necessary showing of compliance for a particular pollutant." The EPA significance levels for air quality impacts are shown in Table 1. If the maximum modeled impact for any pollutant and averaging period is below the appropriate significance level in this table, no further analysis is necessary.

Based on the following USEPA (2010e) guidance, no further analysis is necessary for any location where the modeled impacts from the project alone are below the significance thresholds.

[5] EPA has not yet defined significance levels (SILs) for one-hour NO_2 and SO_2 impacts. However, EPA has suggested that, until SILs have been promulgated, interim values of 4 ppb (7.5 $\mu g/m^3$) for NO_2 and 3 ppb (7.8 $\mu g/m^3$) for SO_2 may be used (USEPA (2010c); USEPA (2010d)). These values will be used in this analysis as interim SILs.
[6] USEPA (1990), p. C.51.

> *The primary purpose of the SILs is to identify a level of ambient impact that is sufficiently low relative to the NAAQS or increments that such impact can be considered trivial or de minimis. Hence, the EPA considers a source whose individual impact falls below a SIL to have a de minimis impact on air quality concentrations that already exist. Accordingly, a source that demonstrates that the projected ambient impact of its proposed emissions increase does not exceed the SIL for that pollutant at a location where a NAAQS or increment violation occurs is not considered to cause or contribute to that violation. In the same way, a source with a proposed emissions increase of a particular pollutant that will have a significant impact at some locations is not required to model at distances beyond the point where the impact of its proposed emissions is below the SILs for that pollutant. When a proposed source's impact by itself is not considered to be "significant," EPA has long maintained that any further effort on the part of the applicant to complete a cumulative source impact analysis involving other source impacts would only yield information of trivial or no value with respect to the required evaluation of the proposed source or modification.*[7]

For $PM_{2.5}$, the highest average of the maximum annual averages and of the 24-hour averages modeled over the five years of meteorological data will be compared with the SILs in Table 1 to determine whether the modeled $PM_{2.5}$ project impacts are significant.[8] For other pollutants, the highest modeled concentrations will be compared with the SILs. For pollutants with modeled project impacts below the significance thresholds, a summary table will show the maximum modeled project impacts plus background concentrations. Although this information is not required by federal modeling guidance, it will be provided as part of the CEQA analysis.

3.6.1.2 Step 2: Project Plus Background

Pollutants/averaging periods that are not screened out in Step 1 are required to undergo a full air quality impact analysis. In Step 2, the ambient impacts of the project are modeled and added to background concentrations. The results are compared to the relevant state and federal ambient standards.

The second step of the compliance demonstration is required to show that the proposed new project, in conjunction with existing sources, will not cause or contribute to a violation of any ambient air quality standard. As discussed in more detail below, the impacts of existing sources are represented by the existing ambient air quality data collected at the monitoring stations shown in Table 2. In accordance with Section 8.2.1 of Appendix W to 40 CFR Part 51,

[7] USEPA (2010e), p. 64891.
[8] USEPA (2010a), p. 6.

Background concentrations are an essential part of the total air quality concentration to be considered in determining source impacts. Background air quality includes pollutant concentrations due to: (1) Natural sources; (2) nearby sources other than the one(s) currently under consideration; and (3) unidentified sources. Typically, air quality data should be used to establish background concentrations in the vicinity of the source(s) under consideration.

If a Step 2 analysis is required, the modeled impacts from the Proposed Project will be added to the representative background concentration for comparison with the California and National Ambient Air Quality Standards (CAAQS and NAAQS). In accordance with USEPA guidelines,[9] the highest second-highest modeled concentrations will be used to demonstrate compliance with the short-term federal standards (except for the statistically based federal one-hour NO_2 and SO_2, and 24-hour $PM_{2.5}$, standards) and the highest modeled concentration will be used to demonstrate compliance with the federal annual standards and all state standards. If the predicted total ground-level concentration is below the state or federal ambient air quality standard for each pollutant and averaging period, no further analysis is required for that pollutant and averaging period.

3.6.1.3 Compliance with Statistically Based Standards

For the one-hour average federal NO_2 standard for the District and CEC analyses, the comparison of impacts with the new federal one-hour standard will be done in accordance with Appendix W of Part 51 of Title 40 of the CFR "Guideline on Air Quality Models" and the tiered process presented in "Modeling Compliance of the Federal 1-Hour NO_2 NAAQS" (CAPCOA guidance document, 2011).[10] Appendix W of Part 51 of Title 40 of the CFR "Guideline on Air Quality Models" has codified three methods that can be used to estimate NO_2 concentration (Tier 1 - Total Conversion, Tier 2 - Ambient Ratio Method or ARM, Tier 3 - Ozone Limiting Method or OLM). According to USEPA guidance (USEPA, 2011a),

While the limited scope of the available field study data imposes limits on the ability to generalize conclusions regarding model performance, these preliminary results of hourly NO_2 predictions for Palau and New Mexico show generally good performance for the PVMRM and OLM/OLMGROUP ALL options in AERMOD. We believe that these additional model evaluation results lend further credence to the use of these Tier 3 options in AERMOD for estimating hourly NO_2

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[9] USEPA (2005), 11.2.3.2 and 11.2.3.3

[10] "This modeling protocol is meant to define the stepwise approach necessary to satisfy the requirements in General Guidance for Implementing the 1-Hour NO_2 National Ambient Air Quality Standard in Prevention of Significant Deterioration Permits, Including an Interim NO_2 Significant Impact Level and the Applicability of Appendix W Modeling Guidance for 1-Hour NO_2 National Ambient Air Quality Standard. Nothing in this protocol should be taken as overriding guidance contained in those two memoranda, or Appendix W of Part 51 of Title 40 of the Code of Federal Regulations (40 CFR 51, Appendix W)." (SJVAPCD, 2010b)

concentrations, and we recommend that their use should be generally accepted provided some reasonable demonstration can be made of the appropriateness of the key inputs for these options, the in-stack NO_2/NOx ratio and the background ozone concentrations.[11]

As discussed above, for the new gas turbines the in-stack NO_2/NOx ratios will be consistent with the ratios used during the permitting of the Pio Pico Project and a NO_2/NOx ratio of 10% will be used for the Diesel emergency engines. Background ozone concentrations in the project area will be represented by five years of ozone data (2008–2012) collected at Camp Pendleton concurrently with the meteorological data. Based on these factors, we propose to use the Tier 3, "OLMGROUP ALL," option for modeling 1-hour NO_2 concentrations.

For demonstrating compliance with the statistically based federal one-hour NO_2 standard, CAPCOA's 2011 guidance document provides 11 progressively more sophisticated methods for combining modeled NO_2 concentrations with background (or monitored) NO_2. These methods, outlined below, were developed to allow demonstration of compliance using the lowest amount of resources necessary. Each tier is a progressively more sophisticated and comprehensive analysis that reduces the level of conservatism without reducing the level of assurance of compliance.

1. Significant Impact Level (SIL) – no background required
2. Max modeled value + max monitored value
3. Max modeled value + 98th pctl monitored value
4. 8th highest modeled value + max monitored value
5. 8th highest modeled value + 98th pctl monitored value
6. (5 yr avg of 98th pctl modeled value) + max monitored value
7. (5 yr avg of 98th pctl of modeled value) + 98th pctl monitored value
8. 5 yr avg of 98th pctl of (modeled value + monthly hour-of-day – 1st high)
9. 5 yr avg of 98th pctl of (modeled value + seasonal hour-of-day – 3rd high)
10. 5 yr average of 98th pctl of (modeled value + annual hour-of-day - 8th high)
11. Paired-Sum: 5 yr avg of 98th pctl of (modeled value + background)

Applicable definitions are provided below.

- *Significant Impact Level (SIL)* is defined as a de minimis impact level below which a source is presumed not to cause or contribute to an exceedance of a NAAQS (see Table 1 above).

- *Max modeled value* is defined as the maximum concentration predicted by the model at any given receptor in any given year modeled.

[11] The Plume Volume Molar Ratio Method (PVMRM) is considered by USEPA to be a Tier 3 screening method, similar to OLM. (USEPA,2011a)

- *8^th highest modeled value* is defined as the highest 8th-highest concentration derived by the model at any given receptor in any given year modeled.

- *5 yr avg of the 98^th pctl* is defined as the highest of the average 8th highest (98th percentile) concentrations derived by the model across all receptors based on the length of the meteorological data period or the X years average of 98th percentile of the annual distribution of daily maximum one-hour concentrations across all receptors, where X is the number of years modeled. (In Appendix W, EPA recommends using five years of meteorological data from a representative National Weather Service site or one year of on-site data.)

- *Monthly hour-of-day* is defined as the three-year average of the 1st highest concentrations (Maximum Hourly) for each hour of the day.

- *Seasonal Hour-Of-Day* is defined as the three-year average of the 3rd highest concentrations for each hour of the day and season

- *Annual hour-of-day* is defined as the three-year average of the 8th highest concentration for each hour of the day

- *Paired-Sum* **(**5 yr avg of the 98th pctl) is the merging of the modeled concentration with the monitored values paired together by month, day, and hour. The sum of the paired values is then processed to determine the X-year average of the 98th percentile of the annual distribution of daily maximum one-hour concentrations across all receptors, where X is the number of years modeled.

For the demonstration of compliance with the federal one-hour NO_2 standard, we will perform analyses at as many of the following tiers as are needed to demonstrate compliance with the state and federal ambient air quality standards: Tier 1, Tier 2, Tier 7, Tier 8, Tier 9, Tier 10, and Tier 11. Hourly NO_2 background data (for the same five years of meteorological data used for the modeling—2008 to 2012) may also be used in order to refine the NAAQS analysis both spatially and temporally. Hourly NO_2 data from the Camp Pendleton monitoring station will be provided by the District. In the event of missing hourly NO_2 data, the missing data procedures described in Section 3.7.1 will be followed to fill in gaps in the hourly NO_2 data. To account for recently permitted nearby stationary sources that are not reflected in the background NO_2 data, we will review the list of projects provided by the SDAPCD (the request for these projects is discussed in Section 3.10) and model the impacts from projects with a NOx net emission increase greater than 5 tons/year (excluding intermittently operated equipment per EPA guidance[12]).

The demonstration of compliance with the federal one-hour SO_2 standard will follow the same steps, except that it will utilize the 99th percentile predicted one-hour average SO_2 concentrations instead of the 98th percentile.

[12] USEPA (2011a), page 10.

For the 24-hour average federal $PM_{2.5}$ standard for the District and CEC analyses, the comparison of impacts with the federal 24-hour average standard will be done in accordance with USEPA March 23, 2010 guidance (USEPA, 2010a). This guidance calls for basing the initial determination of compliance with the standard on the five-year average of the highest modeled annual and 24-hour averages, combined with background concentrations based on the form of the standards (the three-year average of the annual $PM_{2.5}$ concentrations and the three-year average of the 98th percentile 24-hour averages).[13] If a more detailed assessment of $PM_{2.5}$ impacts is required, a Tier 2 analysis will be performed. USEPA's March 23, 2010 memo provides minimal guidance regarding this type of more detailed analysis, saying only "a Second Tier modeling analysis may be considered that would involve combining the monitored and modeled $PM_{2.5}$ concentrations on a seasonal or quarterly basis, and re-sorting the total impacts across the year to determine the cumulative design value."[14] As no additional guidance has been provided, such an analysis would be discussed with the District and CEC staff prior to implementation.

3.6.1.4 State One-Hour NO_2 Standard

Compliance with the state one-hour NO_2 standard will be demonstrated using OLM and the paired-sum approach described above, except that the analysis will use highest, rather than 98^{th} percentile, concentrations, consistent with the form of the state standard.

3.7 Background Ambient Air Quality Data

Background ambient air quality data for the project area will be obtained from the monitoring sites most representative of the conditions that exist at the proposed project site. The Escondido monitoring site is the nearest with background data for PM_{10}, $PM_{2.5}$, and CO. Camp Pendleton is the nearest monitoring site for O_3 and NO_2 background data, and San Diego-Beardsley Street is the nearest monitoring site for SO_2 data. Modeled concentrations will be added to these representative background concentrations to demonstrate compliance with the CAAQS and NAAQS.

Table 2 shows the monitoring stations we propose to use as they provide the most representative ambient air quality background data.

[13] USEPA (2010a), p. 9.
[14] USEPA (2010a), p. 8.

Table 2 Representative Background Ambient Air Quality Monitoring Stations		
Pollutant(s)	**Monitoring Station**	**Distance to Project Site**
PM_{10}, $PM_{2.5}$, CO	Escondido	24 km
NO_2 and O_3	Camp Pendleton	10 km
SO_2	San Diego – Beardsley Street	50 km

For annual NO_2, 24-hour and annual SO_2, and all PM_{10} and CO averaging periods, the highest values monitored during the 2008–2012 period will be used to represent ambient background concentrations in the project area. The one-hour average NO_2 analyses will be performed as described above. Because the three-hour average statistic for SO_2 is no longer available from the USEPA or CARB's websites, one-hour average SO_2 concentrations will be used to represent three-hour average background concentrations for SO_2. For analyses of federal 24-hour and annual $PM_{2.5}$ impacts, the three-year average of the 98th percentile 24-hour monitored levels for the period between 2008 and 2012 will be used to represent project area background because these values correspond to the method used for determining compliance with the federal $PM_{2.5}$ standards and are consistent with the guidance cited above.

3.7.1 Missing Data Protocol

Using the OLM method to model project-generated one-hour NO_2 concentrations requires the use of ambient monitored O_3 concentrations. Because the OLM method uses the ambient ozone concentration for a particular hour to limit the conversion of NO to NO_2, it is important to have ozone concentrations for every hour. It is also important that any missing hourly ozone concentrations be filled in with a value that does not underestimate the ozone concentration for that hour, to avoid underestimating the resulting NO_2 concentration. In addition, computation of total hourly NO_2 concentrations requires use of the ambient monitored hourly NO_2 concentrations from the nearest monitoring station. As is the case for the hourly ozone data, it is important to have a background NO_2 value for every hour that does not underestimate actual background.

As discussed above, background ambient hourly O_3 and NO_2 concentrations for the project area will be provided by the District based on data collected at the monitoring station at Camp Pendleton. While these datasets are expected to exceed USEPA's 90% completeness criterion (that is, more than 90% of the data values are present for each month), there are still occasional missing values that must be filled in. As discussed above, the SDAPCD will be preparing the hourly O_3 and NO_2 background ambient databases. It is our understanding that the SDAPCD will perform the appropriate missing data substitutions based on guidance documents provided by the California Air Pollution Control Officers Association (CAPCOA, 2011).

3.8 Health Risk Assessment

A health risk assessment will be performed according to the Office of Environmental Health Hazard Analysis "Air Toxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments" (OEHHA, 2003). The HRA modeling will be prepared using CARB's Hotspots Analysis and Reporting Program (HARP) computer program (Version 1.4f, May 2012 using the latest HARP Health Database table updated in November 2013). The HARP model will be used to assess cancer risk as well as non-cancer chronic and acute health hazards.

The HARP model incorporates the ISCST3 model previously approved by USEPA. CARB offers a software program that allows AERMOD data to be imported into the HARP model, called HARP On-Ramp. The on-ramp will be used with the most recent versions of AERMOD and HARP for the screening risk assessment. As previously required by the SDAPCD, the following HARP options will be used for the health risk assessment:

- Home grown produce selected (0.15 for the fraction for leafy, exposed, protected, and root vegetables);
- Dermal absorption selected (0.05 m/s deposition rate);
- Soil ingestion selected (0.05 m/s deposition rate);
- Mother's milk selected (0.05 m/s deposition rate); and
- Fish ingestion selected (due to the lagoon near the project site).

3.9 Demolition/Construction Air Quality Impact Analysis

The potential ambient impacts from air pollutant emissions during the demolition/construction activities associated with the Proposed Project will be evaluated by air quality modeling that will account for the construction site location and the surrounding topography; the sources of emissions during construction, including vehicle and equipment exhaust emissions; and fugitive dust.

Types of Emission Sources − Construction of the Proposed Project can be viewed as three main sequential phases: site preparation; construction of foundations; and installation of the gas turbines and associated equipment. The construction impacts analysis will include a schedule for construction operation activities. Site preparation includes site excavation, excavation of footings and foundations, and backfilling operations.

Fugitive dust emissions from the construction of the Proposed Project result from the following activities:

- Excavation and grading at the construction site;
- Onsite travel on paved and unpaved roads and across the unpaved construction site;

- Aggregate and soil loading and unloading operations;
- Raw material transfer to and from material stockpiles; and
- Wind erosion of areas disturbed during construction activities.

Engine exhaust will be emitted from the following sources:

- Heavy equipment used for excavation, grading, and construction of onsite structures;
- Water trucks used to control construction dust emissions;
- Diesel- and gasoline-fueled welding machines, generators, air compressors, and water pumps;
- Gasoline-fueled pickup trucks and Diesel-fueled flatbed trucks used onsite to transport workers and materials around the construction site;
- Transport of mechanical and electrical equipment to the project site;
- Transport of rubble and debris from the site to an appropriate landfill; and
- Transport of raw materials to and from stockpiles.

Similar to construction, the demolition activities associated with the removal of existing Units 1-5 will include both fugitive dust and exhaust emissions. The demolition of the existing structures will include the removal of the main power plant building, administration building, maintenance shop/warehouse, machine shop, paint shop, chemical storage building, intake and discharge tunnels, fuel storage tanks, and the stack. The fugitive dust emissions will be due to activities including demolition of existing structures, loading of debris into haul trucks, and vehicle travel on paved/unpaved surfaces. Engine exhaust emissions will be associated with heavy equipment used for demolition activities, water trucks used for dust control, truck hauling of demolition debris from the site, and worker vehicle travel.

Emissions from a peak activity day will be modeled. Annual average emissions over the demolition/construction period will also be calculated and modeled for comparison with annual standards.

<u>Existing Ambient Levels</u> – The background data discussed earlier will be used to represent existing ambient levels for the demolition/construction analysis as well as the analysis of the impacts of project operations.

<u>Model Options</u> – The AERMOD “OLMGROUP ALL” option will be used to estimate ambient impacts from demolition/construction emissions. The modeling options and meteorological data described above will be used for the modeling analysis. A 10% NO_2/NOx fraction for Diesel demolition/construction equipment will be assumed (see Appendix B).

The demolition/construction sites will be represented as both a set of volume sources and a separate set of area sources in the modeling analysis. Emissions will be divided into three categories: exhaust emissions, mechanically generated fugitive dust emissions, and wind-blown fugitive dust emissions. Exhaust emissions and mechanically generated fugitive dust emissions (e.g., dust from wheels of a scraper) will be modeled as volume sources with a height of 6 meters. Wind-blown fugitive dust emissions and sources at or near the ground that are at ambient temperature and have negligible vertical velocity will be modeled as area sources with a release height of 0.5 meters.

Combustion Diesel PM_{10} emission impacts from demolition/construction equipment will be evaluated to demonstrate that the cancer risk from construction activities will be below ten in one million at all receptors.

For the demolition/construction modeling analysis, the receptor grid will begin at the property boundary and will extend approximately one kilometer in all directions. The receptor grid will be laid out as follows:

1. One row of receptors spaced 25 meters apart along the facility's fence line;
2. Four tiers of receptors spaced 25 meters apart, extending 100 meters from the fence line; and
3. Additional tiers of receptors spaced 60 meters apart, extending from 100 meters to 1,000 meters from the fenceline.

3.10 Cumulative Air Quality Impact Analysis

To address CEC requirements, a cumulative air quality modeling impacts analysis of the project's typical operating mode will be performed in combination with other stationary source emissions sources within a six-mile radius that have received Authorities to Construct and/or modified permits to operate since June 2012, or are in the permitting process. For each criteria pollutant, facilities having an emission increase of less than five tons per year are generally considered to be *de minimis*, and these facilities may be excluded from the cumulative impacts analysis. Information on any recently constructed/permitted sources that might be appropriate for a cumulative air quality impact analysis (as defined above) will be requested from the SDAPCD.

Upon receipt of sufficient information from the local air agencies to allow air dispersion modeling of the recently constructed/permitted non-project sources to be included in the cumulative air quality impact analysis, AERMOD will be used in a procedure similar to that described earlier in this protocol.

3.11 Nitrogen Deposition Analysis

As part of the Petition to Amend filed with the CEC, it will be necessary to include a nitrogen deposition analysis. Nitrogen deposition is the input of NOx and ammonia (NH_3) derived pollutants, primarily nitric acid (HNO_3), from the atmosphere to the biosphere. Nitrogen deposition can lead to adverse impacts on sensitive species including direct toxicity, changes in species composition among native plants, and enhancement of invasive species.

We propose to use a tiered approach to analyze nitrogen deposition impacts for the Proposed Project, as outlined below.

- Tier 1: The total nitrogen emission levels (based on NOx and NH_3 emissions) for the Reconfigured Project will be compared to the baseline nitrogen emission levels for existing Units 1-5 and the peaker gas turbine at the Encina Power Station. If the total nitrogen emissions for the proposed new units will be lower than the baseline levels for the existing units that will be replaced as part of the Proposed Project, the cumulative nitrogen deposition impacts for the Proposed Project will be considered less-than-significant and no further analysis will be performed.

- Tier 2: If the Tier 1 analysis shows possible significant nitrogen deposition impacts, we will perform a nitrogen deposition modeling analysis examining the impacts on nearby areas classified as critical habitat and/or areas containing sensitive biological resources. The AERMOD model will be used for this analysis, and the analysis will compare the nitrogen deposition associated with the net increase in nitrogen emissions (discussed above) to the CEC-established nitrogen disposition significance threshold of 5 kg/ha/yr.[15] If the maximum modeled nitrogen deposition impact in a nearby area of concern is above this threshold, the cumulative nitrogen deposition impacts for the Proposed Project will be considered significant, and the Applicant will propose additional mitigation measures.

[15] Based on discussion by CEC staff during a 10/1/13 CEC workshop for the El Segundo Power Facility Modification Project.

4. REPORTING

The results of the criteria pollutant and TAC modeling will be integrated into the application documents, and will include the information listed below.

- Project Description – Site map and site plan along with descriptions of the emitting equipment and air pollution control systems.

- Model Options and Input – Model options, screening and refined source parameters, criteria pollutant and TAC emission rates, meteorological data, and receptor grids used for the modeling analyses.

- Air Dispersion Modeling – Dispersion modeling results will include the following:

  - Plot plan showing emission points, nearby buildings (including dimensions), cross-section lines, property lines, fence lines, roads, and UTM coordinates;
  - A table showing building heights used in the modeling analysis;
  - Summaries of maximum modeled impacts; and
  - Model input and output files, including BPIP-PRIME and meteorological files as well as hourly ozone and NO_2 files used in demonstrating compliance with the 1-hour NO_2 standard, in electronic format on a compact disc, together with a description (README file) of all filenames.

- HRA – The HRA will include the following:

  - Descriptions of the methodology and inputs to the demolition/construction and operation AERMOD runs;
  - Tables of TAC emission rates and health impacts;
  - Figures showing sensitive receptor locations; and
  - Model input and output files in electronic format on a compact disc, together with a description (README file) of all filenames.

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Appendix A

Information on CTSCREEN Model

The CTDMPLUS and CTSCREEN Models

Complex terrain impacts may need to be modeled with more accuracy than that provided by AERMOD. The use of more refined modeling techniques is specifically addressed in USEPA's Appendix W[1] modeling guidance, as follows:

> *Since AERMOD treats dispersion in complex terrain, we have merged sections 4 and 5 of appendix W, as proposed in the April 2000 NPR [Notice of Proposed Rulemaking]. And while AERMOD produces acceptable regulatory design concentrations in complex terrain, it does not replace CTDMPLUS for detailed or receptor-oriented complex terrain analysis, as we have made clear in Guideline section 4.2.2. CTDMPLUS remains available for use in complex terrain. [p. 68225]*
>
> *4.2.2 Refined Analytical Techniques*
> *d. If the modeling application involves a well defined hill or ridge and a detailed dispersion analysis of the spatial pattern of plume impacts is of interest, CTDMPLUS, listed in Appendix A, is available. CTDMPLUS provides greater resolution of concentrations about the contour of the hill feature than does AERMOD through a different plume-terrain interaction algorithm. [p. 68233]*

CTSCREEN is the same basic model as CTDMPLUS, except that meteorological data are handled internally in a simplified manner. As discussed in the CTSCREEN users guide,[2]

> *Since [CTDMPLUS] accounts for the three-dimensional nature of plume and terrain interaction, it requires detailed terrain and meteorological data that are representative of the modeling domain. Although the terrain data may be readily obtained from topographic maps and digitized for use in the CTDMPLUS, the required meteorological data may not be as readily available.*
>
> *Since the meteorological input requirements of the CTDMPLUS can limit its application, the EPA's Complex-Terrain-Modeling, Technology-Transfer Workgroup developed a methodology to use the advanced techniques of CTDMPLUS in situations where on-site meteorological measurements are limited or unavailable. This approach uses CTDMPLUS in a "screening" mode--actual source and terrain*

[1] 40 CFR 51 Subpart W, as amended November 9, 2005 at 70 FR 68218, "Revision to the Guideline on Air Quality Models: Adoption of a Preferred General Purpose (Flat and Complex Terrain) Dispersion Model and Other Revisions."
[2] USEPA, EPA-600/8-90-087, "User's Guide to CTDMPLUS: Volume 2. The Screening Mode (CTSCREEN)," October 1990.

characteristics are modeled with an extensive array of predetermined meteorological conditions.

This CTDMPLUS screening mode (CTSCREEN) serves several purposes in regulatory applications. When meteorological data are unavailable, CTSCREEN can be used to obtain conservative (safely above those of refined models), yet realistic, impact estimates for particular sources.

Therefore, the use of the CTSCREEN version of CTDMPLUS is consistent with USEPA guidance.

Appendix B

Proposed NO_2/NOx Ratios for Modeling Compliance with One-Hour NO_2 Standards for Diesel Emergency Engines and Demolition/Construction Activities

Proposed NO_2/NOx Ratios for Modeling Compliance with One-Hour NO_2 Standards for Emergency Engines and for Demolition/Construction Activities

The use of the Tier 3 Plume Volume Molar Ratio Method (PVMRM) and Ozone Limiting Method (OLM) options in AERMOD requires the specification of an in-stack ratio (ISR) of NO_2/NOx for each NOx emissions source. The October 27, 2011 California Air Pollution Control Officers Association (CAPCOA) Guidance Document, titled "Modeling Compliance of The Federal 1-Hour NO_2 NAAQS,"[18] emphasized the importance of these in-stack ratios for the 1-hour NO_2 NAAQS, recommending that in-stack ratios used with either the OLM or PVMRM options be justified based on the specific application.

USEPA's Office of Air Quality Planning and Standards (OAQPS) is in the process of creating a database of test results that support in-stack NO_2/NOx ratios for specific source types. We are proposing to use USEPA's ISR database for the Project.

USEPA's ISR database is at *http://www.epa.gov/ttn/scram/no2_isr_database.htm*. As of January 2014, the file NO2_ISR_database.xlsx, which is to provide the NO_2 ISR data that have been submitted via the formal collection initiated by OAQPS, contained listings for several Diesel engines.

Following is a description of the procedures followed to obtain proposed NO_2/NOx ratios from the ISR database for the equipment associated with the Proposed Project.

Diesel Emergency Engines and Demolition/Construction Equipment

1. Sort by fuel to select all Diesel, #2 Diesel, and blank fuel fields to eliminate natural gas, biogas, and waste gas-fueled engines, leaving 40 records.

2. Eliminate any engines equipped with SCR (including the GE LeanNOx System)—the engines associated with the Proposed Project will be emergency firepump/generator engines and will not have SCR, leaving 39 records. Demolition/construction equipment Diesel engines will similarly not have SCR.

The remaining engines range in size from 440 kW to 4,400 kW (590 to 5,900 hp). The NO_2/NOx ratios range from 2.2% to 9.9%, with an average of 6.2%. We are proposing to use a ratio of 10% as reasonable and conservative for the emergency Diesel engines and demolition/construction equipment.

[18] California Air Pollution Control Officers Association (2011). "Modeling Compliance of The Federal 1-Hour NO2 NAAQS." Available at *http://www.valleyair.org/busind/pto/Tox_Resources/CAPCOANO2GuidanceDocument10-27-11.pdf*.

Appendix 5.1E
Air Quality Modeling Inputs

Table 5.1E-1
CECP Amendment
Equipment/Structure Dimensions

Item Number	Equipment Sizes Description	Revision: D Size (LxWxH) in Feet (*length is N-S dimension)
30	Warehouse and Maintenance Building	75x116x30
31	Control Room and Administration Building	100x50x20
8	Gas Compressor Building	50x100x30
9	Air Compressor Building	30x50x20
10	Fire Pump Building	30x20x15
11	Diesel Storage Tank	8 ft Diameter x 6 ft Tall
22	Gas Metering	100x75x15
12	Ammonia Storage	50x75x15
12a	Ammonia Unloading Area	
12b	Ammonia forwarding pumps	
12c	Ammonia unloading pump	
12d	Ammonia Tank	
13	Demineralized Water Tank	43.3 Diameter x 32 Tall
14	Raw/Fire Water Tank	50.1 Diameter x 34 Tall
15	Water Treatment Trailers	(7) Parking Spaces plus (2) Spares
16	CEMS Enclosure	20x30x12
17	Unit Auxiliary Transformer	7.5x11x6
7	BOP PDC	40x15.5x15
100	Ocean Water Trailers	(9) 8x32 with two parking spaces
101	Ocean Water Storage Tank	50.3 Diameter x 34 Tall
102	Ultra Filtration Storage Tank (OWS)	20 Diameter x 20 Tall
103	Ultra Filtration Pumps	(2) 8 x 10
104	Solids unloading Space	
	Power Block	
1	Exhaust Stack	14.25 Diameter (OD) x 90 Tall
2	Combustion Turbine Enclosure	20.3x60x47.75
3	Generator Enclosure	15.5x38x27.5
4	VBV Exhaust Stack	13 Diameter x 48 Tall
5	SCR/COR DUCT WORK	59.25x23x38.7
18	Ammonia Prep Skid	19x8x10
19	Shell and Tube Heat Exchanger	12.1 Diameter x 42.5 Long
6	Fin Fan Coolers	50x160x14
20	Auxiliary Skid	15x13x28
20a	Fuel System	Located inside the aux skid
20b	Lube Oil System	Located inside the aux skid
25	Fire Protection System	6x3.2x5
23	NOx Control Water Injection Skid	8.5x13.5x6.5
21	Evaporative Coolers Water Skid	8.5x13.5x6.5
26	Water Wash Skid and Sump	7x11x8
27	Attemporation Blower Skid	8.5x16.5x6
24	GSU Transformer	35x29x25
28	CTG and Intercooler MCC	50x14.5x15
38	Emergency Diesel Generator	12.5x3.6x6.8
38a	Emergency Diesel Generator Fuel Storage Tank	

Table 5.1E-2
CECP Amendment
Screening Modeling Inputs
(per Gas Turbine)

Case	Amb Temp deg F	Stack height feet	Stack Height meters	Stack Diam feet	Stack Diam meters	Stack flow wacfm	Stack flow m3/sec	Stack Vel ft/sec	Stack Vel m/sec	Stack Temp deg F	Stack Temp deg K
Cold 100% Load	44.5	90.0	27.43	13.5	4.11	1,012,885	478.09	117.94	35.95	763.7	679.65
Cold 25% Load	44.5	90.0	27.43	13.5	4.11	524,635	247.63	61.09	18.62	856.7	731.32
Hot 100% Load w/Evap.	96.0	90.0	27.43	13.5	4.11	985,287	465.07	114.72	34.97	813.1	707.09
Hot 100% load w/o Evap.	96.0	90.0	27.43	13.5	4.11	948,559	447.73	110.45	33.66	821.1	711.54
Hot 25% Load	96.0	90.0	27.43	13.5	4.11	499,004	235.53	58.10	17.71	920.2	766.59
Avg. 100% Load w/Evap.	60.3	90.0	27.43	13.5	4.11	1,023,515	483.11	119.18	36.32	779.1	688.21
Avg. 100% Load w/o Evap.	60.3	90.0	27.43	13.5	4.11	1,022,475	482.62	119.05	36.29	781.7	689.65
Avg. 25% Load	60.3	90.0	27.43	13.5	4.11	523,114	246.91	60.91	18.57	854.2	729.93
	NOx lb/hr	**CO lb/hr**	**PM10 lb/hr**	**SOx lb/hr**		**NOx g/sec**	**CO g/sec**	**PM10 g/sec**	**SOx g/sec**		
Cold 100% Load	8.90	8.60	3.50	2.04		1.121	1.084	0.441	0.257		
Cold 25% Load	3.40	3.40	3.50	0.79		0.428	0.428	0.441	0.100		
Hot 100% Load w/Evap.	8.30	8.10	3.50	1.91		1.046	1.021	0.441	0.241		
Hot 100% load w/o Evap.	8.10	7.80	3.50	1.85		1.021	0.983	0.441	0.234		
Hot 25% Load	3.20	3.10	3.50	0.74		0.403	0.391	0.441	0.093		
Avg. 100% Load w/Evap.	9.00	8.70	3.50	2.07		1.134	1.096	0.441	0.260		
Avg. 100% Load w/o Evap.	9.00	8.80	3.50	2.07		1.134	1.109	0.441	0.261		
Avg. 25% Load	3.50	3.40	3.50	0.79		0.441	0.428	0.441	0.100		

Table 5.1E-3
CECP Amendment
Screening Level Modeling Impacts
(Combined Impacts for Six Gas Turbines)

Operating Mode	Conc. (ug/m3) NO2 1-hr	Conc. (ug/m3) SO2 1-hr	Conc. (ug/m3) CO 1-hr	Conc. (ug/m3) SO2 3-hr	Conc. (ug/m3) CO 8-hr	Conc. (ug/m3) SO2 24-hr	Conc. (ug/m3) PM10 24-hr	Conc. (ug/m3) NO2 Annual	Conc. (ug/m3) SO2 Annual	Conc. (ug/m3) PM10 Annual
Cold 100% Load	20.512	4.701	19.821	2.990	7.116	0.595	1.021	0.215	0.049	0.084
Cold 25% Load	11.794	2.754	11.794	1.526	3.927	0.324	1.430	0.110	0.026	0.113
Hot 100% Load w/Evap.	19.106	4.398	18.645	2.798	6.694	0.557	1.020	0.200	0.046	0.084
Hot 100% load w/o Evap.	19.037	4.358	18.332	2.759	6.574	0.551	1.039	0.199	0.046	0.086
Hot 25% Load	11.281	2.609	10.928	1.443	3.629	0.306	1.449	0.104	0.024	0.114
Avg. 100% Load w/Evap.	20.462	4.699	19.780	2.999	7.109	0.596	1.009	0.215	0.049	0.084
Avg. 100% Load w/o Evap.	20.453	4.706	19.999	3.003	7.188	0.597	1.009	0.215	0.049	0.084
Avg. 25% Load	12.184	2.764	11.836	1.531	3.939	0.325	1.434	0.113	0.026	0.113

Table 5.1E-4
CECP Amendment
Emission Rates and Stack Parameters for Refined Modeling

	Stack Diam, m	Stack Height, m	Temp, deg K	Exhaust Flow, m3/s	Exhaust Velocity, m/s	Emission Rates, g/s NOx	SO2	CO	PM10	Stack Diam, ft	Stack Height, ft	Exh Temp, Deg F	Exh Flow Rate, ft3/m	Exhaust Velocity, ft/s	Emission Rates, lb/hr NOx	SO2	CO	PM10
Averaging Period: One hour NOx																		
Unit 6	4.1	27.4	680	478.0	35.9	1.1214	n/a	n/a	n/a	13.5	90	764	1,012,885	118	8.90	n/a	n/a	n/a
Unit 7	4.1	27.4	680	478.0	35.9	1.1214	n/a	n/a	n/a	13.5	90	764	1,012,885	118	8.90	n/a	n/a	n/a
Unit 8	4.1	27.4	680	478.0	35.9	1.1214	n/a	n/a	n/a	13.5	90	764	1,012,885	118	8.90	n/a	n/a	n/a
Unit 9	4.1	27.4	680	478.0	35.9	1.1214	n/a	n/a	n/a	13.5	90	764	1,012,885	118	8.90	n/a	n/a	n/a
Unit 10	4.1	27.4	680	478.0	35.9	1.1214	n/a	n/a	n/a	13.5	90	764	1,012,885	118	8.90	n/a	n/a	n/a
Unit 11	4.1	27.4	680	478.0	35.9	1.1214	n/a	n/a	n/a	13.5	90	764	1,012,885	118	8.90	n/a	n/a	n/a
Firepump Engine	0.2	6.1	723	0.9	48.3	0.1181	n/a	n/a	n/a	0.5	20	842	1,867	158	0.94	n/a	n/a	n/a
Generator Engine	0.1	21.3	957	1.5	98.1	0.2921	n/a	n/a	n/a	0.5	70	1263	3,185	322	2.32	n/a	n/a	n/a
Averaging Period: One hour CO and SOx																		
Unit 6	4.1	27.4	690	482.6	36.3	n/a	0.2609	1.1088	n/a	13.5	90	782	1,022,475	119	n/a	2.07	8.80	n/a
Unit 7	4.1	27.4	690	482.6	36.3	n/a	0.2609	1.1088	n/a	13.5	90	782	1,022,475	119	n/a	2.07	8.80	n/a
Unit 8	4.1	27.4	690	482.6	36.3	n/a	0.2609	1.1088	n/a	13.5	90	782	1,022,475	119	n/a	2.07	8.80	n/a
Unit 9	4.1	27.4	690	482.6	36.3	n/a	0.2609	1.1088	n/a	13.5	90	782	1,022,475	119	n/a	2.07	8.80	n/a
Unit 10	4.1	27.4	690	482.6	36.3	n/a	0.2609	1.1088	n/a	13.5	90	782	1,022,475	119	n/a	2.07	8.80	n/a
Unit 11	4.1	27.4	690	482.6	36.3	n/a	0.2609	1.1088	n/a	13.5	90	782	1,022,475	119	n/a	2.07	8.80	n/a
Firepump Engine	0.2	6.1	723	0.9	48.3	n/a	0.0002	0.0318	n/a	0.5	20	842	1,867	158	n/a	1.77E-03	0.25	n/a
Generator Engine	0.1	21.3	957	1.5	98.1	n/a	0.0005	0.0422	n/a	0.5	70	1263	3,185	322	n/a	4.21E-03	0.33	n/a
Averaging Period: Three hours SOx																		
Unit 6	4.1	27.4	690	482.6	36.3	n/a	0.2609	n/a	n/a	13.5	90	782	1,022,475	119	n/a	2.07	n/a	n/a
Unit 7	4.1	27.4	690	482.6	36.3	n/a	0.2609	n/a	n/a	13.5	90	782	1,022,475	119	n/a	2.07	n/a	n/a
Unit 8	4.1	27.4	690	482.6	36.3	n/a	0.2609	n/a	n/a	13.5	90	782	1,022,475	119	n/a	2.07	n/a	n/a
Unit 9	4.1	27.4	690	482.6	36.3	n/a	0.2609	n/a	n/a	13.5	90	782	1,022,475	119	n/a	2.07	n/a	n/a
Unit 10	4.1	27.4	690	482.6	36.3	n/a	0.2609	n/a	n/a	13.5	90	782	1,022,475	119	n/a	2.07	n/a	n/a
Unit 11	4.1	27.4	690	482.6	36.3	n/a	0.2609	n/a	n/a	13.5	90	782	1,022,475	119	n/a	2.07	n/a	n/a
Firepump Engine	0.2	6.1	723	0.9	48.3	n/a	0.0001	n/a	n/a	0.5	20	842	1,867	158	n/a	5.89E-04	n/a	n/a
Generator Engine	0.1	21.3	957	1.5	98.1	n/a	0.0002	n/a	n/a	0.5	70	1263	3,185	322	n/a	1.40E-03	n/a	n/a

Table 5.1E-4
Emission Rates and Stack Parameters for Refined Modeling (cont.)

	Stack Diam, m	Stack Height, m	Temp, deg K	Exhaust Flow, m3/s	Exhaust Velocity, m/s	Emission Rates, g/s NOx	Emission Rates, g/s SO2	Emission Rates, g/s CO	Emission Rates, g/s PM10	Stack Diam, ft	Stack Height, ft	Exh Temp, Deg F	Exh Flow Rate, ft3/m	Exhaust Velocity, ft/s	Emission Rates, lb/hr NOx	Emission Rates, lb/hr SO2	Emission Rates, lb/hr CO	Emission Rates, lb/hr PM10
Averaging Period: Eight hours CO																		
Unit 6	4.1	27.4	690	482.6	36.3	n/a	n/a	1.1088	n/a	13.5	90	782	1,022,475	119	n/a	n/a	8.80	n/a
Unit 7	4.1	27.4	690	482.6	36.3	n/a	n/a	1.1088	n/a	13.5	90	782	1,022,475	119	n/a	n/a	8.80	n/a
Unit 8	4.1	27.4	690	482.6	36.3	n/a	n/a	1.1088	n/a	13.5	90	782	1,022,475	119	n/a	n/a	8.80	n/a
Unit 9	4.1	27.4	690	482.6	36.3	n/a	n/a	1.1088	n/a	13.5	90	782	1,022,475	119	n/a	n/a	8.80	n/a
Unit 10	4.1	27.4	690	482.6	36.3	n/a	n/a	1.1088	n/a	13.5	90	782	1,022,475	119	n/a	n/a	8.80	n/a
Unit 11	4.1	27.4	690	482.6	36.3	n/a	n/a	1.1088	n/a	13.5	90	782	1,022,475	119	n/a	n/a	8.80	n/a
Firepump Engine	0.2	6.1	723	0.9	48.3	n/a	n/a	0.0040	n/a	0.5	20	842	1,867	158	n/a	n/a	0.03	n/a
Generator Engine	0.1	21.3	957	1.5	98.1	n/a	n/a	0.0053	n/a	0.5	70	1263	3,185	322	n/a	n/a	0.04	n/a
Averaging Period: 24-hour SOx																		
Unit 6	4.1	27.4	690	482.6	36.3	n/a	0.2609	n/a	n/a	13.5	90	782	1,022,475	119	n/a	2.07	n/a	n/a
Unit 7	4.1	27.4	690	482.6	36.3	n/a	0.2609	n/a	n/a	13.5	90	782	1,022,475	119	n/a	2.07	n/a	n/a
Unit 8	4.1	27.4	690	482.6	36.3	n/a	0.2609	n/a	n/a	13.5	90	782	1,022,475	119	n/a	2.07	n/a	n/a
Unit 9	4.1	27.4	690	482.6	36.3	n/a	0.2609	n/a	n/a	13.5	90	782	1,022,475	119	n/a	2.07	n/a	n/a
Unit 10	4.1	27.4	690	482.6	36.3	n/a	0.2609	n/a	n/a	13.5	90	782	1,022,475	119	n/a	2.07	n/a	n/a
Unit 11	4.1	27.4	690	482.6	36.3	n/a	0.2609	n/a	n/a	13.5	90	782	1,022,475	119	n/a	2.07	n/a	n/a
Firepump Engine	0.2	6.1	723	0.9	48.3	n/a	0.0000	n/a	n/a	0.5	20	842	1,867	158	n/a	7.36E-05	n/a	n/a
Generator Engine	0.1	21.3	957	1.5	98.1	n/a	0.0000	n/a	n/a	0.5	70	1263	3,185	322	n/a	1.75E-04	n/a	n/a
Averaging Period: 24-hour PM10																		
Unit 6	4.1	27.4	767	235.5	17.7	n/a	n/a	n/a	0.4410	13.5	90	920	499,004	58	n/a	n/a	n/a	3.50
Unit 7	4.1	27.4	767	235.5	17.7	n/a	n/a	n/a	0.4410	13.5	90	920	499,004	58	n/a	n/a	n/a	3.50
Unit 8	4.1	27.4	767	235.5	17.7	n/a	n/a	n/a	0.4410	13.5	90	920	499,004	58	n/a	n/a	n/a	3.50
Unit 9	4.1	27.4	767	235.5	17.7	n/a	n/a	n/a	0.4410	13.5	90	920	499,004	58	n/a	n/a	n/a	3.50
Unit 10	4.1	27.4	767	235.5	17.7	n/a	n/a	n/a	0.4410	13.5	90	920	499,004	58	n/a	n/a	n/a	3.50
Unit 11	4.1	27.4	767	235.5	17.7	n/a	n/a	n/a	0.4410	13.5	90	920	499,004	58	n/a	n/a	n/a	3.50
Firepump Engine	0.2	6.1	723	0.9	48.3	n/a	n/a	n/a	0.0002	0.5	20	842	1,867	158	n/a	n/a	n/a	1.65E-03
Generator Engine	0.1	21.3	957	1.5	98.1	n/a	n/a	n/a	0.0001	0.5	70	1263	3,185	322	n/a	n/a	n/a	1.07E-03

Table 5.1E-4
Emission Rates and Stack Parameters for Refined Modeling (cont.)

	Stack Diam, m		Temp, deg K	Exhaust Flow, m3/s	Exhaust Velocity, m/s	Emission Rates, g/s NOx	SO2	CO	PM10	Stack Diam, ft		Exh Temp, Deg F	Exh Flow Rate, ft3/m	Exhaust Velocity, ft/s	Emission Rates, lb/hr NOx	SO2	CO	PM10
Averaging Period: Annual NOx and SOx																		
Unit 6	4.1	27.4	690	482.6	36.3	0.4048	0.0268	n/a	n/a	13.5	90	782	1,022,475	119	3.21	0.21	n/a	n/a
Unit 7	4.1	27.4	690	482.6	36.3	0.4048	0.0268	n/a	n/a	13.5	90	782	1,022,475	119	3.21	0.21	n/a	n/a
Unit 8	4.1	27.4	690	482.6	36.3	0.4048	0.0268	n/a	n/a	13.5	90	782	1,022,475	119	3.21	0.21	n/a	n/a
Unit 9	4.1	27.4	690	482.6	36.3	0.4048	0.0268	n/a	n/a	13.5	90	782	1,022,475	119	3.21	0.21	n/a	n/a
Unit 10	4.1	27.4	690	482.6	36.3	0.4048	0.0268	n/a	n/a	13.5	90	782	1,022,475	119	3.21	0.21	n/a	n/a
Unit 11	4.1	27.4	690	482.6	36.3	0.4048	0.0268	n/a	n/a	13.5	90	782	1,022,475	119	3.21	0.21	n/a	n/a
Firepump Engine	0.2	6.1	723	0.9	48.3	0.0027	0.0000	n/a	n/a	0.5	20	842	1,867	158	0.02	4.03E-05	n/a	n/a
Generator Engine	0.1	21.3	957	1.5	98.1	0.0067	0.0000	n/a	n/a	0.5	70	1263	3,185	322	0.05	9.61E-05	n/a	n/a
Averaging Period: Annual PM10																		
Unit 6	4.1	27.4	767	235.5	17.7	n/a	n/a	n/a	0.1359	13.5	90	920	499,004	58	n/a	n/a	n/a	1.08
Unit 7	4.1	27.4	767	235.5	17.7	n/a	n/a	n/a	0.1359	13.5	90	920	499,004	58	n/a	n/a	n/a	1.08
Unit 8	4.1	27.4	767	235.5	17.7	n/a	n/a	n/a	0.1359	13.5	90	920	499,004	58	n/a	n/a	n/a	1.08
Unit 9	4.1	27.4	767	235.5	17.7	n/a	n/a	n/a	0.1359	13.5	90	920	499,004	58	n/a	n/a	n/a	1.08
Unit 10	4.1	27.4	767	235.5	17.7	n/a	n/a	n/a	0.1359	13.5	90	920	499,004	58	n/a	n/a	n/a	1.08
Unit 11	4.1	27.4	767	235.5	17.7	n/a	n/a	n/a	0.1359	13.5	90	920	499,004	58	n/a	n/a	n/a	1.08
Firepump Engine	0.2	6.1	723	0.9	48.3	n/a	n/a	n/a	0.0001	0.5	20	842	1,867	158	n/a	n/a	n/a	9.05E-04
Generator Engine	0.1	21.3	957	1.5	98.1	n/a	n/a	n/a	0.0001	0.5	70	1263	3,185	322	n/a	n/a	n/a	5.88E-04

Table 5.1E-5
CECP Amendment
Startup/Shutdown Modeling Inputs
Data For Each Unit

Operating Case	Stack Ht. feet	Stack Dia. ft	Stack flow wacfm	Stack flow m3/sec	Stack Vel ft/sec	Stack Vel m/sec	Stack Temp deg F	Stack Temp deg K	NOx lb/hr	CO lb/hr	NOx g/sec	CO g/sec
GT Unit 6 - Startup/Shutdown/Restart	90	13.5	523,114	246.91	60.91	18.57	854.20	729.93	28.24	17.31	3.56	2.18
GT Unit 7 - Startup/Shutdown/Restart	90	13.5	523,114	246.91	60.91	18.57	854.20	729.93	28.24	17.31	3.56	2.18
GT Unit 8 - Startup/Shutdown/Restart	90	13.5	523,114	246.91	60.91	18.57	854.20	729.93	28.24	17.31	3.56	2.18
GT Unit 9 - Startup/Shutdown/Restart	90	13.5	523,114	246.91	60.91	18.57	854.20	729.93	28.24	17.31	3.56	2.18
GT Unit 10 - Startup/Shutdown/Restart	90	13.5	523,114	246.91	60.91	18.57	854.20	729.93	28.24	17.31	3.56	2.18
GT Unit 11 - Startup/Shutdown/Restart	90	13.5	523,114	246.91	60.91	18.57	854.20	729.93	28.24	17.31	3.56	2.18

Table 5.1E-6
CECP Amendment
Commissioning Modeling Inputs
Data For Each Unit

Operating Case	Stack Ht. feet	Stack Dia. ft	Stack flow wacfm	Stack flow m3/sec	Stack Vel ft/sec	Stack Vel m/sec	Stack Temp deg F	Stack Temp deg K	NOx lb/hr	CO lb/hr	PM10 lb/hr	SOx lb/hr	NOx g/sec	CO g/sec	PM10 g/sec	SOx g/sec
GT Unit 6 - Commissioning	90	13.5	523,114	246.91	60.91	18.57	854.20	729.93	90.00	247.67	3.50	2.07	11.34	31.21	0.44	0.26
GT Unit 7 - Commissioning	90	13.5	523,114	246.91	60.91	18.57	854.20	729.93	90.00	247.67	3.50	2.07	11.34	31.21	0.44	0.26
GT Unit 8 - Commissioning	90	13.5	523,114	246.91	60.91	18.57	854.20	729.93	90.00	247.67	3.50	2.07	11.34	31.21	0.44	0.26
GT Unit 9 - Commissioning	90	13.5	523,114	246.91	60.91	18.57	854.20	729.93	90.00	247.67	3.50	2.07	11.34	31.21	0.44	0.26
GT Unit 10 - Commissioning	90	13.5	523,114	246.91	60.91	18.57	854.20	729.93	90.00	247.67	3.50	2.07	11.34	31.21	0.44	0.26
GT Unit 11 - Commissioning	90	13.5	523,114	246.91	60.91	18.57	854.20	729.93	90.00	247.67	3.50	2.07	11.34	31.21	0.44	0.26
Existing Unit 1 - normal operation	383	26	418,696						9.07	55.58	7.55	2.13	1.14	7.00	0.95	0.27
Existing Unit 2 - normal operation	383	26	339,751						10.17	61.77	7.55	2.13	1.28	7.78	0.95	0.27
Existing Unit 3 - normal operation	383	26	370,708						9.94	28.75	8.41	2.37	1.25	3.62	1.06	0.30
Existing Unit 4 - normal operation	383	26	992,604						32.91	22.71	24.18	6.82	4.15	2.86	3.05	0.86
Existing Unit 5 - normal operation	383	26	996,771						37.44	118.80	25.90	7.30	4.72	14.97	3.26	0.92
Existing Units - combined stack =	383	26	3,118,530	1471.98	97.90	29.84	310.00	427.59	99.52	287.61	73.58	20.75	12.54	36.24	9.27	2.61
Existing Peaker GT			609,032	287.47			981.00	800.37	7.50	9.51	2.36	0.67	0.95	1.20	0.30	0.08

Appendix 5.1F
Demolition/Construction Emissions

APPENDIX 5.1F

Demolition/Construction Emissions

The demolition/construction of the Amended CECP is scheduled to occur in the following two phases:

- Construction of the new equipment (24-month period); and
- Demolition of the existing Encina Power Station (22-month period).

There is no overlap between these two phases. The emissions were calculated for each phase, and the results of this analysis are discussed below.

5.1 Emission Activities

The primary emission sources during demolition/construction will include exhaust from heavy construction equipment and vehicles, and fugitive dust generated by grading and excavating activities.

Combustion emissions during demolition/construction will result from the following:

- Exhaust from the diesel construction equipment used for site preparation, grading, excavation, trenching, and construction of onsite structures;
- Exhaust from water trucks used to control construction dust emissions;
- Exhaust from portable welding machines;
- Exhaust from pickup trucks and diesel trucks used to transport workers and materials around the construction site;
- Exhaust from diesel trucks used to deliver concrete, fuel, and construction supplies to the construction site including the heavy hauling of major components using truck and/or rail; and
- Exhaust from vehicles used by workers to commute to the construction site.

Fugitive dust emissions from the demolition/construction will result from the following:

- Dust entrained during site preparation and grading/excavation at the construction site;
- Dust entrained during onsite travel on paved and unpaved surfaces;
- Dust entrained during aggregate and soil loading and unloading operations; and
- Wind erosion of areas disturbed during construction activities.

The detailed demolition/construction emissions calculations are shown in the tables attached to this analysis. As discussed in the modeling protocol submitted to the SDAPCD and CEC (see Appendix 5.1D), the CalEEMod model was used to calculate demolition and construction emissions for the Amended CECP.

5.2 Available Mitigation Measures

Listed below are typical mitigation measures being proposed to control exhaust emissions from the diesel heavy equipment and potential emissions of fugitive dust during demolition/construction activities.

- Unpaved surface travel and disturbed areas in the project demolition/construction site will be watered as frequently as necessary to prevent fugitive dust plumes. The frequency of watering can be reduced or eliminated during periods of precipitation.
- The vehicle speed limit will be 15 miles per hour within the demolition/construction site.
- The demolition/construction site entrances shall be posted with visible speed limit signs.

- Demolition/construction equipment vehicle tires will be inspected and washed as necessary to be cleaned free of dirt prior to entering paved roadways.
- Gravel ramps of at least 20 feet in length will be provided at the tire washing/cleaning station.
- Unpaved exits from the demolition/construction site will be graveled or treated to prevent track-out to public roadways.
- Demolition/construction vehicles will enter the construction site through the treated entrance roadways, unless an alternative route has been submitted to and approved by the Compliance Project Manager.
- Demolition/construction areas adjacent to any paved roadway will be provided with sandbags or other measures as specified in the Storm Water Pollution Prevention Plan (SWPPP) to prevent run-off to roadways.
- Paved roads within the demolition/construction site will be cleaned at least once per day (or less during periods of precipitation) on days when demolition/construction activity occurs to prevent the accumulation of dirt and debris.
- At least the first 500 feet of any public roadway exiting from the demolition/construction site shall be cleaned at least once daily when dirt or runoff from the demolition/construction site is visible on public roadways.
- Soil storage piles and disturbed areas that remain inactive for longer than 10 days will be covered or treated with appropriate dust suppressant compounds.
- Vehicles used to transport solid bulk material on public roadways and having the potential to cause visible emissions will be provided with a cover, or the materials will be sufficiently wetted and loaded onto the trucks in a manner to provide at least one foot of freeboard.
- Wind erosion control techniques (such as windbreaks, water, chemical dust suppressants, and/or vegetation) will be used on all demolition/construction areas that may be disturbed. Any windbreaks installed to comply with this condition shall remain in place until the soil is stabilized or permanently covered with vegetation.

An on-site Air Quality Construction Mitigation Manager will be responsible for directing and documenting compliance with demolition/construction-related mitigation conditions.

5.3 Air Quality Impact Analysis

A dispersion modeling analysis was conducted based on the emissions discussed above using the approach discussed in the modeling protocol submitted to the SDAPCD and CEC (see Appendix 5.1D). Because it will be necessary to continue operating the existing Encina Power Station units during the construction of the new units, the dispersion modeling analysis includes the impacts for the existing Encina units. As shown in the attached detailed emission calculations, the emissions associated with the demolition of the Encina Power Station are lower (daily and annual) than the emissions associated with the construction of the new units. Therefore, because the following construction modeling analysis examines worst-case impacts, a separate modeling analysis was not performed examining the impacts for the demolition of the Encina Power Station.

As shown below in Table 5.1F-1, the results of the analysis indicate that construction activities are not expected to cause or contribute to exceedances of state or federal standards for criteria pollutants, with the exception of the annual state PM_{10}/$PM_{2.5}$ standards and annual federal $PM_{2.5}$ standard. For these pollutants and averaging periods, existing background concentrations already exceed state/federal standards. The best available emission control techniques will be used to minimize emissions during construction. The project construction impacts are not unusual in comparison to most construction sites; construction sites that use good dust suppression techniques and low-emitting vehicles typically do not cause violations of air quality standards. It should also be noted that the maximum impacts shown in Table 5.1F-1 are lower (with the exception of SO_2 impacts) than the construction impacts analyzed for the Licensed CECP[1].

TABLE 5.1F-1
Modeled Maximum Impacts (Demolition/Construction – includes impacts from existing Encina units)

Pollutant	Averaging Time	Maximum Project Impact (µg/m³)	Background (µg/m³)	Total Impact (µg/m³)	State Standard (µg/m³)	Federal Standard (µg/m³)
NO_2	1-hour	134.7	152.4	287	339	--
	98th percentile	115.3	105.3[a]	158	--	188
	Annual	10.8	16.9	28	57	100
SO_2	1-hour	4.7	34.1	39	655	--
	99th percentile	4.7	35.8[c]	41	--	196
	24-hour	0.4	7.9	8	105	--
CO	1-hour	736.2	5,040	5,776	23,000	40,000
	8-hour	162.6	4,238	4,401	10,000	10,000
PM_{10}	24-hour	3.6	43	47	50	150
	Annual	0.9	22.8	24	20	--
$PM_{2.5}$	24-hour	2.9	26[b]	29	--	35
	Annual	0.7	13.2	14	12	12

[a] 1-hour NO_2 background concentration is shown as the 3-year average of the 98th percentile as that is the basis of the federal standard.

[b] 24-hr $PM_{2.5}$ background concentration reflects 3-year average of the 98th percentile values based on form of standard.

[c] 1-hr SO_2 background concentration reflects 3-year average of the 99th percentile values based on form of standard.

A health risk assessment of construction impacts was performed in accordance with OEHHA guidance, which requires adjusting the 70-year lifetime dosage to an exposure period of 9 years (despite the fact that project construction will last for only 24 months). At the point of maximum impact along the fenceline of the project, the annual average diesel particulate matter (DPM) impact is 0.5 $\mu g/m^3$. Based on a DPM 70-year lifetime unit risk factor of $4.15*10^{-4}$, a duration correction factor of 0.129 (9 years/70 years), and a duration correction factor of 0.224 (245 days per year at 8 hours per day vs. 365 days per year at 24 hours per day) to account for a worker along the fenceline, the cancer risk at the property line is calculated at approximately 6 in one million. This is below the SDAPCD significance threshold of 10 in one million. Because the offsite DPM impacts fall off sharply with distance from the project fenceline, the residential risk at the nearest residential receptor, approximately 0.7 km away, is also expected to be below this significance threshold.

5.4 Detailed Demolition and Construction Emission Calculations

Tables 5.1F-2 through 5.1F-21 provide detailed demolition and construction emission calculations.

[1] CEC June 2012 Approval of CECP, Air Quality Table-5.

TABLE 5.1F-2
Construction of Amended CECP - Daily and Annual Construction Emissions

Daily Construction Emissions (peak month) (lbs/day)						
	NOx	CO	VOC	SOx	PM_{10}	$PM_{2.5}$
Onsite						
Off-Road Equipment (combustion)	118.13	144.91	5.90	0.27	5.47	5.47
Off-Road Equipment and On-Site Vehicle (combustion)	118.31	146.18	6.01	0.27	5.47	5.47
Construction - Fugitive Dust					2.76	1.34
On-site Vehicle - Fugitive Dust					0.24	0.06
Subtotal (Fugitive Dust)					3.00	1.40
Subtotal (On-site)	118.31	146.18	6.01	0.27	8.47	6.86
Offsite						
Worker Travel (combustion)	1.28	12.48	1.03	0.03	0.02	0.02
Truck Emissions (combustion)	2.72	4.19	0.34	0.01	0.04	0.04
Worker Travel - Fugitive Dust					2.29	0.61
Truck - Fugitive Dust					0.19	0.05
Subtotal (Offsite)	4.00	16.67	1.37	0.04	2.54	0.71
Total	122.31	162.85	7.38	0.31	11.01	7.58

Peak Construction Emissions (tons/yr, rolling 12-month maximum)						
	NOx	CO	VOC	SOx	PM_{10}	$PM_{2.5}$
Onsite						
Off-Road Equipment (combustion)	10.51	12.78	0.52	0.02	0.49	0.49
Off-Road Equipment and Vehicle (combustion)	10.55	12.94	0.54	0.02	0.49	0.49
Construction - Fugitive Dust					0.32	0.17
On-site Vehicle - Fugitive Dust					0.03	0.01
Subtotal (Fugitive Dust)					0.35	0.18
Subtotal (On-site)	10.55	12.94	0.54	0.02	0.84	0.67
Offsite						
Worker Travel (combustion)	0.14	1.30	0.10	0.00	0.00	0.00
Truck Emissions (combustion)	0.19	0.26	0.02	0.0005	0.000	0.003
Worker Travel - Fugitive Dust					0.24	0.06
Truck - Fugitive Dust					0.01	0.00
Subtotal (Offsite)	0.33	1.57	0.13	0.00	0.26	0.07
Total	10.87	14.51	0.67	0.03	1.09	0.74

TABLE 5.1F-3

Construction of Amended CECP - Modeled Emissions, Short-Term Impacts

Short-Term Impacts (24 hours and less)					
Daily working hours (hrs/day)	8				
	NOx	**CO**	**SOx**	**PM_{10}**	**$PM_{2.5}$**
TOTAL					
Off Road Equipment and On-site Vehicle (Combustion) (lbs/day)	118.31	146.18	0.27	5.47	5.47
Off Road Equipment and On-site Vehicle (Combustion) (lbs/hr)	14.79	18.27	0.03	0.68	0.68
Off Road Equipment and On-site Vehicle (Combustion) (g/sec)	1.86	2.30	0.004	0.09	0.09
Construction and On-site Vehicle (Fugitive Dust) (lbs/day)				3.00	1.40
Construction and On-site Vehicle (Fugitive Dust) (lbs/hr)				0.38	0.17
Construction and On-site Vehicle (Fugitive Dust) (g/sec)				0.05	0.02

TABLE 5.1F-4

Construction of Amended CECP - Modeled Emissions, Long-Term Impacts

Long-Term Impacts (annual)					
Annual Number of Work Days, Rolling 12-month period (days/yr)	262				
Daily working hours (hrs/day)	8				
	NOx	**CO**	**SOx**	**PM10**	**PM2.5**
TOTAL					
Off Road Equipment and On-site Vehicle (Combustion) (lbs/day)	10.55	12.94	0.02	0.49	0.49
Off Road Equipment and On-site Vehicle (Combustion) (lbs/hr)	10.06	12.35	0.02	0.47	0.47
Off Road Equipment and On-site Vehicle (Combustion) (g/sec)	1.27	1.56	0.003	0.06	0.06
Construction and On-site Vehicle (Fugitive Dust) (lbs/day)				0.35	0.18
Construction and On-site Vehicle (Fugitive Dust) (lbs/hr)				0.33	0.17
Construction and On-site Vehicle (Fugitive Dust) (g/sec)				0.04	0.02

TABLE 5.1F-5

Construction of Amended CECP - Greenhouse Gas Emission Calculations

	GHG Emissions (MT, Total for 24-month Construction Period)			
	CO2	**CH4**	**N2O**	**CO2e**
Off-Road Equipment	2661.61	0.63	0	2674.94
Off-Road Equipment and On-site Vehicle	2701.14	0.64	0	2714.44
Worker Travel	327.85	0.02	0	327.97
Truck Emissions	45.35	3.50E-04	0	45.35
Total	3074.03	0.65	0	3087.76

TABLE 5.1F-6

Construction of CECP - Monthly and Annual Emission Calculations

Project Month		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
													ROG												
Off-Road Equipment	(tons/month)	0.011	0.016	0.026	0.030	0.030	0.037	0.033	0.036	0.040	0.036	0.042	0.050	0.048	0.059	0.065	0.047	0.012	0.011	0.007	0.004	0.004	0	0	0
On-site Vehicle	(tons/month)	4.19E-04	5.83E-04	7.49E-04	8.23E-04	1.03E-03	1.21E-03	9.31E-04	1.01E-03	1.11E-03	1.08E-03	1.17E-03	1.29E-03	1.22E-03	1.14E-03	1.09E-03	8.84E-04	5.65E-04	5.18E-04	4.13E-04	4.43E-04	3.97E-04	1.76E-04	1.14E-04	9.50E-05
Hauling Emission	(tons/month)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck Emission	(tons/month)	1.40E-04	5.40E-04	1.78E-03	1.91E-03	3.35E-03	3.40E-03	1.55E-03	1.50E-03	1.63E-03	1.55E-03	1.44E-03	1.75E-03	1.43E-03	7.50E-04	5.00E-04	3.40E-04	3.10E-04	1.20E-04	1.00E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Worker Travel	(tons/month)	0.004	0.005	0.005	0.005	0.005	0.007	0.007	0.008	0.009	0.009	0.010	0.010	0.010	0.010	0.010	0.008	0.005	0.005	0.004	0.004	0.004	0.002	0.001	0.001
Off-Road Equipment	Rolling 12-month total (tons/year)												0.39	0.42	0.47	0.51	0.52	0.51	0.48	0.45	0.42	0.39	0.35	0.31	0.26
Hauling Emission	Rolling 12-month total (tons/year)												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Truck Emission	Rolling 12-month total (tons/year)												0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.00
Worker Travel	Rolling 12-month total (tons/year)												0.08	0.09	0.10	0.10	0.10	0.10	0.10	0.10	0.09	0.09	0.08	0.07	0.07
													NOx												
Off-Road Equipment	(tons/month)	0.21	0.32	0.51	0.58	0.59	0.74	0.66	0.73	0.81	0.74	0.85	1.01	0.96	1.19	1.30	0.94	0.25	0.22	0.14	0.08	0.07	0.00	0.00	0.00
On-site Vehicle	(tons/month)	7.10E-04	1.36E-03	2.94E-03	3.14E-03	4.96E-03	5.25E-03	2.90E-03	2.96E-03	3.22E-03	3.10E-03	3.09E-03	3.60E-03	3.15E-03	2.32E-03	1.98E-03	1.54E-03	1.08E-03	8.11E-04	6.56E-04	5.87E-04	5.25E-04	2.33E-04	1.52E-04	1.25E-04
Hauling Emission	(tons/month)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck Emission	(tons/month)	0.001	0.005	0.016	0.016	0.029	0.029	0.013	0.013	0.014	0.013	0.012	0.015	0.012	0.006	0.004	0.003	0.003	0.001	0.001	0.000	0.000	0.000	0.000	0.000
Worker Travel	(tons/month)	0.005	0.007	0.006	0.007	0.007	0.009	0.009	0.011	0.012	0.011	0.013	0.014	0.013	0.014	0.013	0.011	0.007	0.007	0.005	0.006	0.005	0.002	0.002	0.001
Off-Road Equipment	Rolling 12-month total (tons/year)												7.74	8.49	9.36	10.15	10.51	10.16	9.65	9.13	8.48	7.75	7.01	6.16	5.16
Hauling Emission	Rolling 12-month total (tons/year)												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Truck Emission	Rolling 12-month total (tons/year)												0.18	0.19	0.19	0.18	0.16	0.14	0.11	0.10	0.09	0.07	0.06	0.05	0.03
Worker Travel	Rolling 12-month total (tons/year)												0.11	0.12	0.13	0.13	0.14	0.14	0.13	0.13	0.13	0.12	0.11	0.10	0.09
													CO												
Off-Road Equipment	(tons/month)	0.269	0.402	0.640	0.714	0.715	0.893	0.791	0.883	0.977	0.889	1.016	1.230	1.174	1.454	1.594	1.161	0.326	0.305	0.200	0.099	0.095	0.000	0.000	0.000
On-site Vehicle	(tons/month)	0.005	0.007	0.009	0.010	0.013	0.015	0.012	0.013	0.014	0.014	0.015	0.016	0.015	0.014	0.014	0.011	0.007	0.006	0.005	0.006	0.005	0.002	0.001	0.001
Hauling Emission	(tons/month)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck Emission	(tons/month)	0.002	0.006	0.020	0.023	0.040	0.041	0.019	0.018	0.020	0.019	0.017	0.021	0.017	0.009	0.006	0.004	0.004	0.001	0.001	0.000	0.000	0.000	0.000	0.000
Worker Travel	(tons/month)	0.051	0.064	0.062	0.068	0.068	0.089	0.088	0.100	0.109	0.108	0.120	0.130	0.127	0.130	0.128	0.105	0.065	0.063	0.050	0.056	0.050	0.022	0.014	0.012
Off-Road Equipment	Rolling 12-month total (tons/year)												9.42	10.32	11.38	12.33	12.78	12.39	11.80	11.21	10.42	9.54	8.65	7.64	6.41
Hauling Emission	Rolling 12-month total (tons/year)												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Truck Emission	Rolling 12-month total (tons/year)												0.25	0.26	0.26	0.25	0.23	0.19	0.16	0.14	0.12	0.10	0.08	0.06	0.04
Worker Travel	Rolling 12-month total (tons/year)												1.06	1.13	1.20	1.26	1.30	1.30	1.27	1.23	1.19	1.13	1.04	0.94	0.82
													SO2												
Off-Road Equipment	(tons/month)	4.50E-04	7.30E-04	1.14E-03	1.30E-03	1.35E-03	1.67E-03	1.49E-03	1.63E-03	1.82E-03	1.68E-03	1.96E-03	2.28E-03	2.18E-03	2.70E-03	2.94E-03	2.19E-03	6.10E-04	5.30E-04	3.10E-04	1.80E-04	1.70E-04	0.00E+00	0.00E+00	0.00E+00
On-site Vehicle	(tons/month)	1.00E-05	1.45E-05	1.74E-05	2.19E-05	2.54E-05	3.04E-05	2.44E-05	2.74E-05	2.94E-05	2.94E-05	3.14E-05	3.59E-05	3.34E-05	3.30E-05	3.05E-05	2.75E-05	1.75E-05	1.60E-05	1.30E-05	1.40E-05	1.30E-05	6.00E-06	4.00E-06	3.00E-06
Hauling Emission	(tons/month)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck Emission	(tons/month)	0.00E+00	1.00E-05	3.00E-05	4.00E-05	7.00E-05	7.00E-05	3.00E-05	3.00E-05	3.00E-05	3.00E-05	3.00E-05	4.00E-05	3.00E-05	2.00E-05	1.00E-05	1.00E-05	1.00E-05	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Worker Travel	(tons/month)	1.00E-04	1.30E-04	1.30E-04	1.60E-04	1.50E-04	2.00E-04	2.00E-04	2.30E-04	2.50E-04	2.50E-04	2.70E-04	3.00E-04	2.90E-04	3.00E-04	2.90E-04	2.60E-04	1.60E-04	1.60E-04	1.30E-04	1.40E-04	1.30E-04	6.00E-05	4.00E-05	3.00E-05
Off-Road Equipment	Rolling 12-month total (tons/year)												0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01
Hauling Emission	Rolling 12-month total (tons/year)												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Truck Emission	Rolling 12-month total (tons/year)												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Worker Travel	Rolling 12-month total (tons/year)												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
													PM10												
Fugitive	(tons/month)	2.8E-02	2.7E-02	2.9E-02	2.7E-02	2.7E-02	2.9E-02	0.02	0.03	0.03	0.02	0.03	0.03	0.02	0.03	0.03	0.03	0.00	0.00	0.03	0.03	0.03	0.00	0.00	0.00
Fugitive (On-site Vehicle)	(tons/month)	8.6E-04	1.1E-03	1.2E-03	1.4E-03	1.5E-03	1.9E-03	1.8E-03	2.0E-03	2.2E-03	2.1E-03	2.4E-03	2.6E-03	2.5E-03	2.5E-03	2.4E-03	2.2E-03	1.4E-03	1.3E-03	1.0E-03	1.1E-03	1.0E-03	4.6E-04	3.0E-04	2.4E-04
Fugitive - Hauling	(tons/month)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fugitive - Truck	(tons/month)	7.00E-05	2.70E-04	9.00E-04	1.09E-03	1.91E-03	1.95E-03	8.90E-04	8.60E-04	9.30E-04	8.90E-04	8.20E-04	1.00E-03	8.20E-04	4.30E-04	2.90E-04	2.10E-04	2.00E-04	7.00E-05	7.00E-05	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Fugitive - Worker Travel	(tons/month)	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00
Fugitive	Rolling 12-month total (tons/year)												0.32	0.32	0.32	0.32	0.32	0.30	0.27	0.27	0.27	0.27	0.25	0.22	0.19
Fugitive (On-Site Vehicle)	Rolling 12-month total (tons/year)												0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02
Fugitive - Hauling	Rolling 12-month total (tons/year)												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fugitive - Truck	Rolling 12-month total (tons/year)												0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00
Fugitive - Worker Travel	Rolling 12-month total (tons/year)												0.19	0.21	0.22	0.23	0.24	0.24	0.24	0.23	0.23	0.22	0.20	0.18	0.16
Off-Road Equipment	(tons/month)	0.009	0.015	0.023	0.025	0.026	0.033	0.030	0.034	0.038	0.035	0.040	0.047	0.045	0.056	0.060	0.044	0.012	0.011	0.007	0.003	0.003	0.000	0.000	0.000
On-site Vehicle	(tons/month)	9.96E-06	2.08E-05	4.50E-05	4.55E-05	7.21E-05	7.66E-05	4.26E-05	4.21E-05	4.71E-05	4.46E-05	4.36E-05	5.15E-05	4.46E-05	3.38E-05	2.69E-05	2.19E-05	1.59E-05	1.15E-05	9.48E-06	9.00E-06	8.00E-06	3.00E-06	2.00E-06	2.00E-06
Hauling Emission	(tons/month)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck Emission	(tons/month)	2.00E-05	8.00E-05	2.50E-04	2.40E-04	4.20E-04	4.30E-04	2.00E-04	1.90E-04	2.10E-04	2.00E-04	1.80E-04	2.20E-04	1.80E-04	1.00E-04	6.00E-05	4.00E-05	4.00E-05	1.00E-05	1.00E-05	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Worker Travel	(tons/month)	7.00E-05	9.00E-05	8.00E-05	1.00E-04	1.00E-04	1.30E-04	1.30E-04	1.40E-04	1.60E-04	1.50E-04	1.70E-04	1.90E-04	1.80E-04	1.90E-04	1.80E-04	1.60E-04	1.00E-04	1.00E-04	8.00E-05	9.00E-05	8.00E-05	3.00E-05	2.00E-05	2.00E-05
Off-Road Equipment	Rolling 12-month total (tons/year)												0.36	0.39	0.43	0.47	0.49	0.47	0.45	0.43	0.40	0.36	0.33	0.29	0.24
Hauling Emission	Rolling 12-month total (tons/year)												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Truck Emission	Rolling 12-month total (tons/year)												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Worker Travel	Rolling 12-month total (tons/year)												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

TABLE 5.1F-6 (CONT.)

Construction of CECP - Monthly and Annual Emission Calculations

Project Month		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
		PM2.5																							
Fugitive	(tons/month)	0.015	0.014	0.015	0.014	0.014	0.015	0.014	0.014	0.014	0.014	0.015	0.014	0.014	0.015	0.015	0.015	0.000	0.000	0.013	0.015	0.014	0.000	0.000	0.000
Fugitive (On-site Vehicle)	(tons/month)	2.28E-04	2.96E-04	3.12E-04	3.82E-04	4.14E-04	5.22E-04	4.73E-04	5.29E-04	5.79E-04	5.67E-04	6.29E-04	6.85E-04	6.58E-04	6.60E-04	6.43E-04	5.81E-04	3.65E-04	3.46E-04	2.76E-04	3.04E-04	2.72E-04	1.21E-04	7.80E-05	6.50E-05
Fugitive - Hauling	(tons/month)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fugitive - Truck	(tons/month)	2.00E-05	8.00E-05	2.60E-04	3.10E-04	5.50E-04	5.60E-04	2.50E-04	2.50E-04	2.70E-04	2.50E-04	2.40E-04	2.90E-04	2.30E-04	1.20E-04	8.00E-05	6.00E-05	6.00E-05	2.00E-05	2.00E-05	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.000
Fugitive - Worker Travel	(tons/month)	0.002	0.003	0.003	0.003	0.003	0.004	0.004	0.005	0.005	0.005	0.006	0.006	0.006	0.006	0.006	0.006	0.004	0.003	0.003	0.003	0.003	0.001	0.001	0.001
Fugitive	Rolling 12-month total (tons/year)												0.17	0.17	0.17	0.17	0.17	0.16	0.14	0.14	0.14	0.14	0.13	0.11	0.10
Fugitive (On-Site Vehicle)	Rolling 12-month total (tons/year)												0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00
Fugitive - Hauling	Rolling 12-month total (tons/year)												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fugitive - Truck	Rolling 12-month total (tons/year)												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fugitive - Worker Travel	Rolling 12-month total (tons/year)												0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.05	0.05	0.04
Off-Road Equipment	(tons/month)	0.009	0.015	0.023	0.025	0.026	0.033	0.030	0.034	0.038	0.035	0.040	0.047	0.045	0.056	0.060	0.044	0.012	0.011	0.007	0.003	0.003	0.000	0.000	0.000
On-site Vehicle	(tons/month)	8.96E-06	1.84E-05	4.20E-05	4.15E-05	6.67E-05	7.12E-05	3.86E-05	3.82E-05	4.21E-05	4.06E-05	4.12E-05	4.66E-05	4.22E-05	3.03E-05	2.59E-05	2.09E-05	1.34E-05	1.05E-05	8.48E-06	8.00E-06	7.00E-06	3.00E-06	2.00E-06	2.00E-06
Hauling Emission	(tons/month)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck Emission	(tons/month)	2.00E-05	7.00E-05	2.30E-04	2.20E-04	3.90E-04	4.00E-04	1.80E-04	1.70E-04	1.90E-04	1.80E-04	1.70E-04	2.00E-04	1.70E-04	9.00E-05	6.00E-05	4.00E-05	3.00E-05	1.00E-05	1.00E-05	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Worker Travel	(tons/month)	6.00E-05	8.00E-05	8.00E-05	9.00E-05	9.00E-05	1.20E-04	1.20E-04	1.30E-04	1.40E-04	1.40E-04	1.60E-04	1.70E-04	1.70E-04	1.70E-04	1.70E-04	1.50E-04	9.00E-05	9.00E-05	7.00E-05	8.00E-05	7.00E-05	3.00E-05	2.00E-05	2.00E-05
Off-Road Equipment	Rolling 12-month total (tons/year)												0.36	0.39	0.43	0.47	0.49	0.47	0.45	0.43	0.40	0.36	0.33	0.29	0.24
Hauling Emission	Rolling 12-month total (tons/year)												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Truck Emission	Rolling 12-month total (tons/year)												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Worker Travel	Rolling 12-month total (tons/year)												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		CO2																							
Off-Road Equipment	(MT/month)	42.51	66.76	105.41	119.47	123.43	152.47	135.25	148.39	165.02	151.71	176.78	207.41	197.98	244.55	267.19	195.84	53.48	47.07	28.69	16.47	15.75	0.00	0.00	0.00
On-site Vehicle	(MT/month)	0.85	1.17	1.44	1.71	2.11	2.49	1.97	2.15	2.35	2.30	2.48	2.74	2.59	2.46	2.35	2.03	1.29	1.19	0.95	1.02	0.92	0.41	0.26	0.22
Hauling Emission	(MT/month)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck Emission	(MT/month)	0.24	0.92	3.01	3.62	6.34	6.45	2.94	2.85	3.09	2.94	2.73	3.32	2.72	1.42	0.95	0.70	0.64	0.24	0.21	0.00	0.00	0.00	0.00	0.00
Worker Travel	(MT/month)	8.18	10.33	9.97	11.77	11.69	15.38	15.30	17.26	18.91	18.60	20.80	22.52	21.89	22.52	22.11	19.28	12.00	11.57	9.20	10.24	9.17	4.07	2.64	2.19
Off-Road Equipment	Rolling 12-month total (MT/year)												1,595	1,750	1,928	2,090	2,166	2,096	1,991	1,884	1,752	1,603	1,451	1,274	1,067
Hauling Emission	Rolling 12-month total (MT/year)												0	0	0	0	0	0	0	0	0	0	0	0	0
Truck Emission	Rolling 12-month total (MT/year)												38	41	41	39	36	31	25	22	19	16	13	10	7
Worker Travel	Rolling 12-month total (MT/year)												181	194	207	219	226	227	223	217	210	200	185	167	147
		CH4																							
Off-Road Equipment	(MT/month)	0.012	0.015	0.026	0.031	0.032	0.038	0.032	0.035	0.039	0.035	0.041	0.050	0.048	0.057	0.063	0.044	0.011	0.009	0.008	0.005	0.005	0.000	0.000	0.000
On-site Vehicle	(MT/month)	4.50E-05	5.85E-05	5.94E-05	6.64E-05	6.94E-05	8.84E-05	8.40E-05	9.40E-05	1.03E-04	1.01E-04	1.13E-04	1.23E-04	1.19E-04	1.20E-04	1.18E-04	9.95E-05	6.10E-05	5.90E-05	4.70E-05	5.20E-05	4.70E-05	2.10E-05	1.30E-05	1.10E-05
Hauling Emission	(MT/month)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck Emission	(MT/month)	0.00E+00	1.00E-05	3.00E-05	3.00E-05	5.00E-05	5.00E-05	2.00E-05	2.00E-05	2.00E-05	2.00E-05	2.00E-05	3.00E-05	2.00E-05	1.00E-05	1.00E-05	1.00E-05	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Worker Travel	(MT/month)	4.50E-04	5.70E-04	5.50E-04	6.20E-04	6.20E-04	8.10E-04	8.10E-04	9.10E-04	1.00E-03	9.80E-04	1.10E-03	1.19E-03	1.16E-03	1.19E-03	1.17E-03	9.80E-04	6.10E-04	5.90E-04	4.70E-04	5.20E-04	4.70E-04	2.10E-04	1.30E-04	1.10E-04
Off-Road Equipment	Rolling 12-month total (MT/year)												0.39	0.42	0.46	0.50	0.51	0.49	0.46	0.44	0.41	0.37	0.34	0.30	0.25
Hauling Emission	Rolling 12-month total (MT/year)												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Truck Emission	Rolling 12-month total (MT/year)												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Worker Travel	Rolling 12-month total (MT/year)												0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
		N2O																							
Off-Road Equipment	(MT/month)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
On-site Vehicle	(MT/month)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hauling Emission	(MT/month)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Truck Emission	(MT/month)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Worker Travel	(MT/month)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Off-Road Equipment	Rolling 12-month total (MT/year)												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Off-Road + On-Site Veh	Rolling 12-month total (MT/year)												0	0	0	0	0	0	0	0	0	0	0	0	0
Hauling Emission	Rolling 12-month total (MT/year)												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Truck Emission	Rolling 12-month total (MT/year)												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Worker Travel	Rolling 12-month total (MT/year)												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		CO2e																							
Off-Road Equipment	(MT/month)	42.77	67.07	105.95	120.11	124.09	153.27	135.93	149.12	165.83	152.44	177.63	208.47	198.99	245.74	268.52	196.76	53.70	47.27	28.85	16.57	15.85	0.00	0.00	0.00
On-site Vehicle	(MT/month)	0.85	1.17	1.44	1.71	2.11	2.49	1.97	2.15	2.35	2.30	2.49	2.75	2.59	2.47	2.35	2.03	1.30	1.19	0.95	1.03	0.92	0.41	0.26	0.22
Off-Road + On-Site Veh	(MT/month)	43.62	68.24	107.40	121.83	126.20	155.76	137.90	151.27	168.18	154.73	180.12	211.21	201.59	248.20	270.87	198.79	55.00	48.46	29.81	17.60	16.77	0.41	0.26	0.22
Hauling Emission	(MT/month)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck Emission	(MT/month)	0.24	0.92	3.01	3.63	6.34	6.45	2.95	2.85	3.09	2.95	2.73	3.32	2.72	1.42	0.95	0.70	0.64	0.24	0.21	0.00	0.00	0.00	0.00	0.00
Worker Travel	(MT/month)	8.19	10.34	9.99	11.78	11.70	15.40	15.32	17.28	18.93	18.62	20.82	22.55	21.92	22.55	22.14	19.30	12.01	11.58	9.21	10.26	9.18	4.08	2.65	2.19
Off-Road Equipment	Rolling 12-month total (MT/year)												1,603	1,759	1,938	2,100	2,177	2,106	2,000	1,893	1,761	1,611	1,458	1,281	1,072
Off-Road + On-Site Veh	Rolling 12-month total (MT/year)												1,626	1,784	1,964	2,128	2,205	2,134	2,026	1,918	1,785	1,633	1,479	1,299	1,088
Hauling Emission	Rolling 12-month total (MT/year)												0	0	0	0	0	0	0	0	0	0	0	0	0
Truck Emission	Rolling 12-month total (MT/year)												38	41	41	39	36	31	25	22	19	16	13	10	7
Worker Travel	Rolling 12-month total (MT/year)												181	195	207	219	227	227	223	217	210	200	186	167	147

TABLE 5.1F-7
Construction of CECP – Summer (Peak) Daily Emissions

Project Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
ROG (lbs/day)																								
Off-Road Equipment	0.95	1.52	2.25	2.82	2.87	3.24	3.13	3.29	3.65	3.47	3.64	4.55	4.55	5.37	5.90	4.29	1.23	0.98	0.72	0.35	0.35	0.00	0.00	0.00
On-site Vehicle	0.04	0.06	0.06	0.08	0.10	0.10	0.09	0.09	0.10	0.10	0.10	0.12	0.12	0.11	0.10	0.08	0.06	0.05	0.04	0.04	0.04	0.02	0.01	0.01
Hauling Emission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck Emission	0.01	0.05	0.14	0.17	0.29	0.27	0.14	0.13	0.14	0.14	0.11	0.15	0.13	0.06	0.04	0.03	0.03	0.01	0.01	0.00	0.00	0.00	0.00	0.00
Worker Travel	0.368	0.4869	0.4293	0.5243	0.5209	0.6257	0.6817	0.7341	0.804	0.8285	0.8459	0.9578	0.9753	0.9578	0.9403	0.7752	0.5306	0.4448	0.4067	0.394	0.3686	0.1716	0.1017	0.0921
NOx (lbs/day)																								
Off-Road Equipment	18.67	30.23	44.58	55.62	56.54	64.31	62.62	66.24	73.51	70.31	73.57	91.45	91.45	107.84	118.13	85.87	24.56	19.49	14.44	6.80	6.80	0.00	0.00	0.00
On-site Vehicle	0.06	0.12	0.24	0.29	0.45	0.44	0.26	0.25	0.28	0.28	0.25	0.31	0.28	0.20	0.17	0.13	0.10	0.06	0.06	0.05	0.04	0.02	0.01	0.01
Hauling Emission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck Emission	0.11	0.44	1.31	1.52	2.65	2.46	1.23	1.14	1.23	1.23	1.04	1.33	1.14	0.57	0.38	0.25	0.25	0.08	0.08	0.00	0.00	0.00	0.00	0.00
Worker Travel	0.43	0.57	0.51	0.62	0.61	0.73	0.80	0.86	0.94	0.97	0.99	1.12	1.14	1.12	1.10	0.91	0.62	0.52	0.48	0.46	0.43	0.20	0.12	0.11
CO (lbs/day)																								
Off-Road Equipment	24.46	38.25	55.66	68.03	68.09	77.63	75.37	80.25	88.82	84.67	88.33	111.79	111.79	132.18	144.91	105.58	32.59	26.49	19.99	8.63	8.63	0.00	0.00	0.00
On-site Vehicle	0.49	0.70	0.77	0.93	1.13	1.23	1.09	1.14	1.24	1.27	1.26	1.46	1.45	1.32	1.27	1.03	0.72	0.58	0.53	0.50	0.47	0.22	0.13	0.12
Hauling Emission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck Emission	0.12	0.49	1.46	1.78	3.11	2.89	1.45	1.33	1.45	1.45	1.22	1.56	1.33	0.67	0.45	0.31	0.31	0.10	0.10	0.00	0.00	0.00	0.00	0.00
Worker Travel	4.75	6.28	5.54	6.71	6.67	8.01	8.72	9.40	10.29	10.60	10.83	12.26	12.48	12.26	12.03	9.87	6.76	5.67	5.18	5.02	4.69	2.19	1.29	1.17
SO2 (lbs/day)																								
Off-Road Equipment	0.04	0.07	0.10	0.12	0.13	0.14	0.14	0.15	0.17	0.16	0.17	0.21	0.21	0.25	0.27	0.20	0.06	0.05	0.03	0.02	0.02	0.00	0.00	0.00
On-site Vehicle	1.03E-03	1.46E-03	1.59E-03	2.12E-03	2.54E-03	2.78E-03	2.49E-03	2.61E-03	2.85E-03	2.93E-03	2.91E-03	3.34E-03	3.32E-03	3.06E-03	2.94E-03	2.65E-03	1.85E-03	1.50E-03	1.37E-03	1.29E-03	1.21E-03	5.62E-04	3.33E-04	3.02E-04
Hauling Emission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck Emission	2.40E-04	9.50E-04	2.86E-03	3.81E-03	6.66E-03	6.19E-03	3.09E-03	2.86E-03	3.09E-03	3.09E-03	2.62E-03	3.33E-03	2.86E-03	1.43E-03	9.50E-04	7.10E-04	7.10E-04	2.40E-04	2.40E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Worker Travel	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.01	0.01	0.01	0.01	0.01	0.00	0.00
PM10 (lbs/day)																								
Fugitive	2.56	2.56	2.56	2.56	2.56	2.56	2.35	2.35	2.35	2.35	2.35	2.35	2.35	2.56	2.76	2.56	0.21	0.21	2.56	2.35	2.35	0.00	0.00	0.00
Fugitive (On-site Vehicle)	0.08	0.11	0.10	0.14	0.15	0.17	0.17	0.18	0.20	0.21	0.21	0.24	0.24	0.23	0.22	0.20	0.14	0.12	0.11	0.10	0.10	0.04	0.03	0.02
Fugitive - Hauling	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fugitive - Truck	0.01	0.03	0.08	0.11	0.19	0.17	0.09	0.08	0.09	0.09	0.07	0.09	0.08	0.04	0.03	0.02	0.02	0.01	0.01	0.00	0.00	0.00	0.00	0.00
Fugitive - Worker Travel	0.79	1.04	0.92	1.23	1.22	1.47	1.60	1.73	1.89	1.95	1.99	2.25	2.29	2.25	2.21	2.00	1.37	1.15	1.05	1.02	0.95	0.44	0.26	0.24
Off-Road Equipment	0.83	1.38	2.00	2.42	2.43	2.84	2.87	3.12	3.45	3.37	3.49	4.29	4.29	5.05	5.47	3.99	1.18	0.93	0.72	0.28	0.28	0.00	0.00	0.00
On-site Vehicle	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hauling Emission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck Emission	0.00	0.01	0.02	0.02	0.04	0.04	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Worker Travel	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00
PM2.5 (lbs/day)																								
Fugitive	1.31	1.31	1.31	1.31	1.31	1.31	1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.31	1.34	1.31	0.02	0.02	1.31	1.29	1.29	0.00	0.00	0.00
Fugitive (On-site Vehicle)	0.02	0.03	0.03	0.04	0.04	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.05	0.04	0.03	0.03	0.03	0.03	0.01	0.01	0.01
Fugitive - Hauling	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fugitive - Truck	0.00	0.01	0.02	0.03	0.05	0.05	0.02	0.02	0.02	0.02	0.02	0.03	0.02	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fugitive - Worker Travel	0.21	0.28	0.24	0.33	0.32	0.39	0.42	0.46	0.50	0.52	0.53	0.60	0.61	0.60	0.59	0.53	0.36	0.31	0.28	0.27	0.25	0.12	0.07	0.06
Off-Road Equipment	0.83	1.38	2.00	2.42	2.43	2.84	2.87	3.12	3.45	3.37	3.49	4.29	4.29	5.05	5.47	3.99	1.18	0.93	0.72	0.28	0.28	0.00	0.00	0.00
On-site Vehicle	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hauling Emission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck Emission	0.00	0.01	0.02	0.02	0.04	0.03	0.02	0.02	0.02	0.02	0.01	0.02	0.02	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Worker Travel	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00

TABLE 5.1F-7 (CONT.)
Construction of CECP – Summer (Peak) Daily Emissions

Project Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	CO2 (lbs/day)																							
Off-Road Equipment	4,260	7,008	10,104	12,542	12,958	14,614	14,199	14,870	16,536	15,927	16,945	20,785	20,785	24,506	26,775	19,625	5,895	4,512	3,162	1,579	1,579	0	0	0
On-site Vehicle	90	129	144	187	228	247	215	225	246	252	249	287	285	259	248	214	150	120	110	104	97	45	27	24
Hauling Emission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck Emission	24	97	290	382	668	620	310	286	310	310	262	334	286	143	95	70	70	23	23	0	0	0	0	0
Worker Travel	864	1,143	1,008	1,303	1,294	1,555	1,694	1,824	1,998	2,058	2,102	2,380	2,423	2,380	2,336	2,037	1,394	1,169	1,069	1,035	969	451	267	242
	CH4 (lbs/day)																							
Off-Road Equipment	1.24	1.56	2.49	3.21	3.30	3.67	3.40	3.48	3.90	3.63	3.89	5.04	5.04	5.67	6.35	4.40	1.19	0.90	0.88	0.47	0.47	0.00	0.00	0.00
On-site Vehicle	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00
Hauling Emission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck Emission	2.10E-04	8.40E-04	2.51E-03	2.95E-03	5.16E-03	4.79E-03	2.40E-03	2.21E-03	2.40E-03	2.40E-03	2.03E-03	2.58E-03	2.21E-03	1.11E-03	7.40E-04	5.20E-04	5.20E-04	1.70E-04	1.70E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Worker Travel	0.05	0.06	0.05	0.07	0.06	0.08	0.08	0.09	0.10	0.10	0.11	0.12	0.12	0.12	0.12	0.10	0.07	0.06	0.05	0.05	0.05	0.02	0.01	0.01
	N2O (lbs/day)																							
Off-Road Equipment	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
On-site Vehicle	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hauling Emission	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Truck Emission	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Worker Travel	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	CO2e (lbs/day)																							
Off-Road Equipment	4,286	7,041	10,156	12,609	13,027	14,691	14,270	14,944	16,618	16,003	17,027	20,891	20,891	24,625	26,908	19,717	5,920	4,531	3,181	1,588	1,588	0	0	0
On-site Vehicle	90	129	144	187	228	247	215	225	246	252	249	288	285	259	248	214	150	120	110	104	97	45	27	24
Hauling Emission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck Emission	24	97	290	382	668	620	310	286	310	310	262	334	286	143	95	70	70	23	23	0	0	0	0	0
Worker Travel	865	1,144	1,009	1,304	1,295	1,556	1,695	1,826	2,000	2,061	2,104	2,382	2,426	2,382	2,339	2,040	1,396	1,170	1,070	1,036	970	451	267	242

TABLE 5.1F-8

Construction of CECP – Winter (Peak) Daily Emissions

Project Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	ROG (lbs/day)																							
Off-Road Equipment	0.95	1.52	2.25	2.82	2.87	3.24	3.13	3.29	3.65	3.47	3.64	4.55	4.55	5.37	5.90	4.29	1.23	0.98	0.72	0.35	0.35	0.00	0.00	0.00
On-site Vehicle	0.04	0.06	0.07	0.08	0.11	0.11	0.10	0.10	0.11	0.11	0.11	0.13	0.12	0.11	0.11	0.09	0.06	0.05	0.04	0.04	0.04	0.02	0.01	0.01
Hauling Emission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck Emission	0.01	0.05	0.16	0.19	0.34	0.31	0.16	0.14	0.16	0.16	0.13	0.17	0.14	0.07	0.05	0.03	0.03	0.01	0.01	0.00	0.00	0.00	0.00	0.00
Worker Travel	0.39	0.52	0.46	0.56	0.55	0.66	0.72	0.78	0.85	0.88	0.90	1.02	1.03	1.02	1.00	0.82	0.56	0.47	0.43	0.42	0.39	0.18	0.11	0.10
	NOx (lbs/day)																							
Off-Road Equipment	18.67	30.23	44.58	55.62	56.54	64.31	62.62	66.24	73.51	70.31	73.57	91.45	91.45	107.84	118.13	85.87	24.56	19.49	14.44	6.80	6.80	0.00	0.00	0.00
On-site Vehicle	0.07	0.13	0.26	0.30	0.47	0.46	0.28	0.27	0.29	0.30	0.27	0.33	0.30	0.21	0.18	0.14	0.11	0.07	0.07	0.05	0.05	0.02	0.01	0.01
Hauling Emission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck Emission	0.11	0.45	1.34	1.55	2.72	2.52	1.26	1.16	1.26	1.26	1.07	1.36	1.16	0.58	0.39	0.26	0.26	0.09	0.09	0.00	0.00	0.00	0.00	0.00
Worker Travel	0.49	0.64	0.57	0.69	0.69	0.82	0.90	0.97	1.06	1.09	1.11	1.26	1.28	1.26	1.24	1.02	0.70	0.59	0.54	0.52	0.49	0.23	0.13	0.12
	CO (lbs/day)																							
Off-Road Equipment	24.46	38.25	55.66	68.03	68.09	77.63	75.37	80.25	88.82	84.67	88.33	111.79	111.79	132.18	144.91	105.58	32.59	26.49	19.99	8.63	8.63	0.00	0.00	0.00
On-site Vehicle	0.49	0.71	0.83	1.01	1.27	1.35	1.14	1.18	1.29	1.32	1.30	1.50	1.48	1.32	1.26	1.02	0.72	0.57	0.52	0.49	0.45	0.21	0.13	0.11
Hauling Emission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck Emission	0.16	0.64	1.93	2.40	4.19	3.89	1.95	1.80	1.95	1.95	1.65	2.10	1.80	0.90	0.60	0.43	0.43	0.14	0.14	0.00	0.00	0.00	0.00	0.00
Worker Travel	4.63	6.13	5.40	6.52	6.48	7.78	8.48	9.13	10.00	10.30	10.52	11.91	12.13	11.91	11.69	9.54	6.53	5.48	5.01	4.85	4.54	2.11	1.25	1.13
	SO2 (lbs/day)																							
Off-Road Equipment	0.04	0.07	0.10	0.12	0.13	0.14	0.14	0.15	0.17	0.16	0.17	0.21	0.21	0.25	0.27	0.20	0.06	0.05	0.03	0.02	0.02	0.00	0.00	0.00
On-site Vehicle	9.74E-04	1.38E-03	1.52E-03	2.03E-03	2.44E-03	2.66E-03	2.37E-03	2.47E-03	2.71E-03	2.78E-03	2.75E-03	3.17E-03	3.15E-03	2.89E-03	2.77E-03	2.49E-03	1.74E-03	1.41E-03	1.29E-03	1.21E-03	1.13E-03	5.28E-04	3.13E-04	2.83E-04
Hauling Emission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck Emission	2.40E-04	9.50E-04	2.85E-03	3.79E-03	6.63E-03	6.16E-03	3.08E-03	2.84E-03	3.08E-03	3.08E-03	2.60E-03	3.31E-03	2.84E-03	1.42E-03	9.50E-04	7.10E-04	7.10E-04	2.40E-04	2.40E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Worker Travel	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.00	0.00
	PM10 (lbs/day)																							
Fugitive	2.56	2.56	2.56	2.56	2.56	2.56	2.35	2.35	2.35	2.35	2.35	2.35	2.35	2.56	2.76	2.56	0.21	0.21	2.56	2.35	2.35	0.00	0.00	0.00
Fugitive (On-site Vehicle)	0.08	0.11	0.10	0.14	0.15	0.17	0.17	0.18	0.20	0.21	0.21	0.24	0.24	0.23	0.22	0.20	0.14	0.12	0.11	0.10	0.10	0.04	0.03	0.02
Fugitive - Hauling	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fugitive - Truck	0.01	0.03	0.08	0.11	0.19	0.17	0.09	0.08	0.09	0.09	0.07	0.09	0.08	0.04	0.03	0.02	0.02	0.01	0.01	0.00	0.00	0.00	0.00	0.00
Fugitive - Worker Travel	0.79	1.04	0.92	1.23	1.22	1.47	1.60	1.73	1.89	1.95	1.99	2.25	2.29	2.25	2.21	2.00	1.37	1.15	1.05	1.02	0.95	0.44	0.26	0.24
Off-Road Equipment	0.83	1.38	2.00	2.42	2.43	2.84	2.87	3.12	3.45	3.37	3.49	4.29	4.29	5.05	5.47	3.99	1.18	0.93	0.72	0.28	0.28	0.00	0.00	0.00
On-site Vehicle	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hauling Emission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck Emission	0.00	0.01	0.02	0.02	0.04	0.04	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Worker Travel	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00
	PM2.5 (lbs/day)																							
Fugitive	1.31	1.31	1.31	1.31	1.31	1.31	1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.31	1.34	1.31	0.02	0.02	1.31	1.29	1.29	0.00	0.00	0.00
Fugitive (On-site Vehicle)	0.02	0.03	0.03	0.04	0.04	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.05	0.04	0.03	0.03	0.03	0.03	0.01	0.01	0.01
Fugitive - Hauling	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fugitive - Truck	1.89E-03	7.57E-03	2.27E-02	3.03E-02	5.30E-02	4.92E-02	2.46E-02	2.27E-02	2.46E-02	2.46E-02	2.08E-02	2.65E-02	2.27E-02	1.14E-02	7.57E-03	5.68E-03	5.68E-03	1.89E-03	1.89E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Fugitive - Worker Travel	0.21	0.28	0.24	0.33	0.32	0.39	0.42	0.46	0.50	0.52	0.53	0.60	0.61	0.60	0.59	0.53	0.36	0.31	0.28	0.27	0.25	0.12	0.07	0.06
Off-Road Equipment	0.83	1.38	2.00	2.42	2.43	2.84	2.87	3.12	3.45	3.37	3.49	4.29	4.29	5.05	5.47	3.99	1.18	0.93	0.72	0.28	0.28	0.00	0.00	0.00
On-site Vehicle	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hauling Emission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck Emission	0.00	0.01	0.02	0.02	0.04	0.03	0.02	0.02	0.02	0.02	0.01	0.02	0.02	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Worker Travel	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00

TABLE 5.1F-8 (CONT.)

Construction of CECP – Winter (Peak) Daily Emissions

Project Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	CO2 (lbs/day)																							
Off-Road Equipment	4,260	7,008	10,104	12,542	12,958	14,614	14,199	14,870	16,536	15,927	16,945	20,785	20,785	24,506	26,775	19,625	5,895	4,512	3,162	1,579	1,579	0	0	0
On-site Vehicle	85	122	137	178	220	237	205	213	233	239	236	273	270	245	233	202	141	113	104	97	91	42	25	23
Hauling Emission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck Emission	24	96	288	379	663	616	308	284	308	308	260	331	284	142	95	70	70	23	23	0	0	0	0	0
Worker Travel	811	1073	947	1224	1215	1460	1591	1713	1876	1933	1974	2235	2276	2235	2194	1913	1310	1098	1004	972	910	423	251	227
	CH4 (lbs/day)																							
Off-Road Equipment	1.24	1.56	2.49	3.21	3.30	3.67	3.40	3.48	3.90	3.63	3.89	5.04	5.04	5.67	6.35	4.40	1.19	0.90	0.88	0.47	0.47	0.00	0.00	0.00
On-site Vehicle	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00
Hauling Emission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck Emission	2.10E-04	8.60E-04	2.57E-03	3.02E-03	5.29E-03	4.91E-03	2.46E-03	2.27E-03	2.46E-03	2.46E-03	2.08E-03	2.65E-03	2.27E-03	1.13E-03	7.60E-04	5.40E-04	5.40E-04	1.80E-04	1.80E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Worker Travel	0.05	0.06	0.05	0.07	0.06	0.08	0.08	0.09	0.10	0.10	0.11	0.12	0.12	0.12	0.12	0.10	0.07	0.06	0.05	0.05	0.05	0.02	0.01	0.01
	N2O (lbs/day)																							
Off-Road Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
On-site Vehicle	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hauling Emission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck Emission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Worker Travel	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	CO2e (lbs/day)																							
Off-Road Equipment	4,286	7,041	10,156	12,609	13,027	14,691	14,270	14,944	16,618	16,003	17,027	20,891	20,891	24,625	26,908	19,717	5,920	4,531	3,181	1,588	1,588	0	0	0
On-site Vehicle	85	122	137	179	220	237	205	214	233	239	236	273	270	245	234	202	141	113	104	97	91	42	25	23
Hauling Emission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck Emission	24	96	288	379	663	616	308	284	308	308	260	332	284	142	95	70	70	23	23	0	0	0	0	0
Worker Travel	812	1,075	948	1,225	1,217	1,462	1,592	1,715	1,878	1,935	1,976	2,237	2,278	2,237	2,197	1,915	1,311	1,099	1,005	973	911	424	251	228

TABLE 5.1F-9

Construction of CECP - CalEEMod Input Data

Project Name	CECP Construction	
District	San Diego County	
Wind Speed	2.6	m/s
Precipitation Frequency	40	days/year
Climate Zone	13	
Urbanization Level	Urban	
Expected Operational Year	2021	
Utility Company	San Diego Gas & Electric	
CO2 Intensity Factor	720.49	
CH4 Intensity Factor	0.029	
N2O Intensity Factor	0.006	

CalEEMod Phase Name	Phase Type	Start Date	End Date	# day/Week	Number of Days	Daily hours	Month
Construction 1	Grading	2015/10/01	2015/10/31	5	22	8	1
Construction 2	Grading	2015/11/01	2015/11/30	5	21	8	2
Construction 3	Grading	2015/12/01	2015/12/31	5	23	8	3
Construction 4	Grading	2016/01/01	2016/01/31	5	21	8	4
Construction 5	Grading	2016/02/01	2016/02/29	5	21	8	5
Construction 6	Grading	2016/03/01	2016/03/31	5	23	8	6
Construction 7	Grading	2016/04/01	2016/04/30	5	21	8	7
Construction 8	Grading	2016/05/01	2016/05/31	5	22	8	8
Construction 9	Grading	2016/06/01	2016/06/30	5	22	8	9
Construction 10	Grading	2016/07/01	2016/07/31	5	21	8	10
Construction 11	Grading	2016/08/01	2016/08/31	5	23	8	11
Construction 12	Grading	2016/09/01	2016/09/30	5	22	8	12
Construction 13	Grading	2016/10/01	2016/10/31	5	21	8	13
Construction 14	Grading	2016/11/01	2016/11/30	5	22	8	14
Construction 15	Grading	2016/12/01	2016/12/31	5	22	8	15
Construction 16	Grading	2017/01/01	2017/01/31	5	22	8	16
Construction 17	Grading	2017/02/01	2017/02/28	5	20	8	17
Construction 18	Grading	2017/03/01	2017/03/31	5	23	8	18
Construction 19	Grading	2017/04/01	2017/04/30	5	20	8	19
Construction 20	Grading	2017/05/01	2017/05/31	5	23	8	20
Construction 21	Grading	2017/06/01	2017/06/30	5	22	8	21
Construction 22	Grading	2017/07/01	2017/07/31	5	21	8	22
Construction 23	Grading	2017/08/01	2017/08/31	5	23	8	23
Construction 24	Grading	2017/09/01	2017/09/30	5	20	8	24

TABLE 5.1F-10

Construction of CECP - CalEEMod Equipment Schedule Input

Project Month			**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
Construction Equipment Usage																										
	CalEEMod Equipment Type	**Rating (hp)**																								
CalEEMod INPUT																										
Air Compressors	Air compressors	78	0	2	2	2	2	4	6	8	9	10	10	10	10	12	12	9	2	1	1	0	0	0	0	0
Cranes, 225 Ton	Cranes	350	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0
Cranes, 150 Ton	Cranes	250	0	0	0	0	2	2	2	2	2	2	2	2	2	3	3	3	0	0	0	0	0	0	0	0
Cranes, 40 Ton and 20 Ton	Cranes	185	0	1	2	2	2	2	2	2	3	3	3	6	6	6	6	3	1	1	0	0	0	0	0	0
Light Towers	Dumpers/Tenders	15.5	3	3	3	3	3	3	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Excavator, Backhoe	Excavator	84	1	1	2	2	2	2	2	2	2	2	2	3	3	3	3	2	1	1	1	0	0	0	0	0
Excavator, Motor Grader	Graders	150	1	1	1	1	1	1	0	0	0	0	0	0	0	1	2	1	1	1	1	0	0	0	0	0
Water Trucks	Off-Highway Trucks	500	0	0	0	1	1	1	1	1	1	1	1	1	1	1	2	1	0	0	0	0	0	0	0	0
Trucks, Fuel/Lube	Off-Highway Trucks	210	0	0	0	1	1	1	1	1	2	2	3	4	4	4	4	3	1	0	0	0	0	0	0	0
Trucks, Large	Off-Highway Trucks	180	1	1	3	3	3	3	2	2	2	2	2	2	2	1	1	1	0	0	0	0	0	0	0	0
Paving Equipment	Paving Equipment	120	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	2	2	1	0	0	0	0	0
Compactors	Paving Equipment	145	1	1	1	1	1	1	1	1	1	1	1	3	3	3	3	2	1	1	1	1	1	0	0	0
Truck, Concrete Pump	Pumps	190	0	1	1	1	1	1	1	1	1	1	1	1	1	2	2	2	1	1	0	0	0	0	0	0
Dozer	Rubber Tired Dozer	285	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	1	1	1	0	0	0
Dozer	Rubber Tired Dozer	265	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0
Excavator, Loader	Rubber Tired Loader	200	1	1	2	2	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Excavator, Loader	Rubber Tired Loader	140	1	1	2	2	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Excavator, Loader	Rubber Tired Loader	150	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	0	0	0	0	0	0	0	0	0
Welders	Welders	23	0	1	1	2	4	4	4	5	6	7	10	10	10	10	10	10	5	2	1	1	1	0	0	0

Notes:

CalEEMod default values for usage load factors are used.

No default CalEEMod equipment type for light towers; equipment type that matches the closest in horsepower (dumper/tenders) was chosen to represent light towers, per CalEEMod User Guide Section 4.3.2.

TABLE 5.1F-11

Construction of CECP - CalEEMod Vehicle Trips Input

Project Month	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
No of Days	22	21	23	21	21	23	21	22	22	21	23	22	21	22	22	22	20	23	20	23	22	21	23	20
Construction																								
Workers																								
Plant																								
Insulation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7	9	11	11	11	18	14	0	0	0
Boiler Makers	0	0	3	3	5	10	12	12	19	19	17	19	19	22	19	14	6	6	6	6	6	11	0	0
Masons	0	0	0	2	4	4	4	4	3	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0
Carpenters	3	3	15	25	18	26	26	26	26	26	26	15	15	21	20	11	10	9	7	5	5	2	1	0
Electricians	3	3	5	7	8	10	14	20	24	24	24	25	25	35	35	35	18	15	11	7	7	5	5	5
Ironworkers	0	0	4	9	6	7	13	16	16	22	20	20	20	27	29	31	14	11	10	9	9	3	0	0
Laborers	22	34	34	38	38	38	38	38	38	38	36	28	25	34	25	25	14	13	13	15	15	3	2	2
Millwrights	0	0	0	0	0	0	6	6	7	7	7	11	11	14	13	10	9	8	8	8	8	1	1	1
Operating Engineers	24	30	0	3	6	9	7	9	10	10	12	12	12	13	15	16	9	8	7	7	7	1	1	0
Plasterers	0	0	0	0	0	0	0	0	1	2	2	2	3	4	4	2	2	1	0	0	0	0	0	0
Painters	0	0	0	0	0	0	0	1	1	2	2	4	3	4	4	4	4	4	3	3	2	2	0	0
Pipefitters	3	5	10	10	12	20	30	30	34	34	34	32	34	36	36	36	25	20	20	16	14	4	4	4
Sheetmetal Workers	0	0	0	0	0	2	4	7	7	8	8	9	10	11	11	8	6	5	3	3	3	1	0	0
Sprinkler Fitters	0	0	0	0	0	0	1	1	1	1	3	4	7	7	7	5	5	4	4	3	3	0	0	0
Teamsters	24	27	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1	1	1	0
Surveyors	3	5	5	5	4	5	4	4	3	3	3	3	3	3	3	2	2	2	2	1	1	2	0	0
Manual Staff Subtotal	**82**	**107**	**78**	**104**	**103**	**133**	**161**	**176**	**192**	**199**	**197**	**187**	**190**	**234**	**231**	**210**	**137**	**119**	**107**	**103**	**95**	**36**	**15**	**12**
Other Plant Staff	14	20	34	46	46	46	34	34	38	38	45	44	46	40	38	34	30	21	21	21	21	18	17	17
Plant Total	**96**	**127**	**112**	**150**	**149**	**179**	**195**	**210**	**230**	**237**	**242**	**231**	**236**	**274**	**269**	**244**	**167**	**140**	**128**	**124**	**116**	**54**	**32**	**29**
Linear Construction																								
Laborers												18	21											
Operating Engineers												9	7											
Pipefitters												7	7											
Teamsters												5	4											
Manual Staff Subtotal												**39**	**39**											
Linear Construction Staff												4	4											
Linear Construction Total												**43**	**43**											
Total Construction Staff	**96**	**127**	**112**	**150**	**149**	**179**	**195**	**210**	**230**	**237**	**242**	**274**	**279**	**274**	**269**	**244**	**167**	**140**	**128**	**124**	**116**	**54**	**32**	**29**
Worker Travel (trips/day)	**96**	**127**	**112**	**150**	**149**	**179**	**195**	**210**	**230**	**237**	**242**	**274**	**279**	**274**	**269**	**244**	**167**	**140**	**128**	**124**	**116**	**54**	**32**	**29**

TABLE 5.1F-11 (CONT.)

Construction of CECP - CalEEMod Vehicle Trips Input

Project Month	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
No of Days	22	21	23	21	21	23	21	22	22	21	23	22	21	22	22	22	20	23	20	23	22	21	23	20
Construction Schedule for Truck Deliveries of Equipment																								
Generating Facility																								
Combustion Turbine/Generator							5	13	25	32	34	29	19	10	10									
Mechanical Equipment			5	5	16	16	32	32	54	54	53	53	32	26	13	5	3							
Electrical Equipment and Materials		3	3	8	8	11	16	16	32	32	32	43	37	27	16	16	5	5						
Piping, Supports & Valves		3	4	8	14	27	43	43	53	54	64	53	32	26	16	5	5							
Concrete and Rebar		50	197	245	484	484	105	87	43	17	9													
Miscellaneous Steel/Architectural				5	5	16	27	32	32	26	10	5												
Consumables/Supplies	14	16	35	38	43	43	43	43	43	46	46	46	46	37	37	27	27	10	10	3				
Contractor Mobilization & Demobilization	11	11	16	10	5										3	10	16	10	10	3				
Construction Equipment	5	5	11	8	8	5	5	5	4	4	2	2	1	1	3	3	5	3	3					
Miscellaneous																					3	3	3	3
Subtotal	**30**	**88**	**271**	**327**	**583**	**602**	**276**	**271**	**286**	**265**	**250**	**231**	**167**	**127**	**98**	**66**	**61**	**28**	**23**	**6**	**3**	**3**	**3**	**3**
Project Linears																								
Electrical Equipment and Materials												6	6											
Piping, Supports & Valves												18	18											
Concrete and Rebar												20	23											
Miscellaneous Steel/Architectural												2	4											
Consumables/Supplies												18	18											
Construction Equipment												13	13											
Subtotal												**77**	**82**											
Truck Travel Total	**30**	**88**	**271**	**327**	**583**	**602**	**276**	**271**	**286**	**265**	**250**	**308**	**249**	**127**	**98**	**66**	**61**	**28**	**23**	**6**	**3**	**3**	**3**	**3**
Truck Travel (Average Daily)	**1**	**4**	**12**	**16**	**28**	**26**	**13**	**12**	**13**	**13**	**11**	**14**	**12**	**6**	**4**	**3**	**3**	**1**	**1**	**0**	**0**	**0**	**0**	**0**

TABLE 5.1F-12
Demolition of Existing Encina Power Station - Daily and Annual Construction Emissions

Daily Construction Emissions (peak month) (lbs/day)						
	NOx	**CO**	**VOC**	**SOx**	**PM_{10}**	**$PM_{2.5}$**
Onsite						
Off-Road Equipment (combustion)	53.01	89.66	2.20	0.14	0.22	0.22
Off-Road Equipment and On-Site Vehicle (combustion)	53.20	90.19	2.24	0.14	0.22	0.22
Construction - Fugitive Dust					0.47	0.07
On-site Vehicle - Fugitive Dust					0.18	0.05
Subtotal (Fugitive Dust)					0.65	0.12
Subtotal (On-site)	53.20	90.19	2.24	0.14	0.87	0.34
Offsite						
Worker Travel (combustion)	0.74	7.13	0.59	0.02	0.01	0.01
Truck Emissions (combustion)	0.08	0.14	0.01	0.00	0.00	0.00
Hauling Emissions (combustion)	4.28	4.44	0.36	0.01	0.06	0.06
Worker Travel - Fugitive Dust					1.59	0.42
Truck - Fugitive Dust					0.01	0.00
Hauling - Fugitive Dust					0.32	0.09
Subtotal (Offsite)	5.10	11.70	0.96	0.03	1.99	0.58
Total	58.30	101.89	3.21	0.17	2.86	0.92

Peak Construction Emissions (tons/yr, rolling 12-month maximum)						
	NOx	**CO**	**VOC**	**SOx**	**PM_{10}**	**$PM_{2.5}$**
Onsite						
Off-Road Equipment (combustion)	4.20	7.10	0.18	0.01	0.02	0.02
Off-Road Equipment and Vehicle (combustion)	4.21	7.15	0.19	0.01	0.02	0.02
Construction - Fugitive Dust					0.06	0.01
On-site Vehicle - Fugitive Dust					0.01	0.00
Subtotal (Fugitive Dust)					0.07	0.01
Subtotal (On-site)	4.21	7.15	0.19	0.01	0.09	0.03
Offsite						
Worker Travel (combustion)	0.05	0.47	0.04	0.00	0.00	0.00
Truck Emissions (combustion)	0.01	0.02	0.001	0.00	0.00	0.00
Hauling Emissions (combustion)	0.24	0.24	0.02	0.00	0.00	0.00
Worker Travel - Fugitive Dust					0.11	0.03
Truck - Fugitive Dust					0.00	0.00
Hauling - Fugitive Dust					0.02	0.01
Subtotal (Offsite)	0.30	0.72	0.06	0.00	0.13	0.04
Total	4.51	7.87	0.24	0.01	0.22	0.07

TABLE 5.1F-13

Demolition of Existing Encina Power Station - Modeled Emissions, Short-Term Impacts

Short Term Impacts (24 hours and less)					
Daily working hours (hrs/day)	8				
	NOx	**CO**	**SOx**	**PM_{10}**	**$PM_{2.5}$**
TOTAL					
Off Road Equipment and On-site Vehicle (Combustion) (lbs/day)	53.20	90.19	0.14	0.22	0.22
Off Road Equipment and On-site Vehicle (Combustion) (lbs/hr)	6.65	11.27	0.02	0.03	0.03
Off Road Equipment and On-site Vehicle (Combustion) (g/sec)	0.84	1.42	0.002	0.00	0.00
Construction and On-site Vehicle (Fugitive Dust) (lbs/day)				0.65	0.12
Construction and On-site Vehicle (Fugitive Dust) (lbs/hr)				0.08	0.01
Construction and On-site Vehicle (Fugitive Dust) (g/sec)				0.01	0.00

TABLE 5.1F-14

Demolition of Existing Encina Power Station - Modeled Emissions, Long-Term Impacts

Long Term Impacts (annual)					
Annual Number of Work Days, Rolling 12-month period (days/yr)	261				
Daily working hours (hrs/day)	8				
	NOx	**CO**	**SOx**	**PM_{10}**	**$PM_{2.5}$**
TOTAL					
Off Road Equipment and On-site Vehicle (Combustion) (lbs/day)	4.21	7.15	0.01	0.02	0.02
Off Road Equipment and On-site Vehicle (Combustion) (lbs/hr)	4.04	6.85	0.01	0.02	0.02
Off Road Equipment and On-site Vehicle (Combustion) (g/sec)	0.51	0.86	0.001	0.002	0.002
Construction and On-site Vehicle (Fugitive Dust) (tons/yr)				0.07	0.01
Construction and On-site Vehicle (Fugitive Dust) (lbs/hr)				0.07	0.01
Construction and On-site Vehicle (Fugitive Dust) (g/sec)				0.01	0.00

TABLE 5.1F-15

Demolition of Existing Encina Power Station - Greenhouse Gas Emission Calculations

	GHG Emissions (MT, Total for 22-month Construction Period)			
	CO2	**CH4**	**N2O**	**CO2e**
Off-Road Equipment	1360.73	0.40	0.00	1369.13
Off-Road Equipment and On-site Vehicle	1376.66	0.40	0.00	1385.07
Worker Travel	109.78	0.01	0.00	109.89
Truck Emissions	4.04	0.00	0.00	4.04
Hauling Emissions	80.62	0.00	0.00	80.63
Total	1571.09	0.41	0.00	1579.62

TABLE 5.1F-16

Demolition of Existing Encina Power Station - Monthly and Annual Emission Calculations

Project Month		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
		ROG																					
Off-Road Equipment	(tons/month)	5.45E-03	5.97E-03	8.53E-03	1.00E-02	9.43E-03	1.33E-02	1.97E-02	2.26E-02	2.31E-02	1.52E-02	1.32E-02	1.39E-02	1.56E-02	1.15E-02	9.95E-03	1.15E-02	1.24E-02	5.97E-03	6.54E-03	6.18E-03	6.48E-03	6.77E-03
On-site Vehicle	(tons/month)	7.98E-05	9.53E-05	2.17E-04	4.51E-04	6.41E-04	7.51E-04	7.63E-04	5.65E-04	4.39E-04	2.71E-04	2.01E-04	1.60E-04	1.27E-04	2.30E-04	2.21E-04	2.38E-04	1.78E-04	1.01E-04	6.94E-05	4.70E-05	4.90E-05	4.80E-05
Hauling Emission	(tons/month)	0.00E+00	4.50E-04	5.10E-04	8.70E-04	8.10E-04	3.49E-03	3.06E-03	3.14E-03	2.25E-03	5.40E-04	1.80E-04	4.50E-04	4.00E-05	1.22E-03	2.20E-03	2.22E-03	1.20E-03	2.70E-04	4.00E-05	0.00E+00	0.00E+00	0.00E+00
Truck Emission	(tons/month)	1.00E-04	0.00E+00	1.00E-04	1.10E-04	1.10E-04	1.00E-04	1.10E-04	1.10E-04	1.00E-04	1.10E-04	9.00E-05	1.00E-04	1.00E-04	1.10E-04	9.00E-05	1.10E-04	1.00E-04	1.00E-04	1.10E-04	0.00E+00	0.00E+00	0.00E+00
Worker Travel	(tons/month)	6.50E-04	7.10E-04	1.75E-03	3.88E-03	5.81E-03	5.48E-03	5.81E-03	3.79E-03	3.03E-03	2.26E-03	1.78E-03	1.21E-03	1.10E-03	1.48E-03	8.90E-04	1.02E-03	9.80E-04	7.20E-04	5.10E-04	4.70E-04	4.90E-04	4.80E-04
Off-Road Equipment	Rolling 12-month total (tons/year)												0.16	0.17	0.18	0.18	0.18	0.18	0.17	0.16	0.15	0.13	0.12
Hauling Emission	Rolling 12-month total (tons/year)												0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01
Truck Emission	Rolling 12-month total (tons/year)												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Worker Travel	Rolling 12-month total (tons/year)												0.04	0.04	0.04	0.04	0.03	0.03	0.02	0.02	0.02	0.01	0.01
		NOx																					
Off-Road Equipment	(tons/month)	0.11	0.12	0.18	0.21	0.20	0.30	0.46	0.53	0.56	0.31	0.27	0.28	0.31	0.29	0.25	0.29	0.33	0.14	0.15	0.13	0.13	0.14
On-site Vehicle	(tons/month)	2.10E-04	3.98E-04	6.97E-04	1.23E-03	1.45E-03	3.17E-03	2.94E-03	2.72E-03	2.03E-03	7.62E-04	4.58E-04	5.59E-04	2.85E-04	1.09E-03	1.62E-03	1.67E-03	1.01E-03	3.79E-04	2.14E-04	6.20E-05	6.50E-05	6.30E-05
Hauling Emission	(tons/month)	0	0.00561	0.00631	0.0108	0.0101	0.043	0.0377	0.0387	0.0278	0.0063	0.00214	0.00534	0.00043	0.0143	0.0258	0.0261	0.0141	0.0032	0.00043	0	0	0
Truck Emission	(tons/month)	0.001	0.000	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.000	0.000	0.000
Worker Travel	(tons/month)	0.001	0.001	0.002	0.005	0.008	0.007	0.008	0.005	0.004	0.003	0.002	0.002	0.001	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
Off-Road Equipment	Rolling 12-month total (tons/year)												3.54	3.74	3.91	3.99	4.07	4.20	4.03	3.71	3.30	2.88	2.71
Hauling Emission	Rolling 12-month total (tons/year)												0.19	0.19	0.20	0.22	0.24	0.24	0.20	0.16	0.13	0.10	0.09
Truck Emission	Rolling 12-month total (tons/year)												0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Worker Travel	Rolling 12-month total (tons/year)												0.05	0.05	0.05	0.05	0.04	0.04	0.03	0.02	0.02	0.02	0.01
		CO																					
Off-Road Equipment	(tons/month)	0.197	0.216	0.294	0.341	0.322	0.502	0.784	0.915	0.941	0.535	0.466	0.489	0.545	0.479	0.417	0.479	0.547	0.238	0.261	0.222	0.232	0.243
On-site Vehicle	(tons/month)	0.001	0.001	0.003	0.006	0.008	0.009	0.009	0.007	0.005	0.003	0.002	0.002	0.002	0.003	0.003	0.003	0.002	0.001	0.001	0.001	0.001	0.001
Hauling Emission	(tons/month)	0.000	0.005	0.006	0.010	0.010	0.041	0.036	0.037	0.027	0.006	0.002	0.005	0.000	0.015	0.026	0.026	0.014	0.003	0.000	0.000	0.000	0.000
Truck Emission	(tons/month)	0.001	0.000	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.000	0.000	0.000
Worker Travel	(tons/month)	0.008	0.009	0.022	0.048	0.073	0.068	0.073	0.047	0.038	0.028	0.022	0.015	0.014	0.018	0.011	0.013	0.012	0.009	0.006	0.006	0.006	0.006
Off-Road Equipment	Rolling 12-month total (tons/year)												6.00	6.35	6.61	6.74	6.87	7.10	6.84	6.31	5.62	4.91	4.62
Hauling Emission	Rolling 12-month total (tons/year)												0.19	0.19	0.20	0.22	0.23	0.24	0.20	0.16	0.13	0.10	0.09
Truck Emission	Rolling 12-month total (tons/year)												0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.01
Worker Travel	Rolling 12-month total (tons/year)												0.45	0.46	0.47	0.45	0.42	0.36	0.30	0.23	0.19	0.16	0.14
		SO2																					
Off-Road Equipment	(tons/month)	3.00E-04	3.30E-04	4.50E-04	5.30E-04	4.90E-04	7.70E-04	1.21E-03	1.42E-03	1.45E-03	8.90E-04	7.70E-04	8.10E-04	9.10E-04	7.40E-04	6.90E-04	7.90E-04	8.70E-04	3.70E-04	4.10E-04	3.30E-04	3.50E-04	3.70E-04
On-site Vehicle	(tons/month)	2.00E-06	3.08E-06	7.08E-06	1.56E-05	2.16E-05	2.66E-05	2.65E-05	1.95E-05	1.59E-05	1.01E-05	7.54E-06	6.08E-06	4.00E-06	8.70E-06	7.86E-06	8.86E-06	6.70E-06	3.54E-06	2.00E-06	2.00E-06	2.00E-06	2.00E-06
Hauling Emission	(tons/month)	0.00E+00	2.00E-05	2.00E-05	3.00E-05	3.00E-05	1.40E-04	1.20E-04	1.20E-04	9.00E-05	2.00E-05	1.00E-05	2.00E-05	0.00E+00	5.00E-05	9.00E-05	9.00E-05	5.00E-05	1.00E-05	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Truck Emission	(tons/month)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Worker Travel	(tons/month)	2.00E-05	2.00E-05	6.00E-05	1.40E-04	2.00E-04	1.90E-04	2.00E-04	1.30E-04	1.10E-04	9.00E-05	7.00E-05	5.00E-05	4.00E-05	6.00E-05	3.00E-05	4.00E-05	4.00E-05	3.00E-05	2.00E-05	2.00E-05	2.00E-05	2.00E-05
Off-Road Equipment	Rolling 12-month total (tons/year)												0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Hauling Emission	Rolling 12-month total (tons/year)												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Truck Emission	Rolling 12-month total (tons/year)												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Worker Travel	Rolling 12-month total (tons/year)												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		PM10																					
Fugitive	(tons/month)	4.7E-03	4.7E-03	4.7E-03	4.7E-03	4.7E-03	4.7E-03	4.74E-03	4.74E-03	4.74E-03	4.74E-03	4.74E-03	4.74E-03	4.74E-03	4.74E-03	4.74E-03	4.74E-03	4.74E-03	4.74E-03	4.74E-03	4.74E-03	4.74E-03	4.74E-03
Fugitive (On-site Vehicle)	(tons/month)	2.0E-04	2.3E-04	5.3E-04	1.2E-03	1.7E-03	1.7E-03	1.8E-03	1.2E-03	9.8E-04	7.3E-04	5.6E-04	4.0E-04	3.5E-04	5.2E-04	3.9E-04	4.4E-04	3.7E-04	2.4E-04	1.7E-04	1.4E-04	1.5E-04	1.6E-04
Fugitive - Hauling	(tons/month)	0.00E+00	4.10E-04	4.60E-04	7.80E-04	7.30E-04	3.14E-03	2.76E-03	2.82E-03	2.03E-03	5.00E-04	1.70E-04	4.30E-04	3.00E-05	1.14E-03	2.06E-03	2.08E-03	1.13E-03	2.60E-04	3.00E-05	0.00E+00	0.00E+00	0.00E+00
Fugitive - Truck	(tons/month)	7.00E-05	0.00E+00	7.00E-05	7.00E-05	7.00E-05	7.00E-05	7.00E-05	7.00E-05	7.00E-05	7.00E-05	7.00E-05	7.00E-05	7.00E-05	7.00E-05	7.00E-05	7.00E-05	7.00E-05	7.00E-05	7.00E-05	0.00E+00	0.00E+00	0.00E+00
Fugitive - Worker Travel	(tons/month)	1.85E-03	2.03E-03	4.97E-03	1.10E-02	1.65E-02	1.56E-02	1.65E-02	1.08E-02	8.59E-03	6.92E-03	5.45E-03	3.70E-03	3.35E-03	4.52E-03	2.73E-03	3.14E-03	3.00E-03	2.19E-03	1.57E-03	1.43E-03	1.50E-03	1.57E-03
Fugitive	Rolling 12-month total (tons/year)												0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Fugitive (On-Site Vehicle)	Rolling 12-month total (tons/year)												0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00
Fugitive - Hauling	Rolling 12-month total (tons/year)												0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01
Fugitive - Truck	Rolling 12-month total (tons/year)												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fugitive - Worker Travel	Rolling 12-month total (tons/year)												0.10	0.11	0.11	0.11	0.10	0.08	0.07	0.06	0.05	0.04	0.03
Off-Road Equipment	(tons/month)	0.000	0.001	0.001	0.001	0.001	0.001	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
On-site Vehicle	(tons/month)	2.48E-06	5.32E-06	1.03E-05	1.76E-05	2.10E-05	4.54E-05	4.26E-05	3.92E-05	2.91E-05	1.19E-05	7.10E-06	8.80E-06	4.02E-06	1.64E-05	2.51E-05	2.51E-05	1.54E-05	6.18E-06	3.02E-06	1.00E-06	1.00E-06	1.00E-06
Hauling Emission	(tons/month)	0.00E+00	8.00E-05	9.00E-05	1.50E-04	1.40E-04	6.10E-04	5.40E-04	5.50E-04	4.00E-04	1.00E-04	3.00E-05	8.00E-05	1.00E-05	2.20E-04	4.00E-04	4.00E-04	2.20E-04	5.00E-05	1.00E-05	0.00E+00	0.00E+00	0.00E+00
Truck Emission	(tons/month)	1.00E-05	0.00E+00	1.00E-05	1.00E-05	1.00E-05	1.00E-05	1.00E-05	1.00E-05	1.00E-05	1.00E-05	1.00E-05	1.00E-05	1.00E-05	1.00E-05	1.00E-05	1.00E-05	1.00E-05	1.00E-05	1.00E-05	0.00E+00	0.00E+00	0.00E+00
Worker Travel	(tons/month)	1.00E-05	1.00E-05	4.00E-05	8.00E-05	1.20E-04	1.10E-04	1.20E-04	8.00E-05	6.00E-05	5.00E-05	4.00E-05	3.00E-05	2.00E-05	3.00E-05	2.00E-05	2.00E-05	2.00E-05	2.00E-05	1.00E-05	1.00E-05	1.00E-05	1.00E-05
Off-Road Equipment	Rolling 12-month total (tons/year)												0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.01
Hauling Emission	Rolling 12-month total (tons/year)												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Truck Emission	Rolling 12-month total (tons/year)												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Worker Travel	Rolling 12-month total (tons/year)												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

TABLE 5.1F-16 (CONT.)

Demolition of Existing Encina Power Station - Monthly and Annual Emission Calculations

Project Month		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
													PM2.5										
Fugitive	(tons/month)	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
Fugitive (On-site Vehicle)	(tons/month)	5.20E-05	5.99E-05	1.42E-04	3.08E-04	4.53E-04	4.62E-04	4.83E-04	3.31E-04	2.61E-04	1.95E-04	1.51E-04	1.07E-04	9.25E-05	1.40E-04	1.06E-04	1.17E-04	9.97E-05	6.47E-05	4.55E-05	3.80E-05	4.00E-05	4.20E-05
Fugitive - Hauling	(tons/month)	0.00E+00	1.10E-04	1.30E-04	2.20E-04	2.00E-04	8.60E-04	7.60E-04	7.70E-04	5.60E-04	1.40E-04	5.00E-05	1.20E-04	1.00E-05	3.10E-04	5.70E-04	5.70E-04	3.10E-04	7.00E-05	1.00E-05	0.00E+00	0.00E+00	0.00E+00
Fugitive - Truck	(tons/month)	2.00E-05	0.00E+00	2.00E-05	2.00E-05	2.00E-05	2.00E-05	2.00E-05	2.00E-05	2.00E-05	2.00E-05	2.00E-05	2.00E-05	2.00E-05	2.00E-05	2.00E-05	2.00E-05	2.00E-05	2.00E-05	2.00E-05	0.00E+00	0.00E+00	0.00E+00
Fugitive - Worker Travel	(tons/month)	4.90E-04	5.40E-04	1.32E-03	2.93E-03	4.39E-03	4.13E-03	4.39E-03	2.86E-03	2.28E-03	1.84E-03	1.45E-03	9.80E-04	8.90E-04	1.20E-03	7.20E-04	8.30E-04	8.00E-04	5.80E-04	4.20E-04	3.80E-04	4.00E-04	4.20E-04
Fugitive	Rolling 12-month total (tons/year)												0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Fugitive (On-Site Vehicle)	Rolling 12-month total (tons/year)												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fugitive - Hauling	Rolling 12-month total (tons/year)												0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00
Fugitive - Truck	Rolling 12-month total (tons/year)												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fugitive - Worker Travel	Rolling 12-month total (tons/year)												0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.01	0.01	0.01	0.01
Off-Road Equipment	(tons/month)	0.000	0.001	0.001	0.001	0.001	0.001	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
On-site Vehicle	(tons/month)	2.48E-06	4.78E-06	8.80E-06	1.60E-05	1.95E-05	4.27E-05	3.89E-05	3.60E-05	2.69E-05	1.13E-05	7.10E-06	7.80E-06	4.02E-06	1.53E-05	2.29E-05	2.35E-05	1.43E-05	5.18E-06	3.02E-06	1.00E-06	1.00E-06	1.00E-06
Hauling Emission	(tons/month)	0.00E+00	7.00E-05	8.00E-05	1.40E-04	1.30E-04	5.60E-04	4.90E-04	5.10E-04	3.60E-04	9.00E-05	3.00E-05	8.00E-05	1.00E-05	2.00E-04	3.60E-04	3.70E-04	2.00E-04	5.00E-05	1.00E-05	0.00E+00	0.00E+00	0.00E+00
Truck Emission	(tons/month)	1.00E-05	0.00E+00	1.00E-05	1.00E-05	1.00E-05	1.00E-05	1.00E-05	1.00E-05	1.00E-05	1.00E-05	1.00E-05	1.00E-05	1.00E-05	1.00E-05	1.00E-05	1.00E-05	1.00E-05	1.00E-05	1.00E-05	0.00E+00	0.00E+00	0.00E+00
Worker Travel	(tons/month)	1.00E-05	1.00E-05	3.00E-05	7.00E-05	1.10E-04	1.10E-04	1.10E-04	7.00E-05	6.00E-05	5.00E-05	4.00E-05	2.00E-05	2.00E-05	3.00E-05	2.00E-05	2.00E-05	2.00E-05	1.00E-05	1.00E-05	1.00E-05	1.00E-05	1.00E-05
Off-Road Equipment	Rolling 12-month total (tons/year)												0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.01
Hauling Emission	Rolling 12-month total (tons/year)												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Truck Emission	Rolling 12-month total (tons/year)												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Worker Travel	Rolling 12-month total (tons/year)												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
													CO2										
Off-Road Equipment	(MT/month)	27.53	30.16	40.74	47.99	44.24	69.79	109.42	129.11	130.94	78.75	68.48	71.90	80.90	64.71	59.59	68.53	76.01	32.62	35.73	30.01	31.44	32.15
On-site Vehicle	(MT/month)	0.19	0.26	0.56	1.15	1.61	2.03	2.03	1.55	1.20	0.71	0.52	0.43	0.32	0.65	0.68	0.72	0.51	0.27	0.17	0.12	0.12	0.13
Hauling Emission	(MT/month)	0.00	1.58	1.78	3.04	2.84	12.14	10.66	10.92	7.85	1.91	0.65	1.62	0.13	4.35	7.85	7.91	4.28	0.97	0.13	0.00	0.00	0.00
Truck Emission	(MT/month)	0.22	0.00	0.22	0.23	0.24	0.21	0.24	0.23	0.22	0.24	0.20	0.22	0.23	0.24	0.20	0.24	0.23	0.22	0.24	0.00	0.00	0.00
Worker Travel	(MT/month)	1.60	1.75	4.28	9.51	14.23	13.41	14.23	9.28	7.41	5.75	4.53	3.08	2.79	3.76	2.27	2.61	2.49	1.82	1.30	1.19	1.25	1.25
Off-Road Equipment	Rolling 12-month total (MT/year)												849	902	937	956	976	1,008	971	897	798	699	652
Hauling Emission	Rolling 12-month total (MT/year)												55	55	58	64	69	70	59	49	38	30	28
Truck Emission	Rolling 12-month total (MT/year)												2	2	3	3	3	3	3	3	2	2	2
Worker Travel	Rolling 12-month total (MT/year)												89	90	92	90	83	72	60	47	39	33	28
													CH4										
Off-Road Equipment	(MT/month)	0.009	0.009	0.013	0.015	0.014	0.021	0.033	0.040	0.040	0.023	0.020	0.021	0.024	0.018	0.016	0.018	0.021	0.008	0.009	0.010	0.010	0.010
On-site Vehicle	(MT/month)	8.00E-06	9.54E-06	2.15E-05	4.81E-05	7.11E-05	7.09E-05	7.43E-05	5.03E-05	3.92E-05	2.85E-05	2.20E-05	1.55E-05	1.30E-05	1.96E-05	1.42E-05	1.52E-05	1.36E-05	9.54E-06	6.00E-06	6.00E-06	6.00E-06	6.00E-06
Hauling Emission	(MT/month)	0.00E+00	1.00E-05	1.00E-05	2.00E-05	2.00E-05	9.00E-05	8.00E-05	8.00E-05	6.00E-05	1.00E-05	0.00E+00	1.00E-05	0.00E+00	3.00E-05	6.00E-05	6.00E-05	3.00E-05	1.00E-05	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Truck Emission	(MT/month)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Worker Travel	(MT/month)	8.00E-05	9.00E-05	2.10E-04	4.70E-04	7.00E-04	6.60E-04	7.00E-04	4.60E-04	3.60E-04	2.80E-04	2.20E-04	1.50E-04	1.30E-04	1.80E-04	1.10E-04	1.20E-04	1.20E-04	9.00E-05	6.00E-05	6.00E-05	6.00E-05	6.00E-05
Off-Road Equipment	Rolling 12-month total (MT/year)												0.26	0.27	0.28	0.28	0.29	0.29	0.28	0.26	0.23	0.20	0.18
Hauling Emission	Rolling 12-month total (MT/year)												3.90E-04	3.90E-04	4.10E-04	4.60E-04	5.00E-04	5.10E-04	4.30E-04	3.50E-04	2.70E-04	2.10E-04	2.00E-04
Truck Emission	Rolling 12-month total (MT/year)												0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Worker Travel	Rolling 12-month total (MT/year)												4.38E-03	4.43E-03	4.52E-03	4.42E-03	4.07E-03	3.49E-03	2.92E-03	2.28E-03	1.88E-03	1.58E-03	1.36E-03
													N2O										
Off-Road Equipment	(MT/month)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
On-site Vehicle	(MT/month)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hauling Emission	(MT/month)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Truck Emission	(MT/month)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Worker Travel	(MT/month)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Off-Road Equipment	Rolling 12-month total (MT/year)												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hauling Emission	Rolling 12-month total (MT/year)												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Truck Emission	Rolling 12-month total (MT/year)												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Worker Travel	Rolling 12-month total (MT/year)												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
													CO2e										
Off-Road Equipment	(MT/month)	27.71	30.35	41.01	48.29	44.52	70.24	110.12	129.93	131.78	79.23	68.89	72.34	81.39	65.09	59.92	68.91	76.44	32.80	35.92	30.21	31.65	32.37
On-site Vehicle	(MT/month)	0.19	0.26	0.56	1.15	1.61	2.03	2.04	1.55	1.20	0.71	0.52	0.43	0.32	0.65	0.68	0.72	0.51	0.27	0.17	0.12	0.12	0.13
Hauling Emission	(MT/month)	0.00	1.58	1.78	3.04	2.84	12.14	10.66	10.92	7.85	1.91	0.65	1.62	0.13	4.35	7.85	7.91	4.28	0.97	0.13	0.00	0.00	0.00
Truck Emission	(MT/month)	0.22	0.00	0.22	0.23	0.24	0.21	0.24	0.23	0.22	0.24	0.20	0.22	0.23	0.24	0.20	0.24	0.23	0.22	0.24	0.00	0.00	0.00
Worker Travel	(MT/month)	1.60	1.75	4.29	9.52	14.25	13.43	14.25	9.29	7.41	5.75	4.54	3.08	2.79	3.76	2.27	2.61	2.50	1.82	1.30	1.19	1.25	1.25
Off-Road Equipment	Rolling 12-month total (MT/year)												854	908	943	962	982	1,014	977	903	803	703	656
Hauling Emission	Rolling 12-month total (MT/year)												55	55	58	64	69	70	59	49	38	30	28
Truck Emission	Rolling 12-month total (MT/year)												2	2	3	3	3	3	3	3	2	2	2
Worker Travel	Rolling 12-month total (MT/year)												89	90	92	90	83	72	60	47	39	33	28

TABLE 5.1F-17

Demolition of Existing Encina Power Station – Summer (Peak) Daily Emissions

Project Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
	ROG (lbs/day)																					
Off-Road Equipment	0.52	0.52	0.81	0.91	0.82	1.33	1.71	2.06	2.20	1.32	1.32	1.32	1.41	1.00	1.00	1.00	1.13	0.57	0.57	0.59	0.59	0.59
On-site Vehicle	0.01	0.01	0.02	0.04	0.06	0.08	0.07	0.05	0.04	0.02	0.02	0.02	0.01	0.02	0.02	0.02	0.02	0.01	0.01	0.00	0.00	0.00
Hauling Emission	0.00	0.04	0.05	0.07	0.07	0.33	0.25	0.27	0.20	0.04	0.02	0.04	0.00	0.10	0.21	0.18	0.10	0.02	0.00	0.00	0.00	0.00
Truck Emission	0.01	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00
Worker Travel	0.06	0.06	0.17	0.36	0.52	0.56	0.52	0.35	0.30	0.20	0.18	0.12	0.10	0.13	0.09	0.09	0.09	0.07	0.05	0.05	0.05	0.04
	NOx (lbs/day)																					
Off-Road Equipment	10.79	10.79	16.86	19.15	17.66	30.41	40.39	48.52	53.01	26.78	26.78	26.78	28.28	25.38	25.38	25.38	30.05	12.86	12.86	12.15	12.15	12.15
On-site Vehicle	0.02	0.03	0.06	0.10	0.12	0.30	0.24	0.24	0.18	0.06	0.04	0.05	0.02	0.09	0.16	0.14	0.09	0.03	0.02	0.01	0.01	0.01
Hauling Emission	0.00	0.47	0.58	0.94	0.84	4.15	3.17	3.39	2.56	0.53	0.21	0.49	0.04	1.20	2.49	2.19	1.24	0.29	0.04	0.00	0.00	0.00
Truck Emission	0.08	0.00	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.00	0.00	0.00
Worker Travel	0.07	0.07	0.20	0.43	0.61	0.66	0.61	0.42	0.35	0.24	0.21	0.14	0.12	0.15	0.11	0.11	0.11	0.08	0.05	0.05	0.05	0.05
	CO (lbs/day)																					
Off-Road Equipment	18.76	18.76	27.95	31.04	28.03	50.15	68.21	83.21	89.66	46.55	46.55	46.55	49.55	41.65	41.65	41.65	49.69	22.67	22.67	21.10	21.10	21.10
On-site Vehicle	0.10	0.10	0.26	0.52	0.71	0.91	0.81	0.61	0.50	0.29	0.25	0.19	0.14	0.24	0.25	0.23	0.19	0.12	0.07	0.06	0.06	0.05
Hauling Emission	0.00	0.39	0.48	0.78	0.69	3.41	2.61	2.79	2.10	0.46	0.18	0.43	0.03	1.05	2.17	1.91	1.08	0.26	0.03	0.00	0.00	0.00
Truck Emission	0.10	0.00	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.00	0.00	0.00
Worker Travel	0.81	0.81	2.17	4.59	6.57	7.13	6.57	4.48	3.75	2.54	2.30	1.49	1.29	1.66	1.15	1.15	1.15	0.88	0.58	0.58	0.58	0.54
	SO2 (lbs/day)																					
Off-Road Equipment	0.03	0.03	0.04	0.05	0.04	0.08	0.11	0.13	0.14	0.08	0.08	0.08	0.08	0.06	0.07	0.07	0.08	0.04	0.04	0.03	0.03	0.03
On-site Vehicle	2.65E-04	3.13E-04	7.53E-04	1.50E-03	2.05E-03	2.80E-03	2.46E-03	1.91E-03	1.55E-03	9.19E-04	7.82E-04	5.89E-04	4.38E-04	7.80E-04	8.76E-04	8.16E-04	6.31E-04	3.64E-04	2.20E-04	1.77E-04	1.77E-04	1.77E-04
Hauling Emission	0.00E+00	1.56E-03	1.92E-03	3.12E-03	2.79E-03	1.37E-02	1.05E-02	1.12E-02	8.45E-03	1.91E-03	7.40E-04	1.77E-03	1.40E-04	4.34E-03	9.01E-03	7.90E-03	4.47E-03	1.06E-03	1.30E-04	0.00E+00	0.00E+00	0.00E+00
Truck Emission	2.40E-04	0.00E+00	2.40E-04	2.40E-04	2.40E-04	2.40E-04	2.40E-04	2.40E-04	2.40E-04	2.40E-04	2.40E-04	2.40E-04	2.40E-04	2.40E-04	2.40E-04	2.40E-04	2.40E-04	2.40E-04	2.40E-04	0.00E+00	0.00E+00	0.00E+00
Worker Travel	2.29E-03	2.29E-03	6.14E-03	1.30E-02	1.86E-02	2.02E-02	1.86E-02	1.27E-02	1.06E-02	7.80E-03	7.07E-03	4.58E-03	3.95E-03	5.10E-03	3.54E-03	3.54E-03	3.54E-03	2.71E-03	1.77E-03	1.77E-03	1.77E-03	1.77E-03
	PM10 (lbs/day)																					
Fugitive	0.45	0.41	0.45	0.43	0.41	0.47	0.41	0.43	0.45	0.41	0.47	0.45	0.43	0.41	0.47	0.41	0.43	0.45	0.41	0.45	0.43	0.41
Fugitive (On-site Vehicle)	0.02	0.02	0.05	0.11	0.15	0.18	0.16	0.12	0.10	0.07	0.06	0.04	0.03	0.05	0.04	0.04	0.03	0.02	0.02	0.01	0.01	0.01
Fugitive - Hauling	0.00	0.04	0.04	0.07	0.07	0.32	0.24	0.26	0.20	0.04	0.02	0.04	0.00	0.10	0.21	0.18	0.10	0.02	0.00	0.00	0.00	0.00
Fugitive - Truck	0.01	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00
Fugitive - Worker Travel	0.18	0.18	0.48	1.03	1.47	1.59	1.47	1.00	0.84	0.62	0.56	0.36	0.31	0.40	0.28	0.28	0.28	0.21	0.14	0.14	0.14	0.14
Off-Road Equipment	0.05	0.05	0.07	0.08	0.07	0.12	0.17	0.20	0.22	0.12	0.12	0.12	0.13	0.09	0.09	0.09	0.11	0.05	0.05	0.05	0.05	0.05
On-site Vehicle	3.01E-04	5.03E-04	9.79E-04	1.65E-03	1.89E-03	4.61E-03	3.74E-03	3.59E-03	2.80E-03	1.05E-03	7.31E-04	8.35E-04	4.12E-04	1.47E-03	2.49E-03	2.23E-03	1.41E-03	5.62E-04	2.88E-04	9.90E-05	9.90E-05	9.90E-05
Hauling Emission	0.00	0.01	0.01	0.01	0.01	0.06	0.05	0.05	0.04	0.01	0.00	0.01	0.00	0.02	0.04	0.03	0.02	0.00	0.00	0.00	0.00	0.00
Truck Emission	1.16E-03	0.00E+00	1.16E-03	1.16E-03	1.16E-03	1.16E-03	1.16E-03	1.16E-03	1.16E-03	1.07E-03	1.07E-03	1.07E-03	1.07E-03	1.07E-03	1.07E-03	1.07E-03	1.07E-03	1.07E-03	1.07E-03	0.00E+00	0.00E+00	0.00E+00
Worker Travel	1.29E-03	1.29E-03	3.46E-03	7.32E-03	1.05E-02	1.14E-02	1.05E-02	7.15E-03	5.98E-03	4.36E-03	3.96E-03	2.56E-03	2.21E-03	2.85E-03	1.98E-03	1.98E-03	1.98E-03	1.51E-03	9.90E-04	9.90E-04	9.90E-04	9.90E-04
	PM2.5 (lbs/day)																					
Fugitive	0.07	0.06	0.07	0.07	0.06	0.07	0.06	0.07	0.07	0.06	0.07	0.07	0.07	0.06	0.07	0.06	0.07	0.07	0.06	0.07	0.07	0.06
Fugitive (On-site Vehicle)	5.07E-03	5.33E-03	1.38E-02	2.86E-02	4.02E-02	4.73E-02	4.29E-02	3.07E-02	2.54E-02	1.73E-02	1.54E-02	1.05E-02	8.61E-03	1.25E-02	1.08E-02	1.04E-02	9.23E-03	6.32E-03	4.02E-03	3.70E-03	3.70E-03	3.70E-03
Fugitive - Hauling	0.00	0.01	0.01	0.02	0.02	0.09	0.07	0.07	0.05	0.01	0.00	0.01	0.00	0.03	0.06	0.05	0.03	0.01	0.00	0.00	0.00	0.00
Fugitive - Truck	1.89E-03	0.00E+00	1.89E-03	1.89E-03	1.89E-03	1.89E-03	1.89E-03	1.89E-03	1.89E-03	1.89E-03	1.89E-03	1.89E-03	1.89E-03	1.89E-03	1.89E-03	1.89E-03	1.89E-03	1.89E-03	1.89E-03	0.00E+00	0.00E+00	0.00E+00
Fugitive - Worker Travel	0.05	0.05	0.13	0.27	0.39	0.42	0.39	0.27	0.22	0.16	0.15	0.10	0.08	0.11	0.07	0.07	0.07	0.06	0.04	0.04	0.04	0.04
Off-Road Equipment	0.05	0.05	0.07	0.08	0.07	0.12	0.17	0.20	0.22	0.12	0.12	0.12	0.13	0.09	0.09	0.09	0.11	0.05	0.05	0.05	0.05	0.05
On-site Vehicle	2.76E-04	4.64E-04	9.01E-04	1.53E-03	1.74E-03	4.24E-03	3.44E-03	3.30E-03	2.58E-03	9.68E-04	6.76E-04	7.71E-04	3.81E-04	1.36E-03	2.30E-03	2.05E-03	1.31E-03	5.19E-04	2.67E-04	9.20E-05	9.20E-05	9.20E-05
Hauling Emission	0.00	0.01	0.01	0.01	0.01	0.06	0.04	0.05	0.03	0.01	0.00	0.01	0.00	0.02	0.04	0.03	0.02	0.00	0.00	0.00	0.00	0.00
Truck Emission	1.06E-03	0.00E+00	1.06E-03	1.06E-03	1.06E-03	1.06E-03	1.06E-03	1.06E-03	1.06E-03	9.90E-04	9.90E-04	9.90E-04	9.90E-04	9.90E-04	9.90E-04	9.90E-04	9.90E-04	9.90E-04	9.90E-04	0.00E+00	0.00E+00	0.00E+00
Worker Travel	1.19E-03	1.19E-03	3.20E-03	6.78E-03	9.71E-03	1.05E-02	9.71E-03	6.62E-03	5.53E-03	4.05E-03	3.67E-03	2.37E-03	2.05E-03	2.64E-03	1.83E-03	1.83E-03	1.83E-03	1.40E-03	9.20E-04	9.20E-04	9.20E-04	9.20E-04
	CO2 (lbs/day)																					
Off-Road Equipment	2,891	2,891	4,277	4,809	4,241	7,693	10,488	12,938	13,746	7,548	7,548	7,548	8,107	6,203	6,569	6,569	7,617	3,425	3,425	3,151	3,151	3,082
On-site Vehicle	21	26	61	120	162	232	202	161	130	71	60	47	33	64	76	71	53	29	17	13	13	13
Hauling Emission	0	152	187	304	272	1,340	1,023	1,096	825	184	72	170	13	417	866	759	429	102	12	0	0	0
Truck Emission	23	0	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	0	0	0
Worker Travel	177	177	474	1,005	1,439	1,559	1,439	981	820	581	527	341	294	380	263	263	263	201	132	132	132	126

TABLE 5.1F-17 (CONT.)
Demolition of Existing Encina Power Station – Summer (Peak) Daily Emissions

Project Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
	CH4 (lbs/day)																					
Off-Road Equipment	0.90	0.90	1.33	1.47	1.30	2.35	3.20	3.95	4.18	2.18	2.18	2.18	2.36	1.70	1.74	1.74	2.08	0.89	0.89	1.00	1.00	1.00
On-site Vehicle	8.49E-04	8.82E-04	2.31E-03	4.82E-03	6.83E-03	7.81E-03	7.11E-03	5.01E-03	4.16E-03	2.74E-03	2.45E-03	1.64E-03	1.37E-03	1.92E-03	1.56E-03	1.52E-03	1.39E-03	9.81E-04	6.29E-04	5.99E-04	5.99E-04	5.69E-04
Hauling Emission	0.00E+00	1.07E-03	1.32E-03	2.15E-03	1.92E-03	9.45E-03	7.21E-03	7.72E-03	5.82E-03	1.31E-03	5.10E-04	1.21E-03	9.00E-05	2.97E-03	6.17E-03	5.41E-03	3.06E-03	7.30E-04	9.00E-05	0.00E+00	0.00E+00	0.00E+00
Truck Emission	1.70E-04	0.00E+00	1.70E-04	1.70E-04	1.70E-04	1.70E-04	1.70E-04	1.70E-04	1.70E-04	1.70E-04	1.70E-04	1.70E-04	1.70E-04	1.70E-04	1.70E-04	1.70E-04	1.70E-04	1.70E-04	1.70E-04	0.00E+00	0.00E+00	0.00E+00
Worker Travel	0.01	0.01	0.02	0.05	0.07	0.07	0.07	0.05	0.04	0.03	0.02	0.02	0.01	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
	N2O (lbs/day)																					
Off-Road Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
On-site Vehicle	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hauling Emission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck Emission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Worker Travel	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	CO2e (lbs/day)																					
Off-Road Equipment	2,910	2,910	4,305	4,840	4,268	7,742	10,556	13,021	13,834	7,594	7,594	7,594	8,157	6,239	6,605	6,605	7,660	3,443	3,443	3,172	3,172	3,102
On-site Vehicle	21	26	61	120	162	232	203	161	130	71	60	47	34	64	76	71	53	29	17	13	13	13
Hauling Emission	0	152	187	305	272	1,340	1,023	1,096	825	184	72	170	13	417	866	759	429	102	12	0	0	0
Truck Emission	23	0	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	0	0	0
Worker Travel	177	177	475	1,006	1,440	1,561	1,440	981	821	582	527	341	295	380	264	264	264	202	132	132	132	127

TABLE 5.1F-18

Demolition of Existing Encina Power Station – Winter (Peak) Daily Emissions

Project Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
ROG (lbs/day)																						
Off-Road Equipment	0.52	0.52	0.81	0.91	0.82	1.33	1.71	2.06	2.20	1.32	1.32	1.32	1.41	1.00	1.00	1.00	1.13	0.57	0.57	0.59	0.59	0.59
On-site Vehicle	0.01	0.01	0.02	0.04	0.06	0.08	0.07	0.05	0.04	0.03	0.02	0.02	0.01	0.02	0.02	0.02	0.02	0.01	0.01	0.00	0.00	0.00
Hauling Emission	0.00	0.04	0.05	0.08	0.07	0.36	0.28	0.30	0.22	0.05	0.02	0.04	0.00	0.11	0.23	0.20	0.11	0.03	0.00	0.00	0.00	0.00
Truck Emission	0.01	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00
Worker Travel	0.07	0.07	0.18	0.38	0.55	0.59	0.55	0.37	0.31	0.21	0.19	0.12	0.11	0.14	0.10	0.10	0.10	0.07	0.05	0.05	0.05	0.05
NOx (lbs/day)																						
Off-Road Equipment	10.79	10.79	16.86	19.15	17.66	30.41	40.39	48.52	53.01	26.78	26.78	26.78	28.28	25.38	25.38	25.38	30.05	12.86	12.86	12.15	12.15	12.15
On-site Vehicle	0.02	0.03	0.07	0.11	0.13	0.32	0.26	0.25	0.19	0.07	0.05	0.05	0.03	0.09	0.16	0.14	0.09	0.04	0.02	0.01	0.01	0.01
Hauling Emission	0.00	0.49	0.60	0.97	0.87	4.28	3.27	3.50	2.64	0.55	0.21	0.51	0.04	1.24	2.57	2.26	1.28	0.30	0.04	0.00	0.00	0.00
Truck Emission	0.08	0.00	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.00	0.00	0.00
Worker Travel	0.08	0.08	0.23	0.48	0.68	0.74	0.68	0.47	0.39	0.26	0.24	0.16	0.13	0.17	0.12	0.12	0.12	0.09	0.06	0.06	0.06	0.06
CO (lbs/day)																						
Off-Road Equipment	18.76	18.76	27.95	31.04	28.03	50.15	68.21	83.21	89.66	46.55	46.55	46.55	49.55	41.65	41.65	41.65	49.69	22.67	22.67	21.10	21.10	21.10
On-site Vehicle	0.10	0.10	0.26	0.52	0.70	0.95	0.84	0.65	0.53	0.30	0.25	0.19	0.14	0.25	0.28	0.26	0.21	0.12	0.08	0.06	0.06	0.05
Hauling Emission	0.00	0.50	0.62	1.01	0.90	4.44	3.39	3.63	2.74	0.60	0.23	0.56	0.04	1.37	2.84	2.49	1.41	0.33	0.04	0.00	0.00	0.00
Truck Emission	0.14	0.00	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.00	0.00	0.00
Worker Travel	0.78	0.78	2.08	4.42	6.32	6.85	6.32	4.31	3.60	2.43	2.21	1.43	1.23	1.59	1.10	1.10	1.10	0.84	0.55	0.55	0.55	0.52
SO2 (lbs/day)																						
Off-Road Equipment	0.03	0.03	0.04	0.05	0.04	0.08	0.11	0.13	0.14	0.08	0.08	0.08	0.08	0.06	0.07	0.07	0.08	0.04	0.04	0.03	0.03	0.03
On-site Vehicle	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hauling Emission	0.00E+00	1.55E-03	1.91E-03	3.11E-03	2.78E-03	1.37E-02	1.05E-02	1.12E-02	8.44E-03	1.91E-03	7.40E-04	1.77E-03	1.40E-04	4.33E-03	9.00E-03	7.89E-03	4.46E-03	1.06E-03	1.30E-04	0.00E+00	0.00E+00	0.00E+00
Truck Emission	2.40E-04	0.00E+00	2.40E-04	2.40E-04	2.40E-04	2.40E-04	2.40E-04	2.40E-04	2.40E-04	2.40E-04	2.40E-04	2.40E-04	2.40E-04	2.40E-04	2.40E-04	2.40E-04	2.40E-04	2.40E-04	2.40E-04	0.00E+00	0.00E+00	0.00E+00
Worker Travel	2.15E-03	2.15E-03	5.76E-03	1.22E-02	1.75E-02	1.90E-02	1.75E-02	1.19E-02	9.96E-03	7.32E-03	6.64E-03	4.30E-03	3.71E-03	4.78E-03	3.32E-03	3.32E-03	3.32E-03	2.54E-03	1.66E-03	1.66E-03	1.66E-03	1.66E-03
PM10 (lbs/day)																						
Fugitive	0.45	0.41	0.45	0.43	0.41	0.47	0.41	0.43	0.45	0.41	0.47	0.45	0.43	0.41	0.47	0.41	0.43	0.45	0.41	0.45	0.43	0.41
Fugitive (On-site Vehicle)	0.02	0.02	0.05	0.11	0.15	0.18	0.16	0.12	0.10	0.07	0.06	0.04	0.03	0.05	0.04	0.04	0.03	0.02	0.02	0.01	0.01	0.01
Fugitive - Hauling	0.00	0.04	0.04	0.07	0.07	0.32	0.24	0.26	0.20	0.04	0.02	0.04	0.00	0.10	0.21	0.18	0.10	0.02	0.00	0.00	0.00	0.00
Fugitive - Truck	0.01	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00
Fugitive - Worker Travel	0.18	0.18	0.48	1.03	1.47	1.59	1.47	1.00	0.84	0.62	0.56	0.36	0.31	0.40	0.28	0.28	0.28	0.21	0.14	0.14	0.14	0.14
Off-Road Equipment	0.05	0.05	0.07	0.08	0.07	0.12	0.17	0.20	0.22	0.12	0.12	0.12	0.13	0.09	0.09	0.09	0.11	0.05	0.05	0.05	0.05	0.05
On-site Vehicle	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hauling Emission	0.00	0.01	0.01	0.01	0.01	0.06	0.05	0.05	0.04	0.01	0.00	0.01	0.00	0.02	0.04	0.03	0.02	0.00	0.00	0.00	0.00	0.00
Truck Emission	1.17E-03	0.00E+00	1.17E-03	1.17E-03	1.17E-03	1.17E-03	1.17E-03	1.17E-03	1.17E-03	1.08E-03	1.08E-03	1.08E-03	1.08E-03	1.08E-03	1.08E-03	1.08E-03	1.08E-03	1.08E-03	1.08E-03	0.00E+00	0.00E+00	0.00E+00
Worker Travel	1.29E-03	1.29E-03	3.46E-03	7.32E-03	1.05E-02	1.14E-02	1.05E-02	7.15E-03	5.98E-03	4.36E-03	3.96E-03	2.56E-03	2.21E-03	2.85E-03	1.98E-03	1.98E-03	1.98E-03	1.51E-03	9.90E-04	9.90E-04	9.90E-04	9.90E-04
PM2.5 (lbs/day)																						
Fugitive	0.07	0.06	0.07	0.07	0.06	0.07	0.06	0.07	0.07	0.06	0.07	0.07	0.07	0.06	0.07	0.06	0.07	0.07	0.06	0.07	0.07	0.06
Fugitive (On-site Vehicle)	0.01	0.01	0.01	0.03	0.04	0.05	0.04	0.03	0.03	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00
Fugitive - Hauling	0.00	0.01	0.01	0.02	0.02	0.09	0.07	0.07	0.05	0.01	0.00	0.01	0.00	0.03	0.06	0.05	0.03	0.01	0.00	0.00	0.00	0.00
Fugitive - Truck	1.89E-03	0.00E+00	1.89E-03	1.89E-03	1.89E-03	1.89E-03	1.89E-03	1.89E-03	1.89E-03	1.89E-03	1.89E-03	1.89E-03	1.89E-03	1.89E-03	1.89E-03	1.89E-03	1.89E-03	1.89E-03	1.89E-03	0.00E+00	0.00E+00	0.00E+00
Fugitive - Worker Travel	0.05	0.05	0.13	0.27	0.39	0.42	0.39	0.27	0.22	0.16	0.15	0.10	0.08	0.11	0.07	0.07	0.07	0.06	0.04	0.04	0.04	0.04
Off-Road Equipment	0.05	0.05	0.07	0.08	0.07	0.12	0.17	0.20	0.22	0.12	0.12	0.12	0.13	0.09	0.09	0.09	0.11	0.05	0.05	0.05	0.05	0.05
On-site Vehicle	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hauling Emission	0.00	0.01	0.01	0.01	0.01	0.06	0.04	0.05	0.03	0.01	0.00	0.01	0.00	0.02	0.04	0.03	0.02	0.00	0.00	0.00	0.00	0.00
Truck Emission	1.07E-03	0.00E+00	1.07E-03	1.07E-03	1.07E-03	1.07E-03	1.07E-03	1.07E-03	1.07E-03	1.00E-03	1.00E-03	1.00E-03	1.00E-03	1.00E-03	1.00E-03	1.00E-03	1.00E-03	1.00E-03	1.00E-03	0.00E+00	0.00E+00	0.00E+00
Worker Travel	1.19E-03	1.19E-03	3.20E-03	6.78E-03	9.71E-03	1.05E-02	9.71E-03	6.62E-03	5.53E-03	4.05E-03	3.67E-03	2.37E-03	2.05E-03	2.64E-03	1.83E-03	1.83E-03	1.83E-03	1.40E-03	9.20E-04	9.20E-04	9.20E-04	9.20E-04
CO2 (lbs/day)																						
Off-Road Equipment	2,891	2,891	4,277	4,809	4,241	7,693	10,488	12,938	13,746	7,548	7,548	7,548	8,107	6,203	6,569	6,569	7,617	3,425	3,425	3,151	3,151	3,082
On-site Vehicle	20	25	58	114	153	222	194	154	125	68	57	45	32	61	75	69	51	28	16	12	12	12
Hauling Emission	0	152	187	304	272	1337	1020	1093	823	183	71	170	13	416	864	757	428	102	12	0	0	0
Truck Emission	23	0	23	23	23	23	23	23	23	22	22	22	22	22	22	22	22	22	22	0	0	0
Worker Travel	166	166	445	943	1351	1464	1351	921	770	546	495	320	276	356	247	247	247	189	124	124	124	119

TABLE 5.1F-18 (CONT.)

Demolition of Existing Encina Power Station – Winter (Peak) Daily Emissions

Project Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
	CH4 (lbs/day)																					
Off-Road Equipment	0.90	0.90	1.33	1.47	1.30	2.35	3.20	3.95	4.18	2.18	2.18	2.18	2.36	1.70	1.74	1.74	2.08	0.89	0.89	1.00	1.00	1.00
On-site Vehicle	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hauling Emission	0.00E+00	1.09E-03	1.34E-03	2.18E-03	1.95E-03	9.58E-03	7.31E-03	7.84E-03	5.90E-03	1.33E-03	5.20E-04	1.23E-03	9.00E-05	3.02E-03	6.26E-03	5.49E-03	3.11E-03	7.40E-04	9.00E-05	0.00E+00	0.00E+00	0.00E+00
Truck Emission	1.80E-04	0.00E+00	1.80E-04	1.80E-04	1.80E-04	1.80E-04	1.80E-04	1.80E-04	1.80E-04	1.70E-04	1.70E-04	1.70E-04	1.70E-04	1.70E-04	1.70E-04	1.70E-04	1.70E-04	1.70E-04	1.70E-04	0.00E+00	0.00E+00	0.00E+00
Worker Travel	0.01	0.01	0.02	0.05	0.07	0.07	0.07	0.05	0.04	0.03	0.02	0.02	0.01	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
	N2O (lbs/day)																					
Off-Road Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
On-site Vehicle	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hauling Emission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck Emission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Worker Travel	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	CO2e (lbs/day)																					
Off-Road Equipment	2,910	2,910	4,305	4,840	4,268	7,742	10,556	13,021	13,834	7,594	7,594	7,594	8,157	6,239	6,605	6,605	7,660	3,443	3,443	3,172	3,172	3,102
On-site Vehicle	20	25	58	114	153	222	194	155	125	68	57	45	32	61	75	69	51	28	16	12	12	12
Hauling Emission	0	152	187	304	272	1,337	1,020	1,093	823	183	71	170	13	416	864	758	428	102	12	0	0	0
Truck Emission	23	0	23	23	23	23	23	23	23	22	22	22	22	22	22	22	22	22	22	0	0	0
Worker Travel	166	166	446	944	1,352	1,466	1,352	922	771	546	495	320	277	357	248	248	248	189	124	124	124	119

TABLE 5.1F-19

Demolition of Existing Encina Power Station - CalEEMod Input Data

Project Name	CECP Demolition of EPS	
District	San Diego County	
Wind Speed	2.6	m/s
Precipitation Frequency	40	days/year
Climate Zone	13	
Urbanization Level	Urban	
Expected Operational Year	2021	
Utility Company	San Diego Gas & Electric	
CO2 Intensity Factor	720.49	
CH4 Intensity Factor	0.029	
N2O Intensity Factor	0.006	

For the 22 months of demolition of existing Encina Power Station

CalEEMod Phase Name	Phase Type	Start Date	End Date	# day/Week	Number of Days	Daily hours	Month
Demolition EPS 1	Demolition	2018/04/01	2018/04/30	5	21	8	1
Demolition EPS 2	Demolition	2018/05/01	2018/05/31	5	23	8	2
Demolition EPS 3	Demolition	2018/06/01	2018/06/30	5	21	8	3
Demolition EPS 4	Demolition	2018/07/01	2018/07/31	5	22	8	4
Demolition EPS 5	Demolition	2018/08/01	2018/08/31	5	23	8	5
Demolition EPS 6	Demolition	2018/09/01	2018/09/30	5	20	8	6
Demolition EPS 7	Demolition	2018/10/01	2018/10/31	5	23	8	7
Demolition EPS 8	Demolition	2018/11/01	2018/11/30	5	22	8	8
Demolition EPS 9	Demolition	2018/12/01	2018/12/31	5	21	8	9
Demolition EPS 10	Demolition	2019/01/01	2019/01/31	5	23	8	10
Demolition EPS 11	Demolition	2019/02/01	2019/02/28	5	20	8	11
Demolition EPS 12	Demolition	2019/03/01	2019/03/31	5	21	8	12
Demolition EPS 13	Demolition	2019/04/01	2019/04/30	5	22	8	13
Demolition EPS 14	Demolition	2019/05/01	2019/05/31	5	23	8	14
Demolition EPS 15	Demolition	2019/06/01	2019/06/30	5	20	8	15
Demolition EPS 16	Demolition	2019/07/01	2019/07/31	5	23	8	16
Demolition EPS 17	Demolition	2019/08/01	2019/08/31	5	22	8	17
Demolition EPS 18	Demolition	2019/09/01	2019/09/30	5	21	8	18
Demolition EPS 19	Demolition	2019/10/01	2019/10/31	5	23	8	19
Demolition EPS 20	Demolition	2019/11/01	2019/11/30	5	21	8	20
Demolition EPS 21	Demolition	2019/12/01	2019/12/31	5	22	8	21
Demolition EPS 22	Demolition	2020/01/01	2020/01/31	5	23	8	22

TABLE 5.1F-20

Demolition of Existing Encina Power Station - CalEEMod Equipment Schedule Input

Project Month	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**
Demolition of Existing Encina Power Station																						
CalEEMod INPUT																						
Cranes	0	0	1	1	0	0	2	2	1	1	1	1	2	0	0	0	0	0	0	0	0	0
Crawler Tractors	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Crushing/Proc. Equipment	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	0	0	0
Dumpers/Tenders	0	0	0	2	2	4	5	6	8	4	4	4	4	8	14	14	14	3	3	0	0	0
Excavator	1	1	1	1	1	4	7	9	10	2	2	2	2	5	5	5	7	2	2	1	1	1
Off-Highway Trucks	1	1	1	1	1	2	2	3	3	2	2	2	2	0	0	0	0	0	0	1	1	1
Rubber Tire Loader	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	0	0	0
Skid Steel Loader	2	2	6	8	8	10	10	10	12	6	6	6	6	6	6	6	6	0	0	2	2	2
Surfacing Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tractors/Loaders/Backhoes	2	2	2	2	2	2	2	2	3	2	2	2	2	2	2	2	2	3	3	3	3	3

CalEEMod default values for equipment horsepower (hp) and usage load factors are used.

TABLE 5.1F-21

Demolition of Existing Encina Power Station - CalEEMod Vehicle Trips Input

Project Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
Number of days	**21**	**23**	**21**	**22**	**23**	**20**	**23**	**22**	**21**	**23**	**20**	**21**	**22**	**23**	**20**	**23**	**22**	**21**	**23**	**21**	**22**	**23**
Demolition of Existing Encina Power Station																						
Workers																						
Craft																						
Laborers	10	10	45	105	155	165	146	91	72	56	50	28	25	25	15	15	15	12	10	10	10	10
Operating Engineers	2	2	2	2	2	4	8	10	12	4	4	4	2	8	8	8	8	4	2	2	2	2
Craft Staff Subtotal	**12**	**12**	**47**	**107**	**157**	**169**	**154**	**101**	**84**	**60**	**54**	**32**	**27**	**33**	**23**	**23**	**23**	**16**	**12**	**12**	**12**	**12**
Contractor Staff																						
Construction Manager	3	3	7	13	17	20	20	16	13	10	9	7	6	9	6	6	6	5				
Administrators	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Engineering Supervisor	3	3	1	1	1	1	1	1	1	1	1	1	1	3	1	1	1	1	1	1	1	1
Health and Safety Engineer	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Contractor Staff Subtotal	**10**	**10**	**12**	**18**	**22**	**25**	**25**	**21**	**18**	**15**	**14**	**12**	**11**	**16**	**11**	**11**	**11**	**10**	**5**	**5**	**5**	**5**
Total Number of Workers	**22**	**22**	**59**	**125**	**179**	**194**	**179**	**122**	**102**	**75**	**68**	**44**	**38**	**49**	**34**	**34**	**34**	**26**	**17**	**17**	**17**	**17**
Worker Trip (trips/day)	**22**	**22**	**59**	**125**	**179**	**194**	**179**	**122**	**102**	**75**	**68**	**44**	**38**	**49**	**34**	**34**	**34**	**26**	**17**	**17**	**17**	**17**
Truck Deliveries																						
Equipment Services	1	1	4	4	4	4	8	8	8	8	8	8	8	8	8	8	8	8	8	1	1	1
Oxygen & Propane	1	1	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	0	0	0
Diesel Fuel	4	4	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	2	2	2
Drinking Water	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
First Aid Supplies	1	0	0	0	0	0	1	0	0	0	0	0	1	0	0	0	0	0	1	0	0	0
Small Tools & Supplies	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	2	2	2
Subtotal	**12**	**11**	**25**	**25**	**25**	**25**	**30**	**29**	**29**	**29**	**29**	**29**	**30**	**29**	**29**	**29**	**29**	**29**	**30**	**6**	**6**	**6**
Truck Trips (Average Daily)	**1**	**0**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**0**	**0**	**0**
Truck Hauling																						
ACM/OHMs (Roll-off Bins)	0	40	46	73	58	222	148	163	50	0	0	0	0	0	0	0	0	0	0	0	0	0
C&D (Roll-off Bins)	0	4	4	12	12	8	16	8	6	0	0	0	0	0	0	0	0	0	0	0	0	0
C&D (End-Dump Trucks)	0	0	0	0	0	20	30	40	60	40	20	30	4	4	4	4	4	8	4	0	0	0
Metals (End-Dump Trucks)	0	4	4	7	16	118	129	120	122	19	0	20	0	130	238	240	128	22	0	0	0	0
Hauling Trips (total)	**0**	**48**	**54**	**92**	**86**	**368**	**323**	**331**	**238**	**59**	**20**	**50**	**4**	**134**	**242**	**244**	**132**	**30**	**4**	**0**	**0**	**0**

Appendix 5.1G
ERC Summary (from 8/4/2009 SDAPCD FDOC for the CECP, Appendix D

Summary of Emission Reduction Credits (ERCs) Proposed as Offsets

ERC Certificate No.	Original Issue Date	Type	Pollutant	ERC Amount, tons per year	NOx Equivalent Amount, tons per year	Location of Emission Reductions	Description Emission Reduction	Current Owner
978938-05	6/30/2004	Class A	NOx	35.3	35.3	Naval Air Station—North Island; Foot of Neville Road, Naval Training Center, San Diego; Vesta Street & Ward Road Naval Station San Diego	Permanent shutdown of peaking combustion turbines	Cabrillo Power II, LLC
981518-01	8/01/2006	Class A	NOx	2.3	2.3	3200 Harbor Drive, San Diego	Permanent shutdown of peaking combustion turbines	Cabrillo Power II, LLC
070823-02	11/19/99	Class A	VOCs	5.3	2.65	850 Lagoon Drive, Chula Vista	Shutdown of Vapor Degreasers and Cold Solvent Cleaners	Element Markets, LLC
080212-01	9/22/2006	Class A	VOCs	18.7	9.35	7757 Andrews Avenue, San Diego	Shutdown and restricted operation of wood coating and adhesive application operations	Inland Gas and Electric GP, LLC

Appendix 5.1H
Nearby New/Modified Projects

SIERRA RESEARCH INC
1801 J STREET, SACRAMENTO CA 95811
TEL 916.444.6666
FAX 916.444.8373
http://www.sierraresearch.com

Fax

January 21, 2014

FROM: Kate Gianolini

TO: Virginia Fox
San Diego APCD, Public Records

FAX: 858-586-2601

PAGES: Transmittal Cover Page + 3

COMMENTS:

Please see the attached Request for Public Records and accompanying letter detailing the requested records. We would appreciate an expedited review because there is a very short turn-around time for this project. If there are any questions on this request, please contact Tom Andrews at 916-444-6666. Thank you for your assistance.

SAN DIEGO AIR POLLUTION CONTROL DISTRICT

REQUEST FOR PUBLIC RECORDS

Date: January 21, 2014

Name: Tom Andrews

Agency: Sierra Research

Address: 1801 J Street

City: Sacramento State: CA Zip: 95811

Phone: (916) 444-6666 Fax: (916) 444-8373

I request to inspect the following Public Records (please be specific): Please provide the information discussed in the attached cover letter.

INSPECTION OF PUBLIC RECORDS

The district shall make a determination if the records requested are available with the exception of those records specifically exempted from disclosure by state law and those records labeled as "TRADE SECRET" which are not emission data, within ten (10) days of the date of the receipt of the request. If, for good cause, the determination cannot be made within the ten (10) working days, the District will notify the requesting person the reasons for the delay and when the determination is expected to be made within an additional 14 days, as prescribed by law. Those records labeled as "TRADE SECRETS" shall be governed by the procedure set forth in District Rule 177 Section (g).

If you have any questions, please contact Public Records at (858) 586-2618.

Mail or fax completed form to:

San Diego APCD
Public Records
10124 Old Grove Road
San Diego, CA 92131 Phone: (858) 586-2600 Fax No.: (858) 586-2601

01/06

sierra
research

1801 J Street
Sacramento, CA 95811
Tel: (916) 444-6666
Fax: (916) 444-8373

Ann Arbor, MI
Tel: (734) 761-6666
Fax: (734) 761-6755

January 21, 2014

Virginia Fox
San Diego County Air Pollution Control District
10124 Old Grove Road
San Diego, CA 92131

Subject: Cumulative Air Quality Impacts Analysis Public Records Request
Amended Carlsbad Energy Center Project (CECP)

Dear Ms. Fox:

This is a public records request for specific information needed to perform a cumulative air quality impact analysis. The proposed project is the Amended Carlsbad Energy Center (CECP), and will be located on the property of the existing Encina Power Station, located at 4600 Carlsbad Boulevard, Carlsbad, CA. The proposed CECP would be located at 33 degrees 8 minutes 27 seconds north latitude and 117 degrees 20 minutes 3 seconds west longitude, equivalent to stack Universal Transverse Mercator (UTM) coordinates of 3,666,945.98 meters northing, 468,833.15 meters easting in Zone 11 of North American Datum 1927 (NAD 27).

Specifically, we request the information listed below for facilities located within a six-mile radius of the CECP project site.

- A list of all new Authorities to Construct and/or modified Permits to Operate issued after June 1, 2012, for projects that result in a net emissions increase of 5 tons per year or more of NOx, PM_{10}, SOx, or CO.

- A list of projects for which Authority to Construct permits have not been issued to date but that are reasonably foreseeable and are expected to result in a net emissions increase of 5 tons per year or more of NOx, PM_{10}, SOx, or CO.

- For each new/modified source identified above, please provide the following information, to the extent available:

  - Facility name
  - Facility location
  - Type of new/modified basic emitting equipment
  - Net emission increases for all criteria pollutants

- For each new/modified source identified above, also please provide the following facility information for each stack:
    - Height
    - Inside diameter
    - Exit temperature
    - Exhaust flow rate or velocity
    - Base elevation
    - UTM coordinates

If you have any questions regarding this request, please do not hesitate to call me at (916) 444-6666.

Sincerely,

Tom Andrews
Principal Engineer

Enclosure

Tom W. Andrews

From: Haddad, Suha H. <Suha.Haddad@sdcounty.ca.gov>
Sent: Thursday, February 06, 2014 8:14 AM
To: Tom W. Andrews
Cc: Moore, Steve
Subject: Requested Info.
Attachments: Cabrillo 1.pdf; Cabrillo 2.pdf; Cabrillo 3.pdf; CHPCE La Salina.pdf; Carlsbad Stack Emissions.xls

Good morning,

Attached are the requested information.

Please let me know of any questions

Thank you,

Suha Haddad
(858) 586-2716

EPA United States Environmental Protection Agency

Source Management System

SMS Home | Reports and Queries | Add/Edit Events | Logout

Help | Glossary | Back

FACILITY AND UNIT DETAILS

Cabrillo Power I Encina Power Station, CA (ORISPL 302)

The General Tab for the facility is displayed below. You may access additional information by clicking the other tabs.

General | Units | Generators | Owners/Operators | Representatives | Contacts | Programs

*** Required information.**

***Facility ID (ORISPL):**	302	*** Facility Name:**	Cabrillo Power I Encina Power Station
*** State:**	CA	**County:**	San Diego
EPA Region:	9	**State ID:**	73
EPA AIRS ID:	06-073-00033	**Facility ID (FRS ID):**	110000730433
Latitude:	33.1408 (Latitude Example: 12.1234)	**Longitude:**	-117.3342 (Longitude Example: -123.1234)
NERC Region:	WECC - Western Electricity Coordinating Council		
Facility Description:	12/10/2012 (C. Hillock) Carlsbad Energy Center (listed as Encina Power Station units 6 and 7) is currently under final review by the CA Energy Commission. If built, the units would not be expected to come online before 2016. This project would be on the Encina Power Station site. 10/25/07- S Rosoff (intern) confirmed lat/long data.		

Last Modified: 01/21/2013 (jcarter)

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Internal Memo

Rule 1200 Health Risk Assessment

Facility ID: 01073
Application: **002146**
Project Engineer: Arthur Carbonell
Toxics Risk Analyst: Michael Kehetian
Date Submitted to Toxics: 08/15/12
Date Completed by Toxics: 09/05/12
HRA Tools Used: BEEST-ISC3P

The following estimated risks are valid only for the input data provided by the Project Engineer.

Estimated Risk Levels:

Maximum Individual Cancer Risk (Resident)	0.2 in one million LCP
Chronic Noncancer Health Hazard Index	≤ 1
Acute Health Hazard Index	≤ 1

Process Data:

212-hp Digester Gas Engine

Operation Parameter	**Value**
Fuel Usage (MMscf/hr)	2.45E-03
Hours Per Year	8760

Worst-Case Potential Emissions:

Toxic Air Contaminant	**Emission Factor (lb/MMscf)**	**Emissions (lb/hr)**	**Emissions (lb/yr)**
AMMONIA	4.80E-03	1.18E-05	1.03E-01
BENZENE	1.78E-01	4.37E-04	3.82E+00
CHLOROBENZENE	2.00E-04	4.90E-07	4.29E-03

DICHLOROBENZENE-P	1.80E-03	4.41E-06	3.86E-02
DICHLOROETHANE (EDC, ETHYLENE DICHLORIDE), 1,2-	1.40E-03	3.43E-06	3.00E-02
ETHYL BENZENE	1.00E-03	2.45E-06	2.15E-02
FORMALDEHYDE	1.31E+00	3.21E-03	2.82E+01
HEXANE-N	6.48E-02	1.59E-04	1.39E+00
HYDROCHLORIC ACID	6.46E-01	1.58E-03	1.39E+01
HYDROGEN SULFIDE	2.15E-02	5.27E-05	4.61E-01
METHYL CHLOROFORM (1,1,1-TCA)	1.00E-04	2.45E-07	2.15E-03
METHYL ETHYL KETONE	1.00E-04	2.45E-07	2.15E-03
METHYLENE CHLORIDE	1.00E-04	2.45E-07	2.15E-03
PERCHLOROETHYLENE	5.00E-04	1.23E-06	1.07E-02
TOLUENE	6.48E-02	1.59E-04	1.39E+00
TRICHLOROETHYLENE	3.00E-04	7.35E-07	6.44E-03
XYLENES	4.50E-03	1.10E-05	9.66E-02

Release Parameters:

Stack Height (ft)	18
Stack Diameter (ft)	0.41
Temperature deg F	300
Vertical Airflow (acfm)	534

Discussion

The HRA was conducted in accordance with EPA and OEHHA guidance and District standard procedures. A point source was modeled with refined air dispersion modeling using EPA's ISC-Prime model, actual Oceanside / 1996-1998 meteorology data, complex terrain, and rural dispersion coefficients. Building downwash effects were calculated using the EPA BPIP-Prime model. The receptor grid was sufficiently dense to identify maximum impacts.

Since the engine emissions are based on continuous operations (24 hours per day and 7 days a week) an occupational ground level concentration (GLC) adjustment was not applied referencing the OEHHA Guidance Manual, *Calculating Cancer Risk Using Different Exposure Durations*, Section 8.2.2, *B. Worker*.

APP-002146

2.4 Attachments:
None.

3.0 EMISSIONS

3.1 Emission Estimate Summary:

Table 1: Calculated Normal Emissions					
	NOx	CO	VOC	SOx	PM_{10}
lbs/hr	0.28	2.34	0.37	0.005	0.07
lbs/day	6.73	56.1	8.97	0.12	1.62
tons/yr	1.23	10.2	1.62	0.02	0.30

3.2 Emission Estimate Assumptions:
Operating Schedule: 24 hrs/day, 8760 hrs/yr
Manufacturer's Emission Guarantees: NOx = 0.6 g/BHP-hr
CO = 5.0 g/BHP-hr
VOC = 0.8 g/BHP-hr
Exhaust flow rate calculated using EPA Method 19 (F_d = 9570 dscf/MMBtu)

3.3 Emission Calculations:
See attached calculations sheet.

3.4 Attachments:
None.

4.0 APPLICABLE RULES

4.1 Prohibitory Rules:

Rule 50 – Visible Emissions:
This rule limits air contaminant emissions into the atmosphere of shade greater than Ringlemann Number 1, to a maximum aggregate of three minutes in any consecutive sixty minute time period.
With proper maintenance and operation, no visible emissions are expected from this equipment.

Rule 51 – No Nuisance:
This rule prohibits discharge of air contaminants that cause or have a tendency to cause injury, nuisance or annoyance to people and/or the public or damage to business or property.
With proper maintenance and operation, no nuisance complaints are expected from the operation of this equipment.

Rule 53 – Specific Air Contaminants:
This rule prohibits the discharge of sulfur compounds, calculated as SO_2 in excess of 0.05% by volume on a dry basis and the discharge of particulate matter from combustion sources in excess of 0.10 grains/dscf standardized to 12% CO_2.
The estimated SOx (as SO_2) emissions from this engine is 2.4 ppm. The estimated grain loading from this engine is 0.0033 gr/dscf.

Rule 62 – Sulfur Content of Fuels:
This rule prohibits the use of any gaseous fuel containing more than 10 grains of sulfur compounds, calculated as H_2S, per 100 dscf of gas, and any liquid fuel containing more than 0.5% sulfur by weight.
This rule does not apply to the combustion of digester gas.

APP-002146

1. **Ducted or Stack Emissions** (For 1 or more emission points). Estimate values if you are unsure.

Parameter	Point #1	Point #2	Point #3	Point #4	Point #5	Point #6
Height of Exhaust above ground (ft)	18					
Stack Diameter (or length/width) (ft)	5 in.					
Exhaust Gas Temperature* (°F)	300					
Exhaust Gas Flow (actual cfm or fps)	534					
Is Exhaust Vertical (Yes or No)	Y					
Raincap? (None, Flapper Valve, Raincap)	No					
Distance to Property Line (+/- 10 ft)	20					

* Use "70 °F" or "Ambient" if unknown

2. **Unducted Emissions** (For 1 or more emission points). Estimate if you are unsure.

Describe how unducted gases, vapors, and/or particles get into the outside air. Provide a brief description of the process or operation for each unducted emission point. If unducted emissions come out of building openings such as doors or windows, estimate the **size of the opening** (example – 3 ft x 4 ft window).

If unducted emissions originate outside your buildings, estimate the **size of the emission zone** (example - paint spraying 2' x 2' x 2' bread boxes).

RECEPTOR DATA A receptor is a residence or business whose occupants could be exposed to toxic emissions from your facility. In order to estimate the risk to nearby receptors, please provide the distance from the emission point to the nearest residence and to the nearest business.

Distance to nearest residence 250 ft

Distance to nearest business 250 ft

Distance to nearest school 1790 ft

Name of Preparer: Chuck Solt **Title:** Principal of Lindh & Associate

Phone No.: (916) 729-5004 **E-mail:** Chuck@CSolt.net **Date:** 4/4/2012

NOTE TO APPLICANT:

Before acting on an application for Authority to Construct or Permit to Operate, the District may require further information, plans, or specifications. Forms with insufficient information may be returned to the applicant for completion, which will cause a delay in application processing and may increase processing fees. The applicant should correspond with equipment and material manufacturers to obtain the information requested on this supplemental form.

APCD
AIR POLLUTION CONTROL DISTRICT
COUNTY OF SAN DIEGO

County of San Diego
AIR POLLUTION CONTROL DISTRICT
10124 Old Grove Road, San Diego, CA 92131

(858) 586-2600
FAX (858) 586-2601
Smoking Vehicle Hotline
1-800-28-SMOKE
www.sdapcd.org

February 19, 2013

Owner Manager
CHPCE La Salina LLC
1 Liberty Square, 11th Floor
Boston, MA 02109

After examination of your Application APCD2012-APP-002146 for an Air Pollution Control District (District) Authority to Construct and Permit to Operate for equipment to be located at 1360 TAIT ST, OCEANSIDE, CA 92054 in San Diego County, the District has decided on the following actions:

Authority to Construct is granted pursuant to Rule 20 of the Air Pollution Control District Rules and Regulations for equipment to consist of:

Cogeneration Engine: Liebherr, Model G6926, digester gas fired, 212 BHP, S/N TBD, driving a 150 kW generator.

This Authority to Construct is issued with the following conditions:

1 Operation of this equipment shall be conducted in accordance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.

2 The emissions of oxides of nitrogen (NOx), calculated as nitrogen dioxide, from the engine exhaust shall not exceed 0.6 g/BHP-hr.

3 The emissions of carbon monoxide (CO) from the engine exhaust shall not exceed 5.0 g/BHP-hr.

4 The emissions of volatile organic compounds (VOC), calculated as methane, from the engine exhaust shall not exceed 0.8 g/BHP-hr.

5 The engine shall be equipped with a digester gas fuel flow meter and recorder. This meter shall be in full operation at all times when the engine is in operation and shall be calibrated in accordance with manufacturer's specifications at least once every six months to verify that an accurate reading of plus or minus 5 percent is being maintained.

6 The exhaust stack shall be equipped with source test ports and platforms to allow for the measurement and collection of stack gas samples consistent with all approved test protocols. The ports and platforms shall be constructed in accordance with San Diego Air Pollution Control District Method 3A, Appendix Figure 2, and approved by the District.

7 Within 60 days after the initial startup, an initial source test shall be conducted by an independent, ARB approved tester, or the District, at the applicant's expense, to determine initial compliance with the emission standards of this Authority to Construct. A source test protocol shall be submitted to the District for approval at least 30 days prior to

the initial source test. The source test protocol shall comply with the following requirements:

a. Measurements of outlet oxides of nitrogen (NOx), carbon monoxide (CO), and stack gas oxygen content (O2%) shall be conducted in accordance with the District Source Test Method 100, or the Air Resources Board (ARB) Test Method 100 as approved by the U.S. Environmental Protection Agency (EPA).

b. Measurements of outlet volatile organic compound (VOC) emissions shall be conducted in accordance with the San Diego Air Pollution Control District Methods 25A and/or 18.

c. Source testing shall be performed at no less than 90% of the engine rated load. If it is demonstrated to the District that this engine cannot operate at these conditions, then emissions source testing shall be performed at the highest achievable continuous power rating or under the typical duty cycle or typical operational mode of the engine.

d. During the source test, the site shall measure and record the higher heating value, in BTU per cubic feet, the flow rate, in standard cubic feet per minute, and the composition of the digester gas.

8 Within 30 days after completion of the initial source tests, a final test report shall be submitted to the District for review and approval. The testing contractor shall include, as part of the test report, a certification that to the best of his knowledge the report is a true and accurate representation of the test conducted and the results.

9 Based on source testing, additional monitoring parameters may be established through modification of a Startup Authorization or Permit to Operate to ensure compliance. Operating characteristics monitored by continuous parametric monitors may also be restricted to specified ranges or limits, as determined by the District, based upon manufacturer's recommended operating procedures and initial compliance source test results.

10 This equipment shall be properly maintained and kept in good operating condition at all times.

11 The owner or operator shall change the engine oil and filter, inspect the spark plugs, and inspect/replace as necessary all hoses and belts every 1,440 hours of operation or annually whichever comes first. (NESHAP ZZZZ)

12 The owner or operator shall conduct periodic inspections of this engine, and any add-on control equipment, as applicable, to ensure that the engine and control equipment is operated in compliance with the provision of this Authority to Construct. The periodic inspections shall be conducted at least once every six months.

13 The owner or operator shall conduct periodic maintenance of this engine, and any add-on control equipment, as applicable, as recommended by the engine and control equipment manufacturers or as specified by any other maintenance procedure approved in writing by the District. The periodic maintenance shall be conducted at least once each calendar year.

14 The owner or operator shall keep a manual of recommended maintenance provided by the manufacturer, or other maintenance procedures as approved in writing by the District.

15 The owner or operator shall maintain an operating log containing, at a minimum, the following: records of periodic engine inspections, including the dates the inspection was performed; records of engine maintenance, including the dates maintenance was performed and the nature of the maintenance.

16 The permittee shall comply with all initial and periodic notification requirements specified by 40 CFR 60.4245, including submitting an intial notification and results of all performance testing to the APCD, and any other applicable notification requirements required by 40 CFR 60.7.

17 All records required by this permit shall be kept for a minimum of three years and made available to District personnel upon request.

18 This equipment shall be source tested at least once each permit year (annual source test) to demonstrate compliance with the emission standards contained in this Authority to Construct. For the purposes of this Authority to Construct, a permit year is the 12-month period ending on the last day of the permit expiration month. It is the responsibility of the permittee to schedule the source test with the District. The source test shall be performed or witnessed by the District. Each annual source test shall be separated by at least 90 days from any annual source test performed in a different permit year.

19 Access, facilities, utilities and any necessary safety equipment for source testing and inspection shall be provided upon request of the Air Pollution Control District.

20 This Air Pollution Control District Permit does not relieve the holder from obtaining permits or authorizations required by other governmental agencies.

21 The permittee shall, upon determination of applicability and written notification by the District, comply with all applicable requirements of the Air Toxics "Hot Spots" Information and Assessment Act (California Health and Safety Code Section 44300 et seq.)

This Authority to Construct authorizes temporary operation of the above-specified equipment. This temporary Permit to Operate shall take effect upon written notification to the District that construction (or modification) has been completed in accordance with this Authority to Construct. This temporary Permit to Operate will remain in effect, unless withdrawn or modified by the District, and a revised temporary permit (Startup Authorization) is issued or a Permit to Operate is granted or denied.

Upon completion of construction (or modification) in accordance with this Authority to Construct, and prior to commencing operation, the applicant must complete and mail, deliver or fax the enclosed Construction Completion Notice to the District. After mailing, delivering or faxing the notice, the applicant may commence operation of the equipment. Operation must be in compliance with all the conditions of this Authority to Construct and applicable District Rules.

This Authority to Construct shall be posted on or within 25 feet of the above described equipment or maintained readily available at all times on the operating premises.

This Air Pollution Control District Authority to Construct does not relieve the holder from obtaining permits or authorizations, which may be required by other governmental agencies. This Authority to Construct is not authority to exceed any applicable emission standard established by this District or any other governmental agency. This authorization is subject to cancellation if any emission standard or condition is violated.

Within 30 days after receipt of this Authority to Construct, the applicant may petition the Hearing Board for a hearing on any conditions imposed herein in accordance with Rule 25.

This Authority to Construct will expire on 02/19/2014 unless an extension is granted in writing.

CHPCE La Salina LLC

Application #: APCD2012-APP-002146

February 19, 2013

This is not a Permit to Operate. Please be advised that installation or operation of this process or equipment without written authorization may be a misdemeanor subject to fines and penalties.

If you have any questions regarding this action, please contact me at (858) 586 2741 or via email at Arthur.Carbonell@sdcounty.ca.gov.

Arthur Carbonell
Associate Engineer

CC: Compliance Division

Appendix 5.9A
Sensitive Receptors within 3-Miles of Project Site

Table 5.9A-1
Sensitive Receptors within 3-Miles of CECP

TYPE	NAME	X_COORD	Y_COORD
Daycare	PARKHURST, CARLENE FAMILY CHILD CARE	-117.314164	33.103256
Daycare	CARLSBAD EDUCATIONAL FOUNDATION-PACIFIC RIM ELEM.	-117.30596	33.11021
Daycare	KINDERCARE-CARLSBAD	-117.304659	33.115406
Daycare	BERIAN, KRISTEN FAMILY CHILD CARE	-117.291455	33.116743
Daycare	HANNAY, CAROL FAMILY CHILD CARE	-117.297139	33.117927
Daycare	MA, AMY FAMILY CHILD CARE	-117.304933	33.118095
Daycare	NHA-LAUREL TREE HEAD START	-117.3017	33.121575
Daycare	STEED, SHAWNA FAMILY CHILD	-117.301645	33.121587
Hospital	HOSPICE OF THE NORTH COAST	-117.326944	33.129286
Hospital	HOSPICE OF NORTH COAST	-117.327067	33.129516
College	GEMOLOGICAL INSTITUTE OF AMERICA	-117.317849	33.131271
Daycare	CARLSBAD COUNTRY DAY SCHOOL	-117.304289	33.141853
Daycare	CARLSBAD EDUCATIONAL FOUNDATION - KELLY ELEM.	-117.311178	33.148369
Daycare	HOWARD, LYNNA FAMILY CHILD CARE	-117.331587	33.149835
Daycare	GRISHAM, SYLVIA & JAMES FAMILY CHILD CARE	-117.317959	33.15086
Daycare	BLOSCH, SUSAN FAMILY CHILD CARE	-117.310411	33.151917
Daycare	WATSON, JAMIE AND ERIC FAMILY CHILD CARE	-117.317479	33.152949
School	ST PATRICK	-117.336518	33.153421
Daycare	CARLSBAD EDUCATIONAL FOUNDATION - JEFFERSON ELEM.	-117.339545	33.153804
Daycare	MEGASTAR CHILDRENS CHRISTIAN ACADEMY	-117.336956	33.153974
Daycare	ESTES, CYNTHIA FAMILY DAY CARE	-117.335491	33.155521
Daycare	CASA MONTESSORI DE CARLSBAD	-117.342449	33.155659
Daycare	FRIEDRICHS, ROSIE FAMILY CHILD CARE	-117.346229	33.15843
Nursing	CARLSBAD BY THE SEA	-117.352914	33.15875
Daycare	NHA - CARLSBAD HEAD START	-117.339011	33.158819
Daycare	CARLSBAD MONTESSORI SCHOOL	-117.344394	33.158876
Daycare	GREENE, MARYANN & JAMES FAMILY CHILD CARE	-117.34538	33.159199
Daycare	SAGUILAN, DIGNA FAMILY CHILD CARE	-117.339038	33.159346
Hospital	CARLSBAD BY THE SEA	-117.352215	33.159599
Daycare	CARLSBAD EDUCATIONAL FOUNDATION - MAGNOLIA ELEM.	-117.326725	33.160115
Daycare	PILGRIM DAY CARE CENTER	-117.325903	33.161682
Daycare	HUDGINS, BRENDA FAMILY DAY CARE	-117.320903	33.161929
Daycare	BENAVIDEZ, KARAH FAMILY CHILD CARE	-117.294235	33.162203
Hospital	QUALITY CARE MEDICAL CENTER INC	-117.349585	33.162523
Daycare	VALLE-LICERIO, ROSEMARY FAMILY CHILD CARE	-117.313575	33.162808
Daycare	DANNA, DORA FAMILY CHILD CARE	-117.339381	33.163389
Daycare	HATFIELD, LIGIA & REJANE, MINNIE FAMILY CHILD CARE	-117.332984	33.164161
Daycare	BAGLEY, KATHLEEN FAMILY CHILD CARE	-117.319178	33.164199
Daycare	BIRKLEY, JANICE FAMILY DAY CARE	-117.31248	33.165011
Hospital	LAS VILLAS DE CARLSBAD RESIDENTIAL	-117.344175	33.165279
Hospital	LAS VILLAS DE CARLSBAD HEALTH	-117.344065	33.165279
Nursing	LAS VILLAS DE CARLSBAD HEALTH CENTER	-117.344065	33.165279
Daycare	PACKARD, SUSAN FAMILY CHILD CARE	-117.327916	33.16544
Daycare	VAZIRI, ZAHRA FAMILY CHILD CARE	-117.330382	33.166166
Daycare	CROOT, DEBBIE FAMILY DAY CARE	-117.32767	33.166367
Daycare	COOPER, ANNA FAMILY CHILD CARE	-117.327971	33.166923
Daycare	CARLSBAD CHILDREN'S HOUSE	-117.34838	33.166932
School	BEAUTIFUL SAVIOUR LUTHERAN SCH	-117.33534	33.16709
Daycare	BURT, SHARON FAMILY CHILD CARE	-117.316219	33.1673
Daycare	BURKHALTER, SUZANNE FAMILY CHILD CARE	-117.343065	33.167966
Daycare	BLACKBURN, KATHRYN FAMILY DAY CARE	-117.308891	33.16819
Daycare	CARLSBAD CHILDREN'S GARDEN	-117.34838	33.168614
Daycare	CARLSBAD EDUCATIONAL FOUNDATION-BUENA VISTA ELEM.	-117.342531	33.168884
Daycare	HANNA, LILY BETH & DIA FAMILY CHILD CARE	-117.343216	33.168893
Daycare	KESSNER, ISABEL FAMILY CHILD CARE	-117.334779	33.17137
Hospital	WELL BEING MEDICAL CLINIC	-117.323547	33.173118
Hospital	BRIGHTON GARDENS OF CARLSBAD	-117.323629	33.173213
Nursing	BRIGHTON GARDENS OF CARLSBAD	-117.323629	33.173213
Hospital	NCHS OCEANSIDE CARLSBAD HEALTH CNTR	-117.362858	33.174822
School	BRIGHT HORIZONS	-117.325369	33.175047
Daycare	IMMANUEL LUTHERAN CHILDREN'S LEARNING CENTER	-117.357913	33.175447
School	SOUTH OCEANSIDE ELEMENTARY	-117.358118	33.17746
Daycare	HEDSTROM, LORA AND DENARO, ERIN	-117.353489	33.178171
Daycare	BROCKAVICH, MICHELLE FAMILY CHILD CARE	-117.354954	33.178511
Daycare	MAAC PROJECT HEAD START NORTH COAST	-117.351023	33.179608
Hospital	NORTH COAST KIDNEY CENTER	-117.317438	33.181287
Hospital	QUALITY CARE MEDICAL CENTER	-117.323218	33.182571

Appendix 5.9B
Detailed Noncriteria Emission Calculations

Table 5.9B-1
CECP Amendment
Non-Criteria Pollutant Emission Calculations Gas Turbines (Hourly Emissions)

Pollutant	Uncontrolled Emission Factor (lbs/MMBtu)	Basis	Normal Oper. Controlled Emission Factor (lbs/MMBtu)	Worst Case Startup/Shutdown VOC Emiss. Vs. Normal Operation VOC Emiss.(5) (lbs/hr)/(lbs/hr)	Startup/Shutdown Emission Factor(5) (lbs/MMBtu)	Commissioning Emission Factor(6) (lbs/MMBtu)	Single GT Max. Firing Rate (MMBtu/hr)	Single GT Normal Oper. Emissions (lbs/hr)	Single GT Startup/Shutdown Emissions (lbs/hr)	Single GT Commissioning Emissions (lbs/hr)
Ammonia	6.87E-03	Permit Limit(3)	6.87E-03	2.48	6.87E-03	6.87E-03	983.6	6.76E+00	6.76E+00	6.76E+00
Propylene	7.56E-04	0.5*CATEF(2)	3.78E-04	2.48	9.36E-04	7.56E-04	983.6	3.72E-01	9.21E-01	7.44E-01
Hazardous Air Pollutants (HAPs) - Federal										
Acetaldehyde	4.00E-05	0.5*AP-42(1)	2.00E-05	2.48	4.95E-05	4.00E-05	983.6	1.97E-02	4.87E-02	3.93E-02
Acrolein	6.42E-06	0.5*AP-42(1)	3.21E-06	2.48	7.95E-06	6.42E-06	983.6	3.16E-03	7.82E-03	6.31E-03
Benzene	1.20E-05	0.5*AP-42(1)	5.99E-06	2.48	1.48E-05	1.20E-05	983.6	5.89E-03	1.46E-02	1.18E-02
1,3-Butadiene	4.30E-07	0.5*AP-42(1)	2.15E-07	2.48	5.32E-07	4.30E-07	983.6	2.11E-04	5.24E-04	4.23E-04
Ethylbenzene	3.20E-05	0.5*AP-42(1)	1.60E-05	2.48	3.96E-05	3.20E-05	983.6	1.57E-02	3.90E-02	3.15E-02
Formaldehyde	9.00E-04	0.5*CATEF(2)	4.50E-04	2.48	1.11E-03	9.00E-04	983.6	4.43E-01	1.10E+00	8.85E-01
Hexane, n-	2.54E-04	0.5*CATEF(2)	1.27E-04	2.48	3.15E-04	2.54E-04	983.6	1.25E-01	3.09E-01	2.50E-01
Naphthalene	1.31E-06	0.5*AP-42(1)	6.53E-07	2.48	1.62E-06	1.31E-06	983.6	6.42E-04	1.59E-03	1.28E-03
Total PAHs (listed individually bel	6.43E-07	SUM	3.22E-07	2.48	7.97E-07	6.43E-07	983.6	3.16E-04	7.84E-04	6.33E-04
Acenaphthene	1.86E-08	0.5*CATEF(2)	9.32E-09	2.48	2.31E-08	1.86E-08	983.6	9.17E-06	2.27E-05	1.83E-05
Acenapthyene	1.44E-08	0.5*CATEF(2)	7.21E-09	2.48	1.79E-08	1.44E-08	983.6	7.09E-06	1.76E-05	1.42E-05
Anthracene	3.32E-08	0.5*CATEF(2)	1.66E-08	2.48	4.11E-08	3.32E-08	983.6	1.63E-05	4.04E-05	3.27E-05
Benzo(a)anthracene	2.22E-08	0.5*CATEF(2)	1.11E-08	2.48	2.75E-08	2.22E-08	983.6	1.09E-05	2.70E-05	2.18E-05
Benzo(a)pyrene	1.36E-08	0.5*CATEF(2)	6.82E-09	2.48	1.69E-08	1.36E-08	983.6	6.71E-06	1.66E-05	1.34E-05
Benzo(e)pyrene	5.34E-10	0.5*CATEF(2)	2.67E-10	2.48	6.61E-10	5.34E-10	983.6	2.63E-07	6.50E-07	5.25E-07
Benzo(b)fluoranthrene	1.11E-08	0.5*CATEF(2)	5.54E-09	2.48	1.37E-08	1.11E-08	983.6	5.45E-06	1.35E-05	1.09E-05
Benzo(k)fluoranthrene	1.08E-08	0.5*CATEF(2)	5.40E-09	2.48	1.34E-08	1.08E-08	983.6	5.31E-06	1.32E-05	1.06E-05
Benzo(g,h,i)perylene	1.34E-08	0.5*CATEF(2)	6.72E-09	2.48	1.66E-08	1.34E-08	983.6	6.61E-06	1.64E-05	1.32E-05
Chrysene	2.48E-08	0.5*CATEF(2)	1.24E-08	2.48	3.07E-08	2.48E-08	983.6	1.22E-05	3.02E-05	2.44E-05
Dibenz(a,h)anthracene	2.30E-08	0.5*CATEF(2)	1.15E-08	2.48	2.85E-08	2.30E-08	983.6	1.13E-05	2.80E-05	2.26E-05
Fluoranthene	4.24E-08	0.5*CATEF(2)	2.12E-08	2.48	5.25E-08	4.24E-08	983.6	2.09E-05	5.16E-05	4.17E-05
Fluorene	5.70E-08	0.5*CATEF(2)	2.85E-08	2.48	7.06E-08	5.70E-08	983.6	2.80E-05	6.94E-05	5.61E-05
Indeno(1,2,3-cd)pyrene	2.30E-08	0.5*CATEF(2)	1.15E-08	2.48	2.85E-08	2.30E-08	983.6	1.13E-05	2.80E-05	2.26E-05
Phenanthrene	3.08E-07	0.5*CATEF(2)	1.54E-07	2.48	3.81E-07	3.08E-07	983.6	1.51E-04	3.75E-04	3.03E-04
Pyrene	2.72E-08	0.5*CATEF(2)	1.36E-08	2.48	3.37E-08	2.72E-08	983.6	1.34E-05	3.31E-05	2.68E-05
Propylene oxide	2.90E-05	0.5*AP-42(1)	1.45E-05	2.48	3.59E-05	2.90E-05	983.6	1.43E-02	3.53E-02	2.85E-02
Toluene	1.31E-04	0.5*AP-42(1)	6.53E-05	2.48	1.62E-04	1.31E-04	983.6	6.42E-02	1.59E-01	1.28E-01
Xylene	6.40E-05	0.5*AP-42(1)	3.20E-05	2.48	7.92E-05	6.40E-05	983.6	3.15E-02	7.79E-02	6.30E-02

Notes:
(1) AP-42, Table 3.1-3, 4/00.
(2) From CARB CATEF database (converted from lbs/MMscf to lbs/MMBtu based on site natural gas HHV of 1,019.9 Btu/scf).
(3) Based on 5 ppm ammonia slip from SCR system.
(4) Based on SDAPCD workbook emission factor.
(5) Controlled emission factor adjusted upward based on VOC emission ratio - as required by SDAPCD for the Pio Pico Energy Center.
(6) Based on uncontrolled emission factors - as required by SDAPCD for the Pio Pico Energy Center.

Table 5.9B-2
CECP Amendment
Non-Criteria Pollutant Emissions Gas Turbines (Annual Emissions)

Pollutant	Single Turbine Normal Operating Hours (hrs/yr)	Single Turbine Startup/Shutdown Hours (hrs/yr)	Single Turbine Commissioning Hours (hrs/yr)	Single Turbine(1) Annual Emissions (tons/yr)	Six Turbines(1) Annual Emissions (tons/yr)	Single Turbine Annual Commissioning Emissions (tons/yr)	Six Turbines Annual Commissioning Emissions (tons/yr)
Ammonia	1,900	800	213	9.12	54.73	0.72	4.31
Propylene	1,900	800	213	0.72	4.33	0.08	0.47
Hazardous Air Pollutants (HAPs) - Federal							
Acetaldehyde	1,900	800	213	0.038	0.23	0.004	0.025
Acrolein	1,900	800	213	0.006	0.04	0.001	0.004
Benzene	1,900	800	213	0.011	0.07	0.001	0.008
1,3-Butadiene	1,900	800	213	0.000	0.00	0.000	0.000
Ethylbenzene	1,900	800	213	0.031	0.18	0.003	0.020
Formaldehyde	1,900	800	213	0.859	5.15	0.094	0.564
Hexane, n-	1,900	800	213	0.242	1.45	0.027	0.159
Naphthalene	1,900	800	213	0.001	0.01	0.000	0.001
Total PAHs (listed individually bel	1,900	800	213	0.001	0.00	0.000	0.000
Acenaphthene	1,900	800	213	0.000	0.00	0.000	0.000
Acenapthyene	1,900	800	213	0.000	0.00	0.000	0.000
Anthracene	1,900	800	213	0.000	0.00	0.000	0.000
Benzo(a)anthracene	1,900	800	213	0.000	0.00	0.000	0.000
Benzo(a)pyrene	1,900	800	213	0.000	0.00	0.000	0.000
Benzo(e)pyrene	1,900	800	213	0.000	0.00	0.000	0.000
Benzo(b)fluoranthrene	1,900	800	213	0.000	0.00	0.000	0.000
Benzo(k)fluoranthrene	1,900	800	213	0.000	0.00	0.000	0.000
Benzo(g,h,i)perylene	1,900	800	213	0.000	0.00	0.000	0.000
Chrysene	1,900	800	213	0.000	0.00	0.000	0.000
Dibenz(a,h)anthracene	1,900	800	213	0.000	0.00	0.000	0.000
Fluoranthene	1,900	800	213	0.000	0.00	0.000	0.000
Fluorene	1,900	800	213	0.000	0.00	0.000	0.000
Indeno(1,2,3-cd)pyrene	1,900	800	213	0.000	0.00	0.000	0.000
Phenanthrene	1,900	800	213	0.000	0.00	0.000	0.000
Pyrene	1,900	800	213	0.000	0.00	0.000	0.000
Propylene oxide	1,900	800	213	0.028	0.17	0.003	0.018
Toluene	1,900	800	213	0.125	0.75	0.014	0.082
Xylene	1,900	800	213	0.061	0.37	0.007	0.040
Total (HAPs) =				1.40	8.42	0.15	0.92
Total (All) =				11.25	67.48	0.95	5.70

Notes:
(1) Includes startup/shutdown emissions.

Table 5.9B-3
CECP Amendment
Non-Criteria Pollutant Emission Calculations Emergency Engines

Pollutant	Emission Factor (lbs/Mgal)	Basis	Firepump Fuel Use (gals/hr)	Generator Fuel Use (gals/hr)	Firepump Fuel Use (gals/year)	Generator Fuel Use (gals/year)	Firepump Hourly Emissions (lbs/hr)	Generator Hourly Emissions (lbs/hr)	Firepump Annual Emissions (tons/yr)	Generator Annual Emissions (tons/yr)
Diesel PM (Not a HAPS)	N/A	N/A	14.8	35.9	2960	7180	3.96E-02	2.58E-02	3.96E-03	2.58E-03
Acrolein	1.07E-03	CATEF	14.8	35.9	2960	7180	1.58E-05	3.84E-05	1.584E-06	3.841E-06

Pollutant	Firepump Acute Modeling Hourly Emission Rate (g/sec)	Generator Acute Modeling Hourly Emission Rate (g/sec)	Firepump Chronic/Cancer Risk Modeling Annual Emission Rate (g/sec)	Generator Chronic/Cancer Risk Modeling Annual Emission Rate (g/sec)
Diesel PM (Not a HAPS)	N/A	N/A	1.14E-04	7.41E-05
Acrolein	2.00E-06	4.84E-06	N/A	N/A

Table 5.9B-4
CECP Amendment
Non-Criteria Pollutant Emission Factors
Existing Units 1 - 5 and Peaker Gas Turbine

Pollutant	Boiler Emission Factors(1) lb/MMscf	GT Emission Factors(1) lb/MMscf	Unit 1 Max Firing Rate MMBtu/hr	Unit 2 Max Firing Rate MMBtu/hr	Unit 3 Max Firing Rate MMBtu/hr	Unit 4 Max Firing Rate MMBtu/hr	Unit 5 Max Firing Rate MMBtu/hr	GT Max Firing Rate MMBtu/hr	Natural Gas HHV Btu/scf
Ammonia (not a HAP)	4.58E+00	0.00E+00	1013	1013	1128	3245	3475	317	1019.8
Benzene	2.10E-03	1.22E-02	1013	1013	1128	3245	3475	317	1019.8
Formaldehyde	7.50E-02	7.24E-01	1013	1013	1128	3245	3475	317	1019.8
Hexane	1.30E-03		1013	1013	1128	3245	3475	317	1019.8
Naphthalene	6.10E-04	1.30E-03	1013	1013	1128	3245	3475	317	1019.8
Dichlorobenzene	1.20E-03		1013	1013	1128	3245	3475	317	1019.8
Toluene	3.40E-03	1.33E-01	1013	1013	1128	3245	3475	317	1019.8
1,3-Butadiene		4.00E-04	1013	1013	1128	3245	3475	317	1019.8
Acetaldehyde		4.08E-02	1013	1013	1128	3245	3475	317	1019.8
Acrolein		6.50E-03	1013	1013	1128	3245	3475	317	1019.8
Ethyl Benzene		3.26E-02	1013	1013	1128	3245	3475	317	1019.8
PAHs (other)		2.20E-03	1013	1013	1128	3245	3475	317	1019.8
Xylene		6.53E-02	1013	1013	1128	3245	3475	317	1019.8

Notes:
(1) All factors except hexane and ammonia from the SDAPCD 2009 Toxic Inventory Report for the Encina Power Plant.
Hexane from the Ventura County APCD AB2588 emission factors for natural gas external combustion equipment (greater than 100 MMBtu/hr), May 17, 2001.
Ammonia based on SDAPCD permit limit of 10 ppm @ 3% O2 ammonia slip.

Table 5.9B-5
CECP Amendment
Non-Criteria Pollutant Hourly Emissions
Existing Units 1 - 5 and Peaker Gas Turbine

Pollutant	Unit 1 Emissions lb/hr	Unit 2 Emissions lb/hr	Unit 3 Emissions lb/hr	Unit 4 Emissions lb/hr	Unit 5 Emissions lb/hr	GT Emissions lb/hr
Ammonia (not a HAP)	4.55E+00	4.55E+00	5.07E+00	1.46E+01	1.56E+01	0.00E+00
Benzene	2.09E-03	2.09E-03	2.32E-03	6.68E-03	7.16E-03	3.79E-03
Formaldehyde	7.45E-02	7.45E-02	8.30E-02	2.39E-01	2.56E-01	2.25E-01
Hexane	1.29E-03	1.29E-03	1.44E-03	4.14E-03	4.43E-03	0.00E+00
Naphthalene	6.06E-04	6.06E-04	6.75E-04	1.94E-03	2.08E-03	4.04E-04
Dichlorobenzene	1.19E-03	1.19E-03	1.33E-03	3.82E-03	4.09E-03	0.00E+00
Toluene	3.38E-03	3.38E-03	3.76E-03	1.08E-02	1.16E-02	4.13E-02
1,3-Butadiene	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.24E-04
Acetaldehyde	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.27E-02
Acrolein	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.02E-03
Ethyl Benzene	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.01E-02
PAHs (other)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	6.84E-04
Xylene	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.03E-02

Appendix 5.9C
Modeling Inputs for Screening Level HRA

Table 5.9C-1
CECP Amendment
Non-Criteria Pollutant Emissions Gas Turbines (Modeling Inputs)

Pollutant	For Acute Modeling Hourly Normal Oper. Emission Rate Per Turbine (g/sec) (each)	For Acute Modeling Hourly Startup/Shutdown Emission Rate Per Turbine (g/sec) (each)	For Acute Modeling Hourly Commissioning Emission Rate Per Turbine (g/sec) (each)	For Chronic/Cancer Risk Modeling Annual Normal Oper. Emission Rate(1) Per Turbine (g/sec) (each)	For Chronic/Cancer Risk Modeling Annual Commissioning Emission Rate(1) Per Turbine (g/sec) (each)
Ammonia	8.51E-01	8.51E-01	8.51E-01	2.62E-01	2.07E-02
Propylene	4.68E-02	1.16E-01	9.37E-02	2.08E-02	2.27E-03
Hazardous Air Pollutants (HAPs) - Federal					
Acetaldehyde	2.48E-03	6.14E-03	4.96E-03	1.10E-03	1.20E-04
Acrolein	3.98E-04	9.85E-04	7.96E-04	1.76E-04	1.93E-05
Benzene	7.42E-04	1.84E-03	1.48E-03	3.29E-04	3.60E-05
1,3-Butadiene	2.66E-05	6.60E-05	5.33E-05	1.18E-05	1.29E-06
Ethylbenzene	1.98E-03	4.91E-03	3.97E-03	8.79E-04	9.62E-05
Formaldehyde	5.58E-02	1.38E-01	1.12E-01	2.47E-02	2.71E-03
Hexane, n-	1.57E-02	3.90E-02	3.15E-02	6.97E-03	7.64E-04
Naphthalene	8.09E-05	2.00E-04	1.62E-04	3.59E-05	3.93E-06
Total PAHs (listed individually below)	3.99E-05	9.87E-05	7.97E-05	1.77E-05	1.93E-06
Acenaphthene	1.16E-06	2.86E-06	2.31E-06	5.12E-07	5.60E-08
Acenapthyene	8.94E-07	2.21E-06	1.79E-06	3.96E-07	4.34E-08
Anthracene	2.06E-06	5.09E-06	4.11E-06	9.11E-07	9.98E-08
Benzo(a)anthracene	1.38E-06	3.41E-06	2.75E-06	6.09E-07	6.67E-08
Benzo(a)pyrene	8.45E-07	2.09E-06	1.69E-06	3.74E-07	4.10E-08
Benzo(e)pyrene	3.31E-08	8.19E-08	6.62E-08	1.47E-08	1.61E-09
Benzo(b)fluoranthrene	6.87E-07	1.70E-06	1.37E-06	3.04E-07	3.33E-08
Benzo(k)fluoranthrene	6.69E-07	1.66E-06	1.34E-06	2.97E-07	3.25E-08
Benzo(g,h,i)perylene	8.33E-07	2.06E-06	1.67E-06	3.69E-07	4.04E-08
Chrysene	1.54E-06	3.81E-06	3.07E-06	6.81E-07	7.46E-08
Dibenz(a,h)anthracene	1.43E-06	3.53E-06	2.85E-06	6.31E-07	6.91E-08
Fluoranthene	2.63E-06	6.51E-06	5.25E-06	1.16E-06	1.27E-07
Fluorene	3.53E-06	8.75E-06	7.06E-06	1.56E-06	1.71E-07
Indeno(1,2,3-cd)pyrene	1.43E-06	3.53E-06	2.85E-06	6.31E-07	6.91E-08
Phenanthrene	1.91E-05	4.73E-05	3.82E-05	8.46E-06	9.26E-07
Pyrene	1.69E-06	4.17E-06	3.37E-06	7.47E-07	8.18E-08
Propylene oxide	1.80E-03	4.45E-03	3.59E-03	7.96E-04	8.72E-05
Toluene	8.09E-03	2.00E-02	1.62E-02	3.59E-03	3.93E-04
Xylene	3.97E-03	9.82E-03	7.93E-03	1.76E-03	1.92E-04

Notes:
(1) Includes startup/shutdown emissions.

Table 5.9C-2
CECP Amendment
Non-Criteria Pollutant Modeling Inputs
Existing Units 1 - 5 and Peaker Gas Turbine

Pollutant	Unit 1 Hourly Emiss (g/sec)	Unit 2 Hourly Emiss. (g/sec)	Unit 3 Hourly Emiss. (g/sec)	Unit 4 Hourly Emiss. (g/sec)	Unit 5 Hourly Emiss. (g/sec)	GT Hourly Emiss. (g/sec)
Ammonia (not a HAP)	5.73E-01	5.73E-01	6.38E-01	1.84E+00	1.97E+00	0.00E+00
Benzene	2.63E-04	2.63E-04	2.93E-04	8.42E-04	9.02E-04	4.78E-04
Formaldehyde	9.39E-03	9.39E-03	1.05E-02	3.01E-02	3.22E-02	2.84E-02
Hexane	1.63E-04	1.63E-04	1.81E-04	5.21E-04	5.58E-04	0.00E+00
Naphthalene	7.63E-05	7.63E-05	8.50E-05	2.45E-04	2.62E-04	5.09E-05
Dichlorobenzene	1.50E-04	1.50E-04	1.67E-04	4.81E-04	5.15E-04	0.00E+00
Toluene	4.26E-04	4.26E-04	4.74E-04	1.36E-03	1.46E-03	5.21E-03
1,3-Butadiene	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.57E-05
Acetaldehyde	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.60E-03
Acrolein	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.55E-04
Ethyl Benzene	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.28E-03
PAHs (other)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	8.62E-05
Xylene	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.56E-03