Appendix B to California's Proposed Compliance Plan for the Federal Clean Power Plan:

Documentation of Communications with California EGUs

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A. Background

In developing the goals for California's, U.S. EPA used eGRID data to determine the list of affected units that would be used to calculate the state goals. This list was published at the time of the CPP rule making under the listing of technical support documents; U.S. EPA's data file: Goal Computation Appendix 1-5[1]. In comparing the two databases, ARB determined there was a possibility that some units excluded by U.S. EPA could be affected units. The Air Resources Board staff, in cooperation with the California Energy Commission staff, performed an analysis of each fossil-fueled generator located in California to determine applicability of the CPP.

Staff compared the results of this analysis to the unit list in U.S. EPA's data file and in comparing the two databases, ARB determined there was a possibility that some units excluded by U.S. EPA could be affected units. ARB staff did not have specific details for each unit's design efficiency, potential electric output and full historic operation to fully determine applicability of the CPP.

In order to determine the applicability of the CPP to EGUs in California, ARB sent a letter (below) to all facility owners (including the owners of the additional units ARB believed might meet CPP applicability criteria) stating that ARB believed their units could be affected units. We requested that each owner respond to ARB attesting to their view on the applicability of the CPP to their units, confirming or correcting the data in ARB's possession. If owners or operators believed that some units were not affected units, ARB requested that they provide documentation demonstrating any exemption claimed. The generic letter, the attachments and the listing of facilities contacted is shown below. Table 1 lists each EGU that differs from the published CPP List. An explanation for each EGU will follow:

[1] The list of affected units and excluded units (as supplied by U.S. EPA can be found here: http://www.epa.gov/sites/production/files/2015-11/tsd-cpp-emission-performance-rate-goal-computation-appendix-1-5.xlsx

Table 1 – EGUs Differing from the U.S. EPA List

EIA ID (Plant Code)	EIA Generator ID	Plant Name	Utility Name	Prime Mover	EIA MW	MW Rating Used	Operating Year	Final ARB Determination	U.S. EPA Determination
50748	GEN1	Agnews Power Plant	OLS Energy-Agnews Inc.	CT	24.4	22.8	1990	In	*Out*
50748	GEN2	Agnews Power Plant	OLS Energy-Agnews Inc.	CA	7.6	7.7	1990	In	*Out*
10650	GEN1	Badger Creek Cogen	Juniper Generation LLC	GT	46	47.0	1991	In	*Out*
10649	GEN1	Bear Mountain Cogen	Juniper Generation LLC	GT	46	47.0	1995	In	*Out*
50003	GEN1	Chalk Cliff Cogen	Juniper Generation LLC	GT	46	47.0	1990	In	*Out*
10635	GEN1	Corona Cogen	Juniper Generation LLC	GT	47	47.0	1988	In	*Out*
10156	GEN2	Fresno Cogen Partners	Wellhead Services Inc	CA	10	8.3	1990	In	*Out*
377	4	Grayson	City of Glendale	ST	50	44.0	1959	In	*Out*
377	5	Grayson	City of Glendale	ST	50	44.0	1964	In	*Out*
10349	GEN1	Greenleaf 2 Power Plant	Calpine Corp-Yuba City	GT	49.5	50.0	1989	In	*Out*
10496	GTAG	Kern River Cogeneration	Kern River Cogeneration Co	GT	75	75.0	1985	In	*Out*
10496	GTBG	Kern River Cogeneration	Kern River Cogeneration Co	GT	75	75.0	1985	In	*Out*
10496	GTCG	Kern River Cogeneration	Kern River Cogeneration Co	GT	75	75.0	1985	In	*Out*
10405	GEN1	Kingsburg Cogen	KES Kingsburg LP	CT	23.1	23.1	1990	In	*Out*
10405	GEN2	Kingsburg Cogen	KES Kingsburg LP	CA	13.1	13.1	1990	In	*Out*
54768	GEN1	Live Oak Cogen	Juniper Generation LLC	GT	46	47.0	1992	In	*Out*
55748	CTG1	Los Esteros Critical Energy Center	Los Esteros Critical Energy Facility LLC	GT	45	49.9	2003	In	*Out*
55748	CTG2	Los Esteros Critical Energy Center	Los Esteros Critical Energy Facility LLC	GT	45	49.9	2003	In	*Out*
55748	CTG3	Los Esteros Critical Energy	Los Esteros Critical Energy Facility LLC	GT	45	49.9	2003	In	*Out*

		Center								
55748	CTG4	Los Esteros Critical Energy Center	Los Esteros Critical Energy Facility LLC	GT	45	49.9	2003	In	*Out*
50612	GEN1	McKittrick Cogen	Juniper Generation LLC	GT	46	47.0	1991	In	*Out*
52169	A	Midway Sunset Cogen	Midway-Sunset Cogeneration Co	GT	78	78.0	1989	In	*Out*
52169	B	Midway Sunset Cogen	Midway-Sunset Cogeneration Co	GT	78	78.0	1989	In	*Out*
52169	C	Midway Sunset Cogen	Midway-Sunset Cogeneration Co	GT	78	78.0	1989	In	*Out*
54371	ODC1	Oildale Energy LLC	Oildale Energy LLC	GT	42.2	40.0	1984	In	*Out*
50851	GEN1	CI Power Cogeneration	CSUCI Site Authority	CT	23.5	23.6	1988	In	*Out*
50851	GEN2	CI Power Cogeneration	CSUCI Site Authority	CA	7.6	7.6	1988	In	*Out*
50850	GEN1	OLS Energy Chino	OLS Energy-Chino	CT	23.5	23.6	1987	In	*Out*
50850	GEN2	OLS Energy Chino	OLS Energy-Chino	CA	7.3	7.6	1987	In	*Out*
10438	GEN1	SEGS II	Sunray Operating Services LLC	ST	30	30.0	1985	In	*Out*
10439	GEN1	SEGS III	FPL Energy Operating Services Inc - SEGS	ST	34.2	34.2	1986	In	*Out*
10440	GEN1	SEGS IV	FPL Energy Operating Services Inc - SEGS	ST	34.2	34.2	1986	In	*Out*
10446	GEN1	SEGS IX	FPL Energy Operating Services Inc - SEGS	ST	92	108.2	1990	In	*Out*
10441	GEN1	SEGS V	FPL Energy Operating Services Inc - SEGS	ST	34.2	34.2	1987	In	*Out*
10442	GEN1	SEGS VI	FPL Energy Operating Services Inc - SEGS	ST	35	35.0	1988	In	*Out*
10443	GEN1	SEGS VII	FPL Energy Operating Services Inc - SEGS	ST	35	35.0	1988	In	*Out*
10444	GEN1	SEGS VIII	FPL Energy Operating Services Inc - SEGS	ST	92	108.2	1989	In	*Out*
50134	GTBG	Sycamore Cogeneration	Sycamore Cogeneration Co	GT	75	75.0	1987	In	*Out*
50134	GTDG	Sycamore Cogeneration	Sycamore Cogeneration Co	GT	75	75.0	1987	In	*Out*
57564	CTG	Algonquin Power Sanger LLC	Algonquin Power Sanger LLC	CT	49	60.5	2007	Out	In
57564	STG2	Algonquin Power Sanger LLC	Algonquin Power Sanger LLC	CA	12.5	12.5	2012	Out	In
10677	UNT2	CES Placerita Power Plant	CES Placerita Inc	CT	60	50.0	1988	Out	In

10677	UNT3	CES Placerita Power Plant	CES Placerita Inc	CA	30	20.0	1988	Out	In
389	4	El Centro	Imperial Irrigation District	ST	81.6	81.6	1968	Out	In
10342	TG1	Foster Wheeler Martinez	Foster Wheeler Power Sys Inc	CT	40	45.0	1987	Out	In
10342	TG2	Foster Wheeler Martinez	Foster Wheeler Power Sys Inc	CT	40	45.0	1987	Out	In
10342	TG3	Foster Wheeler Martinez	Foster Wheeler Power Sys Inc	CA	33.5	37.5	1987	Out	In
54238	STG	Port of Stockton Energy Facility	DTE Stockton LLC	ST	54	49.9	1987	Out	In

This list was compiled as follows.

<u>Addition of EGUs</u>

First, ARB staff identified additional EGUs in the following seven categories:

1) There is one combined cycle facility for which U.S. EPA included the turbine part (CT) of a combined cycle turbine, but did not include the steam part of the combined cycle turbine as required in the definition of a combustion turbine (it was excluded based on being less than 25 MWs). Therefore, the steam turbine has been added to the list of affected units for this facility:

    - Fresno Cogeneration Partners (EIA # 10156 (50.3MW (CT)[2] + 10 MW (CA))

2) There are four facilities (eight EGUs) where EPA excluded both the turbine part (CT) and the steam part (CA) of a combined cycle plant because each individual part had a capacity of less than 25 MWs. However, when the steam part (CA) and the turbine part (CT) are added together – as they must be to determine the capacity of the unit as a whole -- they are greater than 25 MWs. These included the following:

    i. Kingsburg Cogen (EIA # 10405) 23.1 MW (CT) + 13.1 (CA) = 36.2 MWs;
    ii. Agnews power Plant (EIA# 50748), 24.4 MW (CT) + 7.6 MW (CA) = 32 MWs;
    iii. OLS Chino (EIA # 50850) 23.5 MW (CT) + 7.3 MW (CA) = 30.8 MWs; and
    iv. CI Power Cogeneration (formerly OLS Camarillo) (EIA # 50851) 23.5 MW (CT) + 7.3 MW (CA) = 30.8 MWs

3) There is one facility (two EGUs) that were excluded as non-fossil type (<10% NG). These steam units burn landfill gas but historically also burn greater than 10 percent natural gas, and so are not eligible for exemption:

    - Grayson Unit 4, 5 (EIA # 377)

4) There are eight units that EPA excluded as non-fossil solar units, however, these units also utilize natural gas-fired steam boilers that are rated at greater than 250 MMBtu/Hr to provide additional generation and do not meet the exemption requirements. These include:

    i. SEGS II, III, IV, V, VI, VII, VIII and IX (EIA #s 10438, 0439,10440, 10441,10442,10443,40144, and 10446)

[2] California is following the nomenclature for the prime mover codes from the form instruction under U.S. Energy Information Administration – Form 860. Under the form instructions, a “CA” is a combined cycle steam part; a “CT” is a combine cycle turbine part; and a “GT” is a combustion (gas) turbine that does not include the combustion part of a combined cycle.
See:https://www.eia.gov/survey/form/eia_860/instructions.pdf

5) There are 10 facilities (13 units) that U.S. EPA excluded as “simple cycle units.” However, these units are combined heat and power units and do not meet the exemption requirements for combined heat and power units:

- Greenleaf 2 – Gen 1 (EIA # 10349)
- Corona Cogen – Gen 1(EIA 10635)
- Bear Mountain Cogen - Gen1 (EIA # 100890)
- Badger Creek Cogen – Gen1 (EIA # 100897)
- Chalk Cliff Cogen – Gen1 (EIA # 101520)
- McKittrick Cogen – Gen1 (EIA # 100296)
- Oil Dale – ODC1 (EIA 100891)
- Live Oak Cogen – Gen1 (EIA # 101044)
- Sycamore Cogen - units: GTGB, GTGD (EIA 100866)
- Kern River Cogen units: GTAG, GTBG, and GTCG (EIA # 10496)

6) There are four units, Los Esteros – units: CTG1, CTG2, CTG3 and CTG4 (EIA # 101143), that, prior to 2012, operated as simple cycle units. These units were idled in 2012 during which time a HRSG and an associated steam turbine was being constructed. The steam turbine portion of this facility was listed as an “under construction natural gas-fired combined cycle.” The four simple cycle units were listed as “excluded.” These four units, as well as the completed steam turbine are now operating as a combined cycle facility. Therefore, the four simple cycle units have been added as affected units.

7) There is one facility, (3 units) that EPA excluded as commercial/industrial units that are combined heat and power units that do not meet the exemption requirements for combined heat and power: Midway Sunset – Units: A, B and C (EIA # 52169)

<u>Deletion of Units Listed by EPA as Affected Units</u>

ARB also determined that several units identified by U.S. EPA as affected units do not meet CPP eligibility definitions, and so are not affected EGUs. There are two categories of excluded units:

1. There are three facilities (six units) that were excluded based on their historic generation being less than 219,000 MWs/Yr:

    - El Centro Unit 4 (EIA # 389)
    - Algonquin Power Sanger LLC Units CTG and SGT2 (EIA # 57564)
    - Foster Wheeler Martinez Units TG1, TG2 and TG3 (EIA #10342)

2. There are three facilities (three units) that were excluded because the units had been shut down prior to 2012.

- CES Placerita Power Plant (Units 2 and 3) (EIA # 10677). CES Placerita was shut down in 2010.
- Hanford Unit Gen1 (EIA # 10373) was shut down in 2011.
- The Port of Stockton (EIA # 54238) was listed as an affected unit by U.S. EPA as a coal-fired facility. This facility (as a coal plant) shut down in January of 2011. In 2014 this facility received an Authority to Construct to convert from a coal plant to a biomass plant. The facility has federally enforceable permit conditions that allow only for burning of biomass and a limit of natural gas usage to less than 10 percent.

Units That Will Be Considered to Be Affected Units Based on Future Generation

There are an additional three units that were not operating in 2012 or 2014 but began construction before January 8, 2014. These units are scheduled to go online in late 2016. These are affected units that are not included for goal computation or for the 2014 inventory that will be submitted, but will be affected units once they commence operation.

- Scattergood (EIA 101004) Units 4, 5, and 6 will consist of two - 109 MW combustion turbines and one - 213 MW steam turbine.

Units That Were Considered to Be Under Construction Affected Units That Are Not Affected Units

There are two facilities (two units) that were not listed in the overall list of affected units,[3] but were included as under construction natural gas combined cycle facilities in the UNCC tab of Appendix 1-5 (as discussed above). One of these units did not begin construction prior to 1/8/2014 so will be considered as new units and subject to 111(b):

- Glenarm (listed as 68 MW with no ORIS code). This facility broke ground July 3, 2014.

One facility (one unit) will not generate more than 25 MWs or sell more than 219,000 MWs to the grid:

- Algonquin (EIA 55292) is a 12.5 MW plant

[3] See Appendix 2 of U.S. EPA's Technical Support Document - Emission Performance Goal Computation: http://www.epa.gov/sites/production/files/2015-11/tsd-cpp-emission-performance-rate-goal-computation-appendix-1-5.xlsx

Air Resources Board

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Sacramento, California 95812 • www.arb.ca.gov

Matthew Rodriquez
Secretary for Environmental Protection

Edmund G. Brown Jr.
Governor

September 16, 2015

John Doe
President
TEST Company
PO Box 1234
Road to Nowhere
Timbuktu, CA 12345

Dear John Doe:

As you may know, the U.S. Environmental Protection Agency (U.S. EPA) released the final Clean Power Plan (CPP) on August 3, 2015. The CPP, codified as Subpart UUUU of Chapter 40, Part 60, of the Code of Federal Regulations (C.F.R.), requires states, including California, to establish standards of performance for carbon dioxide emissions from certain existing electric generating units (EGU).[1] The California Air Resources Board (ARB), in coordination with the California Energy Commission, the California Public Utilities Commission and local air districts, is developing California's compliance plan for this federal rule. The purpose of this letter is to inform you that ARB has information indicating that EGUs, which your company owns or operates, are covered for purposes of the CPP. We request that you inform ARB if you have information to the contrary.

The federal rules provide applicability criteria for affected EGUs in 40 C.F.R. § 60.5845 and list exclusions in 40 C.F.R. § 60.5850.[2] An affected EGU, generally, is any fossil-fired steam generating unit, integrated gasification combined cycle (IGCC) or stationary combustion turbine that commenced construction on or before January 8, 2014; is capable of selling more than 25 MWs to a utility power distribution system, and has a base load rating of greater than 250 MMBtu/hr heat input. However, pursuant to § 60.5850, EGUs are excluded from being affected units if they meet certain exemption criteria.

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[1] See http://www2.epa.gov/cleanpowerplan

[2] See http://www2.epa.gov/sites/production/files/2015-08/documents/cpp-final-rule.pdf

The EGUs that you own or operate which ARB believes to be covered by the CPP are:
Energy Galore - TEST, Unit A: 1 million MW

We understand you may own additional units that are not contained on the list. If you believe any of these units are affected units, please identify these units in your response.

We are requesting that you respond to this letter by October 16, 2015, with the following information: for each EGU ARB staff has identified above, please reply indicating either (A) you concur with ARB's applicability determination or (B) you do not concur. If you do not concur, please identify the specific regulatory exemption you believe applies, and provide the appropriate information substantiating the exemption. ARB staff anticipate that exemptions for certain steam generating units and combined heat and power units are the most likely to be relevant.

If you claim an exemption for steam generating and IGCC units, you must provide a copy of the relevant current federal operating permit(s) with reference to the specific conditions that limit the ability of the unit to operate above specific parameters as codified. (See 40 C.F.R. § 60.5850(a)(2)).

If you claim any exemption for any combined heat and power unit(s), you must either provide a copy of the relevant current federal operating permit(s) with reference to the specific conditions that limited the annual electric sales as codified and state that you have historically never gone above this limit, or provide historical information that demonstrates that you have always limited the annual net electric sales to less than the greater of 219,000 MWh or the design efficiency multiplied by the potential electric output; as required by the exemption calculation. (See 40 C.F.R. § 60.5850(a)(5)).

Please note that you must use the definitions for "design efficiency" and "potential electric output" that are provided in Subpart TTTT of Chapter 40, Part 60, of the Code of Federal Regulations[3] for evaluating the applicability of exemptions.

When you reply, please include a signed statement attesting that the information is true and accurate, and is being provided by a party authorized to do so.

ARB staff anticipates holding the first CPP workshop in October 2015. In order to stay informed of the progress of the California CPP, and to receive information on upcoming meetings, white papers, and draft plans, we recommend that you join the list serve for

[3] See http://www.epa.gov/airquality/cpp/cps-final-rule.pdf

California's CPP, which can be found here:
http://www.arb.ca.gov/listserv/listserv_ind.php?listname=cc.

Thank you for your attention in this matter. If you have any questions concerning this request, or to submit the requested data, please contact Christopher Gallenstein, Staff Air Pollution Specialist, at (916) 324-8017 or via email at cgallens@arb.ca.gov.

Sincerely,

/s/ Edie Chang

Edie Chang
Deputy Executive Officer

Enclosure

cc: Christopher Gallenstein
Industrial Strategies Division

CAPCOA Engineering Managers Subcommitee

Attachment: Selected Provisions Relevant to Clean Power Plan Applicability

For your convenience, ARB has excerpted sections from the U.S. EPA's final rules that are relevant to the applicability determination. These excerpts are intended only as a starting point. Please refer to those rules themselves on U.S. EPA's website for more details.

Applicability and Exclusion Criteria from 40 C.F.R. Subpart UUUU.

§60.5845 What affected EGUs must I address in my State plan?

(a) The EGUs that must be addressed by your plan are any affected steam generating unit, IGCC, or stationary combustion turbine that commenced construction on or before January 8, 2014.

(b) An affected EGU is a steam generating unit, IGCC, or stationary combustion turbine that meets the relevant applicability conditions specified in paragraph (b)(1) through (3) of this section except as provided in §60.5850.

(1) Serves a generator connected to a utility power distribution system with a nameplate capacity of 25 MW-net or greater (i.e., capable of selling greater than 25 MW of electricity);
(2) Has a base load rating (i.e., design heat input capacity) greater than 260 GJ/hr (250 MMBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel);
and (3) Stationary combustion turbines that meet the definition of either a combined cycle or combined heat and power combustion turbine.

§60.5850 What EGUs are excluded from being affected EGUs?

(a) EGUs that are excluded from being affected EGUs are:

(1) EGUs that are subject to subpart TTTT of this part as a result of commencing construction after the subpart TTTT applicability date; and those subject to subpart TTTT of this part as a result of commencing modification or reconstruction;

(2) Steam generating units and IGCC units that are currently and always have been subject to a federally enforceable permit limiting annual net-electric sales to one-third or less of its potential electric output, or 219,000 MWh or less;

(3) Non-fossil units (i.e., units that are capable of combusting 50 percent or more non-fossil fuel) that have always historically limited the use of fossil fuels to 10 percent or less of the annual capacity factor or are subject to a federally enforceable permit limiting fossil fuel use to 10 percent or less of the annual capacity factor.

(4) Stationary combustion turbines not capable of combusting natural gas (e.g., not connected to a natural gas pipeline)

(5) EGUs that are combined heat and power units that have always historically limited, or are subject to a federally enforceable permit currently limiting and always historically limiting, annual net-electric sales to a utility distribution system to the design efficiency times the potential electric output or 219,000 MWh (whichever is greater), or less;

(6) EGUs that serve a generator along with other steam generating unit(s), IGCC(s), or stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each steam generating unit, IGCC, or stationary combustion turbine) is 25 MW or less;

(7) EGUs that are a municipal waste combustor unit that is subject to subpart Eb of this part; and

(8) EGUs that are a commercial or industrial solid waste incineration unit that is subject to subpart CCCC of this part.

Definitions from 40 C.F.R. Subpart TTTT

§60.5580 What definitions apply to this subpart?

[….]

Design efficiency means the rated overall net efficiency (e.g., electric plus useful thermal output) on a lower heating value basis at the base load rating, at ISO conditions, and at the maximum useful thermal output (e.g., CHP unit with condensing steam turbines would determine the design efficiency at the maximum level of extraction and/or bypass). Design efficiency shall be determined using one of the following methods: ASME PTC 22 Gas Turbines (incorporated by reference, see §60.17), ASME PTC 46 Overall Plant Performance (incorporated by reference, see §60.17) or ISO 2314:2009 Gas turbines – acceptance tests (incorporated by reference, see §60.17).

[…]

Potential electric output means 33 percent or the base load rating design efficiency at the maximum electric production rate (e.g., CHP units with condensing steam turbines will operate at maximum electric production), whichever is greater, multiplied by the base load rating (expressed in MMBtu/h) of the EGU, multiplied by 106 Btu/MMBtu, divided by 3,413 Btu/KWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 h/yr (e.g., a 35 percent efficient affected EGU with a 100 MW (341 MMBtu/h) fossil fuel heat input capacity would have a 310,000 MWh 12 month potential electric output capacity).

	H	I	J	K	L	M	N	O
1	CompanyName	ContactName	ContactTitle	POBox	Street	City	State	Zip
2	NRG West	Sean Beatty	Director, Regulatory Affairs	P.O. Box 192	696 W. 10th Street	Pittsburg	CA	94565-
3	LSP Morro Bay LLC	Steven Goschke	Plant Manager		1290 Embarcadero Road	Morro Bay	CA	93442-
4	Duke Energy Moss Landing & Oakland LLC	Janet Bowen	Business Planner	PO Box 690	7301 State Highway 1	Moss Landing	CA	95039-
5	NRG West	Sean Beatty	Director, Regulatory Affairs	P.O. Box 192	696 W. 10th Street	Pittsburg	CA	94565-
6	Cabrillo Power I LLC (NRG West Coast Inc)	Jerry Carter	Plant Manager		4600 Carlsbad Blvd.	Carlsbad	CA	92008-
7	AES Alamitos LLC	Sid Phan	Station Engineer		690 North Studabaker Road	Long Beach	CA	90803-
8	NRG West	Sean Beatty	Director, Regulatory Affairs	P.O. Box 192	696 W. 10th Street	Pittsburg	CA	94565-
9	El Segundo Power LLC	Ken Riesz	Plant Manager		301 Vista del Mar	El Segundo	CA	90245-
10	NRG West	Sean Beatty	Director, Regulatory Affairs	P.O. Box 192	696 W. 10th Street	Pittsburg	CA	94565-
11	AES Huntington Beach LLC	Krishna Pullabhotla	Station Engineer		21730 Newland Street	Huntington Beach	CA	92646-
12	NRG West	Sean Beatty	Director, Regulatory Affairs	P.O. Box 192	696 W. 10th Street	Pittsburg	CA	94565-
13	NRG West	Sean Beatty	Director, Regulatory Affairs	P.O. Box 192	696 W. 10th Street	Pittsburg	CA	94565-
14	AES Redondo Beach LLC	James Bresnahan	Environmental Manager		1100 Harbor Drive	Redondo Beach	CA	90277-
15	Southern California Edison (SCE)	Manuel Alvarez	Sacramento Office		2244 Walnut Grove Avenue	Rosemead	CA	91770-3714
16	City of Glendale	John Escudero	Power Plant Operations Supervisor		800 Air Way	Glendale	CA	91201-
17	Imperial Irrigation District	Jose Landeros	Assistant Manager, Energy		333 E BARIONI BLVD	Imperial	CA	92251-
18	Los Angeles Department of Water & Power (LADWP)	Pjoy Chua	Manager of Regulatory Standards and Compliance		111 N. Hope Street, Room 1246	Los Angeles	CA	90012-
19	Los Angeles Department of Water & Power (LADWP)	Pjoy Chua	Manager of Regulatory Standards and Compliance		111 N. Hope Street, Room 1246	Los Angeles	CA	90012-
20	Los Angeles Department of Water & Power (LADWP)	Pjoy Chua	Manager of Regulatory Standards and Compliance		111 N. Hope Street, Room 1246	Los Angeles	CA	90012-
21	Los Angeles Department of Water & Power (LADWP)	Pjoy Chua	Manager of Regulatory Standards and Compliance		111 N. Hope Street, Room 1246	Los Angeles	CA	90012-
22	City of Pasadena	Herman Leung	Settlements Manager		150 Los Robles, Suite 200	Pasadena	CA	91101-

	H	I	J	K	L	M	N	O
1	CompanyName	ContactName	ContactTitle	POBox	Street	City	State	Zip
23	Burbank Water and Power	Ron Maxwell	Power Production Engineer		PO BOX 631 - 164 West Magnolia Boulevard	Burbank	CA	91503-0631
24	Modesto Irrigation District	Christina Cardoza	Power System Analyst		PO Box 4060 - 1231 Eleventh Street	Modesto	CA	95354-
25	City of Redding Electric Utility	Mark Haddad, CPA	Financial Manager		PO Box 496071 - 777 Cypress Avenue	Redding	CA	96049-6071
26	Central Valley Financing	Regulatory Reporting	Power Plant Manager	PO Box 15830		Sacramento	CA	95852-
27	Sacramento Municipal Utility District (SMUD)	Jessica Kasparian	Supervisor, Energy Settlements		PO Box 15830 - MS-A404	Sacramento	CA	95852-
28	Sacramento Municipal Utility District (SMUD)	Jessica Kasparian	Supervisor, Energy Settlements		PO Box 15830 - MS-A404	Sacramento	CA	95852-
29	ACE Cogeneration Co	Steve Haleman	Lead O&M Technician	PO Box 66		Trona	CA	93592-
30	Calpine Gilroy Cogen LP	Regulatory Reporting	Power Plant Manager		50 West San Fernando Street	San Jose	CA	95113-
31	Fresno Cogeneration Partners	Jon C Kimble	Plant Manager		8105 South Lassen Avenue	San Joaquin	CA	93660-
32	Cardinal Cogen	Craig Goldberg	Finance Manager		288 Campus Drive, Building 14-105	Stanford	CA	94305-
33	Energy Operations Group LLC	Thomas M. Campone	Facility Manager		17171 S. Central Avenue	Carson	CA	90746-
34	Chevron Products Co. - SoCal	Richard Brantley	Cogen Specialist		324 West El Segundo Boulevard	El Segundo	CA	90245-
35	Calpine King City Cogeneration LLC	Regulatory Reporting	Power Plant Manager		750 Metz Road	King City	CA	93930-
36	Foster Wheeler Martinez Inc. / Martinez Cogen Limited Partnership	Brian Fischer	Business Manager		550 Solano Way	Martinez	CA	94553-
37	Calpine Greenleaf Inc.	Regulatory Reporting	Power Plant Manager	PO Box 3330	5087 South Township Road	Yuba City	CA	95992-
38	Calpine Greenleaf Inc.	Regulatory Reporting	Power Plant Manager	PO Box 3330	5087 South Township Road	Yuba City	CA	95992-
39	KES Kingsburg L.P	Ryan Keefe	Facility Manager		11765 Mountain View Ave.	Kingsburg	CA	93631-
40	Inland Paperboard and Packaging	Steven Graham	Mill Controller		5100 Jurupa Street	Ontario	CA	91761-
41	Sunray Energy Inc	Nathan Witte	Information Systems Manager	PO BOX 338	35100 Santa Fe Street	Daggett	CA	92327-338
42	Luz Solar Partners Ltd III	c/o Kramer Junction Compa			41100 Highway 395	Boron	CA	93516-
43	Luz Solar Partners Ltd IV	c/o Kramer Junction Compa			41100 Highway 395	Boron	CA	93516-
44	Luz Solar Partners Ltd V	c/o Kramer Junction Compa			41100 Highway 395	Boron	CA	93516-
45	Luz Solar Partners Ltd VI	c/o Kramer Junction Compa			41100 Highway 395	Boron	CA	93516-
46	Luz Solar Partners Ltd VII	Glen T King	Safety/Environmental Specialist		PO Box 1400	Juno Beach	FL	33408-
47	Luz Solar Partners Ltd VIII	FPL Energy LLC		PO Box 14000		Juno Beach	FL	33408-
48	Luz Solar Partners Ltd IX	FPL Energy LLC		PO Box 14000		Juno Beach	FL	33408-
49	County of Los Angeles .	Yuri Garabekyan	Chief engineer		29300 The Old Road	Saugus	CA	91350-
50	Kern River Cogeneration Co	Carolyn Grant	Acting Executive Director	PO Box 80598		Bakersfield	CA	93380-
51	Mid-Set Cogeneration Co	Kelly S. Lucas	Executive Director	PO Box 80178		Bakersfield	CA	93380-

	H	I	J	K	L	M	N	O
1	CompanyName	ContactName	ContactTitle	POBox	Street	City	State	Zip
52	Tesoro Refining & Marketing Company LLC	Michelle Willson	Business Manager		2101 East Pacific Coast Highway	Wilmington	CA	90744-
53	LA County ISD (Civic Center)	David R. Adams	Chief Engineer		301 North Broadway	Los Angeles	CA	90012-
54	Corona Energy Partners Ltd	Robert W. Henderson		PO Box 2511	1001 Louisiana Street	Houston	TX	77002-
55	Air Products and Chemicals Inc.	Josh Livengood	Site Supervisor		700 N.Henry Ford Ave.	Wilmington	CA	90744-
56	Bear Mountain Limited	Robert W. Henderson		PO Box 2511	1001 Louisiana Street	Houston	TX	77002-
57	Badger Creek Limited	Dan Cosle	Asset Manager		34759 Lencioni Ave	Bakersfield	CA	93308-
58	Clean Energy Systems Inc	Larry Trowsdale			3035 Prospect Park Drive, Suite 150	Rancho Cordova	CA	95670-
59	Karnavati Holdings Inc.	Fred Samson	Manager Utilities Facility		9401 Indian Creek Parkway	Overland Park	KS	66210-
60	Rio Bravo	Steve W. Iliff	Financial Manager		19100 Von Karman, Suite 450	Irvine	CA	92612-
61	Rio Bravo	Steve W. Iliff	Financial Manager		19100 Von Karman, Suite 450	Irvine	CA	92612-
62	Applied Energy LLC	John Edwards	Manager - Utility Contracts		8835 Balboa Avenue, Suite D	San Diego	CA	92123-
63	Applied Energy LLC	John Edwards	Manager - Utility Contracts		8835 Balboa Avenue, Suite D	San Diego	CA	92123-
64	Applied Energy LLC	John Edwards	Manager - Utility Contracts		8835 Balboa Avenue, Suite D	San Diego	CA	92123-
65	Energy Operations Group	Allen Hess	Plant Manager	PO Box 1090	14486 Borax Rd.	Boron	CA	93516-
66	Chalk Cliff Ltd	Robert W. Henderson		PO Box 2511	1001 Louisiana Street	Houston	TX	77002-
67	Rio Tinto Minerals	Mike Bonomo, PE	Energy Manager		14486 Borax Road	Boron	CA	93516-
68	Coalinga Cogeneration Company	Kelly S. Lucas	Executive Director	PO Box 81078		Bakersfield	CA	93380-
69	Sycamore Cogeneration Co	C.M. Grant	Acting Executive Director		PO Box 80598	Bakersfield	CA	93380-
70	Berry Petroleum Company	Irvin E. Bonsal Jr.	Sr. Field Services Manager		5201 Truxtun Avenue, Suite 100	Bakersfield	CA	93309-0640
71	Watson Cogeneration Company (Tesoro Refining & Marketing)	Michael J. Milos	Commercial Analyst	P.O. Box 6203	22850 South Wilmington Avenue	Carson	CA	90749-
72	ExxonMobil Production Company	Shelby Pennington	Regulatory Specialist	P.O. Box 4358		Houston	TX	77210-
73	Ripon Cogeneration LLC	Aaron Honor	Plant Manager		944 South Stockton Avenue	Ripon	CA	95366-
74	AltaGas Pomona Energy Inc.	George Munoz	Authorized Representative		1507 Mt Vernon Avenue	Pomona	CA	91768-
75	ConocoPhillips Company San Francisco Refinery	Shawn L.Opitz	Plant Superintendent		1380 San Pablo Avenue	Rodeo	CA	94572-
76	Procter & Gamble Paper Products Company	Kim Lim	Energy Business Manager		800 North Rice Avenue	Oxnard	CA	93030-
77	Tesoro Refining and Marketing Company	Gregory Flagg	Process Engineer		2101 East Pacific Coast Highway	Wilmington	CA	90744-
78	Harbor Cogeneration Co	Greg Trewitt	Vice President, Operations and Technical	P.O. Box 550	505 Pier B Avenue	Wilmington	CA	90744-
79	McKittrick Ltd	Robert W. Henderson		PO Box 2511	1001 Louisiana Street	Houston	TX	77002-

	H	I	J	K	L	M	N	O
1	CompanyName	ContactName	ContactTitle	POBox	Street	City	State	Zip
80	O.L.S. Energy - Agnews Inc.	Regulatory Reporting	Power Plant Manager		717 Texas Avenue	Houston	TX	77002-
81	Delta Power Company LLC	Bill Wimer			67 Park Place East	Morristown	NJ	7960 -
82	OLS Energy Chino	William Wimer	Plant Manager	PO Box 1520		Chino	CA	91708-
83	U S Trust Co of California	Regulatory Reporting	Power Plant Manager		1947 W Potrero Road	Camarillo	CA	93018-
84	Sargent Canyon Cogeneration Co	Kelly Lucas	Executive Director	PO Box 81018		Bakersfield	CA	93380-
85	Salinas River Cogeneration Co	Kelly Lucas	Executive Director	PO Box 80778		Bakersfield	CA	93380-
86	Wheelabrator Technologies Inc.	Laura Annis	Controller		11500 Balsam Street	Norwalk	CA	90650-
87	UCLA	Lewis L. Rosman	Director Energy Services		731 Charles E. Young Drive South, Suite 3120D	Los Angeles	CA	90095-
88	Chevron Products Co. - NorCal	Stephen Mitchell	Energy Coordinator	PO Box 1272		Richmond	CA	94802-
89	Midway Sunset Cogeneration Co	Dave Falella	Executive Director		3466 West Crocker Springs Road	Fellows	CA	93224-
90	DTE Stockton LLC	Daniel Hildebrand	Plant Manager		2526 West Washington Street, Mail: PPD	Stockton	CA	95203-
91	Oildale Energy LLC	Helen Vesser	General Manager		2420 Camino Ramon, Suite 101	San Ramon	CA	94583-
92	Western Power and Steam	Donnie Williams	Assistant Plant Manager		3300 Manor Street	Bakersfield	CA	93308-
93	ConocoPhillips	Regulatory Reporting	Power Plant Manager		600 North Dairy Ashford	Houston	TX	77079-
94	Goal Line LP	Robert Mason	Facility Manager		555 N. Tulip Street	Escondido	CA	92025-
95	Live Oak Limited	Robert W. Henderson		PO Box 2511	1001 Louisiana Street	Houston	TX	77002-
96	Shell Oil Products US - Martinez Refinery	Ryan Sanford	Operations Support Engineer		3485 Pacheco Boulevard	Martinez	CA	94553-
97	Crockett Cogeneration LP	Adam Christodoulou	Plant Engineer		550 Loring Avenue	Crockett	CA	94525-
98	Calpine Corporation - West Region	Chris German	West Region Asset Management Director		4160 Dublin Blvd. - Suite 100	Dublin	CA	94562-
99	La Paloma Generating Co. LLC	Ray Hanley	Project Construction Manager		7500 Old Georgetown Road	Bethesda	MD	20814-6161
100	Sunrise Cogeneration & Pwr Co	Regulatory Reporting	Power Plant Manager	PO Box 81617		Bakersfield	CA	93380-
101	Calpine Corporation - West Region	Chris German	West Region Asset Management Director		4160 Dublin Blvd. - Suite 100	Dublin	CA	94562-
102	Altagas Blythe Operations Inc.	Mike Ludwin	Plant General Manager		385 North Buck Blvd	Blythe	CA	92225-
103	Delta Energy Center LLC	Regulatory Reporting	Power Plant Manager		1200 Arcy Lane	Pittsburg	CA	94565-
104	Calpine Corporation - West Region	Chris German	West Region Asset Management Director		4160 Dublin Blvd. - Suite 100	Dublin	CA	94562-

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1	CompanyName	ContactName	ContactTitle	POBox	Street	City	State	Zip
105	Calpine Corp & Bechtel Enterprise	Regulatory Reporting	Power Plant Manager		6700 Koll Cntr Parkway	Pleasanton	CA	95466-
106	Elk Hills Power LLC	Bob Bond	Power Plant Team Leader		4026 Skyline Road	Tupman	CA	93276-
107	High Desert Power Project LLC	Frank Carelli	Plant Engineer		19000 Perimeter Road	Victorville	CA	92394-
108	Air Products and Chemicals Inc.	Josh Livengood	Site Supervisor		700 N.Henry Ford Ave.	Wilmington	CA	90744-
109	Pastoria Energy Facility L.L.C	Regulatory Reporting	Power Plant Manager		50 West San Fernando Street	San Jose	CA	95113-
110	Calpine Corporation - West Region	Chris German	West Region Asset Management Director		4160 Dublin Blvd. - Suite 100	Dublin	CA	94562-
111	Valero Refining Company - California	Greg Imazu	Refinery Energy Coordinator		3400 East Second Street	Benicia	CA	94510-
112	Inland Empire Energy Center	Frank Escobedo	Director, Asset Management		26226 Antelope Road	Menifee	CA	92585-
113	GWF Energy LLC	John Archibald	C.P.T Manager		14950 W.Schulte Rd.	Tracy	CA	95377-
114	Sacramento Municipal Utility District (SMUD)	Jessica Kasparian	Supervisor, Energy Settlements		PO Box 15830 - MS-A404	Sacramento	CA	95852-
115	San Diego Gas & Electric (SDG&E)	Brian Martin	Plant Engineer		2300 Harveson Place	Escondido	CA	92029-
116	Silicon Valley Power	Voula Brown	Staff Aide II		1500 Warburton Avenue	Santa Clara	CA	95050-3713
117	Bicent (California) Malburg LLC	D Dunlap			2575 Park Lane, Suite 200	Lafayette	CO	80026-
118	Burbank Water and Power	Ron Maxwell	Power Production Engineer		PO BOX 631 - 164 West Magnolia Boulevard	Burbank	CA	91503-0631
119	Turlock Irrigation Distict	Jody Melo	Energy Settlements and Trading		PO Box 949 - 333 East Canal Drive	Turlock	CA	95381-
120	City of Roseville	Julie Manfredi	Electric Compliance Analyst		2090 Hilltop Circle	Roseville	CA	95747-
121	City of Riverside Public Utilities Department	Chuck Casey	Utility Generation Manager		5901 Payton Ave	Riverside	CA	92504-
122	Calpine Corporation - West Region	Chris German	West Region Asset Management Director		4160 Dublin Blvd. - Suite 100	Dublin	CA	94562-
123	Pacific Gas & Electric (PG&E)	Joseph E. Minkstein	Manager Technical Services		P.O. Box 770000 - Mail Code N11B	San Francisco	CA	94177-

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1	CompanyName	ContactName	ContactTitle	POBox	Street	City	State	Zip
124	Pacific Gas & Electric (PG&E)	Joseph E. Minkstein	Manager Technical Services		P.O. Box 770000 - Mail Code N11B	San Francisco	CA	94177-
125	Algonquin Power Systems	Bernie Reed	Plant Manager		2845 Bristol Circle	Oakville, Ontario, Canada	ON	
126	El Segundo Power LLC	Ken Riesz	Plant Manager		301 Vista del Mar	El Segundo	CA	90245-
127	Northern California Power Agency	Gillian Biedler	Energy Resource Analyst		651 Commerce Drive	Roseville	CA	95678-

B. Justification for Inclusion of Units as Affected Units

The following identifies and justifies electrical generation units that U.S. EPA had excluded from being affected units. These units are described by the type of exclusion based on seven different categories. These are discussed in detail with supporting documentation below.[4]

1) There is one combined cycle facility for which U.S. EPA included the turbine part (CT) of a combined cycle turbine, but did not include the steam part (CA) (heat recovery steam generator (HRSG)) of the combined cycle turbine (it was excluded based on being less than 25 MWs):

    i. Fresno Cogeneration Partners (EIA # 10156) owns a combined cycle facility for which U.S. EPA included the 50.3 MW (55 MW per permit) turbine part (CT) of the combined cycle turbine, but did not include the 10 MW steam part (CA) (heat recovery steam generator (HRSG) (it was excluded based on being less than 25 MWs). Staff reviewed eGrid, CEC, and EIA 860 data, the district permit (C-14-11-10) and acknowledgement by Fresno Cogeneration Partners of the applicability of the CPP. Therefore, the HRSG has been added to the list of affected units for this facility. The letter from Fresno Cogeneration Partners confirming applicability of the 10 MW steam part, the district permit listing the HRSG as part of a combined cycle plant (C-14-11-10) and the permit (C-14-10-6) documenting the exemption status of two additional units follows:

[4] ARB has included letters received for exempted units in Appendix X.

To: Chris G

Fresno Cogeneration Partners, L.P.

8105-B South Lassen Avenue
San Joaquin, CA 93660
(559) 693-2494 Fax (559) 693-4665

16 October 2015

Edie Chang
Deputy Executive Officer
Air Resources Board (ARB)
1001 I Street
P.O. Box 2815
Sacramento, CA 95812

Dear Ms. Chang:

Fresno Cogeneration Partners (FCP) is in receipt of your letter dated September 16, 2015 requesting that we notify the California ARB on whether any affected electric generating units (EGUs) owned and operated at the FCP are subject to or exempt from the US Environmental Protection Agency's (USEPA) Clean Power Plan (CPP) as codified as 40 CCFR, Part 60, Subpart UUUU. Our response is provided below.

EGUs Subject to the CPP

Based on our review of the regulations and our facility and equipment permits, we concur that FCP has two units which meet the applicability criteria under Subpart UUUU. These units are part of the combined-cycle combustion turbine system permitted under San Joaquin Valley Air Pollution Control District (SJVAPCD) Permit to Operate No. C-14-11-10. The system consists of a General Electric LM-6000 combustion turbine generator (denoted ARB's letter as GEN4) and a 10 MW steam turbine generator (denoted in ARB's letter as GEN2).

EGUs Subject to CPP	
§60.5845(b) An affected EGU is a steam generating unit, IGCC, or stationary combustion turbine that meets the relevant applicability conditions specified in paragraph (b)(1) through (3) of this section except as provided in §60.5850.	San Joaquin Valley Air Pollution Control District (SJVAPCD) Permit to Operate No. C-14-11-10 (Denoted in ARB's letter as GEN2 and GEN4).
(1) Serves a generator connected to a utility power distribution system with a nameplate capacity of 25 MW-net or greater (i.e., capable of selling greater than 25 MW of electricity);	Has a nameplate capacity of 55 MW, including a 45 MW General Electric LM-6000 combustion gas turbine.
(2) Has a base load rating (i.e., design heat input capacity) greater than 260 GJ/hr (250 MMBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel); and	The nameplate heat input rating for Permit to Operate No. C-14-11-10 exceeds this threshold.
(3) Stationary combustion turbines that meet the definition of either a combined cycle or combined heat and power combustion turbine.	Permit to Operate No. C-14-11-10 is a combined-cycle unit and includes a 10 MW steam turbine generator with a Heat Recovery Steam Generator (HRSG).

EGUs Exempt from to the CPP

Based on our review of the regulations and our facility and equipment permits, FCP has identified one existing EGU as being exempt from the CPP regulations. That unit is operated under SJVAPCD Permit to Operate No. C-14-10-6. The regulatory citations that exempt the EGUs are listed as well as a brief description that supports the exemption. In addition, we have included a copy of the federal operating permit for the exempt unit.

EGUs Exempt from CPP	
§60.5850(a) EGUs that are excluded from being affected EGUs are:	SJVAPCD Permit to Operate No. C-14-10-6
(5) EGUs that are combined heat and power units that have always historically limited, or are subject to a federally enforceable permit currently limiting and always historically limiting, annual net-electric sales to a utility distribution system to the design efficiency times the potential electric output or 219,000 MWh (whichever is greater), or less;	This unit is a Pratt & Whitney model FT4A9 combustion gas turbine with a nameplate generator output of 23 MW. The unit is below the net-electric sales threshold and thus it does not meet this criterion and is not subject to Subpart UUUU.
(6) EGUs that serve a generator along with other steam generating unit(s), IGCC(s), or stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each steam generating unit, IGCC, or stationary combustion turbine) is 25 MW or less;	This Pratt and Whitney FT4A9 turbine is a simple-cycle unit. It does not meet this criterion and is not subject to Subpart UUUU

If you have any questions regarding this submittal, please do not hesitate to contact me.

Regards

Andrew Robertson
Plant Manager

I certify that I am the authorized official for this facility and that based on information and belief formed after reasonable inquiry, the statements and information in this document and in all attached documents are true, accurate, and complete.

Attachments:

1. CARB letter dated 16 September 2015
2. SJVAPCD PTO #C-14-11-10
3. SJVAPCD PTO #C-14-10-6

INSPECTION WORKSHEET

EXPIRATION DATE: 08/31/2015

LEGAL OWNER OR OPERATOR: FRESNO COGENERATION PARTNERS
MAILING ADDRESS: 8105-B S LASSEN AVE
SAN JOAQUIN, CA 93660

LOCATION: 8105 S LASSEN AVE
SAN JOAQUIN, CA 93660

INSPECT PROGRAM PARTICIPANT: NO

EQUIPMENT DESCRIPTION:
55 MW COGENERATION UNIT INCLUDING 45 MW GENERAL ELECTRIC LM-6000PC GAS TURBINE WITH SELECTIVE CATALYTIC REDUCTION AND CO OXIDATION CATALYST, 10 MW STEAM TURBINE, AND HEAT RECOVERY STEAM GENERATOR WITH A HRSG BYPASS STACK

CONDITIONS

1. The HRSG bypass stack shall only be utilized when the main stack is not utilized (except during transition periods between the stacks) and the HRSG bypass stack shall be subject to all of the same requirements as the main stack at all times. [District Rule 2201] Federally Enforceable Through Title V Permit
2. The owner/operator shall perform an initial relative accuracy test as specified by 40 CFR Part 60 Appendix B to certify the new stack probe in the HRSG bypass stack, and every 720 stack operating hours per 40 CFR Part 75 Appendix B Section 2.3.3 thereafter. [District Rule 1080] Federally Enforceable Through Title V Permit
3. Calibration gas audit linearity checks shall be performed quarterly or every 168 stack operating hours per 40 CFR Part 75 Appendix B Section 2.2.4. [District Rule 1080] Federally Enforceable Through Title V Permit
4. {2257} Sulfur compound emissions shall not exceed 0.2% by volume, 2,000 ppmv, on a dry basis averaged over 15 consecutive minutes. [40 CFR 60.333(a); County Rules 404 (Madera), 406 (Fresno), and 407 (Kings, Merced, San Joaquin, Tulare, Kern, and Stanislaus)] Federally Enforceable Through Title V Permit
5. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201, 3.1] Federally Enforceable Through Title V Permit
6. {1898} The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102]
7. This unit shall be fired exclusively on PUC-quality natural gas and the PUC-quality natural gas shall have a total sulfur content less than or equal to 1.0 gr/100 scf. [40 CFR 60.333(b) and District Rules 2201 and 4201] Federally Enforceable Through Title V Permit
8. The fuel sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tarrif sheet or transportation contract or (ii) monitored weekly using ASTM Methods D4084, D5504, D6228, or Gas Processors Association Standard 2377. If the fuel sulfur content is less than 1.0 gr/100 scf for 8 consecutive weeks, then the monitoring frequency shall be every 6 months. If any six-month monitoring tests result in a fuel sulfur content exceedance, weekly monitoring shall resume. [40 CFR 60.334(h)(3)] Federally Enforceable Through Title V Permit
9. Gas turbine heat input shall not exceed 2,824,250 MMBtu/year based on a 12-month rolling sum. Compliance with this limit shall be determined at the end of each month. [District NSR Rule] Federally Enforceable Through Title V Permit
10. Units subject to the Specific Limiting Condition (SLC) plan are C-14-1, '-2, '-10, '-11, and '-12. [District Rule 2201] Federally Enforceable Through Title V Permit
11. Combined emission rate for all units subject to the SLC plan shall not exceed any of the following: 120.9 lb-PM10/day, 50.9 lb-SOx/day, 209.2 lb-NOx/day, 562.7 lb-CO/day, or 45.7 lb-VOC/day. [District Rule 2201] Federally Enforceable Through Title V Permit
12. The combined annual emissions rates for all units subject to the SLC plan shall not exceed either of the following: 48,539 lb-NOx/year or 199,889 lb-CO/year. [District Rule 2201] Federally Enforceable Through Title V Permit

13. Gas turbine engine and generator lube oil vents shall be equipped with mist eliminators. Visible emissions from lube oil vents shall not exhibit opacity of 5% or greater except for up to three minutes in any hour. [District NSR Rule] Federally Enforceable Through Title V Permit

14. For each unit subject to the SLC, the permittee shall maintain all necessary records in order to show compliance with the daily and annual SLC limits, including (but not limited to) the following: 1) amount of fuel used, 2) HHV of fuel, 3) calculated daily emissions for each air contaminant emitted, and 4) daily emissions measured by CEMS. [District NSR Rule] Federally Enforceable Through Title V Permit

15. The permittee shall apply to revise each Permit to Operate subject to the SLC when any unit subject to the SLC has a District-authorized change in daily emission rate, or Permit to Operate is surrendered or sold. [District NSR Rule] Federally Enforceable Through Title V Permit

16. Except during thermal stabilization, emission rates from the gas turbine shall not exceed any of the following: 2.0 ppmvd NOx @ 15% O2 (based on a 3-hour rolling average), 1.25 lb-SOx/hr, 2.85 lb-PM10/hr, 20 ppmv CO @ 15% O2, 2 ppmv VOC @ 15% O2, or 10 ppmv-ammonia @ 15% O2 (based on a 1-hour rolling average). [40 CFR 60.332, District NSR and District Rules 4703, 5.1 and 5.2 and 4102] Federally Enforceable Through Title V Permit

17. During thermal stabilization, emissions rates from the gas turbine shall not exceed any of the following: 20 lb-NOx/hr (based on a 3-hour rolling average), 1.25 lb-SOx/hr, 2.85 lb-PM10/hr, 19.40 lb-CO/hr (based on a 3-hour rolling average), 1.12 lb-VOC/hr, or 20 ppmv-ammonia @ 15% O2 (based on a 1-hour rolling average). [40 CFR 60.332, District NSR Rule and District Rules 4703, 5.1 and 5.2 and 4102] Federally Enforceable Through Title V Permit

18. Ammonia slip shall be calculated as follows: ammonia slip ppmv @ 15% O2 = {[a-(b x c/1,000,000)] x 1,000,000/b}, where a = ammonia injection rate (lb/hr)/17 (lb/lb mol), b = dry exhaust gas flow rate (lb/hr)/29 (lb/lb mol), and c = change in measured NOx concentration ppmv at 15% O2 across the catalyst. [District Rule 2201] Federally Enforceable Through Title V Permit

19. The thermal stabilization period shall be defined as the start up or shut down time during which the exhaust gas is not within the normal operating temperature range, not to exceed two hours. [District Rule 4703, 3.25] Federally Enforceable Through Title V Permit

20. Compliance testing to measure the PM10, NOx (as NO2), VOC, CO, ammonia emissions, and fuel gas sulfur of this permit unit shall be conducted at least once every twelve months. [District Rules 2201, 4703, 6.3, 40 CFR 60.332(a), (b), and 40 CFR 60.333] Federally Enforceable Through Title V Permit

21. The following test methods shall be used. PM10: EPA Method 5 (front half and back half) or EPA Method 201A/202, NOx: EPA Method 7E or 20, CO: EPA Method 10 or 10B, O2: EPA Method 3, 3A, or 20, VOC: EPA Method 18 or 25, ammonia: BAAQMD ST-1B, and fuel gas sulfur content: ASTM D3246. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rule 1081; District Rule 4703, 6.4; and 40 CFR 60.335(b)] Federally Enforceable Through Title V Permit

22. HHV and LHV of the fuel shall be determined using ASTM D3588, ASTM 1826, or ASTM 1945. [40 CFR 60.332(a)(b) and District Rule 4703, 6.4.5] Federally Enforceable Through Title V Permit

23. Any gas turbine with an intermittently operated auxiliary burner shall demonstrate compliance with the auxiliary burner both on and off. [40 CFR 60.335(b)(3) and District Rule 4703] Federally Enforceable Through Title V Permit

24. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081] Federally Enforceable Through Title V Permit

25. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081] Federally Enforceable Through Title V Permit

26. For units equipped with CEM, CEM records shall be used in place of calculated emissions. [District Rule 2201] Federally Enforceable Through Title V Permit

27. Permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100] Federally Enforceable Through Title V Permit

INSPECTION WORKSHEET

28. The District shall be notified in writing within 10 days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100] Federally Enforceable Through Title V Permit

29. The owner or operator shall install, certify, maintain, operate, and quality-assure a Continuous Emissions Monitoring System (CEMS) which continuously measures and records the exhaust gas NOx (before and after the SCR catalyst) and O2 concentrations. The CEMS shall be capable of monitoring emissions during startups and shutdowns, as well as during normal operating conditions. [40 CFR 50.334(b) and District Rules 1080, 2201, and 4703] Federally Enforceable Through Title V Permit

30. The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. [40 CFR 60.334(b)(2) and District Rule 1080] Federally Enforceable Through Title V Permit

31. Results of the CEM system shall be averaged over three hour periods using consecutive 15-minute sampling periods in accordance with either EPA Method 7E or EPA Method 20 for NOx, EPA Methods 10 or 10B for CO, or EPA Methods 3, 3A, or 20 for)2, or, if continuous emission monitors are used, all applicable requirements of CFR 60.13. [40 CFR 60.13 and District Rule 4703, 5.1, 6.4] Federally Enforceable Through Title V Permit

32. The NOx, CO, and O2 CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60 Appendix B Performance Specifications 2, 3, and 4A. [40 CFR 60.334(b)(1) and District Rule 1080] Federally Enforceable Through Title V Permit

33. The owner or operator shall maintain CEMS records that contain the following: the occurrence and duration of any start-up, shutdown, or malfunction, performance testing evaluations, calibration, checks, adjustments, maintenance, duration of any periods during which a continuous monitoring system or monitoring device is inoperative, and emissions measurements. [40 CFR 60.7(b) and District Rule 1080] Federally Enforceable Through Title V Permit

34. Audits of continuous emissions monitors shall be conducted quarterly, except during quarters in which relative accuracy and total accuracy testing is performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080] Federally Enforceable Through Title V Permit

35. Permittee shall comply with all applicable source sampling requirements of District Rule 1081. [District Rule 1081] Federally Enforceable Through Title V Permit

36. The owner/operator shall perform a relative accuracy test (RATA) as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080] Federally Enforceable Through Title V Permit

37. The owner or operator shall, upon written notice from the APCO, provide a summary of the data obtained from the CEM systems. this summary shall be in the form and the manner prescribed by the APCO. [District Rule 1080, 7.1] Federally Enforceable Through Title V Permit

38. The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NOx emissions, nature and the cause of excess (if known), corrective actions taken and preventative measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period and used to determine compliance with an emissions standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [40 CFR 60.334(j), (j)(5) and District Rule 1080] Federally Enforceable Through Title V Permit

39. APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080] Federally Enforceable Through Title V Permit

40. Results of the CEM system shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3 or by other methods deemed equivalent by mutual agreement with the District, the California Air Resources Board, and the Environmental Protection Agency. [District Rule 1080, 6.0] Federally Enforceable Through Title V Permit

41. In the event of a breakdown of monitoring equipment, the owner shall notify the APCO as soon as reasonably possible, but no later than eight (8) hours after its detection, unless the owner or operator demonstrates to the APCO's satisfaction that a longer reporting period was necessary, and shall initiate repairs. The owner shall inform the APCO of the intent to shut down any monitoring equipment at last 24 hours prior to the event. [District Rule 1080, 10.0] Federally Enforceable Through Title V Permit

42. Permittee shall maintain records of the following: 1) the occurrence and duration of any start-up, shutdown, or malfunction in the operation of the permit unit; 2) performance testing, evaluations, calibrations, checks, adjustments, and maintenance of CEMS; and 3) emission measurements. [District Rule 1080, 7.3] Federally Enforceable Through Title V Permit

43. Permittee shall maintain records of the following: 1) annual hours of operation, 2) daily and annual fuel consumption, 3) daily and annual continuous emission monitor measurements, 4) daily calculated ammonia slip, and 5) daily and annual emission rates. [District Rules 2201 and 4703, 6.2.6] Federally Enforceable Through Title V Permit

44. Permittee shall submit a written report for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: 1) time intervals, data and magnitude of excess emissions, nature and cause of excess (if known), corrective actions taken and preventive measures adopted; 2) averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; 3) applicable time and date of each period during which the CEM was inoperative (except for zero and span checks) and 4) the nature of system repairs and adjustments; 5) a negative declaration when no excess emissions occurred. [District Rule 1080, 8.0] Federally Enforceable Through Title V Permit

45. Permittee shall maintain on file copies of natural gas bills. [District Rule 2201] Federally Enforceable Through Title V Permit

46. A violation of emission standards indicated by the CEM system shall be reported to the APCO within 96 hours. [District Rule 1080, 9.0] Federally Enforceable Through Title V Permit

47. The minimum ammonia injection rate shall be reported to the District and the injection rate shall be monitored during CEM breakdowns to demonstrate NOx emission compliance. [District Rule 4703, 6.2.5] Federally Enforceable Through Title V Permit

48. The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing, evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rule 4703, 6.2.4 and 40 CFR 60.7(b)] Federally Enforceable Through Title V Permit

49. The permittee shall maintain the following records: hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, and calculated NOx mass emission rates (lb/hr). [District Rules 2201 and 2529, 9.4.2] Federally Enforceable Through Title V Permit

50. The owner or operator of a stationary gas turbine system shall maintain all records of required monitoring data and support information for inspection at any time for a period of five years. [District Rule 2520, 9.4.2] Federally Enforceable Through Title V Permit

51. The owners and operators of each affected source and each affected unit at the source shall: (i) Operate the unit in compliance with a complete Acid Rain permit application or a superceding Acid Rain permit issued by the permitting authority; and (ii) Have an Acid Rain permit. [40 CFR 72] Federally Enforceable Through Title V Permit

52. The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75. [40 CFR 75] Federally Enforceable Through Title V Permit

INSPECTION WORKSHEET

53. The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program. [40 CFR 75] Federally Enforceable Through Title V Permit

54. The owners and operators of each source and each affected unit at the source shall: (i) Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)) not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and (ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide. [40 CFR 73] Federally Enforceable Through Title V Permit

55. Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act. [40 CFR 77] Federally Enforceable Through Title V Permit

56. An affected unit shall be subject to the sulfur dioxide requirements starting on the later of January 1, 2000, or the deadline for monitoring certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3) that is not a substitution or compensating unit. [40 CFR 72, 40 CFR 75] Federally Enforceable Through Title V Permit

57. Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program. [40 CFR 72] Federally Enforceable Through Title V Permit

58. An allowance shall not be deducted in order to comply with the requirements under 40 CFR part 73, prior to the calendar year for which the allowance was allocated. [40 CFR 73] Federally Enforceable Through Title V Permit

59. An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or the written exemption under 40 CFR 72.7 and 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization. [40 CFR 72] Federally Enforceable Through Title V Permit

60. An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right. [40 CFR 72] Federally Enforceable Through Title V Permit

61. The owners and operators of each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides. [40 CFR 72] Federally Enforceable Through Title V Permit

62. The designated representative of an affected unit that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77. [40 CFR 77] Federally Enforceable Through Title V Permit

63. The owners and operators of an affected unit that has excess emissions in any calendar year shall: (i) Pay without demand the penalty required, and pay up on demand the interest on that penalty; and (ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77. [40 CFR 77] Federally Enforceable Through Title V Permit

64. The owners and operators of the each affected unit at the source shall keep on site the following documents for a period of five years from the date the document is created. This period may be extended for cause, at any time prior to the end of five years, in writing by the Administrator or permitting authority: (i) The certificate of representation for the designated representative for the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site beyond such five-year period until such documents are superceded because of the submission of a new certificate of representation changing the designated representative. [40 CFR 72] Federally Enforceable Through Title V Permit

65. The owners and operators of each affected unit at the source shall keep on site each of the following documents for a period of five years from the date the document is created. This period may be extended for cause, at any time prior to the end of five years, in writing by the Administrator or permitting authority; (ii) All emissions monitoring information, in accordance with 40 CFR part 75; (iii) Copies of all reports, compliance certifications and other submissions and all records made or required under the Acid Rain Program; (iv) Copies of all documents used to complete an Acid Rain permit application and any other submission that demonstrates compliance with the requirements of the Acid Rain Program. [40 CFR 75] Federally Enforceable Through Title V Permit

66. The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR 75 Subpart I. [40 CFR 75] Federally Enforceable Through Title V Permit

San Joaquin Valley
Air Pollution Control District

PERMIT UNIT: C-14-10-6 **EXPIRATION DATE:** 08/31/2015

EQUIPMENT DESCRIPTION:
23 MW ELECTRICAL GENERATOR POWERED BY A PRATT AND WHITNEY MODEL FT4A9 GAS-FIRED, SIMPLE CYCLE TURBINE ENGINE WITH DRY LOW NOX (DLN) TECHNOLOGY OR WATER INJECTION, A SELECTIVE CATALYTIC REDUCTIONS (SCR) SYSTEM, AN OXIDATION CATALYST, AN INLET AIR EVAPORATIVE COOLER, AND LUBE OIL VENT MIST ELIMINATORS

PERMIT UNIT REQUIREMENTS

1. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201, 3.1] Federally Enforceable Through Title V Permit
2. Sulfur compound emissions shall not exceed 0.2% by volume, 2,000 ppmv, on a dry basis averaged over 15 consecutive minutes. [40 CFR 60.333(a); County Rules 404 (Madera), 406 (Fresno), and 407 (Kings, Merced, San Joaquin, Tulare, Kern, and Stanislaus)] Federally Enforceable Through Title V Permit
3. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201] Federally Enforceable Through Title V Permit
4. Gas turbine shall be equipped with a calibrated continuous monitoring system to measure and record hours of operation and fuel consumption. [District Rules 2201, 2520 9.4.2, and 4703 6.2.1] Federally Enforceable Through Title V Permit
5. The gas turbine engine and generator lube oil vents shall be equipped with mist eliminators. Visible emissions from lube oil vents shall not exhibit opacity of 5% or greater except for up to three minutes in any hour. [District Rule 2201] Federally Enforceable Through Title V Permit
6. The heat input to the turbine shall not exceed 1,320,000 MMBtu/year based on a 12-month rolling sum. Compliance with this limit shall be determined at the end of each month. [District Rule 2201] Federally Enforceable Through Title V Permit
7. Units subject to the Specific Limiting Condition (SLC) plan are C-14-1, -2, '-10, '-11, and '-12. [District Rule 2201] Federally Enforceable Through Title V Permit
8. Combined emission rate for all units subject to the SLC plan shall not exceed any of the following: 120.9 lb-PM10/day, 50.9 lb-SOx/day, 209.2 lb-NOx/day, 562.7 lb-CO/day, or 45.7 lb-VOC/day. [District Rule 2201] Federally Enforceable Through Title V Permit
9. The combined annual emissions rates for all units subject to the SLC plan shall not exceed either of the following: 48,539 lb-NOx/year or 199,889 lb-CO/year. [District Rule 2201] Federally Enforceable Through Title V Permit
10. The permittee shall apply to revise each Permit to Operate subject to the SLC when any unit subject to the SLC has a District-authorized change in daily emissions rate, or Permit to Operate is surrendered or sold. [District Rule 2201] Federally Enforceable Through Title V Permit
11. For each unit subject to the SLC, the permittee shall maintain all necessary records in order to show compliance with the daily and annual SLC limits, including (but not limited to) the following: 1) amount of fuel used, 2) HHV of fuel, 3) calculated daily emissions for each air contaminant emitted, 4) daily emissions measured by CEMS, 5) and calculated combined annual emissions for NOx and CO. [District Rule 2201] Federally Enforceable Through Title V Permit

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

This unit shall be fired exclusively on PUC-quality natural gas and the PUC-quality natural gas shall have a total sulfur content of less than or equal to 1.0 gr/100 scf. [40 CFR 60.333(b) and District Rules 2201 and 4201] Federally Enforceable Through Title V Permit

The fuel sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, or tariff sheet or transportation contract or (ii) monitored weekly using ASTM Methods D4084, D5504, D6228, or GAS Processors Association Standard 2377. If the fuel sulfur content is less than 1.0 gr/100 scf for 8 consecutive weeks, then the monitoring frequency shall be every 6 months. If any six-month monitoring tests result in a fuel sulfur content exceedance, weekly monitoring shall resume. [40 CFR 60.334(h)(3)] Federally Enforceable Through Title V Permit

14. Except during transitional operation period, emission rates from the gas turbine shall not exceed any of the following: PM10: 2.22 lb/hr, SOx (as SO2): 0.98 lb/hr, NOx (as NO2): 5.0 ppmvd @ 15% O2 and 6.20 lb/hr (based on a 3-hour average), VOC: 2.0 ppmvd @ 15% O2 and 0.88 lb/hr, CO: 12.0 ppmvd @ 15% O2 and 8.07 lb/hr (based on a 3-hour rolling average), or ammonia: 10 ppmvd @ 15% O2 (based on a 1-hour rolling average). [District Rules 2201, 4102, 4301, 4703 and 40 CFR Part 60 Subpart GG] Federally Enforceable Through Title V Permit

15. During transitional operation period, emission rates from the gas turbine shall not exceed any of the following: PM10: 2.22 lb/hr, SOx (as SO2): 0.98 lb/hr, NOx (as NO2): 20 lb/hr (based on a 3-hour rolling average), VOC: 0.88 lb/hr, CO: 8.07 lb/r (based on a 3-hour rolling average), or ammonia: 20 ppmvd @ 15% O2 (based on a 1-hour rolling average). [District Rules 2201, 4102, 4301, 4703 and 40 CFR Part 60 Subpart GG] Federally Enforceable Through Title V Permit

16. Transitional operation period shall be any of the following periods as they are define in Rule 4703: bypass transition period, primary re-ignition period, reduced load period start-up or shutdown. [District Rule 4703] Federally Enforceable Through Title V Permit

17. Permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100] Federally Enforceable Through Title V Permit

18. In the event of a breakdown of monitoring equipment, the owner shall notify the APCO as soon as reasonably possible, but no later than eight (8) hours after its detection, unless the owner or operator demonstrates to the APCO's satisfaction that a longer reporting period was necessary, and shall initiate repairs. The owner shall inform the APCO of the intent to shut down any monitoring equipment at least 24 hours prior to the event. [District Rule 1080, 10.0] Federally Enforceable Through Title V Permit

9. A violation of emissions standards indicated by the CEM system shall be reported to the APCO within 96 hours. [District Rule 1080, 9.0] Federally Enforceable Through Title V Permit

!0. The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100] Federally Enforceable Through Title V Permit

1. Compliance with the ammonia slip limit shall be demonstrated by using the following calculation procedure: ammonia slip ppmv @ 15% O2 = ((a-(bxc/1,000,000)) x 1,000,000/b), where a = ammonia injection rate (lb/hr)/17 lb/lb.mol, b = dry exhaust gas flow rate (lb/hr)/29(lb/lb.mol), and c = change in measure NOx concentration ppmv @ 15% O2 across catalyst. [District Rule 2201] Federally Enforceable Through Title V Permit

2. Compliance testing to measure the PM10, NOx (as NO2), VOC, CO, ammonia emissions, and fuel gas sulfur content of this permit unit shall be conducted at least once every twelve months. [District Rules 2201 and 4703, 6.3 and 40 CFR 60.332 (a), (b) and 40 CFR 60.333] Federally Enforceable Through Title V Permit

3. The following test methods shall be used. PM10: EPA Method 5 (front half and back half), NOx: EPA Method 7E or 20, CO: EPA Method 10 or 10B, O2: EPA Method 3, 3A, or 20, VOC: EPA Method 18 or 25, ammonia: BAAQMD ST-1B, and fuel gas sulfur content: ASTM D3246. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081, 4703, 6.4, and 40 CFR 60.335(b)] Federally Enforceable Through Title V Permit

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE
These terms and conditions are part of the Facility-wide Permit to Operate.

Facility Name: FRESNO COGENERATION PARTNERS
Location: 8105 S LASSEN AVE, SAN JOAQUIN, CA 93660
14-10-6 Jan 10 2011 8:27AM -- HARRISR

HHV and LHV of the fuel shall be determined using ASTM D3588, ASTM 1826, or ASTM 1945. [40 CFR 60.332(a),(b) and District Rule 4703, 6.4.5] Federally Enforceable Through Title V Permit

Permittee shall comply with all applicable source sampling requirements of District Rule 1081. [District Rule 1081] Federally Enforceable Through Title V Permit

26. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. [District Rule 1081] Federally Enforceable Through Title V Permit

27. Compliance demonstration (source testing) shall be District witnessed, or authorized and the samples shall be collected by a California Air Resources Board certified testing laboratory. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. The results of each source test shall be submitted to the District within 60 days of source testing. [District Rule 1081] Federally Enforceable Through Title V Permit

28. The owner or operator shall install, certify, maintain, operate, and quality-assure a Continuous Emissions Monitoring System (CEMS) which continuously measures and records the exhaust gas NOx (before and after the SCR catalyst), CO, and O2 concentrations. The CEMS shall be capable of monitoring emissions during startups and shutdowns, as well as during normal operating conditions. [40 CFR 50.334(b) and District Rules 1080, 2201, and 4703] Federally Enforceable Through Title V Permit

29. The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. [40 CFR 60.334(b)(2) and District Rule 1080] Federally Enforceable Through Title V Permit

30. Results of the CEM system shall be averaged over three hour periods using consecutive 15-minute sampling periods in accordance with either EPA Method 7E or EPA Method 20 for NOx, EPA Methods 10 or 10B for CO, or EPA Methods 3, 3A, or 20 for O2, or all applicable requirements of CFR 60.13. [40 CFR 60.13 and District Rule 4703 5.1, 6.4] Federally Enforceable Through Title V Permit

The NOx, CO, and O2 CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60 Appendix B Performance Specifications 2 and 3. [40 CFR 60.334(b)(1) and District Rule 1080] Federally Enforceable Through Title V Permit

32. The owner or operator shall maintain CEMS records that contain the following: the occurrence and duration of any start-up, shutdown, or malfunction, performance testing evaluations, calibration, checks, adjustments, maintenance, duration of any periods during which a continuous monitoring system or monitoring device is inoperative, and emissions measurements. [40 CFR 60.7(b) and District Rule 1080] Federally Enforceable Through Title V Permit

33. Audits of continuous emissions monitors shall be conducted quarterly, except during quarters in which relative accuracy and total accuracy testing is performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080] Federally Enforceable Through Title V Permit

34. The owner/operator shall perform a relative accuracy test (RATA) as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080] Federally Enforceable Through Title V Permit

35. The owner or operator shall, upon written notice from the APCO, provide a summary of the data obtained from the CEM systems. this summary shall be in the form and the manner prescribed by the APCO. [District Rule 1080, 7.1] Federally Enforceable Through Title V Permit

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NOx emissions, nature and the cause of excess (if known), corrective actions taken and)reventative measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period and used to determine compliance with an emissions standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [40 CFR 60.334(j), (j)(5) and District Rule 1080] Federally Enforceable Through Title V Permit

37. The owner or operator shall report periods of excess emissions that are defined as follows: any one-hour period during which the average-water-to-fuel ratio (when the CEMS is not operational and Dry-Low NOx technology is not being used), as measured by the continuous monitoring system, falls below the water-to-fuel ratio determined to demonstrate compliance with the NOx emission limit. Each report shall include average water-to-fuel ratio, average fuel consumption, ambient conditions, and gas turbine load. [40 CFR 60.334(c)(1)] Federally Enforceable Through Title V Permit

38. Results of the CEM system shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3 or by other methods deemed equivalent by mutual agreement with the District, the California Air Resources Board, and the Environmental Protection Agency. [District Rule 1080, 6.0] Federally Enforceable Through Title V Permit

39. The continuous monitor of fuel, water, and water-to-fuel ratio system shall be used to determine the fuel consumption and the water-to-fuel ratio necessary to comply with the NOx emissions limits at 30, 50, 75, and 100% of peak load or at four points in the normal operating range of the gas turbine, including the minimum point in the range and peak load. All loads shall be corrected to ISO conditions using the appropriate equations supplied by the manufacturer. [40 CFR 60.335(c)(2)] Federally Enforceable Through Title V Permit

40. The minimum ammonia injection rate shall be reported to the District and the injection rate shall be monitored by the operator during CEM breakdowns to demonstrate NOx emission compliance. [District Rule 2201] Federally Enforceable Through Title V Permit

41. APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080] Federally Enforceable Through Title V Permit

42. The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing, evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rule 4703, 6.2.4 and 40 CFR 60.7(b)] Federally Enforceable Through Title V Permit

43. The permittee shall maintain the following records: hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, and calculated NOx mass emission rates (lb/hr). [District Rules 2201 and 2520, 9.4.2] Federally Enforceable Through Title V Permit

44. The owner or operator of a stationary gas turbine system shall maintain all records of required monitoring data and support information for inspection at any time for a period of five years. [District Rule 2520, 9.4.2] Federally Enforceable Through Title V Permit

2) There are four facilities where EPA excluded both the turbine part (CT) and the steam part (CA) of a combined cycle plant because each individual part had a capacity of less than 25 MWs. However, when the steam part (CA) and the turbine part (CT) are added together – as they must be to determine the capacity of the unit as a whole -- they are greater than 25 MWs. These included the following:

    i. Kingsburg Cogen (EIA # 10405) owns a combined cycle facility that includes a 23.1 MW (CT) + 13.1 (CA) = 36.2 MWs. Staff reviewed the eGrid, CEC data and acknowledgement by Kingsburg Cogeneration of the applicability of the CPP. Therefore, the combined cycle facility has been added to the list of affected units. The letter from Kingsburg Cogeneration follows:

Gallenstein, Christopher@ARB

From:	Joel Lepoutre <jlepoutre@purenergyllc.com>
Sent:	Friday, October 02, 2015 10:11 AM
To:	Gallenstein, Christopher@ARB
Cc:	Ryan Keefe
Subject:	Clean Power Plan EGU List

Dear Mr. Gallenstein,

Kingsburg Cogen (KES Kingsburg, L.P.) is in receipt of CARB's September 16, 2015 letter regarding Kingsburg Cogen's applicability to the Clean Power Plan Regulations.

Kingsburg Cogen has reviewed the exemption criteria and agrees with ARB's applicability determination.

This email response serves as Kingsburg Cogen's attestation as requested by the subject letter. If you require a more formal attestation, please let us know.

Regards,

Joel Lepoutre
West Coast Asset Manager
PURENERGY
MANAGEMENT SERVICES L.L.C.
19405 Avenida Castilla
Murrieta, CA 92562

Phone: 951.302.3701
Fax: 951.302.2652
Cell: 714.746.5960

Website: www.purenergyllc.com
email: jlepoutre@purenergyllc.com

ii. Agnews Power Plant (EIA# 50748) owns a combined cycle facility that includes a 24.4 MW (CT) + 7.6 MW (CA) = 32 MWs; Staff reviewed the eGrid, CEC data and acknowledgement by Agnews Power Plant of the applicability of the CPP. Therefore, the combined cycle facility has been added to the list of affected units. The letter from Agnews Power Plant follows:

CALPINE CORPORATION

NYSE CPN

4160 Dublin Boulevard
Suite 100
Dublin CA 94568
925.557.2238

October 23, 2015

Edie Chang
Deputy Executive Officer
California Air Resources Board
1001 I Street
Sacramento, CA 94812

Subject: Air Resources Board Request For Information Regarding Electric Generating Units Subject To The U.S. Environmental Protection Agency's Clean Power Plan

Dear Ms. Chang:

On behalf of Calpine Energy Services, L.P. (hereinafter, "CES"), I write to respond to the letters that the California Air Resources Board ("ARB") sent to Calpine Corporation ("Calpine") regarding the treatment of certain electric generating units ("EGUs") located in California under the U.S. Environmental Protection Agency's ("EPA") Final "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units" (i.e., the "Clean Power Plan" or "CPP"). CES appreciates the additional week ARB provided to respond to these letters.

ARB states in these letters that it is developing California's compliance plan for the CPP and indicates the EGUs that ARB believes are subject to the CPP (i.e., affected EGUs). As the entity which operates consolidated accounts under the Cap-and-Trade Regulation on behalf of each of the owners of the facilities for which ARB is requesting information, CES hereby responds to ARB with respect to all of the subject facilities.

The ARB letters state that "[t]he EGUs that you own or operate which ARB believes to be covered by the CPP are" as follows:

- "**Agnews Power Plant**, Unit GEN1: 22.8 MW (Combined-Cycle Combustion Turbine), Unit GEN2: 7.7 MW (Combined-Cycle Steam Turbine)"[1];

[1] Letter from Edie Chang, Deputy Executive Officer, ARB, to Power Plant Manager, O.L.S. Energy – Agnews Inc. (Sep. 16, 2015) (emphasis added).

LEGAL_US_W # 83561513.3

ARB indicated that all of the above EGUs are "covered by the CPP". While CES agrees that the identified *facilities* are each covered by the CPP, ARB's letters could be read to incorrectly imply that each of the listed steam turbines constitutes a *separate* "affected EGU" under the CPP. In fact, with respect to a natural gas combined-cycle ("NGCC") facility, the heat recovery steam generating unit, associated steam turbine, and resulting capacity should be treated as part of the associated combined cycle combustion turbine(s) for purposes of determining whether the stationary combustion turbine is an "affected EGU" subject to the CPP; in other words, neither the steam turbine, which does not combust any fossil fuel, nor the associated heat recovery steam generator ("HRSG"), should be identified as a separate affected EGU. Therefore, the steam turbines in the above-listed facilities should not be identified as separate affected EGUs, but should be considered as part of the relevant stationary combustion turbine(s) that constitutes an affected EGU under the CPP.

ARB correctly states that, under the CPP, "[a]n affected EGU, generally, is any fossil-fired steam generating unit, integrated gasification combined cycle (IGCC) or stationary combustion turbine" that satisfies certain criteria.[9] However, under the CPP, "[s]tationary combustion turbines" are subject to the CPP only if they "meet the definition of either a combined cycle or combined heat and power combustion turbine."[10] Further, a "[c]ombined cycle unit means an electric generating unit that uses a stationary combustion turbine from which the heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit to generate additional electricity."[11] Additionally, "[s]tationary combustion turbine means all equipment, including but not limited to the turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post-combustion emissions control technology, and any ancillary components and sub-components comprising... any combined cycle combustion turbine..."[12] Thus, CES believes that, in the case of NGCC units, the affected EGU should be defined to include both the combustion turbine itself and the associated steam turbine.[13]

[8] Letter from Edie Chang, Deputy Executive Officer, ARB, to Chris German, West Region Asset Management Director, Calpine Corporation – West Region (Sep. 16, 2015) (regarding Sutter Energy Center) (emphasis added).

[9] *See* note 1 *supra*.

[10] CPP (pre-publication version) (Aug. 3, 2015) at 1508, 40 C.F.R. §60.5845(b)(3).

[11] *Id.* at 1544, §60.5880.

[12] *Id.*

[13] This is further supported by the preamble to the CPP, which indicates that, "[t]he only natural gas fired EGUs currently considered affected units under the 111(d) applicability criteria are NGCC units capable of supplying more than 25 MW of electrical output to the grid. The data and rates for these units represent all emissions and MWh output associated with both the combustion turbines as well as all associated heat recovery steam generating units. The remainder of the section will use the term 'NGCC' to collectively refer to these natural gas fired EGUs." CPP (pre-publication version) at 771, note 731; *see also id.* at 273-74 (stating that "[c]ombined cycle combustion turbine means any stationary combustion

Appendix A: EGUs Identified by ARB

ARB-Identified EGU	CES Concurrence/ Clarification
Agnews Unit GEN1: 22.8 MW (Combined-Cycle Combustion Turbine)	Concur that unit is affected EGU subject to CPP, but ARB's stated capacity should include capacity of steam turbine
Agnews Unit GEN2: 7.7 MW (Combined-Cycle Steam Turbine)	Disagree that unit is affected EGU under CPP; capacity should be included within combustion turbine's capacity
Gilroy Cogen Unit GEN1: 85.4 MW (Combined-Cycle Combustion Turbine)	Concur that unit is affected EGU subject to CPP, but ARB's stated capacity should include capacity of steam turbine
Gilroy Cogen Unit GEN2: 38 MW (Combined-Cycle Steam Turbine)	Disagree that unit is affected EGU under CPP; capacity should be included within combustion turbine's capacity
Los Esteros Unit CTG1: 49.9 MW (Combined-Cycle Combustion Turbine)	Concur that unit is affected EGU subject to CPP, but ARB's stated capacity should account for capacity of steam turbine
Los Esteros Unit CTG2: 49.9 MW (Combined-Cycle Combustion Turbine)	Concur that unit is affected EGU subject to CPP, but ARB's stated capacity should account for capacity of steam turbine
Los Esteros Unit CTG3: 49.9 MW (Combined-Cycle Combustion Turbine)	Concur that unit is affected EGU subject to CPP, but ARB's stated capacity should account for capacity of steam turbine
Los Esteros Unit CTG4: 49.9 MW (Combined-Cycle Combustion Turbine)	Concur that unit is affected EGU subject to CPP, but ARB's stated capacity should account for capacity of steam turbine
Los Esteros Unit CAG5: 126.07 MW (Combined-Cycle Steam Turbine)	Disagree that unit is affected EGU under CPP; capacity should be included within combustion turbines' capacities
Los Medanos Unit CTG1: 172 MW (Combined-Cycle Combustion Turbine)	Concur that unit is affected EGU subject to CPP, but ARB's stated capacity should account for capacity of steam turbine
Los Medanos Unit CTG2: 172 MW (Combined-Cycle Combustion Turbine)	Concur that unit is affected EGU subject to CPP, but ARB's stated capacity should account for capacity of steam turbine
Los Medanos Unit STG3: 250 MW (Combined-Cycle Steam Turbine)	Disagree that unit is affected EGU under CPP; capacity should be included within combustion turbines' capacities
Otay Mesa Unit 1-01: 199 MW (Combined-Cycle Combustion Turbine)	Concur that unit is affected EGU subject to CPP, but ARB's stated capacity should account for capacity of steam turbine
Otay Mesa Unit 1-02: 199 MW (Combined-	Concur that unit is affected EGU subject to

Appendix B: EGUs Not Identified by ARB

EGU	Applicability
Delta Energy Center (ORIS Code 55333) Unit CTG1: 212 MW (Combined-Cycle Combustion Turbine)	Affected Combined Cycle Combustion Turbine
Delta Energy Center (ORIS Code 55333) Unit CTG2: 212 MW (Combined-Cycle Combustion Turbine)	Affected Combined Cycle Combustion Turbine
Delta Energy Center (ORIS Code 55333) Unit CTG3: 213.5 MW (Combined-Cycle Combustion Turbine)	Affected Combined Cycle Combustion Turbine
Delta Energy Center (ORIS Code 55333) Unit STG1: 306 MW (Combined-Cycle Steam Turbine)	Not itself an affected EGU, but its indicated capacity should be included as part of above three combustion turbines' capacities
King City [Cogeneration] (ORIS Code 10294) Unit GTG: 90.8 MW (Combined-Cycle Combustion Turbine)	Affected Combined Cycle Combustion Turbine
King City [Cogeneration] (ORIS Code 10294) Unit STG: 42.4 MW (Combined-Cycle Steam Turbine)	Not itself an affected EGU, but its indicated capacity should be included with above combustion turbine's capacity

iii. OLS Chino (EIA # 50850) owns a combined cycle facility that includes a 23.6 MW (CT) + 7.6 MW (CA) = 31.2 MWs. Staff reviewed the eGrid and CEC data. Based on this data, the combined cycle facility has been added to the list of affected units.

iv. CI Power Cogeneration (formerly OLS Camarillo) (EIA # 50851) owns a combined cycle facility that includes a 23.6 MW (CT) + 7.6 MW (CA) = 31.2 MWs. Staff reviewed the eGrid, CEC data and acknowledgement by CI Power of the applicability of the CPP. Therefore, the combined cycle facility has been added to the list of affected units. The letter from CI power follows:

Channel Islands
CALIFORNIA STATE UNIVERSITY

SITE AUTHORITY
CI POWER
45 Rincon Drive Suite 104-A
805-437-2667
805-437-2681 fax

October 08, 2015

Now CSUCI Site Authority

Mr. Christopher Gallenstien
Staff Air Pollution Specialist
California Air Resources Board
1001 I Street
P.O. Box 2815
Sacramento, CA 95812

Re: Clean Power Plan Applicability Determination

Dear Mr. Gallenstien:

CI Power Cogeneration has reviewed CARB's letter dated September 16, 2015. Based on that review, CI Power concurs that the Electric Generating Units identified as OLS Energy Camarillo, Unit GEN1: 23:59 (Combined-Cycle Combustion Turbine) and Unit GEN2: 7.6 MW (Combined-Cycle Steam Turbine) are covered by the USEPA's final Clean Power Plan.

I would like to also take the opportunity to provide updated Facility and Contact Information. OLS Energy Camarillo is no longer the owner of this facility. The current owners are the Trustees of CSU and CSUCI Site Authority. The facility name is CI Power Cogeneration Plant. The Facility Contact information is as follows:

Jeffery Smith
Plant Manager
(805) 437-3795
jeff.smith@csuci.edu
1947 W. Potrero Road
Camarillo, CA 93012.

Should you have any further questions, please contact myself or Jeff Smith at the Facility.

Based on information and belief formed after reasonable inquiry, as the designated Responsible Official, the statements and information in this document are true, accurate and complete.

Very truly yours,

Ms. Ysabel Trinidad
Vice President
(805) 437-8878

3) There were two units (one facility) Glendale Water and Power, Grayson Units 4 and 5 (EIA # 377) that were excluded by U.S. EPA as non-fossil type units combusting land fill gas. (The other units at this facility were listed as affected units.) However, though these units combust landfill gas, they also historically combust greater than 10 percent natural gas, and so are not exempt from being affected units. This information was confirmed by ARB data and acknowledgement by Glendale Water and Power. Therefore, these units have been added to the list of affected units. The letter from Glendale Water and Power follows:

glendale california

City of Glendale
Glendale Water & Power
Administration

141 N. Glendale Ave., Level 4
Glendale, CA 91206-4975
Tel 818.548.2107 Fax 818.552.2852
www.glendaleca.gov

October 7, 2015

Ms. Edie Chang
Deputy Executive Officer
California Air Resources Board
P.O. Box 2815
Sacramento, CA 95812

SUBJECT: Clean Power Plan - City of Glendale Water & Power Covered Electric Generating Units at Grayson Power Plant

Dear Ms. Chang:

This is in response to your letter to Mr. John Escudero on September 16, 2015 regarding applicability of the Clean Power Plan (CPP) on certain electric generating units that we own and operate. We concur with your determination that the following units are covered in the CPP:

1. Unit 1: 20 MW (Combined-Cycle Steam Turbine)
2. Unit 2: 20 MW (Combined-Cycle Steam Turbine)
3. Unit 4: 44 MW (Steam Turbine)
4. Unit 5: 44 MW (Steam Turbine)
5. Unit 8A: 30 MW (Combined-Cycle Combustion Turbine)
6. Unit 8BC: 60 MW (Combined-Cycle Combustion Turbine)

I attest that the above is a true and accurate statement.

If you need additional information, please contact Mr. John Escudero, Power Plant Superintendent, at (818) 548-2148, or by email at jescudero@glendaleca.gov.

Sincerely,

Ramon Z. Abueg
Chief Assistant General Manager

RZA/JG:to

c: John Escudero, Power Plant Superintendent
Maurice Oillataguerre, Environmental Program Administrator
Joan Gaerlan, Environmental Program Specialist

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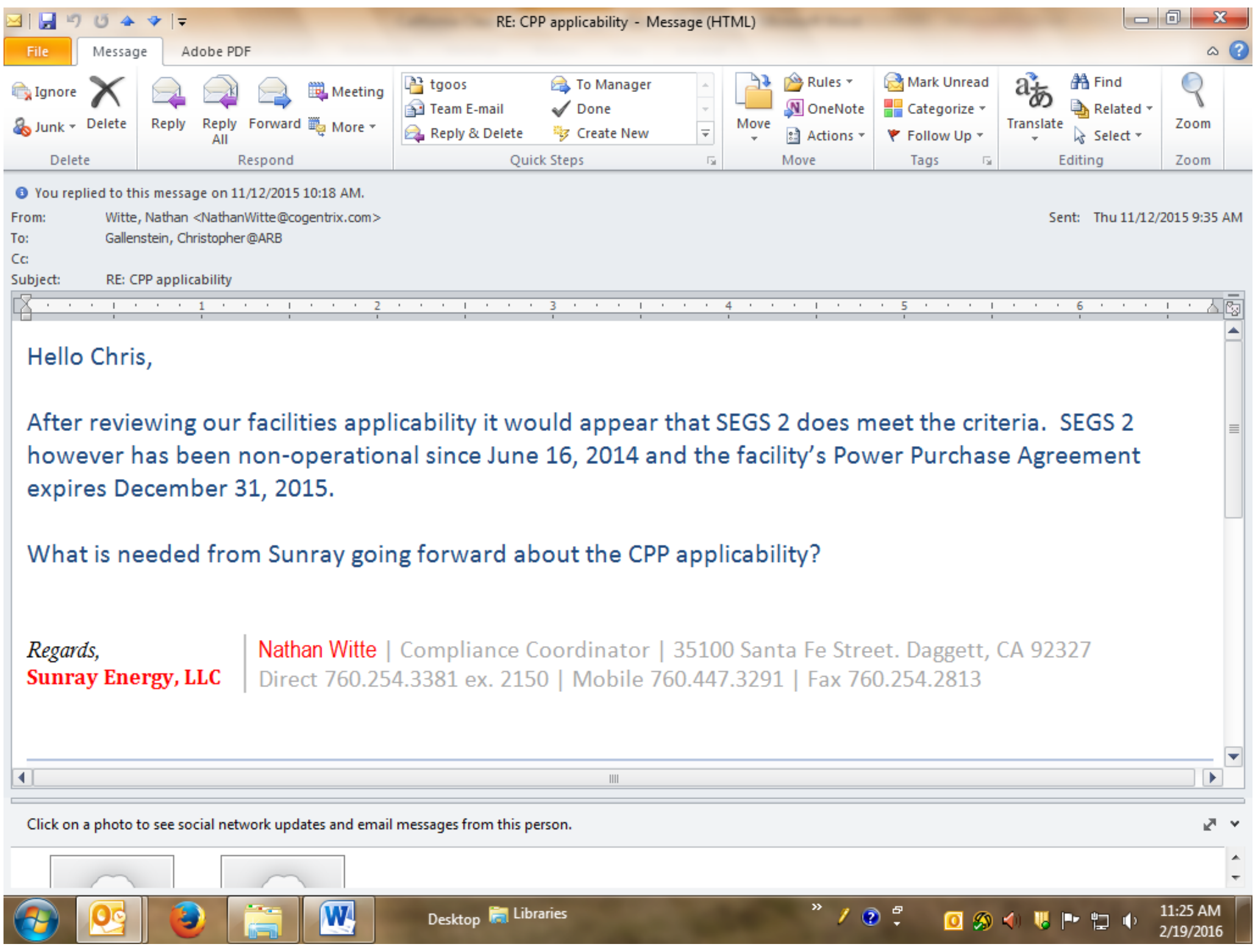
4) There are eight units that EPA excluded as non-fossil solar units however, these units also utilize natural gas-fired steam boilers that are rated at greater than 250 MMBtu/Hr to provide additional generation and do not meet the exemption requirements.

   i. Sunray Power, LLC, which owns SEGS Unit II (EIA #10438). Information from CEC and ARB was obtained which indicated that this unit may not be an exempt unit. This information was confirmed by Sunray Power. Therefore this unit was added to the list of affected units. The email correspondence follows:



RE: CPP applicability - Message (HTML)

You replied to this message on 11/12/2015 10:18 AM.

From: Witte, Nathan <NathanWitte@cogentrix.com>
Sent: Thu 11/12/2015 9:35 AM
To: Gallenstein, Christopher@ARB
Cc:
Subject: RE: CPP applicability

Hello Chris,

After reviewing our facilities applicability it would appear that SEGS 2 does meet the criteria. SEGS 2 however has been non-operational since June 16, 2014 and the facility's Power Purchase Agreement expires December 31, 2015.

What is needed from Sunray going forward about the CPP applicability?

Regards,
Sunray Energy, LLC

Nathan Witte | Compliance Coordinator | 35100 Santa Fe Street. Daggett, CA 92327
Direct 760.254.3381 ex. 2150 | Mobile 760.447.3291 | Fax 760.254.2813

ii – ix: NextEra Energy Operating Services, Inc. owns SEGS units: III, IV, V, VI, VII, VIII and IX (EIA #s 10439,10440, 10441,10442,10443,40144, and 10446, respectfully). Information from CEC and ARB was obtained which indicated that these units may not be exempt units. This information was confirmed by Sunray Power. Therefore these units were added to the list of affected units. This information was confirmed by ARB staff and confirmed in a letter from Nextera Energy. Therefore these units were added to the list of affected units. The Nextera Energy letter follows:

NextEra Energy Operating Services, Inc., 41100 US Highway 395, Boron,
CA 93516
760-762-5562

October 12, 2015

Mr. Christopher Gallenstein
Industrial Strategies Division
Project Assessment Branch, 7th Floor
California Air Resources Board
P.O. Box 2815
Sacramento, CA 95812

Subject: Clean Power Plan

Dear Mr. Gallenstein:

We are in receipt of you letters to us regarding your determination that the Clean Power Plan (CPP) CFR 40, Part 60, Subpart UUUU applies to our facilities.

We concur with your determination that the CPP is applicable to the following electric generating units:

SEGS III, Unit GEN 1

SEGS IV, Unit GEN 1

SEGS V, Unit GEN 1

SEGS VI, Unit GEN 1

SEGS VII, Unit GEN 1

SEGS VIII, Unit GEN 1

SEGS IX, Unit GEN 1

If you have any questions, please contact me at 760-762-1505.

I declare, under penalty of perjury under the laws of the state of California, that, based on information and belief formed after reasonable inquiry, all information provided in this letter is true, accurate, complete, and I am authorized to provide this information.

Sincerely,

Glen King
Environmental Specialist
Luz Solar Partners III – IX

cc: file

5) There are 13 units (10 facilities) that U.S. EPA excluded as “simple cycle units.” However, these units are, in fact, combined heat and power units that do not meet the exemption requirements for combined heat and power units. These units are described below:

   i. Greenleaf 2 – Gen 1 (EIA # 10349). Information from CEC and ARB was obtained which indicated that this unit may not be an exempt unit. This information was confirmed by ARB staff and confirmed in a letter from Greenleaf 2. Therefore, this unit was added to the list of affected units. The Greenleaf 2 letter follows:

ProEnergx
5ERVICE5
"Experience our Energy"

Greenleaf ENERGY
Unit 2 LLC

875 N. Walton Avenue
Yuba City, California 95993

P.O. Box 3070
Yuba City, California 95992

October 6, 2015

530.821.2056 Phone
530.821.2055 Fax

Mr. Christopher Gallenstein
Staff Air Quality Specialist
California Air Resources Board
1001 I Street, PO Box 2815
Sacramento, CA 95812

Subject: Clean Power Plan Applicability- Greenleaf Energy Unit 2

Dear Mr. Gallenstein,

We have reviewed your letter dated September 16, 2015 regarding the Clean Power Plan. Greenleaf Energy Unit 2 concurs with CARB's applicability determination for our facility.

As a duly authorized representative of Greenleaf Energy Unit 2, I attest that to the best of my understanding of the requirements of the Clean Power Plan that Greenleaf Energy Unit 2 is covered under this plan.

Sincerely,

Plant Manager
Greenleaf Energy Units 1 and 2

ii. The following facilities are owned by Juniper Generation:

- Bear Mountain Cogeneration - Gen1 (EIA # 100890)
- Badger Creek Cogeneration – Gen1 (EIA # 100897)
- Chalk Cliff Cogeneration – Gen1 (EIA # 101520)
- Oak Cogeneration – Gen1 (EIA # 101044)
- McKittrick Cogen – Gen1 (EIA # 100296)

Staff contacted the agent for Juniper Generation to confirm the status of the Juniper Generation facilities. Based on this conversation, staff has included the Juniper Generation units as affected units. Staff documented this telephone conversation in the email below: These facilities are combined heat and power facilities that do not meet the exemptions requirements of the CPP:

Email:
From: Gallenstein, Christopher@ARB
Sent: Wednesday, January 13, 2016 11:10 AM
To: dconsie@camsops.com
Cc: Segall, Craig@ARB
Subject: Juniper Generation And the CPP

Dan:
Thank you for the call this morning to discuss the Juniper Generation facilities/units. I talked with Craig Segal and there is no legal mandate for you to attest to the applicability of the Juniper Generation units. Based on our call, your calculations show that these units are affected units and are "OK" with ARB listing them as affected units. As such, I will leave them as affected units for purposes of submitting our plan to U.S EPA. If you have any questions on this matter, please contact me.

Christopher Gallenstein
Staff Air Pollution Specialist
Project Assessment Branch, 7th Floor
California Air Resources Board
P.O. Box 2815
Sacramento, CA 95812
Phone: (916) 324-8017

iii. Oil Dale – ODC1 (EIA 100891). Information from CEC and ARB was obtained which indicated that this unit may not be an exempt unit. This information was confirmed by ARB staff and confirmed in a letter from Oil Dale. Therefore, this unit was added to the list of affected units. The Oildale letter follows:

OILDALE ENERGY LLC

October 16, 2015

Christopher Gallenstein
Air Resources Board
P.O. Box 2815
Sacramento, CA 95812

Dear Mr. Gallenstein,

In response to your letter of September 16, 2015, we concur that we believe that our Oildale Energy LLC gas turbine unit is covered by the CPP.

We are authorized to attest to the above.

Sincerely,

Alex Sugaoka

Alex Sugaoka
Vice President

2420 CAMINO RAMON, SUITE 101 - SAN RAMON, CA 94583 - (925) 244-1100 - (925) 244-1101/FAX

iv. Sycamore Cogen - units: GTGB, GTGD (EIA 100866). Information from CEC and ARB was obtained which indicated that these units may not be exempt units. This information was confirmed by Chevron Power Holdings. Therefore, these units were added to the list of affected units. The Chevron Power Holdings letter follows:

✓

Chevron

Chevron Power Holdings, Inc
Chevron Power and Energy Management Company
(a division of Chevron U.S.A Inc)
P.O. Box 81438
Bakersfield, CA 93380
Tel 661 615 4630
Fax 661 615 4610

October 15, 2015

SY-10549

Ms. Edie Chang
Deputy Executive Officer
Mr. Christopher Gallenstein
Staff Air Pollution Specialist
Air Resources Board
1001 I Street
P.O. Box 2815
Sacramento, California 95812

Re: Sycamore Cogeneration Facility
Exemption of Two Units under CPP

Dear Ms. Chang and Mr. Gallenstein:

Chevron Power Holdings Inc. ("CPHI"), successor in interest to Sycamore Cogeneration Company, and owner of the Sycamore Cogeneration Facility ("Sycamore Facility"), has received your letter dated September 16, 2015 ("September 16 Letter"). The September 16 Letter asks for concurrence or non-concurrence with the Air Resources Board's ("ARB") determination that the Sycamore Facility owns or operates electric generating units ("EGU") that are covered by the U.S. EPA's Clean Power Plan ("CPP"), as it was released by the EPA in unofficial, pre-publication format on its website on August 3, 2015.

As discussed below, two of the Sycamore Facility's four units qualify for the CPP's exclusion of combined heat power ("CHP") units from categorization as "Affected EGUs", as set forth in the CPP at 40 C.F.R. Section 60.5850(a)(5).

A. Background

The September 16 Letter references the following Sycamore units that it believes are covered by CPP:

- Unit GTAG: 75 MW (simple-cycle gas turbine)
- Unit GTBG: 75 MW (simple-cycle gas turbine)
- Unit GTCG: 75 MW (simple-cycle gas turbine)
- Unit GTDG: 75 MW (simple-cycle gas turbine)

i.

As an initial matter, CPHI notes that the published version of the CPP likely will differ from the pre-publication version. In particular, neither definitions of "design efficiency" and "potential electric output" nor cross references to other regulations containing definitions of "design efficiency" and "potential electric output" were provided in the pre-publication version of the CPP. These definitions are essential to application of the CHP exclusion.[1] Further, CPHI understands the pre-publication version contains certain verbiage errors, which could affect application of the CHP exclusion, and that EPA plans to correct said errors in the final version of the CPP that will be published in the *Federal Register*. As of the date of CPHI's preparation of this response, the CPP had not yet been published in the *Federal Register*. CPHI reserves the right to modify and/or supplement its response to the extent any changes are made in the published version as such changes may affect whether the subject units are "Affected EGUs" under the CPP.

B. The CHP Exclusion Applies to Units GTAG and GTCG

CPHI does not concur with ARB's designation of two Sycamore Units as covered by CPP: Unit GTAG (which CPHI refers to as Sycamore Unit 1), and Unit GTCG (which CPHI refers to as Sycamore Unit 3).

These units currently operate, and historically have operated, as baseload CHP units and meet the criteria for the exclusion provided in Section 60.5850(a)(5). Enclosed as Attachment 1 to this letter are CPHI's calculations substantiating that these units' annual net electric sales have been less than the design efficiency multiplied by the potential electric output of the units.

Actual operating data is provided separately for each of these units for calendar years 2012, 2013 and 2014. These years correspond approximately to the timeframe in which the units have been subject to ARB Mandatory Reporting Regulation.[2]

---

1 For purposes of responding to the September 16 Letter, ARB asserts that respondents must use the definitions of "design efficiency" and "potential electric output" as they are set forth in EPA's Clean Pollution Standards in Rule 111(b) for new and modified EGUs under Chapter 40, Part 60, Subpart TTTT of the Code of Federal Regulations.

2 For purposes of determining "design efficiency" CPHI calculated an efficiency percentage based on the description of the term in the first sentence of the definition from 40 C.F.R. Subpart TTTT. This determination is also consistent with manner in which CPHI has previously determined design efficiency of its cogeneration plants in other contexts, i.e., for purposes of compliance with California's QF Efficiency Monitoring Program. CPHI was unable to perform testing under the ASME or ISO methods referenced in the second sentence of the definition of design efficiency in time for preparation of this submission by the ARB's requested deadline; however, the data used in the calculations is actual plant recorded data. Although CPHI submits that its design efficiency determination is an appropriate and accurate reflection of design efficiency consistent with EPA's CPP definitions, CPHI commits to supplement its response to ARB with additional data to the extent ARB deems it necessary to comply with the September 16 Letter.

C. Attestations

By signing this letter, I certify that, based on my inquiry of those individuals with primary responsibility for operation of and recordkeeping for the pertinent units, the information contained herein is true and accurate to the best of my knowledge and belief. By signing this letter, I also certify that I am authorized to make this submission on behalf of CPHI.

Sincerely,

Carolyne Grant

Carolyne M. Grant
Asset Manager
Chevron Power Holdings, Inc.
Sycamore Cogeneration Facility

DAJ/ab

Attachment

Design Efficiency Calculations for the Sycamore Cogeneration Facility
2012 - 2014

Annual Data Sourced from CARB Facility Audit Report

$Design\ Eff = ((Net\ Electical\ Output\ MW \times (3.413\ MMBtu/MWhr)) + Thermal\ Output\ MMBtu/hr\ ))/(Fuel\ Consumption\ MMBtu/hr)$

Unit: Sycamore Cogeneration Facility #1

(A)	(B)	C	(D)	E	(F)	(G)	(H)	(I)	(J)	(K)
								Potential Electric Output MWHRS	Exemption Calculation (MWHRS)	CHP Exemption Met?
	Net Electric Output (mWhr)	Net Electric Output (mW)	Thermal Output (mmbtu)	Thermal Output (mmbtu/hr)	Fuel Consume (mmbtu) LHV conversion	Fuel Consume (mmbtu/hr) LHV conversion	Annual Design Efficiency LHV	((design eff lhv*baseload heat input*1000000)/(3413*1000)*8760	Potential Electric Output - Actual Net Electric Output	
2014	657,154	77.3	3,610,342	424.8	7,298,463	858.8	80.2%	1,767,849	1,110,695	Yes (B < I)
2013	603,815	79.9	3,250,950	430.2	6,814,325	901.7	78.0%	1,804,088	1,200,273	Yes (B < I)
2012	528,224	79.1	2,819,940	422.1	5,980,812	895.2	77.3%	1,775,941	1,247,717	Yes (B < I)

Unit: Sycamore Cogeneration Facility #3

(A)	(B)	C	(D)	E	(F)	(G)	(H)	(I)	(J)	(K)
								Potential Electric Output MWHRS	Exemption Calculation (MWHRS)	CHP Exemption Met?
	Net Electric Output (mWhr)	Net Electric Output (mW)	Thermal Output (mmbtu)	Thermal Output (mmbtu/hr)	Fuel Consume (mmbtu) LHV conversion	Fuel Consume (mmbtu/hr) LHV conversion	Annual Design Efficiency LHV	((design eff lhv*baseload heat input*1000000)/(3413*1000)*8760	Potential Electric Output - Actual Net Electric Output	
2014	666,285	78.3	3,614,902	424.6	7,421,866	871.8	79.3%	1,775,504	1,109,219	Yes (B < I)
2013	569,214	80.1	3,045,462	428.6	6,251,994	879.9	79.8%	1,801,966	1,232,752	Yes (B < I)
2012	497,752	78.7	2,690,402	425.2	5,211,083	823.6	84.2%	1,780,567	1,282,815	Yes (B < I)

v. Kern River Cogen units: GTAG, GTBG, and GTCG (EIA # 10496). Information from CEC and ARB was obtained which indicated that these units may not be exempt units. This information was confirmed by Chevron Power Holdings. Therefore, these units were added to the list of affected units. The Chevron Power Holdings letter follows:

Chevron

Chevron Power Holdings, Inc
Chevron Power and Energy Management Company
(a division of Chevron U.S.A Inc)
P.O. Box 81438
Bakersfield, CA 93380
Tel 661 615 4630
Fax 661 615 4610

October 15, 2015

KR-10772

Ms. Edie Chang
Deputy Executive Officer
Mr. Christopher Gallenstein
Staff Air Pollution Specialist
Air Resources Board
1001 I Street
P.O. Box 2815
Sacramento, California 95812

Re: Kern River Cogeneration Facility
Exemption of Unit GTDG under CPP

Dear Ms. Chang and Mr. Gallenstein:

Chevron Power Holdings Inc. ("CPHI"), successor in interest to Kern River Cogeneration Facility, and owner of the Kern River Cogeneration Facility ("Kern River Facility"), has received your letter dated September 16, 2015 ("September 16 Letter"). The September 16 Letter asks for concurrence or non-concurrence with the Air Resources Board's ("ARB") determination that the Kern River Facility owns or operates electric generating units ("EGU") that are covered by the U.S. EPA's Clean Power Plan ("CPP"), as it was released by the EPA in unofficial, pre-publication format on its website on August 3, 2015.

As discussed below, one of the Kern River Facility's four units qualify for the CPP's exclusion of combined heat power ("CHP") units from categorization as "Affected EGUs", as set forth in the CPP at 40 C.F.R. Section 60.5850(a)(5).

A. Background

The September 16 Letter references the following Kern River Facility units that it believes are covered by CPP:

- Unit GTAG: 75 MW (simple-cycle gas turbine)
- Unit GTBG: 75 MW (simple-cycle gas turbine)
- Unit GTCG: 75 MW (simple-cycle gas turbine)
- Unit GTDG: 75 MW (simple-cycle gas turbine)

As an initial matter, CPHI notes that the published version of the CPP likely will differ from the pre-publication version. In particular, neither definitions of "design efficiency" and "potential electric output" nor cross references to other regulations containing definitions of "design efficiency" and "potential electric output" were provided in the pre-publication version of the CPP. These definitions are essential to application of the CHP exclusion.[1] Further, CPHI understands the pre-publication version contains certain verbiage errors, which could affect application of the CHP exclusion, and that EPA plans to correct said errors in the final version of the CPP that will be published in the *Federal Register*. As of the date of CPHI's preparation of this response, the CPP had not yet been published in the *Federal Register*. CPHI reserves the right to modify and/or supplement its response to the extent any changes are made in the published version as such changes may affect whether the subject units are "Affected EGUs" under the CPP.

B. The CHP Exclusion Applies to Unit GTDG

CPHI does not concur with ARB's designation of one Kern River Facility Unit as covered by CPP: Unit GTDG (which CPHI refers to as Kern River Unit 4).

This unit currently operates, and has historically operated, as a baseload CHP unit and meets the criteria for the exclusion provided in Section 60.5850(a) (5). Enclosed as Attachment 1 to this letter are CPHI's calculations substantiating that these units' annual net electric sales have been less than the design efficiency multiplied by the potential electric output of the units.

Actual operating data is provided for calendar years 2012, 2013 and 2014. These years correspond approximately to the timeframe in which the units have been subject to ARB Mandatory Reporting Regulation.[2]

1 For purposes of responding to the September 16 Letter, ARB asserts that respondents must use the definitions of "design efficiency" and "potential electric output" as they are set forth in EPA's Clean Pollution Standards in Rule 111(b) for new and modified EGUs under Chapter 40, Part 60, Subpart TTTT of the Code of Federal Regulations.

2 For purposes of determining "design efficiency" CPHI calculated an efficiency percentage based on the description of the term in the first sentence of the definition from 40 C.F.R. Subpart TTTT. This determination is also consistent with manner in which CPHI has previously determined design efficiency of its cogeneration plants in other contexts, i.e., for purposes of compliance with California's QF Efficiency Monitoring Program. CPHI was unable to perform testing under the ASME or ISO methods referenced in the second sentence of the definition of design efficiency in time for preparation of this submission by the ARB's requested deadline; however, the data used in the calculations is actual plant recorded data. Although CPHI submits that its design efficiency determination is an appropriate and accurate reflection of design efficiency consistent with EPA's CPP definitions, CPHI commits to supplement its response to ARB with additional data to the extent ARB deems it necessary to comply with the September 16 Letter.

C. Attestation

By signing this letter, I certify that, based on my inquiry of those individuals with primary responsibility for operation of and recordkeeping for the pertinent units, the information contained herein is true and accurate to the best of my knowledge and belief. By signing this letter, I also certify that I am authorized to make this submission on behalf of CPHI.

Sincerely,

Carolyne Grant

Carolyne M. Grant
Asset Manager
Chevron Power Holdings, Inc.
Kern River Cogeneration Facility

DAJ/AB

Attachment

Design Efficiency Calculations for the Kern River Cogeneration Facility

2012 - 2014

Annual Data Sourced from CARB Facility Audit Report

$$Design\ Eff = ((Net\ Electical\ Output\ MW \times (3.413\ MMBtu/MWhr)) + Thermal\ Output\ MMBtu/hr\ ))/(Fuel\ Consumption\ MMBtu/hr)$$

Unit: Kern River Cogeneration Facility #4

(A)	(B)	C	(D)	E	(F)	(G)	(H)	(I)	(J)	(K)
								Potential Electric Output MWHRS	Exemption Calculation (MWHRS)	CHP Exemption Met?
	Net Electric Output (mWhr)	Net Electric Output (mW)	Thermal Output (mmbtu)	Thermal Output (mmbtu/hr)	Fuel Consume (mmbtu) LHV conversion	Fuel Consume (mmbtu/hr) LHV conversion	Annual Design Efficiency LHV	((design eff lhv*baseload heat input*1000000)/(3413*1000)*8760	Potential Electric Output - Actual Net Electric Output	
2014	653,066	77.4	3,393,593	402.3	7,320,886	867.8	76.8%	1,710,650	**1,057,584**	Yes (B < I)
2013	623,925	75.2	3,387,553	408.4	7,074,079	852.8	78.0%	1,707,085	**1,083,160**	Yes (B < I)
2012	426,940	73.6	2,368,924	408.2	4,849,498	835.5	78.9%	1,691,973	**1,265,033**	Yes (B < I)

6) There are four units that prior to 2012 operating as simple cycle units. These units were idled in 2012 during which time a HRSG was being constructed. The HRSG portion of this facility was listed as an “under construction natural gas-fired combined cycle. The four simple cycle units were listed as “excluded.” These four units, as well as the completed HRSG are now operating as a combined cycle facility. Therefore, the four simple cycle units need to be added as affected units. i.e. facility as a whole needs to be considered as affected units.

    i. Los Esteros – units: CTG1, CTG2, CTG3 and CTG4 (EIA # 101143)

7) There are 3 units (one facility) that EPA excluded as commercial/industrial units that are combined heat and power units that do not meet the exemption requirements for combined heat and power:

    i. Midway Sunset – Units: A, B and C (EIA # 52169). Information from CEC and ARB was obtained which indicated that these units may not be exempt units. This information was confirmed by Midway Sunset. Therefore, these units were added to the list of affected units. The Midway Sunset letter follows:

MIDWAY SUNSET
Cogeneration Company

October 12, 2015 CC-1925

Edie Chang
Deputy Executive Officer
California Air Resources Board
1001 I Street, P.O. Box 2815
Sacramento, CA 95812

Subject: Clean Power Plan (CPP) Coverage of Midway Sunset Cogeneration Company's (MSCC's) Three Combined Heat and Power (CHP) Generating Units (Unit A, Unit B and Unit C)

Dear Edie Chang,

MSCC has received your letter dated September 16, 2015 asking confirmation that MSCC's three CHP Gas Turbines are covered for purposes of the CPP. After review of your letter with the attached Applicability and Exclusion Sections from 40 C.F.R. Subpart UUUU, MSCC concurs with the Air Resources Board's (ARB's) applicability determination for MSCC's Unit A, Unit B and Unit C. Please note, MSCC feels a more definitive description of the three units would be Combined Heat and Power, Simple-Cycle Gas Turbines.

I attest that the above information is true and accurate and that I have the authority to make that attestation.

Sincerely,

D. Faiella

Dave Faiella
Executive Director

cc: File CC-1925
G. Jans
S. Henriksen

3466 W. Crocker Springs Road • P.O. Box 457 • Fellows, CA 93224-0457 • (661) 768-3000 • Fax (661) 768-4570

C. Justification for Exclusion of Affected Units

The following identifies and justifies electrical generation units that U.S. EPA had included as affected units, but should not be considered affected units. These units are described by the type of exclusion. These are discussed in detail with supporting documentation below.[5]

1) There are six units that were excluded based on their historic generation being less than 219,000 MWs/Yr.

    i. El Centro Unit 4 (EIA # 389). Staff reviewed the ARB, eGrid and CEC data and the Title V permit and determined that this unit has historically operated less than 219,000MWs per year. This exemption was confirmed by Imperial Irrigation District. Therefore, this unit has been deleted from the list of affected units. The letter from Imperial Irrigation District and a copy of the Title V permit follow:

[5] ARB has included letters received for exempted units in Appendix X.

IID

A century of service.

www.iid.com

October 15, 2015

Mr. Edie Chang
Deputy Executive Officer
California Air Resources Board
1001 I Street P.O. Box 2815
Sacramento, CA 95812

Subject: IID's response to ARB "Affected EGUs" Letter dated September 16, 2015

Dear Mr. Chang:

Imperial Irrigation District (IID), concurs with ARB determination that El Centro, Unit 2: 34.5 MW (Combined- Cycle Steam Turbine), Unit 2A: 89.9 MW (Combined- Cycle Combustion Turbine), Unit 30: 65.88 MW (Combined- Cycle Steam Turbine), Unit 31: 43.2 MW (Combined- Cycle Combustion Turbine), Unit 32: 43.2 MW (Combined- Cycle Combustion Turbine) are covered for purposes of the Clean Power Plan.

However, IID would like to claim an exemption for Unit 4: 81.6 MW (Steam Turbine) under 40 C.F.R. § 60.5850(a)(2).

El Centro Unit 4 Title V Permit to Operate (PTO) #1156A-2 limits its fuel usage rate to 2,180,714.4 MMBtu/yr. See attached "ECGS Unit 4 PTO#1156A-2 (Issued 06.13.12)" B.5.

The attached "ECGS U4 PTO Limit Conversion" spreadsheet is used as reference to convert the fuel usage rate limit of 2,180,714.4 MMBtu/yr. to MWh/yr.

2,180,714.4 MMBtu/yr * 1000000 / 11,463 Btu/kWh / 1000 = 190,239.41 MWh/yr.

Unit 4 has historically never exceeded the 219,000 MWh annual net electric sales' limit.

I, Michael Taylor, certify that I am authorized to execute this attestation; that I am familiar with the above statement; that, to the best of my information, knowledge and belief, the statement is true and correct as of the date of signing.

Michael J. Taylor

Michael J. Taylor
Assistant Manager, Energy

Attachments
Cc: C. Stills
T. King
J. Landeros

IMPERIAL IRRIGATION DISTRICT
OPERATING HEADQUARTERS · P.O BOX 937 · IMPERIAL, CA 92251

El Centro Generating Station Unit 4

Net Maximum Annual Generation Capability

Net Output MW	Corr Net Heat Rate Btu/kWh	Heat Input Limit MMBtu/yr [3]	Calculated Maximum Net Generation Capability (based on Heat Input Limit) MWh/yr	Comments
63.21	11,463	2,180,714.40	**190,239.41**	Note 1
60.52	11,138	2,180,714.40	**195,798.06**	Note 2

Notes:

1. Year 2000 McHale & Associates Test Report for ECGS Unit 4
2. Year 2014 Imperial Irrigation District Heat Rate Test Data
3. ICAPCD PTO 1156A-2 Condition B.5, Issued 06/13/2012

Actual Net Annual Generation Data

Year	Net Actual Generation (MWh)	Comments
2014	**105,850**	
2013	**90,976**	
2012	**161,186**	
2011	**173,386**	Prior to Revised PTO 1156A-2
2010	**201,356**	
2009	**138,938**	
2008	**201,766**	
2007	**119,377**	
2006	**57,719**	

150 SOUTH NINTH STREET
EL CENTRO, CA 92243-2850

IMPERIAL COUNTY CALIFORNIA

AIR POLLUTION CONTROL DISTRICT

TELEPHONE: (760) 482-4606
FAX: (760) 353-9904

June 13, 2012

Imperial Irrigation District
333 E. Barioni Blvd.
Imperial, CA 92251

Dear Mr. Henryk A. Olstowski:

Enclosed please find Conditions for Authority to Construct **#1156A-2** for replacing ECGS Unit 4 Cooling Tower located at 485 E. Villa Road. El Centro, Ca.

Please sign and date Authority to Construct and <u>return our copy to our office.</u>

It is the responsibility of the permit holder to contact the APCD within thirty (30) days of the commencement of operation to setup a time and date for an inspection of the unit(s). A Permit to operate **<u>will not</u>** be issued until the permitted equipment has been observed under operation, and determined to comply with all applicable Rules, Regulations and Permit Conditions.

If you have any questions regarding this permit, please do not hesitate to call **Thomas Brinkerhoff at 760-482-4606.**

Sincerely,

Norma A. Amavizca

Norma A. Amavizca
Office Technician

Enclosures:

7. The APCO or his authorized representatives, upon the presentation of credentials, shall be permitted to enter upon the premises:
   a. To inspect the stationary source, including equipment, work practices, operations, and emissions-related activity; and
   b. To inspect and duplicate records required by this Operating Permit; and
   c. To sample substances or monitor emissions from the source or other parameters to assure compliance with the Permit or applicable requirements. Monitoring of emissions can include source testing.

B. Stack Emissions Limits and Standards

1. Unit 4 Stack emissions shall be limited to the following standards in the following table:

Pollutant	Natural Gas	No.6 Fuel Oil (Secondary Fuel)
Nitrogen Oxides	140 lbs/hr	140 lbs/hr
Sulfur Dioxide	200 lbs/hr	200 lbs/hr

2. The Permittee shall not release or discharge combustion contaminants into the atmosphere from any single emissions unit in excess of 0.01 grains per dry cubic foot of gas at standard conditions @3%O_2. This emissions limit does not apply during periods of startup or shutdown and during changes in load when bringing the combustion process up to operating levels. Each start-up or shutdown period shall not exceed eight (8.0) hours.

3. The Permittee shall not release or discharge into the atmosphere from any single source of emission, any air contaminant as dark or darker as designated as No. 1 on the Ringlemann Chart (20% opacity) for a period or periods aggregating more than three (3) minutes in any hour.

4. The Permittee shall not burn any gaseous fuel containing sulfur compounds in excess of 50 grains per 100 cubic feet of gaseous fuel, calculated as hydrogen sulfide at standard conditions, or any liquid fuel having a sulfur content in excess of 0.5 percent by weight.

5. Unit 4 shall not exceed the total annual fuel usage rate of 2,180,714.4 MMBtu per year.

calculations based on sulfur content of fuel(s). The stack concentrations and emissions rates shall be measured, corrected to and calculated for the following:

a. Nitrogen Oxides: ppm at 3% O_2, dry and lb/hr.
b. PM-10: gr/scf at 3% O_2
c. SO_2: By calculations, lbs/hr, ppm.
d. Natural gas and fuel oil consumption.
e. Electricity generated during the test.

5. The Permittee shall submit all approved source test protocols at least thirty (30) days before commencing stack testing.

6. The APCD may at any reasonable time take samples of fuels and stack emissions for independent testing. The cost of such testing shall be borne by the Permittee

7. The permittee shall provide, properly install, and maintain in good working order a continuous emissions monitoring system for oxides of nitrogen (NOx) and oxygen (O_2).

8. The APCD shall inspect, as it determines to be necessary, the monitoring devices to ensure that such devices are functioning properly.

9. The continuous emission monitoring system shall be installed, calibrated, maintained, and operated according to the following sections:

   a. The continuous emissions monitoring system shall meet the standards of 40 CFR Part 60.45.
   b. Calibration gas mixtures shall meet the specifications in 40 CFR Part 51, Appendix P, Section 3.3 and Part 60, Appendix B, Performance Specification 2, Section 2.1.
   c. Cycling times shall be those specified in 40 CFR Part 60, Appendix P, Sections 3.4, 3.4.1, and 3.4.2.
   d. The continuous NOx monitoring system shall meet the applicable performance specification requirements in 40 CFR Part 51, Appendix P, and 40 CFR Part 60, Appendix B.
   e. The continuous O_2 monitoring system shall meet the performance specification requirements in 40 CFR Part 51, Appendix P and 40 CFR Part 60, Appendix B.

E. Reporting Requirements

1. The Permittee shall submit a written quarterly report, or at any time upon APCD request, for the performance of Unit 4. The report shall include Unit 4 emissions recorded by the CEMs, sulfur content of liquid fuel, sulfur content of gaseous fuel, and fuel consumption rates, and any other information relating to air emissions.

Equipment List

1. Equipment Specifications:

   A. Unit 4 – Wall Fired Boiler, Riley Stoker Boiler with Six Peabody Burners. The unit has a net power output of 74 MW and a total combustion heat input of 829.8 MMBtu/hr.

   B. Continuous Emissions Monitors: NO_X, SO_2, and O_2 (SO_2 is a calculated value).

   C. Cooling System: Marley Induced Draft Counterflow Cooling Tower, with Drift Eliminator Control of 0.0005% and a 41,000 gallon per minute design circulating water flow rate.

IMPERIAL COUNTY

AIR POLLUTION CONTROL DISTRICT
2012 APCD PERMIT

Facility name and mailing address:

IMPERIAL IRRIGATION DISTRICT
333 E. BARIOINI BLVD.
IMPERIAL, CA 92251

Permit Number:	**1156 ATC**
PAID	**Active**
Fee for the Year	$172.00
Permit Type	POWER GENERATION
Location Address	485 E. VILLA UNIT 4 EL CENTRO, CA 92243
Resp. Agent	HENRYK OLSTOWSKI
Phone	760-339-0517
Issued:	**6/13/2012**
Expires:	**12/31/2012**

TB

CERTIFICATION BY AUTHORIZED AGENT

The permit presented here is correct. The authorizations, certifications, and information from the application and permit being renewed, remain valid and will be kept with this ANNUAL PERMIT RENEWAL.

DATE ______________________ SIGNATURE ______________________________

CERTIFICATION BY APC DIVISION MANAGER

The PERMIT RENEWAL become valid when signed by authorized agent.

This permit, or an approved facsimile, shall be mounted so as to be clearly visible in an accessible place within 25 feet of the article, machine, equipment, or other contrivance, or maintained readily available at all times on the operating premises. (Rule 201D)

KEEP THIS COPY FOR POSTING

compliance problems at ECGS. Therefore, Condition A.6 will remain as it is presented in draft ATC 1156A-2 and past ATCs. Also, please note that permit conditions in IID's local air district permits can be more stringent than conditions found in IID's Title V Permits.

Comment 6: *"Remove 80 MW and replace with 74 MW."* (Pg. 10, under Equipment List 1.A.)

Response: This correction to the power output of Unit 4 will be reflected in the final ATC.

If you have any questions or would like to discuss this matter in further detail, please feel free to contact the undersigned at your convenience by calling (760) 482-4606.

Sincerely,

Thomas Brinkerhoff
Air Pollution Control Engineer

ii. Algonquin Power Sanger LLC Units CTG and SGT2 (EIA # 57564). Staff reviewed the ARB, eGrid and CEC data and the Title V permit and determined that each unit has historically operated less than 219,000MWs per year. This exemption was confirmed by Algonquin Power Sanger. Therefore, each unit has been deleted from the list of affected units. The letter from Algonquin Power Sanger follows:

Gallenstein, Christopher@ARB

From:	Leslie Greener <Leslie.Greener@libertyutilities.com>
Sent:	Thursday, October 29, 2015 9:21 AM
To:	Gallenstein, Christopher@ARB
Cc:	David Holmes; Bernie Reed
Subject:	RE: CPP Applicability Response from Algonquin Power Sanger LLC

Good Morning Chris,

To clarify, our facility is a cogeneration facility that supplies steam, heat and electricity to our on-site hydro mulch facility. Also, the net-electric sales to PG&E historically for our site have never exceed 219,000 MWh.

Please let me know if you have any additional questions,

Thanks,

Leslie

Leslie Greener, B.Sc. | Liberty-Algonquin Business Services | Senior Project Manager - EHS
P: 905-465-6736| M: 647-204-1855

From: Leslie Greener
Sent: Wednesday, October 28, 2015 2:26 PM
To: cgallens@arb.ca.gov
Cc: Bernie Reed; David Holmes
Subject: CPP Applicability Response from Algonquin Power Sanger LLC

Good Afternoon Chris,

Please find attached our response in regards to the ARB's request for applicability determination of the CPP regulations to our facility.

If you have any questions, please give me a call,

Thanks,

Leslie

Leslie Greener, B.Sc. | Liberty-Algonquin Business Services | Senior Project Manager - EHS
P: 905-465-6736| M: 647-204-1855
E: leslie.greener@libertyutilities.com
354 Davis Road, Suite 100, Oakville, ON L6J 2X1

Liberty Algonquin
Business Services

TAKE TWO Minutes to ensure you have everything you need to do your job safely...

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iii. Foster Wheeler Martinez Units TG1, TG2 and TG3 (EIA #10342). Staff reviewed the ARB and CEC data determined that these units have historically operated less than 219,000MWs per year. This exemption was confirmed by Foster Wheeler. Therefore, these units have been deleted from the list of affected units. The letter from Imperial Irrigation District and a copy of the Title V permit follow:

Gallenstein, Christopher@ARB

From:	Natalie.Braden@shell.com
Sent:	Thursday, October 22, 2015 3:39 PM
To:	Gallenstein, Christopher@ARB
Cc:	Lynley.Harris@shell.com; Erin.McDonald@shell.com; kevin.n.vance@shell.com
Subject:	Applicability of the Clean Power Plan (CPP) to the Shell Martinez Refinery

Dear Christopher:

This is the Shell Martinez Refinery's response to the letter from Edie Chang to Ryan Sanford dated September 16, 2015. Note that Mr. Sanford is no longer in that role so please address future correspondence to Lynley Harris (lynley.harris@shell.com). The table below shows the electric generating units (EGUs) that ARB potentially identified as affected units. All 3 of these units are integral parts of a combined heat and power unit (CHP unit). In a phone conversation with Lynley Harris, you agreed that it was acceptable to designate the Shell Martinez Refinery Cogen Plant as the potentially affected EGU instead of each component. The Cogen Plant consists of 2 natural gas fired gas turbine generators (GTG1/GTG2), 2 associated heat recovery steam generators (HRSG1/HRSG2) with supplemental firing, and 1 unfired steam turbine generator (STG1).

Table 1: Applicability Determination

Affected EGUs per ARB		Shell response	
EGU	Type	Concur	Reason
GTG1	40 MW combined-cycle combustion turbine	no	Part of an exempt CHP Unit
GTG2	40 MW combined-cycle combustion turbine	no	Part of an exempt CHP Unit
STG1	20 MW combined – cycle steam turbine	no	Part of an exempt CHP Unit. It is also not a fired unit

The Shell Martinez Refinery Cogen Plant is exempt because it meets the criteria in 40 CFR §60.5850(a)(5)

It is a combined heat and power unit with historical annual net-electric sales to a utility distribution system of less than 219,000 MWh. Table 2 shows the annual net electric sales to a utility distribution system from when the Cogen Plant came online through 2014. All years are less than 219,000 MWh.

Table 2: annual net electric sales to a utility distribution system from Cogen

Year	Net electric sales (MWh)
2014	18,724

2013	31,749
2012	44,469
2011	34,392
2010	32,234
2009	38,612
2008	8,606
2007	30,931
2006	15,938
2005	21,835
2004	13,478
2003	23,435
2002	36,777
2001	21,090
2000	12,338
1999	1,611
1998	18,551
1997	12,026
1996	64,210

Based on my inquiry of the person or persons who prepared this document and to the best of my knowledge and belief, the information provided in this letter is true and accurate. I am authorized to make this attestation.

Please contact me if you have additional questions.

Natalie

Natalie Braden
Environmental Affairs Manager - Shell Martinez Refinery
Shell Martinez Refinery, 3485 Pacheco Blvd, Martinez CA 94553
Tel: +1 925-313-3705 **Email:** natalie.braden@shell.com

2) ARB excluded three units because the units had been shut down prior to 2012.

    i. CES Placerita Power Plant (Units 2 and 3) (EIA # 10677). Based on information received from the California Energy Commission, CES Placerita was shut down in 2010. Based on this information, CES Placerita Units 2 and 3 are not affected units. The data from CEC follows:

Declaration

Person submitting the Report:

Joseph E Johnson
Team Leader
AES Placerita, Inc.
20885 Placerita Canyon Road
Newhall, CA 91321
(661)254-8970 x 61721
(661)254-6143 Fax
joe.johnson@aes.com

Company responsible for submitting the Report:

AES Placerita, Inc.
20885 Placerita Canyon Road
Newhall, CA 91321
(661)254-8970 x 61721
(661)254-6143 Fax

Reporting Period: 2010, Quarters 1-4

I certify under the penalty of perjury of the laws of the State of California that I am authorized by
AES Placerita, Inc.
to submit the enclosed report. This report fulfills the requirement for CCR, Title 20, Division 2, Section 1304. The matters contained in this report are, to the best of my knowledge and belief and based on diligent investigation, true, accurate, complete and in compliance with these regulations.

Joseph E Johnson, Team Leader

February 25, 2011
Date

Signed declaration to be submitted to: California Energy Commission
1. via email to QFERGEN@energy.state.ca.us as a PDF attachment or;
2. via fascimile to (916) 654-4559 or;
3. via US postal mail to 1516 Ninth Street, MS-20, Sacramento CA 95814

CEC-1304 Schedule 1 Part A — Power Plant Identification

Reporting Period — Year: 2010 — Quarter: 1 thru 4

Line No.		
1	**Plant Name**	AES Placerita, Inc.
2	**CEC Plant ID**	G0006
3	**EIA Plant ID**	10677
4	**Qualifying Facility ID (if applicable)**	
5	**Plant Location**	
a	Street Address	20885 Placerita Canyon Road
b	City	Newhall
c	County	Los Angeles
d	State	California
e	Zip Code	91321
f	Latitude (optional)	
g	Longitude (optional)	
h	Operating Mode (specify) (1)	
j	Interconnection Agreement Type (2)	
6	**Plant Owner**	
a	Full Legal Name	The AES Corporation
b	PO Box	
c	Street Address	4300 Wilson Boulevard
d	City	Arlington
e	State	Virginia
f	Zip Code	22203
7	**Plant Operator**	(Leave blanks if same as owner)
a	Full Legal Name	
b	PO Box	
c	Street Address	
d	City	
e	State	
f	Zip Code	
8	**Nameplate Capacity (MW)**	120.00
9	**Number of Generators**	3
10	**NAICS Code of Thermal Host if Cogeneration**	4910
11	**NAICS Code of Direct Onsite User of Electricity**	n/a
12	**Date of Sale (during Reporting Period)**	n/a
13	**Purchaser of Plant (during Reporting Period)**	n/a
a	Full Legal Name	
b	PO Box	
c	Street Address	
d	City	
e	State	
f	Zip Code	
g	Contact Person	
h	Telephone Number	
Notes	(1) Operating Mode: For example, independent power producer, cogeneration, dispatched as part of a demand side management program, parallel operation with utility deliveries in order achieve premium power reliability, customer-dispatched to reduce delivered energy charges, peak shaving, emergency/backup/interruptible, load-following; control and stabilization; synchronous condenser; spinning reserve, etc. Please specify.	
	(2) Interconnection Agreement Type. For example, interconnection agreements required by interconnection standards adopted in California Public Utilities Commission D.00-12-037 and in modifications to that decision, net energy metering agreement.	

CEC-1304 Schedule 1 Part B

Generator Information

	Reporting Period	Year:	2010
		Quarter:	1 thru 4
Plant Name		CEC Plant ID:	G0006
		EIA Plant ID:	10677

Line No.		
1	**Generator (Unit) ID**	Unit 1
2	**Generator Nameplate Capacity (MW)**	50 mw
3	**Date of Initial Operation**	June 1, 1988
4	**Operating Status**	Non-Operational
5	**Date of Retirement (if retired during reporting period)**	n/a
6	**Prime Mover Type**	Gas Turbine (GT)
7	**Primary Fuel**	Natural Gas
	Primary Fuel Physical Units (MCF,bbl., ton or other)	mmbtu
8	**Secondary Fuel**	None
	Secondary Fuel Physical Units (MCF,bbl., ton or other)	
9	**Number of Wind Turbines**	n/a
10	**Part of Combined-cycle Unit?** (Yes/No)	Yes
Notes		

CEC-1304 Schedule 1 Part B

Generator Information

Reporting Period	Year:	2010
	Quarter:	1 thru 4
Plant Name	CEC Plant ID:	G0006
	EIA Plant ID:	10677

Line No.		
1	**Generator (Unit) ID**	Unit 2
2	**Generator Nameplate Capacity (MW)**	50 mw
3	**Date of Initial Operation**	June 1, 1988
4	**Operating Status**	Non-Operational
5	**Date of Retirement (if retired during reporting period)**	n/a
6	**Prime Mover Type**	Gas Turbine (GT)
7	**Primary Fuel**	Natural Gas
	Primary Fuel Physical Units (MCF,bbl., ton or other)	mmbtu
8	**Secondary Fuel**	None
	Secondary Fuel Physical Units (MCF,bbl., ton or other)	
9	**Number of Wind Turbines**	n/a
10	**Part of Combined-cycle Unit?** (Yes/No)	Yes

Notes

CEC-1304 Schedule 1 Part B

Generator Information

	Reporting Period	Year:	2010
		Quarter:	1 thru 4
Plant Name		CEC Plant ID:	G0006
		EIA Plant ID:	10677

Line No.		
1	**Generator (Unit) ID**	Unit 3
2	**Generator Nameplate Capacity (MW)**	20 mw
3	**Date of Initial Operation**	June 1, 1988
4	**Operating Status**	Non-Operational
5	**Date of Retirement (if retired during reporting period)**	n/a
6	**Prime Mover Type**	Steam Turbine (ST)
7	**Primary Fuel**	None
	Primary Fuel Physical Units (MCF,bbl., ton or other)	
8	**Secondary Fuel**	
	Secondary Fuel Physical Units (MCF,bbl., ton or other)	
9	**Number of Wind Turbines**	n/a
10	**Part of Combined-cycle Unit?** (Yes/No)	Yes

Notes

CEC-1304 Schedule 2 Part A

Generation and Fuel Use by Generator

Reporting Period Year: 2010

Quarter: 1 thru 4

One Schedule 2-A for each generator (unit) in plant.

CEC Plant ID: G0006

EIA Plant ID: 10677

Generator (Unit) ID: Entire Plant

Qualifing Facility ID:

			Primary Energy Source :				Secondary Energy Source:			
Month	Gross MWh	Net MWh	Fuel Use in MCF, bbl. or ton	Fuel Use in MMBtu	Fuel Supplied by Tolling Agreement (Percent) (1)	Fuel Cost (1)	Fuel Use in MCF, bbl. or ton	Fuel Use in MMBtu	Fuel Supplied by Tolling Agreement (Percent) (1)	Fuel Cost (1)
January	0	0	0	0	0	0	0	0	0	0
February	0	0	0	0	0	0	0	0	0	0
March	0	0	0	0	0	0	0	0	0	0
April	0	0	0	0	0	0	0	0	0	0
May	0	0	0	0	0	0	0	0	0	0
June	0	0	0	0	0	0	0	0	0	0
July	0	0	0	0	0	0	0	0	0	0
August	0	0	0	0	0	0	0	0	0	0
September	0	0	0	0	0	0	0	0	0	0
October	0	0	0	0	0	0	0	0	0	0
November	0	0	0	0	0	0	0	0	0	0
December	0	0	0	0	0	0	0	0	0	0
Annual Total (2)	0	0	0	0	0	0	0	0	0	0

Notes:

(1) Fuel Cost and Fuel Supplied by Tolling Agreement is required for plants of 50 MW or more. Fuel Cost is for any portion of fuel not supplied through a tolling agreement. Fuel Cost will be kept confidential.

(2) For plants with plant nameplate capacity of less than 10 MW, monthly data are not required.

(1 MMBtu = 10 therms)

CEC-1304 Schedule 2 Part A Addendum **Cogeneration and Fuel Use by Generator**

Reporting Period Year:	
Quarter:	

One Schedule 2-A(Cogen) for each cogenerator (unit) in plant.

CEC Plant ID:	
EIA Plant ID:	
Generator (Unit) ID:	

	Primary Energy Source Type Fuel Use in MCF, bbl. or ton			Primary Energy Source Type Fuel Use in MMBtu			Secondary Energy Source Type Fuel Use in MCF, bbl. or ton			Secondary Energy Source Type Fuel Use in MMBtu		
Month	Fuel Attributable to Electric Generation (1)	Fuel Attributable to Useful Thermal (1)	Total Fuel Used (2)	Fuel Attributable to Electric Generation (1)	Fuel Attributable to Useful Thermal (1)	Total Fuel Used (2)	Fuel Attributable to Electric Generation (1)	Fuel Attributable to Useful Thermal (1)	Total Fuel Used (2)	Fuel Attributable to Electric Generation (1)	Fuel Attributable to Useful Thermal (1)	Total Fuel Used (2)
January			0			0			0			0
February			0			0			0			0
March			0			0			0			0
April			0			0			0			0
May			0			0			0			0
June			0			0			0			0
July			0			0			0			0
August			0			0			0			0
September			0			0			0			0
October			0			0			0			0
November			0			0			0			0
December			0			0			0			0
Annual Total (3)	0	0	0	0	0	0	0	0	0	0	0	0
Notes												

(1) Due to the wide variety of useful thermal processes available to cogeneration plants assume 100% conversion of fuel to useful thermal. Accordingly, useful thermal energy is equal to fuel use.
(2) Total fuel is automatically copied from the previous page.
(3) For plants with plant nameplate capacity of less than 10 MW, monthly data is not required.

(1 MMBtu = 10 therms)

CEC-1304 Schedule 2 Part B **Sales by Power Plant**

One Schedule 2-B for each power plant.

Reporting Period **Year:** 2010
Quarter: 1 thru 4

CEC Plant ID: G0006
EIA Plant ID: 10677

Month	Onsite Use (self-gen) MWh	Sales for Resale MWh	Sales to End-User 1 MWh	End User 1 NAICS Code	Sales to End-User 2 MWh	End User 2 NAICS Code
January	0	0	0	0	0	0
February	0	0	0	0	0	0
March	0	0	0	0	0	0
April	0	0	0	0	0	0
May	0	0	0	0	0	0
June	0	0	0	0	0	0
July	0	0	0	0	0	0
August	0	0	0	0	0	0
September	0	0	0	0	0	0
October	0	0	0	0	0	0
November	0	0	0	0	0	0
December	0	0	0	0	0	0
Annual Total (1)	0	0	0	0	0	0

Note: Net plant output = onsite use + sales for resale + sales to end-users.

(1) For plants with plant nameplate capacity of less than 10 MW, monthly data are not required.

CEC-1304 Schedule 3 Part A	Suggested Form	Year	2010
Environmental Information Related to Water Supply and Wastewater Discharge Annual Report		CEC Plant ID	G0006
(For power plants 20 MW or larger, prepare a form CEC-1304 Schedule 3-A for each generator unit.)		EIA Plant ID	10667
		Generator (Unit) ID	1 thru 3

1. Water Supply

1a	Cooling Technology	IAC-E,SC-WCT	1f	Backup Water Supply Source	None
1b	If "other" cooling technology, please describe				
1c	Primary Water Supply Source	P	1g	Name of Backup Water Purveyor, Wastewater Supplier, or Well ID(s)	
1d	Name of Primary Water Purveyor, Wastewater Supplier, or Well ID(s)	Newhall County Water District			
1e	Primary Water Supply Average Total Dissolved Solids (mg/L)	?	1h	Backup Water Supply Average Total Dissolved Solids (mg/L)	?
	☐ *Check this box if water use is not metered and cannot be reasonably estimated.*		1i	Regional Water Quality Control Board	3

Volume of Water Required (gallons)	1j. ☐ Inlet-Air Cooling	1k. ☐ Intercooling	1l. ☐ Steam-Cycle Cooling	1m. ☐ Other Cooling	1n. ☐ Sanitation	1o. ☐ Landscaping	1p. ☐ Other Water Use	1q. ☐ Daily Maximum
January	0	0	0	0	**30088**	124000	0	7200
Febraury	0	0	0	0	**30980**	70000	0	7200
March	0	0	0	0	**32500**	80260	0	7200
April	0	0	0	0	**30158**	100000	0	7200
May	0	0	0	0	**32280**	50000	0	7200
June	0	0	0	0	**31964**	75000	0	7200
July	0	0	0	0	**36000**	83680	0	7200
August	0	0	0	0	**40000**	75192	0	7200
September	0	0	0	0	**37988**	60000	0	7200
October	0	0	0	0	**30000**	93972	0	7200
November	0	0	0	0	**31000**	121592	0	7200
December	0	0	0	0	**33304**	40000	0	7200

1r	Metering Frequency		1s	Metering Technology	

2. Wastewater Disposal

	☐ *Check box if waste water discharge is not measured or can not be reasonably estimated.*	
2a	Wastewater Disposal Method	T-O
2b	Average Total Dissolved Solids (mg/L)	?
2c	Equipment Manufacturer	None
2d	Year of Installation	
2e	Waste Reduction Equipment or Measures Taken	None
2f	Name of the Facility or Water Body Receiving the Wastewater	

Notes:

Volume of Waste Water Discharge (tons or gallons)	2g. Daily Maximum	2h. Monthly Total
January	0	0
Febraury	0	0
March	0	0
April	0	0
May	0	0
June	0	0
July	0	0
August	0	0
September	0	0
October	0	0
November	0	0
December	0	0

CEC-1304 Schedule 3 Part B
Environmental Information Related to Biological Resources

Reporting Period

Year	2010
CEC Plant ID	G0006
EIA Plant ID	10677

One Schedule 3B for each power plant.

Check here if there have been no "takes" or biomass killed by impingement ☐

Owners of power plants with a generating capacity of 1-MW or more shall submit copies of reports or filings required by regulations, permits, or contract conditions that identify any of the following information for the previous calendar year:

1. Documentation of the "take" of terrestrial, avian and aquatic wildlife subject to legal protection under California Fish & Game Code § 2050 et seq., 16 U.S.C.A. § 1371 et seq., 16 U.S.C.A. § 1531 et seq., and 16 U.S.C. A. § 668 et seq. that occurred as a result of operation of the power plant.

2. Documentation and identification of the biomass (by weight) and species composition of fishes and marine mammals killed by impingement on the intake screens of each once-through cooling system.

Notes:

W:\111D Power Plant info\email responses affected units\CES Placerita.xls 3B

CEC-1304 Schedule 3 Part C

Environmental Information Related to Biological Resources

Reporting Period

Year	2010
CEC Plant ID	G0006
EIA Plant ID	10667

One Schedule 3C for each power plant.

Check here if there have been no public health or environmental quality violations. ☐

Owners of power plants with a generating capacity of 1-MW or more shall submit copies of any written notification provided by any state or federal regulatory agency for the following:

1. Any violation of an applicable statute, regulation, or permit condition related to public health or environmental quality created by operation of the power plant during the previous calendar year, or for which there is an ongoing investigation regarding a potential violation at the time that the data identified in this subdivision is required to be filed with the Commission.

Notes:

W:\111D Power Plant info\email responses affected units\CES Placerita.xls 3C

ii. Hanford Unit Gen1 (EIA # 10373). Based on information from CEC, this unit was shut down in 2011. Therefore, this unit is not considered an affected unit. Information from CEC follows:

CEC-1304 Schedule 1 Part A		Power Plant Identification
		Reporting Period Year: 2011 Quarter: 4
Line No.		
1	**Plant Name**	Hanford
2	**CEC Plant ID**	C0007
3	**EIA Plant ID**	10373
4	**Qualifying Facility ID (if applicable)**	QF86-138-007
5	**Plant Location**	
a	Street Address	10596 Idaho Avenue
b	City	Hanford
c	County	Kings
d	State	CA
e	Zip Code	93230
f	Latitude (optional)	
g	Longitude (optional)	
h	Operating Mode (specify) (1)	
i	Interconnection Agreement Type (2)	Independent Power Producer
6	**Plant Owner**	Generator Interconnection Agreement
a	Full Legal Name	Hanford L.P.
b	PO Box	
c	Street Address	4300 Railroad Avenue
d	City	Pittsburg
e	State	CA
f	Zip Code	94565
7	**Plant Operator**	
a	Full Legal Name	
b	PO Box	
c	Street Address	
d	City	
e	State	
f	Zip Code	
8	**Nameplate Capacity (MW)**	24.00
9	**Number of Generators**	1
10	**NAICS Code of Thermal Host if Cogeneration**	
11	**NAICS Code of Direct Onsite User of Electricity**	221112 Electric Power Generation, Fossil Fuel
12	**Date of Sale (during Reporting Period)**	n/a
13	**Purchaser of Plant (during Reporting Period)**	n/a
a	Full Legal Name	n/a
b	PO Box	n/a
c	Street Address	n/a
d	City	n/a
e	State	
f	Zip Code	
g	Contact Person	
h	Telephone Number	
Notes	(1) Operating Mode: For example, independent power producer, cogeneration, dispatched as part of a demand side management program, parallel operation with utility deliveries in order achieve premium power reliability, customer-dispatched to reduce delivered energy charges, peak shaving, emergency/backup/interruptible, load-following; control and stabilization; synchronous condenser; spinning reserve, etc. Please specify.	
	(2) Interconnection Agreement Type. For example, interconnection agreements required by interconnection standards adopted in California Public Utilities Commission D.00-12-037 and in modifications to that decision, net energy metering agreement.	

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CEC-1304 Schedule 1 Part B

Generator Information

Reporting Period Year:	2011
Quarter:	4
CEC Plant ID:	C0007
EIA Plant ID:	10373

Plant Name
Hanford

Line No.		
1	Generator (Unit) ID	GEN1
2	Generator Nameplate Capacity (MW)	24.00
3	Date of Initial Operation	September 1, 1990
4	Operating Status	Retired
5	Date of Retirement (if retired during reporting period)	October 18, 2011
6	Prime Mover Type	Steam Turbine
7	Primary Fuel	PC
	Primary Fuel Physical Units (MCF,bbl., ton or other)	TON
8	Secondary Fuel	DFO
	Secondary Fuel Physical Units (MCF,bbl., ton or other)	BARREL
9	Number of Wind Turbines	NONE
10	Part of Combined-cycle Unit? (Yes/No)	NO

Notes

O:\Regulatory\CEC REPORTS\2011\4th Quarter\CEC Form 1304, Site 8, 4th qtr 2011 1-B

CEC-1304 Schedule 2 Part A

Generation and Fuel Use by Generator

Reporting Period	Year:	2011
	Quarter:	4

One Schedule 2-A for each generator (unit) in plant.

Hanford

CEC Plant ID:	C0007
EIA Plant ID:	10373
Generator (Unit) ID:	GEN 1
Qualifing Facility ID:	QF86-138-007

			Primary Energy Source : PC				Secondary Energy Source: DFO				Secondary Energy Source: NG			
Month	Gross MWh	Net MWh	Fuel Use in MCF, bbl. or ton	Fuel Use in MMBtu	Fuel Supplied by Tolling Agreement (Percent) (1)	Fuel Cost (1)	Fuel Use in MCF, bbl. or ton	Fuel Use in MMBtu	Fuel Supplied by Tolling Agreement (Percent) (1)	Fuel Cost (1)	Fuel Use in MCF, bbl. or ton	Fuel Use in MMBtu	Fuel Supplied by Tolling Agreement (Percent) (1)	Fuel Cost (1)
January	7,949	6,741	3,446	92,236			0	0			1,669	1,717		
February	15,874	12,915	6,440	173,674			0	0			0	0		
March	15,916	13,293	6,624	175,046			0	0			0	0		
April	10,219	8,484	4,722	124,019			0	0			27.46	29.00		
May	8,803	7,350	3,620	94,873			0	0			14.44	15.00		
June	12,494	10,563	5,263	143,733			0	0			22.73	24.00		
July	18,066	15,435	7,038	192,363			0	0			0	0		
August	12,751	10,794	5,175	140,698			0	0			0	0		
September	0	0	0	0			0	0			0	0		
October	0	0	0	0			0	0			0	0		
November	0	0	0	0			0	0			0	0		
December	0	0	0	0			0	0			0	0		
Annual Total (2)	102,072	85,575	42,328	1,136,642	0	0	0	0			1,733	1,785		

Notes:

(1) Fuel Cost and Fuel Supplied by Tolling Agreement is required for plants of 50 MW or more. Fuel Cost is for any portion of fuel not supplied through a tolling agreement. Fuel Cost will be kept confidential.

(2) For plants with plant nameplate capacity of less than 10 MW, monthly data are not required. **(1 MMBtu = 10 therms)**

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CEC-1304 Schedule 2 Part B — Sales by Power Plant

One Schedule 2-B for each power plant.

Reporting Period — Year: 2011 — Quarter: 4

Hanford

CEC Plant ID: C0007
EIA Plant ID: 10373
GEN 1
QF86-138-007

Month	Onsite Use (self-gen) MWh	Sales for Resale MWh	Sales to End-User 1 MWh	End User 1 NAICS Code	Sales to End-User 2 MWh	
January	1,208	6,741				
February	2,959	12,915				
March	2,623	13,293				
April	1,735	8,484				
May	1,453	7,350				
June	1,931	10,563				
July	2,631	15,435				
August	1,957	10,794				
September	0	0				
October	0	0				
November	0	0				
December	0	0				
Annual Total (1)	16,497	85,575				

Note: Net plant output = onsite use + sales for resale + sales to end-users.

(1) For plants with plant nameplate capacity of less than 10 MW, monthly data are not required.
Net plant output = gross megawatts

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iii. The Port of Stockton (EIA # 54238) was listed as an affected unit by U.S. EPA as a coal-fired facility. This facility (as a coal plant) shut down in January of 2011. In 2014 this facility received an Authority to Construct (N-645-36-1) to convert from a coal plant to a biomass plant. The facility has federally enforceable permit conditions that allows only for burning of biomass and a limit of natural gas usage to less than 10 percent. Based on this information, Port of Stockton is not an affected unit. The letter and Authority to Construct follows:

DTE Stockton, LLC

2526 West Washington Street
Stockton, Calif. 95203
(209) 320-3717 Fax (209) 320-3735

September 30, 2015

Christopher Gallenstein
Staff Air Pollution Specialist
Air Resources Board
1001 I Street
PO Box 2815
Sacramento, CA 95812

In response to the ARB's letter dated September 16, 2015, I do not concur that the Electric Generating Unit operated at the Port of Stockton Energy Facility, Unit STG: 49.9 MW (Steam Turbine) is covered by the Clean Power Plan.

The EGU is subject to a federally enforceable permit limiting fossil fuel use to 10 percent or less of the annual capacity factor and is excluded from being an affected EGU pursuant to section 60.5850 (a)(3). Attached is a copy of the permit, with condition 18 limiting the total annual heat input to the unit from natural gas combustion to 612,324 MMBtu (10 percent of the annual capacity factor) in any one calendar year.

I declare that based on the information and belief formed after reasonable inquiry, the statements and information provided in the document are true, accurate, and complete.

Sincerely,

D Heath Hildebrand
Plant Manager
DTE Stockton, LLC

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

AUTHORITY TO CONSTRUCT

PERMIT NO: N-645-36-1 **ISSUANCE DATE:** 05/19/2014

LEGAL OWNER OR OPERATOR: DTE STOCKTON, LLC
MAILING ADDRESS: 2526 W. WASHINGTON STREET
STOCKTON, CA 95203

LOCATION: 2526 W. WASHINGTON STREET
STOCKTON, CA 95203

EQUIPMENT DESCRIPTION:
MODIFICATION OF 54 MW (GROSS) ELECTRICAL GENERATING STATION WITH A 699 MMBTU/HR STOKER BOILER EQUIPPED WITH A 100 MMBTU/HR NATURAL GAS-FIRED STARTUP BURNER, MULTICLONE AND ELECTROSTATIC PRECIPITATOR, TRONA INJECTION AND WET SCRUBBER, OXIDATION CATALYST, AND SELECTIVE CATALYTIC REDUCTION: TO REVISE THE EQUIPMENT DESCRIPTION TO READ "DRY SORBENT INJECTION" RATHER THAN "TRONA INJECTION" AND TO ALLOW THE USE OF THE CO2 MONITOR IN LIEU OF THE O2 MONITOR FOR CEMS MEASUREMENTS. POST-PROJECT EQUIPMENT DESCRIPTION: 54 MW (GROSS) ELECTRICAL GENERATING STATION WITH A 699 MMBTU/HR STOKER BOILER EQUIPPED WITH A 100 MMBTU/HR NATURAL GAS-FIRED STARTUP BURNER, MULTICLONE AND ELECTROSTATIC PRECIPITATOR, DRY SORBENT INJECTION AND WET SCRUBBER, OXIDATION CATALYST, AND SELECTIVE CATALYTIC REDUCTION

CONDITIONS

1. The facility shall submit an application to modify the Title V permit in accordance with the timeframes and procedures of District Rule 2520. [District Rule 2520] Federally Enforceable Through Title V Permit
2. Authority to Construct N-645-36-2 shall be implemented concurrently with, or prior to, this Authority to Construct permit. [District Rule 2201]
3. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101 and 40 CFR 60.43b(f) and (g)]
4. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
5. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (209) 557-6400 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Seyed Sadredin, Executive Director / APCO

Arnaud Marjollet, Director of Permit Services
N-645-36-1 : May 19 2014 6:56AM – PEIRCEN : Joint Inspection NOT Required

20. Wood residue consists of wood pieces or particles which are generated from the manufacturing or production of wood products, harvesting, processing or storage of raw wood materials, or construction and demolition activities. [District Rules 2201 and 4102]

21. Biomass and wood waste fuels shall not include pressure-treated wood and shall not contain compounds listed in Title 22, California Code of Regulations, 66261.24(a)(2)(A) in excess of the following concentrations by weight: 500 ppm antimony and/or antimony compounds, 500 ppm arsenic and/or arsenic compounds, 1,000 ppm asbestos, 10,000 ppm barium and/or barium compounds (excluding barite), 75 ppm beryllium and/or beryllium compounds, 100 ppm cadmium and/or cadmium compounds, 500 ppm chromium (VI) compounds, 2,500 ppm chromium and/or chromium (III) compounds, 8,000 ppm cobalt and/or cobalt compounds, 2,500 ppm copper and/or copper compounds, 18,000 ppm fluoride salts, 1,000 ppm lead and/or lead compounds, 20 ppm mercury and/or mercury compounds, 3,500 ppm molybdenum and/or molybdenum compounds, 2,000 ppm nickel and/or nickel compounds, 100 ppm selenium and/or selenium compounds, 500 ppm silver and/or silver compounds, 700 ppm thallium and/or thallium compounds, 2,400 ppm vanadium and/or vanadium compounds, and 5,000 ppm zinc and/or zinc compounds. [District Rule 4102]

22. The permittee shall be allowed a 24-month period to evaluate the operational variability and optimum control effectiveness of the proposed exhaust emission control system to meet the design emission rate of 0.040 lb-NOx/MMBtu. During the evaluation period, the permittee shall operate and maintain the boiler and the emission control system in such a manner as to minimize NOx emissions, and shall perform all required source testing and monitoring. The evaluation period shall begin upon the first day of the initial source test, and shall terminate after 24 months. [District Rule 2201]

23. During the 24-month evaluation period, NOx emissions in excess of 0.040 lb/MMBtu, but less than or equal to 0.065 lb/MMBtu, on a block 24-hour average basis shall not constitute a violation of this permit. [District Rule 2201]

24. During the 24-month evaluation period, the permittee shall submit annual status reports on the performance of the NOx emission control system. Each status report is due at the same time as the annual source test report. The status report shall, at a minimum, include actual operating time, calculated heat input to the boiler, actual NOx emissions as measured by the CEM system, daily and annual average actual NOx emission rates (in lb/MMBtu), and an analysis of system performance to date and expected performance for the next year. [District Rule 2201]

25. If NOx emissions continue to exceed, or are projected to exceed, 0.040 lbs/MMBtu on a block 24-hour average basis after the 24-month evaluation period, the permittee shall submit a final report containing all monitoring and source test data to the District within 90 days after the end of the evaluation period. The report shall include a detailed analysis of all factors that prevent achievement of the expected emission rate, as well as a detailed explanation of the steps taken to operate and maintain the boiler and the emission control system in such a manner as to minimize emissions. The report shall also propose an enforceable NOx emission limit, which shall not exceed 0.065 lb/MMBtu on a block 24-hour average basis. [District Rule 2201]

26. Upon submittal of the report, the District shall re-evaluate BACT requirements for NOx from this class and category of source and establish an appropriate BACT emissions limit. Within 30 days of receipt of the District's determination, the permittee shall submit an Authority to Construct application to incorporate the revised emissions limit. In no case shall the NOx emission limitation be higher than 0.065 lbs/MMBtu on a block 24-hour average basis. [District Rule 2201]

27. Following the 24-month evaluation period and prior to issuance of an Authority to Construct with a revised NOx emission limit, NOx emissions in excess of 0.040 lb/MMBtu, but less than or equal to 0.065 lb/MMBtu, on a block 24-hour average basis shall not constitute a violation of this permit. [District Rule 2201]

28. If NOx emissions do not exceed, and are not projected to exceed, the expected emission rate of 0.040 lb/MMBtu on a block 24-hour average basis after the 24-month evaluation period, then the expected emission rate of 0.040 lb/MMBtu on a block 24-hour average basis shall become an enforceable NOx emission limit. If the permittee fails to submit the required final report within 90 days after the end of the evaluation period, the permittee shall be considered to stipulate that an enforceable NOx emission limit of 0.040 lb/MMBtu on a block 24-hour average basis is achievable and will be made enforceable. [District Rule 2201]

29. Except during periods of startup and shutdown, emission rate from this biomass-fired boiler shall not exceed 0.065 lb-NOx/MMBtu. Initial and annual compliance with this limit shall be demonstrated by source testing. Ongoing compliance with this limit shall be determined from CEM data on a block 24-hour average basis as defined in District Rule 4352 (amended May 18, 2006). [District Rules 2201 and 4352]

CONDITIONS CONTINUE ON NEXT PAGE

47. This unit shall be tested for compliance with the NOx, CO, PM10, SOx, VOC, and NH3 emissions limits at least once every 12 months. The PM source test required by condition 61 may be conducted in lieu of PM10 testing required by this condition, provided all PM is assumed to be PM10 as specified in condition 70. [District Rules 1081, 2201, and 4352, and 40 CFR 60.8(a)]
48. This unit shall be tested for compliance with the PM emission limit at least once every 36 months. [40 CFR 60.8(a), 40 CFR 60.43b(d), and 40 CFR 63.11220(a)]
49. This unit shall be tested to determine the HCl emission factor at least once every 12 months. The permittee shall measure and record the effluent pH and liquid flow rate in the wet scrubber every 15 minutes during the source test. [District Rule 2201]
50. Permittee shall test fuel to determine the higher heating value at least once every 12 months. [District Rules 1081 and 2201, and 40 CFR 60.8(a)]
51. Permittee shall test fuel for contaminants at least once every 12 months, or whenever requested by the District. The District shall be notified at least 15 days prior to scheduled sample collection. [District Rules 2201 and 4102, and 40 CFR 60.8(a)]
52. Testing of the fuel for contaminants shall be conducted on a representative sample collected upstream of and as close as practicable to the fuel metering bins. [District Rules 2201 and 4102]
53. Fuel shall be tested for contaminants in accordance with the wet extraction test procedure detailed in Title 22 California Code of Regulations, Division 4.5, Chapter 11, Appendix II. [District Rules 2201 and 4102]
54. NOx emissions for source test purposes shall be determined using EPA Methods 7E and 19 or ARB Method 100 and EPA Method 19. [District Rules 1081 and 4352]
55. CO emissions for source test purposes shall be determined using EPA Method 10 or ARB Method 100. [District Rules 1081 and 4352]
56. PM10 emissions for source test purposes shall be determined using EPA Methods 201A, 202, and 19. [District Rules 1081 and 4352]
57. In lieu of performing a source test for PM10, the results of the total particulate test may be used for compliance with the PM10 emission limit provided the results include both the filterable and condensable (back half) particulates, and that all particulate matter is assumed to be PM10. If this option is exercised, source testing shall be conducted using CARB Method 5 or EPA Method 5 (including condensable (back half) particulates). [District Rule 1081]
58. PM emissions required to be source tested under condition 61 shall be determined using EPA Methods 5 or 17 (filterable (front half) PM only), and 19. [40 CFR 60.43b(d)(2) and 40 CFR 63.11212]
59. Stack gas oxygen shall be determined using EPA Method 3 or 3A or ARB Method 100. [District Rules 1081 and 4352]
60. SOx emissions for source test purposes shall be determined using EPA Method 6 or ARB Method 100. [District Rules 1081 and 4352]
61. VOC emissions for source test purposes shall be determined using EPA Method 18, 25A, or 25B, or ARB Method 100. [District Rules 1081 and 4352]
62. Source testing for ammonia slip shall be conducted utilizing BAAQMD Method ST-1B. [District Rules 1081 and 2201]
63. HCl emissions for source test purposes shall be determined using EPA Methods 26 or 26A, and 19. [District Rule 2201]
64. Testing for fuel higher heating value shall be conducted using ASTM Method D5865-01a or District-approved equivalent method. [District Rules 1081 and 4352, and 40 CFR 75 Appendix F]
65. The exhaust stack shall be equipped with a continuous emissions monitor (CEM) for NOx, CO, SOx, and either O2 or CO2. The CEM shall meet the requirements of 40 CFR parts 60 (for CO) and 75 (for NOx, SOx, and O2 or CO2), except as specified in 40 CFR 60, Subpart Db, and shall be capable of monitoring emissions during startups and shutdowns as well as during normal operating conditions. The CEM shall be used to demonstrate compliance with the Rule 2201 emission limits. [District Rules 1080 and 2201]

CONDITIONS CONTINUE ON NEXT PAGE

77. Permittee shall record the heat input to the unit from each fuel combusted on a daily basis. Permittee shall maintain records of the annual capacity factor for each fuel combusted on a 12-month rolling average basis, and shall update the annual capacity factor for each fuel at the end of each calendar month. [District Rules 1070 and 4001, and 40 CFR 60.49b(d)(1)]

78. Permittee shall retain and maintain on site all data from the continuous opacity monitoring system. [District Rules 1070 and 4001, and 40 CFR 60.39b(f)]

79. Permittee shall maintain records of solid fuel higher heating value and fuel contaminant testing results. [District Rules 1070 and 4352]

80. Permittee shall maintain records of emissions from this boiler on a calendar quarter basis. Records of quarterly emissions shall be updated at least once each calendar month in which the boiler operates. [District Rule 2201]

81. Permittee shall maintain records of HCl emissions from this boiler on a rolling 12-consecutive-month basis. Records of HCl emissions shall be updated at least once each calendar month in which the boiler operates. [District Rules 2201, 4002, and 4102]

82. All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rules 2201 and 4352]